Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

August 30, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Richard E. Ludwig, President
TECO Power Services
702 North Franklin Street
Tampa, FL 33602

Re: DEP File No. PSD-FL-140(A)
Hardee Power Station, Unit 2B
75 MW Simple Cycle Combustion Turbine Project

Dear Mr. Ludwig:

Enclosed is one copy of the Draft PSD Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the above referenced project to be located at the existing Hardee Power Station approximately 3.5 miles north of State Road 62 on County Road 663 in Fort Green Springs, Hardee County, Florida. The Department's Intent to Issue PSD Permit and the "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT" must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time 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 A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any questions, please call Mr. Jeff Koerner, P.E. at 850/414-7268.

Sincerely,

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

CHF/AAL/jfk

Enclosures

In the Matter of an Application for Permit by:

TECO Power Services
702 North Franklin Street
Tampa, FL 33602
Authorized Representative:
Richard E. Ludwig, President

Permit No. PSD-FL-140(A)
PPS No. PA89-25
Facility ID No. 0490015
Facility: Hardee Power Station
Project: Addition of Unit 2B

INTENT TO ISSUE PSD PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration of Air Quality (copy of Draft PSD Permit attached) for the proposed project, detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, TECO Power Services, proposes to add one General Electric Model No. PG7121 7EA dual-fuel simple cycle combustion turbine with electrical generator set having a nominal power production of 75 MW. The new unit will use the existing infrastructure including oil storage and support equipment. Dry low-NOx (DLN) combustion technology will be used to control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will be used to control nitrogen oxide emissions when firing low sulfur distillate oil as a backup fuel for up to 876 hours per year. Combustion design and clean fuels will be used to minimize emissions of carbon monoxide, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. TECO Power Services identifies the new combustion turbine as "Unit 2B".

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that a permit under the provisions for the Prevention of Significant Deterioration (PSD) of Air Quality is required for the proposed work.

The Department intends to issue this PSD permit based on the belief that reasonable assurances have been provided by the applicant 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. and 40 CFR 52.21.

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 PSD Permit." The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. 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. Where there is more than one newspaper of general circulation in the county, the newspaper used must be one with significant circulation in the area that may be affected by the permit. 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). The Department suggests that you publish the notice within thirty days of receipt of this letter. 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 or other authorization. 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) & (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 a public hearing (meeting) concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of "Public Notice of Intent to Issue PSD Permit." Written comments and requests for a public meeting 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.

This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with any certification hearing held pursuant to Section 403.507.

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 of the Florida Statutes. 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 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) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), 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 of the Florida Administrative Code.

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, as well as the rules and statutes which entitle the petitioner to relief; and (f) A demand for relief.

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

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. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

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

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

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that the Intent to Issue PSD Permit, the Public Notice, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the Draft Permit were sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 8-30-99 to the person(s) listed:

cc: Mr. Richard E. Ludwig, President, TECO*
Mr. Paul L. Carpinone, TECO
Mr. Thomas W. Davis, ECT
Mr. Buck Oven, DEP Power Plant Siting Office
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS
Mr. Bill Thomas, DEP SW District Office

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.

(Clerk) 8-30-99 (Date)

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "*Return Receipt Requested*" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Richard Ludwig, Pres.
TECO Power Serv.
702 N. Franklin St.
Tampa, Fl 33602

4a. Article Number
Z 333 618 133

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery SEP - 1 1999

5. Received By: *(Print Name)*

6. Signature: *(Addressee or Agent)*
X

8. Addressee's Address *(Only if requested and fee is paid)*

Thank you for using Return Receipt Service.

PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

Z 333 618 133

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Richard Ludwig	
Street & Number TECO Power	
Post Office, State, & ZIP Code Tampa Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 8-30-99 PSD-FI-140a PA 89-25	

PS Form **3800**, April 1995

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. PSD-FL-140(A)

PPS No. PA89-25

TECO Power Services

Hardee Power Station – Unit 2B

Hardee County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to TECO Power Services. The permit is to install one General Electric Model No. PG7121 7EA dual-fuel simple cycle combustion turbine with electrical generator set having a nominal power production of 75 MW. The new unit will use the existing infrastructure including oil storage and support equipment. Pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, a Best Available Control Technology (BACT) determination was required for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2). Dry low-NOx (DLN) combustion technology will be used to control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will be used to control nitrogen oxide emissions when firing low sulfur distillate oil as a backup fuel for up to 876 hours per year. Combustion design and clean fuels will be used to minimize emissions of carbon monoxide, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. The applicant's name and address are: Richard E. Ludwig, President and Authorized Representative; TECO Power Services; 702 North Franklin Street, Tampa, FL 33602.

Based on the permit application and Department's BACT determination, the maximum pollutant emissions from the combustion turbine (in tons per year) are summarized below.

Pollutant	Project Potential Emissions	PSD Significant Emissions Rate
CO (First 12 months)	237	100
CO (After First 12 Months)	188	100
NOx	199	40
PM_{10}	50	15
SO_2	44	40
VOC	10	40

An air quality impact analysis was conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class I and Class II significant impact levels.

The Department will accept written comments and requests for a public hearing (meeting) concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of "Public Notice of Intent to Issue PSD Permit." Written comments 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.

This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3).

NOTICE TO BE PUBLISHED

IN THE NEWSPAPER

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 of the Florida Statutes. 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 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) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), 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 of the Florida Administrative Code.

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, as well as the rules and statutes which entitle the petitioner to relief; and (f) A demand for relief.

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.

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 111 S. Magnolia Drive, Suite 4 Tallahassee, Florida 32301	Dept. of Environmental Protection South District Office 3804 Coconut Palm Drive Tampa, Florida 33619-8318	TECO Power Services 702 North Franklin Street Tampa, FL 33602
Telephone: 850/488-0114 Fax: 850/922-6979	Telephone: (813) 744-6100 Fax: (813) 744-6084	Telephone: 813/228-1311 Fax: 813/228-1360

The complete project file includes the Draft Permit, the application, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the New Resource Review Section 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

AND

PRELIMINARY DETERMINATION

TECO Power Services

Hardee Power Station

New Combustion Turbine Project – Unit 2B
Nominal 75 MW, Simple Cycle, General Electric Model 7EA

Hardee County, Florida

Facility I.D. No. 049-0015

Permit No. PSD-FL-140(A) / PA89-25

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation

August 28, 1999

1.0 APPLICATION INFORMATION

1.1 Applicant Name and Address

TECO Power Services
702 North Franklin Street
Tampa, FL 33602

Authorized Representative:
Richard E. Ludwig, President

1.2 Reviewing and Processing Schedule

06/18/99: The Department received a PSD application prepared by the applicant's consultant, Environmental Consulting & Technology (ECT).

07/15/99: The Department requested additional information.

07/23/99: The Department received additional information from the applicant.

08/19/99: The Department received additional information from the applicant modifying the proposed standards for CO emissions; application deemed complete.

2.0 EXISTING FACILITY INFORMATION

2.1 Existing Facility Description

The Hardee Power Station is an existing electric power generating plant with a nominal capacity of 295 MW. The plant presently consists of a combined-cycle unit, a simple cycle unit, fuel oil storage, and ancillary support equipment. The existing combined-cycle unit includes two General Electric Model 7EA combustion turbines with electrical generators, two unfired heat recovery steam generators (HRSG), and a common steam turbine. The existing simple-cycle unit is also a General Electric Model 7EA combustion turbine with electrical generator. Each combustion turbine is fired primarily with natural gas. Low sulfur distillate oil is fired as a backup fuel.

2.2 Facility Location

The project will be located at the existing Hardee Power Station approximately 3.5 miles north of State Road 62 on County Road 663 in Fort Green Springs, Hardee County, Florida. The UTM coordinates are Zone 17, 404.8 km E, 3057.4 km N and the map coordinates are Latitude 27° 38' 20", Longitude 81° 58' 29".

2.3 Standard Industrial Classification Codes (SIC)

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

2.4 Regulatory Categories

Power Plant Siting: The facility is subject to certain requirements of Chapter 403, Part II, F.S. and Chapter 62-17, F.A.C., Electric Power Plant and Transmission Line Siting, including the Conditions of Site Certification No. PA89-25.

Title IV - Acid Rain: The facility operates emissions units subject to several applicable provisions of Title IV of the Clean Air Act which defines the Acid Rain program.

Title V – Major Source: The facility is classified as a "major" source of air pollution with respect to Title V of the Clean Air Act because emissions of at least one regulated air pollutant, such as carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

PSD Major Source: This facility belongs to an industry listed in the 28 Major Facility Categories of Table 212.400-1, F.A.C. Because emissions of at least one criteria pollutant are greater than 100 TPY, the facility is also a "major facility" with respect to the Prevention of Significant Deterioration (PSD) of Air Quality program. Pursuant to Rule 62-212.400, F.A.C., each modification to a PSD major source requires a PSD review and determination of the Best Available Control Technology (BACT) if the resulting emissions increases are greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C.

NSPS Sources: The existing facility includes new stationary combustion turbines which are subject to regulation under the federal New Source Performance Standards in 40 CFR 60, Subpart GG, and adopted by reference in Rule 62-204.800, F.A.C.

3.0 PROPOSED PROJECT

3.1 Project Description

The applicant, TECO Power Services, proposes to add one General Electric Model No. PG7121 7EA dual-fuel simple cycle combustion turbine with electrical generator set having a nominal power production of 75 MW. TECO Power Services identifies the new combustion turbine as "Unit 2B". The new unit will use the existing infrastructure including oil storage and support equipment. Dry low-NOx (DLN) combustion technology will be used to control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will be used to control nitrogen oxide emissions when firing low sulfur distillate oil as a backup fuel for up to 876 hours per year. Combustion design and clean fuels will be used to minimize emissions of carbon monoxide, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. Exhaust gases from the combustion turbine will exit an 85 feet high rectangular stack (9 feet by 19 feet) at approximately 1000°F with a volumetric flow rate of 1,465,518 acfm. These parameters are based on firing natural gas at 100% of base load, cooling the turbine inlet air to 59°F, and ambient conditions of 60% relative humidity and 14.7 psi.

3.2 Project Emissions

Table 3.2 This table summarizes potential emissions increases and the resulting PSD applicability.

Pollutant	Project Potential Emissions (Tons Per Year)[c]	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	Subject To BACT?
CO	237 / 188[a]	100	Yes	Yes
NOx	199[b]	40	Yes	Yes
Pb	0.03[b]	0.60	No	No
PM/PM_{10}	50[b]	15	Yes	Yes
SAM	5[b]	7	No	No
SO_2	44[b]	40	Yes	Yes
VOC	10[b]	40	No	No

a - Based on 25 (20) ppmvd for gas (876 hours of oil) firing the first year of operation / 20 ppmvd for gas or oil firing thereafter.

b - Based on worst case of 7884 hours per year of gas firing and 876 hours per year of oil firing and GE data. Assumes all particulate matter is PM_{10}.

- The project is not a major source of hazardous air pollutants (HAPs) and is not subject to any specific industry or HAP control requirements pursuant to Section 112 of the Clean Air Act.

Therefore, the proposed combustion turbine project is subject to PSD review and a Best Available Control Technology (BACT) determination for CO, NOx, PM_{10}, and SO_2.

4.0 RULE APPLICABILITY

4.1 PSD Review

As previously discussed, the existing facility is considered a PSD major source and is located in Hardee County, an area that is currently in attainment, or designated as unclassifiable, for all air pollutants subject to a National Ambient Air Quality Standard (AAQS). In addition, the proposed project will emit pollutants exceeding the Significant Emission Rates defined in Table 212.400-1, F.A.C. Therefore, the project is subject to a review for the Prevention of Significant Deterioration of Air Quality accordance with Rule 62-212.400, F.A.C.

The PSD review consists of two parts. The first part requires the Department to establish the Best Available Control Technology (BACT) for each significant pollutant (CO, NOx, PM_{10}, and SO_2). The second part requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from proposed project upon soils, vegetation, wildlife, and visibility; and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project.

4.2 State Regulations

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

Chapter 62-4	Permitting Requirements
Chapter 62-17	Electrical Power Siting Provisions
Chapter 62-204	Ambient Air Quality Protection and Standards, PSD Increments, and Federal Regulations Adopted by Reference
Chapter 62-210	Required Permits, Public Notice and Comments, Reports, Stack Height Policy, Circumvention, Excess Emissions, Forms and Instructions.
Chapter 62-212	Preconstruction Review, PSD Requirements, and BACT Determinations
Chapter 62-213	Operation Permits for Major Sources of Air Pollution
Chapter 62-214	Acid Rain Program Requirements
Chapter 62-296	Emission Limiting Standards
Chapter 62-297	Test Requirements, Test Methods, Supplementary Test Procedures, Capture Efficiency Test Procedures, Continuous Emissions Monitoring Specifications, and Alternate Sampling Procedures

4.3 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.

40 CFR 52.21	Prevention of Significant Deterioration
40 CFR 60	NSPS Subpart GG – Stationary Gas Turbines
40 CFR 60	Subpart A, General Provisions for NSPS Sources
40 CFR 72	Acid Rain Permits
40 CFR 73	Allowances
40 CFR 75	Monitoring
40 CFR 77	Acid Rain Program - Excess Emissions

5.0 SUMMARY OF BACT DETERMINATION

The Department has determined that a combination of control technologies for the firing of different fuels represents BACT for this project. Dry low-NOx (DLN) combustion technology will be used to control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will be used to control nitrogen oxide emissions when firing low sulfur distillate oil as a backup fuel for up maximum of 876 hours in any consecutive 12 months. Combustion design and clean fuels will be used to minimize emissions of carbon monoxide, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. A detailed analysis of the BACT Determination is presented in Appendix BD of the Draft Permit included with the Department's Intent to Issue Permit. The following table summarizes the resulting emissions standards.

Table 5-A. Summary of Emissions Standards

EU-004: GE Model 7EA Combustion Turbine		
Pollutant	**Controls**[b]	**Emission Standard**
CO	Gas Firing W/DLN, First 12 Months After Initial Startup	25.0 ppmvd @ 15% oxygen 54.0 pounds per hour
	Gas Firing W/DLN, After First 12 Months After Initial Startup	20.0 ppmvd @ 15% oxygen 43.0 pounds per hour
	Oil Firing W/Wet Injection	20.0 ppmvd @ 15% oxygen 43.0 pounds per hour
NOx	Gas Firing W/DLN	9.0 ppmvd @ 15% oxygen 32.0 pounds per hour
	Oil Firing W/Wet Injection	42.0 ppmvd @ 15% oxygen 167.0 pounds per hour
PM/PM_{10}	Fuel Sulfur Specifications and Combustion Design	Visible emissions ≤ 10% opacity
SAM[a]/SO_2	Natural Gas Sulfur Specification	2 grain per 100 SCF of gas
	Low Sulfur Distillate Oil Sulfur Specification	0.05% sulfur by weight
VOC[a]	Gas Firing W/Combustion Design	2.0 ppmvd as methane 2.0 pounds per hour
	Oil Firing W/Combustion Design	4.0 ppmvd as methane 5.0 pounds per hour

These standards or the equivalents and the emissions rates in terms of pounds per hour are included in the specific conditions of the draft permit. Note: The standards for SAM, and VOC are not BACT standards, but limits to ensure pollutant emissions remain below the corresponding significant emissions rates.

6.0 AIR QUALITY ANALYSIS

6.1 Introduction

The proposed project will increase emissions of four pollutants at levels in excess of PSD significant amounts: PM_{10}, CO, NOx, and SO_2. PM_{10}, SO_2, and NOx are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO is a criteria pollutant and has only AAQS and significant impact levels defined for it.

The applicant's initial PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project predicted no significant impacts; therefore, further applicable AAQS and PSD increment impact analyses for these pollutants were not required. Based on the preceding discussion the air quality analyses required by the PSD regulations for this project are the following:

- A significant impact analysis for PM_{10}, CO, SO_2, and NO_X;
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

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

6.2 Models and Meteorological Data Used in the Significant Impact Analysis

The EPA-approved SCREEN3 (screening model) and Industrial Source Complex Short-Term (ISCST3) dispersion models were used to evaluate the pollutant emissions from the proposed project. These models determine ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. They incorporate 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. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfy the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at St. Petersburg/Clearwater, Florida (surface data) and Ruskin, Florida (upper air data). The 5-year period of meteorological data was from 1992 through 1996. These NWS stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

For determining the project's significant impact area in the vicinity of the facility and if there are significant impacts from the project on any PSD Class I area, the highest predicted short-term concentrations and highest predicted annual averages were compared to their respective significant impact levels.

6.3 Significant Impact Analysis

Initially, the applicant conducts modeling using only the proposed project's emissions at worst load conditions. In order to determine worst-case load conditions the SCREEN3 model was used to evaluate dispersion of emissions from the combined cycle facility for three loads (50%, 75%, and 100%) and three seasonal operating conditions (summer, winter, and average). Once the worst-case loads are identified, the applicant utilizes the ISCST3 model to evaluate impacts at these loads, and compares the results to the significant impact levels. If this modeling at worst-case load conditions shows significant impacts, additional multi-facility modeling is required to determine the project's impacts on the existing air quality and any applicable AAQS and PSD increments.

Receptors were placed along the fence line of the facility, which is located in a PSD Class II area, at 100-meter intervals. They were also placed in the Chassahowitzka National Wilderness Area (CNWA), which is the closest PSD Class I area. CNWA is located approximately 130 km northwest of the project. The receptor grid for predicting maximum concentrations in the vicinity of the project was a Cartesian receptor grid that contained near field, mid field, and far field receptors with dimensions centered on the simple-cycle facility stack. The inner portion of the grid had receptors at 100 m spacing out to 3,000 m. A 250-m spacing was used out to 5,000 m; and a 500-m spacing was used out to 15,000 m. For predicting impacts at the CNWA, thirteen discrete receptors along the border of the PSD Class I area were used. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project are predicted in the vicinity of the facility or in the CNWA. The tables below show the results of this modeling.

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS IN THE VICINITY OF THE FACILITY

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.002	1	NO
	24-hour	0.07	5	NO
CO	8-hour	0.65	500	NO
	1-hour	5.23	2000	NO
NO_2	Annual	0.011	1	NO
SO_2	Annual	0.003	1	NO
	24-hour	0.23	5	NO
	3-hour	1.74	25	NO

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS (CNWA)

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Proposed EPA Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.0003	0.2	NO
	24-hour	0.009	0.3	NO
NO_2	Annual	0.003	0.1	NO
SO_2	Annual	0.0005	0.1	NO
	24-hour	0.03	0.2	NO
	3-hour	0.2	1	NO

The results of the significant impact modeling show that there are no significant impacts predicted from emissions from this project; therefore, no further modeling was required.

6.4.4 Impacts Analysis

Impacts On Soils, Vegetation, And Wildlife

Very low emissions are expected from this natural gas-fired combustion turbine in comparison with conventional power plant generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X, SO_2 and sulfuric acid mist as a result of the proposed project, including background concentrations and all other nearby sources, will be less than the respective ambient air quality standards (AAQS). The project impacts are less than the significant impact levels, which in-turn, are less than the applicable allowable increments for each pollutant. Because the AAQS are designed to protect both the public health and welfare and the project impacts are less than significant, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

Impact On Visibility

Natural gas and low sulfur distillate fuel oil are clean fuels and produce little ash. This will minimize smoke formation. The low NOx and SO_2 emissions will also minimize plume opacity. Because no add-on control equipment and no reagents are required, there will be no steam plume or tendency to form ammoniated particulate species. A regional haze analysis was performed which shows that the proposed project will not result in adverse impacts on visibility in the nearest PSD Class I area.

Growth-Related Air Quality Impacts

There will be short-term increases in the labor force to construct the project. These temporary increases will not result in significant commercial and residential growth in the vicinity of the project. Operation of the additional unit will require 2 more permanent employees, which will cause no significant impact on the local area.

7.0 CONCLUSION

The Public Service Commission has determined that a number of power projects will be needed over the next few years to meet the rising electrical power needs throughout the State of Florida. This project is a response to predicted statewide and regional growth. The proposed project has a small overall physical "footprint," low water requirements, and among the lowest air emissions per unit of electric power generated compared to similar projects.

Based on the technical review of the complete PSD application, reasonable assurances provided by the applicant, the preliminary BACT determination, and the conditions specified in the Draft Permit, the Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations. Jeff Koerner, P.E., is the permitting engineer responsible for reviewing the application, recommending the BACT determination, and drafting the permit. Chris Carlson is the project meteorologist responsible for reviewing and validating the Air Quality Analysis for this project.

DRAFT

PERMITTEE:

TECO Power Services
702 North Franklin Street
Tampa, FL 33602

Permit No.	PSD-FL-140(A) / PA89-25
Facility ID No.	0490015
SIC No.	4911
Expires:	(DRAFT)

Authorized Representative:
Richard E. Ludwig, President

PROJECT

This permit is issued pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit). This existing facility is an electric power generating plant with a nominal capacity of 295 megawatts (MW). The proposed project will add another simple cycle, dual-fuel, General Electric Model 7EA combustion turbine with electrical generator (75 MW).

LOCATION

The project will be located at the existing Hardee Power Station approximately 3.5 miles north of State Road 62 on County Road 663 in Fort Green Springs, Hardee County, Florida. The UTM coordinates are Zone 17, 404.8 km E, 3057.4 km N and the map coordinates are Latitude 27° 38' 20", Longitude 81° 58' 29".

STATEMENT OF BASIS

This PSD permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40 CFR 52.21. The permittee is authorized to modify the facility 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.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A - Terminology
Appendix BD - Department's BACT Determination
Appendix GC - Construction Permit General Conditions
Appendix GG - NSPS Subpart GG Requirements for Gas Turbines
Appendix XS - CEMS Excess Emissions Report

DRAFT

Howard L. Rhodes, Director
Division of Air Resources Management

DRAFT

FACILITY DESCRIPTION

This existing facility is an electric power generating plant with a nominal capacity of 295 megawatts (MW). The plant presently consists of a combined-cycle unit, a simple cycle unit, fuel oil storage, and ancillary support equipment. The combined-cycle unit includes two General Electric Model 7EA combustion turbines with electrical generators, two unfired heat recovery steam generators (HRSG), and a common steam turbine. The simple-cycle unit is also a General Electric Model 7EA combustion turbine with electrical generator. Each combustion turbine is fired primarily with natural gas and with low sulfur distillate oil as a backup fuel.

NEW EMISSIONS UNIT

The proposed project will add the following new emissions unit.

ARMS ID No.	EMISSION UNIT DESCRIPTION
004	The new unit will consist of a General Electric Model No. PG7121 7EA dual-fuel simple cycle combustion turbine with electrical generator having a nominal power production output of 75 MW. Dry low-NOx (DLN) combustion technology will be used to control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will be used to control nitrogen oxide emissions when firing the backup fuel of low sulfur distillate oil. TECO Power Services identifies the new combustion turbine as "Unit 2B".

REGULATORY CLASSIFICATION

This project is subject to certain requirements of Chapter 403, Part II, F.S. and Chapter 62-17, F.A.C., Electric Power Plant and Transmission Line Siting, including a modification of the Conditions of Site Certification No. PA89-25. The facility and project are subject to the applicable Acid Rain provisions of Title IV of the Clean Air Act. The facility is classified as a "major", Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM10), sulfur dioxide (SO2), nitrogen oxides (NOx), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

The facility is within an industry included in the 28 Major Facility Categories listed in Table 212.400-1, F.A.C. Because emissions of at least one criteria pollutant are greater than 100 TPY, the facility is also a "major facility" with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Therefore, each modification to this facility resulting in emissions increases greater than the Significant Emissions Rates specified in Table 62-212.400-2 also requires a PSD review and Best Available Control Technology (BACT) determination. For this project, emissions of carbon monoxide and nitrogen oxides are major and emissions of particulate matter and sulfur dioxide are significant. This permit specifies emissions standards that result from establishing the Best Available Control Technology (BACT) for each of these pollutants.

This project is subject to regulation under the New Source Performance Standards, 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines.

PERMIT HISTORY

(DRAFT)	Modification of Conditions of Certification Approved
(DRAFT)	Received proof the Public Notice was published in the ____ issue of the _____
08-30-99	Distributed Intent to Issue Permit
08-19-99	Received additional information from the applicant; application complete.
07-23-99	Received additional information from the applicant.
06-18-99	Received PSD permit application and request to revise site certification.

DRAFT

GENERAL AND ADMINISTRATIVE REQUIREMENTS

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

2. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Southwest District, Florida Department of Environmental Protection (SWDEP), 3804 Coconut Palm Drive, Tampa, FL 33619-8218 and phone number 813/744-6100.

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

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

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-296, 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 facility owner or operator from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

6. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]

7. Permit Expiration: For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C]

8. BACT Determination: In conjunction with extension of the 18 month period to commence or continue construction, 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. [40 CFR 52.21(j)(4)]

9. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

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

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

12. Title V Permit: This permit authorizes construction of the permitted emissions unit 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 and receive a Title V operation permit prior to expiration of this permit. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation and a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

This permit addresses the following new emissions unit.

ARMS EU ID No.	EMISSION UNIT DESCRIPTION
004	**Combustion Turbine**: This permit authorizes the installation of one General Electric Model No. PG7121 (7EA) dual-fuel, simple-cycle combustion turbine with electrical generator set to produce a nominal 75 MW of electricity. The new unit will use the existing infrastructure including natural gas connections, oil storage and auxiliary equipment. Dry low-NOx (DLN) combustion technology will be used to control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will be used to control NOx emissions when firing low sulfur distillate oil as a backup fuel. Combustion design and clean fuels will be used to minimize emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC. Exhaust gases from the combustion turbine will exit an 85 feet high rectangular stack (9 feet by 19 feet) at approximately 1000°F with a volumetric flow rate of 1,465,518 acfm. These parameters are based on firing natural gas at 100% of base load, cooling the turbine inlet air to 59°F, and ambient conditions of 60% relative humidity and 14.7 psi. TECO identifies the new combustion turbine as "Unit 2B".

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: This emissions unit is subject to Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), and sulfur dioxide (SO_2). [Rule 62-212.400, F.A.C.]

2. NSPS Requirements: The combustion turbine (EU-004) 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**, incuding:

   - 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
   - 40 CFR 60.19, General Notification and Reporting Requirements

   (b) **Subpart GG, Standards of Performance for Stationary Gas Turbines**, identified in *Appendix F* of this permit. These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

PERFORMANCE RESTRICTIONS

3. Permitted Capacity: The combustion turbine shall operate only in simple-cycle mode and generate a nominal 75 MW of electrical power. Operation of this unit shall not exceed 880 mmBTU per hour of heat input from firing natural gas nor 950 mmBTU per hour of heat input from firing low sulfur distillate oil. The maximum heat inputs are based on the lower heating value (LHV) of each fuel, an inlet air supply cooled to 59°F, a relative humidity of 60%, an ambient air pressure of 14.7 psi, and 100% of base load. Therefore, maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's performance curves, corrected for site conditions or equations for correction to other ambient conditions, shall be provided to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definition – Potential Emissions)]

4. Simple Cycle Operation Only: The emissions standards specified in this permit are the result of BACT determinations based on the combustion turbine operating only in the simple cycle mode. Specifically, the NOx BACT determination eliminated several control alternatives based on technical considerations and costs due to the elevated temperatures of the exhaust gas. In the future, the permittee may request to operate this unit in a combined cycle mode by installing a new heat recovery steam generator or connecting this unit to an existing heat recovery steam generator. Such a request to later operate this unit in a combined cycle mode shall require a modification of this permit consisting of a full PSD permit application including new BACT determinations for all technically feasible control options.

5. Allowable Fuels: The combustion turbine shall be fired by pipeline natural gas containing no more than 2 grains of sulfur per 100 dry standard cubic feet of gas. As a backup fuel, the combustion turbine may be fired with No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Compliance with limits on fuel sulfur content shall be demonstrated by the record keeping requirements and/or the conditions of the Alternate Monitoring Plan specified in this permit. It is noted that these limitations are much more stringent than the NSPS sulfur dioxide limitation and assure compliance with 40 CFR 60.333 and 60.334. [Applicant Request, Rule 62-210.200, F.A.C. (Definition - Potential Emissions)]

6. Hours of Operation: The hours of operation of the combustion turbine are not limited when firing natural gas (8760 hours per year). The combustion turbine shall not fire low sulfur distillate oil for more than 876 hours during any consecutive 12 months. Operation below 50% of baseline operation shall be limited to two (2) hours per unit cycle (breaker open to breaker closed). The permittee shall install, calibrate, operate and maintain fuel flow meters to measure and accumulate the amount of each fuel fired in the combustion turbine. [Applicant Request; Rule 62-212.400, F.A.C. (BACT); Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

7. 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 combustion turbine and pollution control devices in accordance with the guidelines and procedures established by each equipment manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

8. 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 owner or operator shall notify the Compliance Authority as soon as possible, but at least within one (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the 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 and the regulations. [Rule 62-4.130, F.A.C.]

EMISSIONS CONTROLS

9. Automated Control System: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, tune, operate, and maintain the General Electric Speedtronic™ Gas Turbine Control System. This system shall be designed and operated to monitor and control the gas turbine combustion process and operating parameters including, but not limited to: fuel distribution and staging, turbine speed, load conditions, combustion temperatures, water injection, and fully automated startup, shutdown, and cool-down. [Design; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

10. Combustion Controls: The owner and operators shall employ "good operating practices" in accordance with the manufacturer's recommended operating procedures to control CO, NOx, and VOC emissions. Prior to the required initial emissions performance testing, the combustion turbine, dry low-NOx (DLN) combustors, and Speedtronic™ control system shall be tuned to optimize the reduction of CO, NOx, and VOC emissions. Thereafter, these systems shall be maintained and tuned, as necessary, to minimize pollutant emissions. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

11. DLN Combustion Technology: To control NOx emissions when firing natural gas, the permittee shall install, tune, operate and maintain dry low-NOx (DLN) combustors on the combustion turbine. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific DLN system prior to commencement of operation. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

12. Water Injection: To control NOx emissions when firing low sulfur distillate oil, the permittee shall install, calibrate and operate an automated water injection system. This system shall be maintained and adjusted to provide the minimum NOx emissions possible by water injection. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific water injection system prior to commencement of operation. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

13. 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.]

14. 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.]

EMISSIONS STANDARDS

15. Emissions Standards Summary: The following table summarizes the emissions standards determined by the Department. These standards or the equivalents are provided in the specific permit conditions.

EU-004: GE Model 7EA Combustion Turbine		
Pollutant	**Controls[b]**	**Emission Standard**
CO	Gas Firing W/DLN, First 12 Months After Initial Startup	25.0 ppmvd @ 15% oxygen 54.0 pounds per hour
	Gas Firing W/DLN, After First 12 Months After Initial Startup	20.0 ppmvd @ 15% oxygen 43.0 pounds per hour
	Oil Firing W/Wet Injection	20.0 ppmvd @ 15% oxygen 43.0 pounds per hour
NOx	Gas Firing W/DLN	9.0 ppmvd @ 15% oxygen 32.0 pounds per hour
	Oil Firing W/Wet Injection	42.0 ppmvd @ 15% oxygen 167.0 pounds per hour
PM/PM10	Fuel Sulfur Specifications and Combustion Design	Visible emissions ≤ 10% opacity (PM estimated at 0.002 grains/dscf)
SAM[a]/SO2	Natural Gas Sulfur Specification	2 grain per 100 SCF of gas
	Low Sulfur Distillate Oil Sulfur Specification	0.05% sulfur by weight
VOC[a]	Gas Firing W/Combustion Design	2.0 ppmvd as methane 2.0 pounds per hour
	Oil Firing W/Combustion Design	4.0 ppmvd as methane 5.0 pounds per hour

[a] The VOC and SAM standards are synthetic (PSD) minor limits - not BACT limits.

[b] DLN means dry low-NOx controls. Oil firing is limited to 876 hours during any consecutive 12 months.

16. Carbon Monoxide (CO)

(a) **Gas Firing:** During the first 12 months after initial startup, CO emissions shall not exceed 54.0 pounds per hour nor 25.0 ppmvd corrected to 15% oxygen based on a 3-hour test average when firing natural gas in the combustion turbine. Thereafter, CO emissions shall not exceed 43.0 pounds per hour nor 20.0 ppmvd corrected to 15% oxygen based on a 3-hour test average when firing natural gas in the combustion turbine.

(b) **Oil Firing**: When firing low sulfur distillate oil in the combustion turbine, CO emissions shall not exceed 43.0 pounds per hour nor 20.0 ppmvd based on a 3-hour test average.

The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Method 10 and the performance testing requirements of this permit. [Rule 62-212.400, F.A.C. (BACT)]

17. Nitrogen Oxides (NOx)

(a) **Gas Firing**: When firing natural gas in the combustion turbine, NOx emissions shall not exceed 32.0 pounds per hour nor 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average. In addition, NOx emissions shall not exceed 9.0 ppmvd corrected to 15% oxygen based on a 24-hour block average for data collected from the continuous emissions monitor.

(b) **Oil Firing**: When firing low sulfur distillate oil in the combustion turbine, NOx emissions shall not exceed 167.0 pounds per hour nor 42.0 ppmvd corrected to 15% oxygen based on a 3-hour test average. In addition, NOx emissions shall not exceed 42.0 ppmvd corrected to 15% oxygen based on a 3-hour block average for data collected from the continuous emissions monitor.

NOx emissions are defined as emissions of oxides of nitrogen measured as NO_2. The permittee shall demonstrate compliance by conducting tests in accordance with EPA Methods 7E, 20 and the performance testing requirements of this permit. Compliance with the 3-hour and 24-hour block averages shall be demonstrated by collecting and reporting data in accordance with the conditions for the NOx continuous emissions monitor specified by this permit. [Rule 62-212.400, F.A.C. (BACT)]

18. Particulate Matter (PM/PM_{10}), Sulfuric Acid Mist (SAM) and Sulfur Dioxides (SO_2)

(a) **Fuel Specifications**: Emissions of PM, PM_{10}, SAM, and SO_2 shall be limited by the good combustion techniques and the fuel sulfur limitations specified in this permit. The permittee shall demonstrate compliance with the fuel sulfur limits by maintaining records of the sampling and analysis required by this permit and/or as specified in the provisions of the Alternate Monitoring Plan. [Rule 62-212.400, F.A.C. (BACT)]

(b) **VE Standard**: As a surrogate for PM/PM_{10} emissions, visible emissions from the operation of the combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The permittee shall demonstrate compliance with this standard shall by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. [Rule 62-212.400, F.A.C. (BACT)]

19. Volatile Organic Compounds (VOC)

(a) **Gas Firing**: When firing natural gas in the combustion turbine, VOC emissions shall not exceed 2.0 pounds per hour nor 2.0 ppmvd based on a 3-hour test average.

(b) **Oil Firing**: When firing low sulfur distillate oil in the combustion turbine, VOC emissions shall not exceed 5.0 pounds per hour nor 4.0 ppmvd based on a 3-hour test average.

The VOC emissions shall be measured and reported as methane. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Methods 18, 25, and/or 25A and the performance testing requirements of this permit. [Application, Design, Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

20. 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. These emissions shall be included in the calculation of the 24-hour NOx averages for compliance determinations. [Rule 62-210.700, F.A.C.]

21. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, or malfunction of the combustion turbine shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions resulting from startup to simple cycle mode shall not exceed one (1) hour. In no case shall excess emissions from startup, shutdown, and malfunction exceed two hours in any 24-hour period. If excess emissions occur due to malfunction, the owner or operator shall notify the Compliance Authority within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. [Applicant Request, Vendor Data and Rule 62-210.700, F.A.C.]

EMISSIONS PERFORMANCE TESTING

22. Combustion Turbine Testing Capacity: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 110 percent of the value reached during the test 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 purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C. [Rule 62-297.310(2), F.A.C.]

23. Calculation of Emission Rate: 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.]

24. Applicable Test Procedures

    (a) **Required Sampling Time.**

    1. 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. [Rule 62-297.310(4)(a)1., F.A.C.]

    2. The minimum observation period for a visible emissions compliance test shall be sixty (60) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. [Rule 62-297.310(4)(a)2., F.A.C.]

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

(d) **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)(d), F.A.C.]

25. 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.]

26. Sampling Facilities: The permittee shall design the combustion turbine stack to accommodate adequate testing and sampling locations in order to determine compliance with the applicable emission limits specified by this permit. Permanent stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C. [Rules 62-4.070 and 62-204.800, F.A.C., and 40 CFR 60.40a(b)]

27. Performance Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C.

(a) **EPA Method 7E**, "Determination of Nitrogen Oxide Emissions from Stationary Sources". This method may be used to determine compliance with the annual 3-hour NOx limit.

(b) **EPA Method 9**, "Visual Determination of the Opacity of Emissions from Stationary Sources".

(c) **EPA Method 10**, "Determination of Carbon Monoxide Emissions from Stationary Sources". All CO tests shall be conducted concurrently with NOx emissions tests.

(d) **EPA Method 20**, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." This test shall be used to determine compliance for the initial performance tests and may be used to determine compliance with the annual 3-hour NOx limit.

(e) **EPA Methods 18, 25 and/or 25A**, "Determination of Volatile Organic Concentrations."

No other test methods may be used for compliance testing unless prior DEP approval is received, in writing, from the DEP Emissions Monitoring Section Administrator in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C.

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

29. Initial Tests Required: Initial compliance with the allowable emission standards specified in this permit shall be determined within 60 days after achieving the maximum production rate, but not later

than 180 days after initial operation of the emissions unit. Initial tests for emissions from the combustion turbine shall be conducted for CO, NOx, VOC, and visible emissions individually for the firing of natural gas and low sulfur distillate oil. Initial NOx performance test data shall also be converted into the units of the corresponding NSPS Subpart GG emissions standards to demonstrate compliance (see Appendix GG). [Rule 62-297.310(7)(a)1., F.A.C.]

30. Annual Performance Tests: Annual performance tests for CO, NOx, and visible emissions from the combustion turbine shall be conducted individually for the firing of natural gas and low sulfur distillate oil. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). When conducted at permitted capacity, the annual NOx continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the annual compliance stack test. [Rule 62-297.310(7)(a)4., F.A.C.]

31. Tests Prior to Permit Renewal: During the federal fiscal year (October 1st to September 30th) prior to renewing the air operation permit, the permittee shall also conduct individual performance tests for VOC emissions for firing natural gas and low sulfur distillate oil. [Rule 62-297.310(7)(a)3., F.A.C.]

32. Tests After Substantial Modifications: All performance tests required for initial startup shall also be conducted after any substantial modification and appropriate shake-down period of air pollution control equipment including the replacement of dry low-NOx combustors. Shakedown periods shall not exceed 100 days after re-starting the combustion turbine. [Rule 62-297.310(7)(a)4., F.A.C.]

33. VE Tests After Shutdown: Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions (VE) compliance test once per each five-year period, coinciding with the term of its air operation permit. [Rule 62-297.310(7)(a)8., F.A.C.]

34. 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.]

CONTINUOUS MONITORING REQUIREMENTS

35. NOx CEM: The permittee shall install, calibrate, operate, and maintain a continuous emission monitoring system (CEMS) to measure and record NOx and oxygen concentrations in the combustion turbine exhaust stack. A monitor for carbon dioxide may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen. NOx data collected by the CEMS shall be used to demonstrate compliance with the 3-hour and 24-hour block emissions standards for NOx. The block averages shall be determined by calculating the arithmetic average of all hourly emission rates for the respective averaging period. Each 1-hour average shall be expressed in units of ppmvd corrected to 15% oxygen and calculated using at least two valid data points at least 15 minutes apart. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C. When NOx monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified averaging period.

    (a) The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of: Rule 62-297.520, F.A.C., including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications 2 and 3; 40 CFR 60.7(a)(5); 40 CFR 60.13; 40 CFR 60, Appendix F; and 40 CFR Part 75. A monitoring plan shall be provided to the DEP Emissions Monitoring Section Administrator, EPA and the Compliance Authority for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62. The plan shall consist of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location.

(b) Continuous emission monitoring data required by this permit shall be collected and recorded during all periods of operation including startup, shutdown, and malfunction, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Although recorded, emissions during periods of startup, shutdown and malfunction are subject to the excess emission conditions specified in this permit. When the CEMS reports NOx emissions in excess of the standards allowed by this permit, the owner or operator shall notify the Compliance Authority within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. The Department may request a written report summarizing the excess emissions incident.

[Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7].

COMPLIANCE DEMONSTRATIONS

36. Records: 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 DEP representatives upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

37. Fuel Records

(a) Natural Gas: The permittee shall demonstrate compliance with the fuel sulfur limit for natural gas specified in this permit by maintaining records of the sulfur content of the natural gas being supplied for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or equivalent methods. These methods shall be used to determine the sulfur content of the natural gas fired in accordance with any EPA-approved custom fuel monitoring schedule (see Alternate Monitoring Plan) or natural gas supplier data or the natural gas sulfur content referenced in 40 CFR 75 Appendix D. 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 pursuant to 40 CFR 60.335(e). However, the permittee is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used to determine the fuel sulfur content for compliance with the 40 CFR 60.333 SO_2 standard.

(b) Low Sulfur Distillate Oil: For all bulk shipments of low sulfur distillate oil received at this facility, the permittee shall obtain from the fuel vendor an analysis identifying the sulfur content. Methods for determining the sulfur content of the distillate oil shall be ASTM D129-91, D2622-94, or D4294-90 or equivalent methods. Records shall specify the test method used and shall comply with the requirements of 40 CFR 60.335(d).

[Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

38. Alternate Monitoring Plan: Subject to EPA approval, the following alternate monitoring may be used to demonstrate compliance.

(a) The NOx CEM data may be used in lieu of the monitoring system for water-to-fuel ratio and the reporting of excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG. Subject to EPA approval, the calibration of the water-to-fuel ratio-monitoring device required in 40 CFR 60.335(c)(2) will be replaced by the 40 CFR 75 certification tests of the NOx CEMS.

(b) The NOx CEM data shall be used in lieu of the requirement for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG.

(c) When requested by the Department, the CEMS emission rates for NOx on this unit shall be corrected to ISO conditions to demonstrate compliance with the NOx standard established in 40 CFR 60.332.

(d) A *custom fuel monitoring schedule* pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following conditions are met.

  (1) The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.

  (2) The permittee shall submit a monitoring plan, certified by signature of the Authorized Representative, that commits to using a primary fuel of pipeline supplied natural gas containing no more than 2 grains of sulfur per 100 SCF of gas pursuant to 40 CFR 75.11(d)(2);

  (3) Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

This custom fuel-monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

[40 CFR 60, Subpart GG, Applicant Request]

39. Monthly Operations Summary: By the fifth calendar day of each month, the owner or operator shall record the following information in a written log for the previous month of operation: the amount of hours each fuel was fired; the quantity of each fuel fired; the calculated average heat input of each fuel fired in mmBTU per hour, based on the lower heating value; and the average sulfur content of each fuel. In addition, the owner or operator shall record the hours of oil firing for the previous 12 months of operation. The Monthly Operations Summary shall be maintained on site in a legible format available for inspection at the Department's request. [Rule 62-4.160(15), F.A.C.]

REPORTS

40. Emissions Performance Test Reports: A report indicating the results of the required emissions performance tests shall be submitted to the 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.].

41. Excess Emissions Reporting: If excess emissions occur due to malfunction, the owner or operator shall notify the Compliance Authority within (1) working day 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. Following the NSPS format (40 CFR 60.7, Subpart A) periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the standards specified in this permit. Within thirty (30) days following each calendar quarter, the permittee shall submit a report on any periods of excess emissions that occurred during the previous calendar quarter to the Compliance Authority. This quarterly report shall follow the format provided in Appendix XS of this permit. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7]

42. <u>Annual Operating Report</u>: 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.]

APPENDIX A - TERMINOLOGY

ABBREVIATIONS AND ACRONYMS

°F	- Degrees Fahrenheit
DEP	- State of Florida, Department of Environmental Protection
DARM	- Division of Air Resource Management
EPA	- United States Environmental Protection Agency
F.A.C.	- Florida Administrative Code
F.S.	- Florida Statute
SOA	- Specific Operating Agreement
UTM	- Universal Transverse Mercator
CT	- Combustion Turbine
DB	- Duct Burner
HRSG	- Heat Recovery Steam Generator
DLN	- Dry Low-NOx Combustion Technology
SCR	- Selective Catalytic Reduction
OC	- Oxidation Catalyst Technology for CO Control

RULE CITATIONS

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

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

Example:	**[Rule 62-213.205, F.A.C.]**	
Where:	62	- refers to Title 62 of the Florida Administrative Code (F.A.C.)
	62-213	- refers to Chapter 62-213, F.A.C.
	62-213.205	- refers to Rule 62-213.205, F.A.C.

Facility Identification (ID) Number:

Example:	Facility ID No. 099-0001	
Where:	099	- 3 digit number indicates that the facility is located in Palm Beach County
	0221	- 4 digit number assigned by state database identifies specific facility

New Permit Numbers:

Example:	Permit No. 099-2222-001-AC or 099-2222-001-AV	
Where:	AC	- identifies permit as an Air Construction Permit
	AV	- identifies permit as a Title V Major Source Air Operation Permit
	099	- 3 digit number indicates that the facility is located in Palm Beach County
	2222	- 4 digit number identifies a specific facility
	001	- 3 digit sequential number identifies a specific permit project

Old Permit Numbers:

Example:	Permit No. AC50-123456 or AO50-123456	
Where:	AC	- identifies permit as an Air Construction Permit
	AO	- identifies permit as an Air Operation Permit
	123456	- 6 digit sequential number identifies a specific permit project

APPENDIX GC - CONSTRUCTION PERMIT GENERAL CONDITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

(a) Determination of Best Available Control Technology (X);

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

(c) Compliance with New Source Performance Standards (X).

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.

DRAFT

Hardee Power Station Combustion Turbine Project (Unit 2B)
TECO Power Services
PSD-FL-140(A) and PA89-25
Hardee County, Florida

1.0 EXISTING FACILITY

The Hardee Power Station is an existing electric power generating plant with a nominal capacity of 295 megawatts (MW) located approximately 3.5 miles north of State Road 62 on County Road 663 in Fort Green Springs, Hardee County, Florida. The plant presently consists of a combined-cycle unit, a simple cycle unit, fuel oil storage, and ancillary support equipment. The combined-cycle unit includes two General Electric Model 7EA combustion turbines with electrical generators, two unfired heat recovery steam generators (HRSG), and a common steam turbine. The simple-cycle unit is also a General Electric Model 7EA combustion turbine with electrical generator. Each combustion turbine is fired primarily with natural gas. Low sulfur distillate oil is fired as a backup fuel.

The existing facility is a fossil fuel fired steam electric plant with a heat input greater than 250 mmBTU per hour, an industry included in the 28 Major Facility Categories listed in Table 212.400-1, F.A.C. Because emissions of at least one criteria pollutant are greater than 100 TPY, the facility is considered a "major facility" with respect to Rule 62-212.400, F.A.C. - Prevention of Significant Deterioration (PSD). Therefore, a PSD review and a Best Available Control Technology (BACT) determination is required for each pollutant that will experience an emissions increase greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C.

2.0 PROJECT DESCRIPTION

The applicant, TECO Power Services, proposes to add one General Electric Model No. PG7121 7EA dual-fuel simple cycle combustion turbine with electrical generator set having a nominal power production of 75 MW. The new unit will use the existing infrastructure including oil storage and support equipment. Dry low-NOx (DLN) combustion technology will be used to control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will be used to control nitrogen oxide emissions when firing low sulfur distillate oil as a backup fuel for up to 876 hours per year. Combustion design and clean fuels will be used to minimize emissions of carbon monoxide, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. Emissions will exit the combustion turbine at through a rectangular stack that is 85 feet in height. The applicant identifies the new combustion turbine as "Unit 2B".

As a result of fuel combustion, this project will emit significant emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), and sulfur dioxide (SO_2) as well as minor emissions of sulfuric acid mist (SAM), volatile organic compounds (VOC). Therefore, the project is subject to review for the Prevention of Significant Deterioration (PSD) of Air Quality and a determination of the Best Available Control Technology (BACT) must be made for CO, NOx, PM/PM_{10}, and SO_2 in accordance with Rule 62-212.400, F.A.C. A detailed description of the PSD applicability analysis and BACT determination follows. Additional information regarding the overall project, air quality impacts, and rule applicability are provided in the Department's Technical Evaluation and Preliminary Determination that accompanies the Department's Intent to Issue Permit.

3.0 APPLICATION PROCESSING SCHEDULE

06/18/99: The Department received PSD application prepared by the applicant's consultant, Environmental Consulting & Technology (ECT).

07/15/99: The Department requested additional information.

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07/23/99: The Department received additional information from the applicant.

08/19/99: The Department received additional information from the applicant modifying the proposed standards for CO emissions; application deemed complete.

4.0 PSD APPLICABILITY REVIEW

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

- 250 tons per year or more of any regulated air pollutant, OR
- 100 tons per year or more of any regulated air pollutant and it falls under one of the 28 Major Facility Categories listed in Table 62-212.400-1, F.A.C.

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

This project will be located in Hardee County, an area that is currently in attainment, or designated as unclassifiable, for all air pollutants subject to a National Ambient Air Quality Standard (AAQS). The existing facility is considered a fossil fuel fired steam electric plant with a heat input greater than 250 mmBTU per hour, an industry included in the 28 Major Facility Categories listed in Table 212.400-1, F.A.C. Because existing facility emissions of at least one criteria pollutant are greater than 100 TPY, the facility is considered a major facility with respect PSD in accordance with Rule 62-212.400, F.A.C. The following table summarizes the potential emissions increases and PSD applicability for this new project.

Pollutant	Project Potential Emissions (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	Subject To BACT?
CO	237 / 188[a]	100	Yes	Yes
NOx	199[b]	40	Yes	Yes
Pb	0.03[b]	0.60	No	No
PM/PM_{10}	50[b]	15	Yes	Yes
SAM	5[b]	7	No	No
SO_2	44[b]	40	Yes	Yes
VOC	10[b]	40	No	No

[a] - "237 TPY" is based on 25 ppmvd for gas during the first 12 months. "188 TPY" is based on 20 ppmvd for gas firing after the first 12 months. Both calculations include 876 hours of oil firing.

[b] - Based on worst case of 7884 hours per year of gas firing and 876 hours per year of oil firing and GE data. Assumes all particulate matter is PM_{10}.

Therefore, the proposed combustion turbine project is subject to PSD review and a Best Available Control Technology (BACT) determination for CO, NOx, PM_{10}, and SO_2.

5.0 BACT DETERMINATION PROCEDURE

For projects subject to PSD review, it is the Department's responsibility to determine the Best Available Control Technology (BACT) for each regulated pollutant emitted in excess of a Significant Emission Rate. 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. In addition to the information submitted by the applicant, the Department may rely upon other available information in making its BACT determination and shall also give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact 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 should be performed for each emissions unit and pollutant under consideration. In general, EPA has identified five key steps in the top-down BACT process: identify alternative control technologies; eliminate technically infeasible options; rank remaining technologies by control effectiveness; evaluate the most effective controls considering energy, environmental, and economic impacts; and select BACT. A BACT determination must not result in the selection of control technology that would not meet any applicable emission limitation under 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants). The combustion turbine project is subject to 40 CFR 60, Subpart GG, a New Source Performance Standards (NSPS) which regulates Stationary Gas Turbines, adopted by reference in Rule 62-204.800, F.A.C. There are no applicable NESHAP regulations.

The Department will consider the control or reduction of "non-regulated" air pollutants when determining the BACT limit for regulated pollutants, and will weigh control of non-regulated air pollutants favorably when considering control technologies for regulated pollutants. The Department will also favorably consider control technologies that utilize pollution prevention strategies. These approaches are consistent with EPA's consideration of environmental impacts and EPS's stated policy for pollution prevention.

6.0 PROJECT ANALYSIS AND BACT DETERMINATIONS

For this project, the following pollutants are subject to a BACT determination: CO, NOx, PM_{10}, and SO_2. The applicant proposed control strategies for these pollutants in the PSD permit application. Besides the information submitted by the applicant, the Department also relied on the following information:

- Comments from the National Park Service dated July 8, 1999;

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- Comments from EPA Region 4 dated August 16, 1999;
- DOE web site information on Advanced Turbine Systems Project;
- Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines;
- General Electric technical product literature regarding the DLN-1 combustor design, CO/NOx performance curves vs. load, and the Speedtronic™ Mark V Gas Turbine Control System.
- Emissions stack test results (September/October 1996) for a similar GE Model 7EA combustion gas turbine located at the Panda-Brandywine Cogeneration Facility in Brandywine, Maryland.
- Letter from General Electric guaranteeing proposed CO and NOx emissions standards dated July 22, 1999.
- Goal Line Environmental Technology Website: http://www.glet.com;
- TEC Website – www.teco-energy.com;
- Catalytica Website – www.catalytica-inc.com
- ARMS compliance data for similar General Electric 7EA units located at Gainesville Regional Utilities' Deerhaven Station and Kissimmee Utilities Authority's Cane Island Plant.

6.1 NITROGEN OXIDES (NOX)

6.1.1 Discussion of NOx Emissions

{Much of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NOx Emissions from Stationary Gas Turbines. Specific project information is included where applicable.}

A gas turbine is sometimes referred to a "heat engine". In operation, hot combustion gases are diluted with additional air from the compressor section and directed to the turbine section at temperatures up to 2350°F. During simple cycle operation, electrical power is produced directly from the hot expanding exhaust gases in the form of shaft horsepower. Because of the high temperatures, the primary pollutant of concern for combustion turbines is nitrogen oxides or NOx. Uncontrolled NOx emissions from small turbines may range from 100 to 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @ 15% oxygen). For large modern turbines, the Department estimates uncontrolled emissions to range from 100 to 200 ppmvd @ 15% oxygen. The New Source Performance Standard regulating NOx emissions from stationary gas turbines is 75 ppmvd @ 15% oxygen corrected to ISO conditions, which must then be corrected for the fuel-bound nitrogen content and heat rate of the given unit.

Nearly all of the NOx is emitted as nitric oxide (NO) which is then readily oxidized in the exhaust system or the atmosphere to the more stable NO_2 molecule. Emissions of NOx are a result of the oxidation of nitrogen available in the combustion air (thermal and prompt NOx) and conversion of chemically-bound nitrogen in the fuel (fuel-bound NOx). *Thermal NOx* forms in the high temperature area of the gas turbine combustor, increases exponentially with increasing flame temperature, and increases linearly with increasing residence time. *Prompt NOx* forms near the flame front as intermediate combustion products and is a relatively small fraction of total NOx in lean, near-stoichiometric combustors. However, prompt NOx may become an important consideration for units using dry low-NOx combustors and lean fuel mixtures. *Fuel-bound NOx* forms from the combustion of fuels containing bound nitrogen. This phenomenon is not important when combusting natural gas or distillate fuel oil, which contain negligible fuel-bound nitrogen. Other factors that may also increase NOx emissions are combustion turbine loads and ambient conditions.

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6.1.2 Applicant's Proposed NOx Controls

The following summarizes the applicant's list of potential control alternatives and identifies those alternatives that are not technically feasible for this project.

Dry Low-NOx Combustor Design (DLN): The U.S. Department of Energy has provided millions of dollars of funding to a number of manufacturers of combustion turbines to develop low pollutant-emitting units. Efforts over the last ten years have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel and air prior to combustion in the primary zone. The combustor design for this project is the General Electric DLN-1 that operates in four distinct modes: primary, lean-lean, secondary, and premix. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in the lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in the secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. The premix mode of operation occurs at loads between 50% to 100% of base load and provides the lowest NOx emissions. A very important aspect of DLN technology is the control and staging of these modes of operation, which are automatically controlled by the General Electric Speedtronic™ Mark V Gas Turbine Control System. For this project, the manufacturer has guaranteed NOx emissions levels of 9 ppmvd @ 15% oxygen when firing natural gas and employing DLN controls. Another control method must be employed when firing fuel oil.

Wet Injection (WI): Water or steam is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NOx emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the same level of NOx control. However, there is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine. Standard combustor designs with wet injection can generally achieve NOx emissions of 42/65 ppmvd for gas/oil firing. Advanced combustor designs generate lower NOx emissions to begin with and can tolerate greater amounts of water or steam injection before causing flame instability. Advanced combustor designs with wet injection can achieve NOx emissions of 25/42 ppmvd for gas/oil firing.

Conventional Selective Catalytic Reduction (SCR): This 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. SCR is a commercially available, demonstrated control technology currently employed on several combined cycle combustion turbine projects capable of very low NOx emissions (< 3.5 ppmvd). However, conventional SCR is not technically feasible because the combustion turbine exhaust temperature of 1100°F is too high for standard catalysts and the oxidation reaction would not occur.

"Hot" Selective Catalytic Reduction (SCR): Due to the temperature limitation of conventional SCR catalysts, manufacturers have developed specially formulated zeolite catalysts designed to further the reduction reaction at temperatures up to 1025°F which is within the range of the exhaust gas temperature (1100°F) of this project. Typical NOx removal efficiencies for a hot SCR system would be 70% to 90% removal. Hot SCR is technically feasible for this project.

Selective Non-Catalytic Reduction (SNCR): In the SNCR process, ammonia or urea is injected at high temperatures without a catalyst to reduce NOx emissions to nitrogen and water vapor. However, the exhaust temperature must be maintained above 1600°F to allow the reaction to occur, otherwise uncontrolled NOx will be emitted as well as unreacted ammonia. In addition, the exhaust temperature must not exceed 2000°F or ammonia will actually be oxidized creating additional NOx emissions. SNCR is not feasible because the combustion turbine exhaust temperature of 1100°F is too low.

Non-Selective Catalytic Reduction (NSCR): NSCR uses a platinum/rhodium catalyst to reduce NOx to nitrogen and water vapor in exhaust gas streams containing less than 3% oxygen. This technology has only been applied to automobiles and stationary reciprocating engines. NSCR is not technically feasible because the oxygen content of the combustion turbine exhaust (13% to 15% oxygen) is too high.

SCONOx™: SCONOx™ is a NOx and CO control system exclusively offered by Goal Line Environmental Technologies. 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 requires a HRSG for use with a gas turbine. SCONOx™ is not technically feasible because the combustion turbine exhaust temperature of 1100°F is too high.

XONON™: XONON™ is an emerging technology that partially burns fuel in a low temperature pre-combustor and completes combustion in a catalytic combustor. The result is partial combustion with a lower temperature and NOx formation followed by flame-less catalytic combustion to further inhibit NOx formation. The technology has been demonstrated on only a few gas turbines that are much smaller than the proposed project. However, General Electric has teamed with Catalytica and plans to develop a combustor for gas turbines in the 80-90 MW range. XONON™ is rejected as an emerging technology that has not yet been demonstrated for this size gas turbine.

Of the control alternatives discussed, only DLN combustor technology, wet injection, and hot SCR remain as viable control options. Because DLN is not really a control option when firing oil, DLN and wet injection were combined to form a single option for evaluation purposes. The following table ranks these options in order of control effectiveness.

Control Option	Fuel	Controlled Emissions ppmvd, @ 15% O_2	Control Efficiency	Reduction TPY	Totals TPY	Cost per Ton of NOx Removed
Hot SCR	Gas	3.5	65.5%[a]	82.6	130.5	$10,189/ton NOx[b]
	Oil	16	65.5%	47.9		
DLN	Gas	25.0	Baseline	Baseline	Baseline	Baseline
Wet Injection	Oil	42.0	Baseline	Baseline		

Table Notes:

[a] Based on emissions from DLN-controlled level to SCR-controlled level. Assumes similar level of control for gas or oil firing.

[b] Based on estimated installed capital cost of $4,644,270 and a total annualized cost of $1,240,955 per year from the application and a vendor quote.

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Selective catalytic reduction (SCR) with ammonia injection is recognized as the top control option for this project and would result in an overall NOx reduction of 130.5 tons per year. The applicant reviewed SCR for the following additional adverse impacts.

Energy Impacts: Installation of SCR would result in an energy penalty due to the pressure drop across the catalyst bed of nearly 3.5 inches of water. This equates to nearly 4 million kWh per year of potential lost power generation. Based on a power cost of $0.030/kWh, this results in a lost energy cost of $118,260 per year.

Environmental Impacts: SCR requires the injection of ammonia at slightly above the stoichiometric rate which inevitably results in ammonia "slip" or emissions of unreacted ammonia. The applicant estimates as much as 25 tons of unreacted ammonia could slip by the SCR system. During startups, upsets, malfunctions, or as a result of catalyst degradation, ammonia emissions could exceed the odor threshold and cause ambient odor problems. Ammonia may react with sulfur to generate up to additional 50% more PM_{10} emissions in the form of ammonium sulfates and bisulfates. Ammonia has been designated as an Extremely Hazardous Substance under federal SARA Title III regulations. Finally, the spent catalyst could be considered hazardous requiring handling and disposal subject to RCRA regulations.

Economic Impacts: For purposes of comparison, DLN technology (and wet injection) was selected as the baseline because General Electric offers no other combustor design for this model combustion turbine. The applicant estimated the incremental, annualized cost of SCR with respect to DLN technology (and wet injection) to be nearly $10,189 per ton of NOX removed based on 100% base load operation. These costs are the result of substantial costs related to installation, equipment, catalyst replacement, energy consumption, and ammonia usage.

The applicant rejected SCR primarily based on unreasonable costs associated with controlling low NOx emissions. The applicant proposed the following as the best available controls:

Gas Firing: DLN technology with a NOx emissions standard of 9.0 ppmvd @ 15% oxygen; and

Oil Firing: Wet injection with a NOx emissions standard of 42.0 ppmvd @ 15% oxygen.

The applicant indicated that this proposal is consistent with recent Department BACT determinations for similar simple cycle combustion turbines in Florida as well as the determination made by other states for similar units.

6.1.3 Department's NOx BACT Determination

In general, the Department agrees with the applicant that DLN combustion technology for gas firing and wet injection for oil firing represents BACT for this simple cycle combustion turbine. The Department recognizes hot SCR as the top control option, but likewise rejects it due to adverse energy, environmental, and primarily economic impacts. Energy and environmental impacts are relatively minimal. The Department gives no consideration to potential odor problems due to malfunctions or catalyst degradation, as these are compliance issues. There appears to be a typo or calculation error in the applicant's estimated incremental cost per ton of NOx removed for the hot SCR option because $1,240,955 per year ÷ 130.5 tons per year of NOx removed equals $9509 per ton. Using the applicant's vendor cost proposals, the Department roughly estimates the incremental cost for the hot SCR control option to be $9211 per ton of NOx removed. This estimate considers a capital recovery factor of 7% and a credit of $25 per ton of NOx removed for Title V fees. The Department similarly rejects SCR primarily based on unreasonable costs associated with controlling very low NOx emissions. Therefore, the Department determines that the Best Available Control Technology for this project is the following.

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Gas Firing: DLN technology with a NOx emissions standard of 9.0 ppmvd @ 15% oxygen; and

Oil Firing: Wet injection with a NOx emissions standard of 42.0 ppmvd @ 15% oxygen.

This BACT determination is much more stringent than the standards of NSPS, Subpart GG. Compliance with the BACT emissions limiting standards shall be demonstrated by conducting initial and annual performance tests in accordance with EPA Method 20. Compliance shall be demonstrated with separate performance tests conducted for the firing of natural gas as well as for the firing of low sulfur distillate oil. In addition, a certified continuous emissions monitor shall be used to demonstrate compliance with these BACT limits based on a 24-hour block average for gas firing and a 3-hour block average for oil firing. The CEMS RATA results may be used demonstrate compliance provided the capacity, notice, and reporting requirements for the annual test are met.

6.2 CARBON MONOXIDE (CO)

6.2.1 Discussion of CO Emissions

Emissions of carbon monoxide (CO) will result from incomplete fuel combustion while operating the combustion turbine. Typically, CO emissions are inversely proportional to NOx emissions. However, new advanced combustor designs have been able to also lower CO emissions while reducing NOx emissions. The project will generate significant emissions of CO (> 100 tons per year) and must therefore apply the best available control technology (BACT).

6.2.2 Applicant's Proposed CO BACT

The applicant identifies two control options that are technically feasible and commercially available for combustion turbines: an oxidation catalyst and combustion process design. Noble metal oxidation catalysts may be incorporated into the combustion turbine exhaust. These catalysts promote the oxidation of CO to carbon dioxide (CO_2) at much lower temperatures (650°F to 1150°F) than possible for oxidation without the catalyst. For this project, the exhaust gas temperature of 1100°F is in the proper design range and at this temperature, the control efficiency is primarily a function of gas residence time. Increasing the catalyst bed depth will increase the gas residence time, but will also increase the pressure drop across the catalyst bed causing an undesirable energy loss. This leads to the following simplified analysis.

Control Option	Fuel	Controlled Emissions ppmvd, @ 15% O_2	Control Efficiency	Reduction TPY	Totals TPY	Cost per Ton of NOx Removed[c]
Oxidation Catalyst	Gas	2.0	90%	153.2[a]	170.2	$1900/ton NOx[b]
	Oil	2.0	90%	17.0[a]		
Combustion Design	Gas	20.0[c]	Baseline	Baseline	Baseline	Baseline
	Oil	20.0	Baseline	Baseline		

Table Notes:

[a] Based on emissions from DLN-controlled level to oxidation catalyst-controlled level. Assumes similar level of control for gas or oil firing.

[b] Based on estimated installed capital cost of $1,368,919 and a total annualized cost of $323,438 per year.

[c] Initially, the applicant requested a CO emissions limit of 25 ppmvd when firing natural gas. An oxidation catalyst would reduce the corresponding annual CO emissions by nearly 210 tons per year with a cost of $1550 per ton removed which the Department was considering for cost effectiveness. For an identical unit.

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the applicant also provided CO emissions test reports that indicated much lower emissions levels were achievable for DLN with the GE 7EA. Although unable to secure a guarantee from General Electric, the applicant requested a lower CO emission standard of 20 ppmvd which is reflected in this table.

An oxidation catalyst is recognized as the top control option and the applicant reviewed this option for the following additional adverse impacts.

Energy Impacts: Installation of an oxidation catalyst would result in an energy penalty due to the pressure drop across the catalyst bed of nearly 1.0 inch of water. This equates to about 1.3 million kWh per year of potential lost power generation. Based on a power cost of $0.030/kWh, this results in a lost energy cost of $39,420 per year.

Environmental Impacts: An oxidation catalyst would also readily oxidize other compounds as well as CO. For example, when firing distillate oil, SO_2 would be oxidized to SO_3 which would combine with moisture to form additional sulfuric acid mist as well as PM_{10}. An oxidation catalyst does not remove CO, but simply accelerates the natural atmospheric oxidation process of CO to CO_2. Further reduction of CO beyond levels inherent to the DLN design would not result in any additional environmental benefits or improved ambient air quality.

Economic Impacts: For purposes of comparison, DLN technology (and wet injection) was selected as the baseline because General Electric offers no other combustor design for this model combustion turbine. The applicant estimated the incremental, annualized cost of an oxidation catalyst with respect to the baseline (DLN/wet injection) to be nearly $1900 per ton of CO removed. These costs are the result of substantial costs related to installation, equipment, catalyst replacement, and energy consumption.

The applicant rejected SCR primarily based on unreasonable costs associated with controlling inherently low CO emissions. The applicant proposed the following as the best available controls:

Gas Firing: Combustion design with a CO emissions standard of 20.0 ppmvd @ 15% oxygen; and

Oil Firing: Combustion design with a CO emissions standard of 20.0 ppmvd @ 15% oxygen.

In addition, the applicant requested a permit condition be added if unable to comply with the lower CO emission standard during any annual test. The condition would allow the permittee to request a compliance schedule and establish final compliance within 12 months of such a request.

6.2.3 Department's CO BACT Determination

In general, the Department agrees with the applicant that the good combustion characteristics of the General Electric Model 7EA represent BACT for this project. However, the Department rejects the applicant's argument that the further reduction of CO emissions would have negligible ambient impacts. Ambient impacts are evaluated in the modeling analysis and are not considered in the BACT determination. The Department gives further consideration to the following items:

- At the requested CO emissions standards of 20/20 ppmvd for gas/oil firing, the Department believes an oxidation catalyst is not quite cost effective at $1900 per additional ton of CO removed, relative to the significant emissions rates for other regulated pollutants.
- The Department is aware of two similar GE 7EA units permitted in Florida. The Gainesville Regional Utilities' Deerhaven Station operates a simple cycle peaking unit with a NOx limit of 15 ppmvd and a CO limit to remain under 100 tons per year. Stack tests indicate CO emissions of 7.1 ppmvd with NOx emissions at 7.9 ppmvd. Kissimmee Utilities Authority's Cane Island Plant operates a combined cycle unit with a CO limit of 20 ppmvd and a NOx emissions limit of 25 ppmvd. However, this unit has tested at a rate of 9.7 ppmvd for CO and 10.5 ppmvd for NOx.

- Stack test information submitted by the applicant for an identical unit in Brandywine, Maryland indicates actual tested CO emissions levels of less than 10 ppmvd for firing natural gas and less than 5 ppmvd for firing distillate oil.
- The Department is aware that General Electric guarantees CO/NOx limits for the DLN-1 combustor dependent on the tuning for NOx. In other words, GE is able to tune the DLN-1 combustor for very low NOx emissions at the expense (or possibility) of increasing CO emissions. However, based on the available stack test information, these guarantees appear very conservative.
- Conversations with the applicant indicate that General Electric is unwilling to guarantee a lower CO limit due to some site-specific problems with other installations. However, GE was able to make specific modifications to the combustor to lower the CO emissions for these sites.
- The RACT/BACT/LAER Clearinghouse database identifies only a few projects where an oxidation catalyst was required as BACT. In each of these projects, the units were either much larger or much smaller than the General Electric Model 7EA.

The Department rejects the oxidation catalyst primarily based on the costs associated with controlling inherently low CO emissions. The Department believes the applicant has provided reasonable assurance that the proposed combustion turbine is capable of complying with the lower emissions standards of 20/20 ppmvd for gas/oil firing. Therefore, the Department determines that the Best Available Control Technology for this project is the following.

Gas Firing: Combustion design with a CO emissions standard of 25.0 ppmvd @ 15% oxygen during the first 12 months after initial startup and 20.0 ppmvd @ 15% oxygen thereafter; and

Oil Firing: Combustion design with a CO emissions standard of 20.0 ppmvd @ 15% oxygen.

The higher emission rate will allow sufficient time for the installation, tuning, and perhaps combustor modification, if necessary. Initial and annual compliance with the BACT standards shall be demonstrated by conducting individual performance tests in accordance with EPA Method 10 for firing natural gas and low sulfur distillate oil.

6.3 PARTICULATE MATTER (PM/PM_{10}), SULFURIC ACID MIST (SAM) AND SULFUR DIOXIDE (SO_2)

6.3.1 Discussion of PM/PM_{10}, SAM, and SO_2 Emissions

Emissions of particulate matter, sulfur dioxide, and sulfuric acid mist will result from the combustion of the gas turbine fuels. Particulate matter emissions increase with incomplete fuel combustion as well as with higher concentrations of ash, sulfur, and trace elements in the fuel. Most of the particulate matter emitted from these types of processes will be less than 10 microns in diameter (PM_{10}). Similarly, emissions of sulfur dioxide and sulfuric acid mist are a function of the amount of fuel sulfur. Gas turbines are subject to the following New Source Performance Standards for sulfur dioxide in 40 CFR 60, Subpart GG:

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

6.3.2 Applicant's Proposed PM/PM_{10}, SAM, and SO_2 BACT

The applicant identified several available control technologies for particulate matter removal including centrifugal collectors, electrostatic precipitators, fabric filters, and wet scrubbers. General Electric, the combustion turbine manufacturer, guarantees PM_{10} emissions for the Model 7EA unit of no more than 10 pounds per hour for natural gas firing and 26 pounds per hour for low sulfur distillate oil firing, including filterable and condensable fractions of the sampling train. Based on the design flow rate, this equates to approximately 0.002 grains per dry standard cubic feet of exhaust gas or roughly the emissions concentrations to be expected *after* control by a fabric filter. This level of emissions would be difficult to control with add-on equipment as well as measure during a performance test.

The applicant indicated that wet or dry flue gas desulfurization and fuel treatment could be applied to this project to remove sulfur compounds. Although no cases of flue gas desulfurization applied to combustion turbines were identified, this option is technically feasible. Fuel treatment involves the desulfurization of natural gas and distillate oil by the fuel vendor prior to delivery to the user. For this project, the applicant has requested the use of pipeline quality natural gas containing less than 2 grains of sulfur per 100 SCF and distillate oil containing no more than 0.05% sulfur by weight. Limiting the sulfur content of the fuels also establishes the maximum potential SAM and SO_2 emissions. At these already very low levels, the control efficiency of an add-on technology would be unreasonably low and cost prohibitive.

The applicant proposed the following low sulfur, clean fuels as the best viable controls for this project.

Gas Firing: Pipeline quality natural gas containing no more than 2 grains of sulfur per 100 SCF, and

Oil Firing: No. 2 distillate oil containing no more than 0.05% sulfur by weight.

The applicant provided information collected from EPA's RACT/BACT/LAER Clearinghouse indicating low-sulfur, clean fuels to be the predominant BACT control for these pollutants for combustion turbines. Typically, BACT has been established as pipeline-grade natural gas containing negligible sulfur as the primary fuel and low sulfur (< 0.05% sulfur by weight) distillate oil as a backup fuel.

6.3.3 Department's PM/PM_{10}, SAM, and SO_2 BACT Determination

The Department agrees with the applicant. It would be cost prohibitive to add equipment to control already very low emissions of particulate matter, sulfur dioxide, and sulfuric acid mist. A top-down BACT determination was not required. The specification of fuels containing low concentrations of sulfur constitutes a pollution prevention technique, is given favorable consideration by the Department, and remains consistent with EPA direction. Therefore, the Department determines that the Best Available Control Technology for this project is the designed combustion process of the GE Model 7EA unit and the following fuel specifications.

Gas Firing: The combustion turbine shall be fired primarily by pipeline natural gas containing no more than 2 grains of sulfur per 100 standard cubic feet of natural gas.

Oil Firing: The combustion turbine may be fired with No. 2 (or a superior grade) distillate fuel oil containing no more than 0.05% sulfur by weight and for no than 876 hours per consecutive 12 month period.

Limiting the sulfur content of the fuels to the above levels is clearly more stringent than the NSPS limit for sulfur dioxide. In addition, the measurement of particulate matter at these very low concentrations is uncertain. Therefore, the Department will specify the following permit condition as a surrogate for particulate matter.

Visible Emissions: Visible emissions from the combustion turbine exhaust shall not exceed 10% opacity.

Compliance with the fuel specifications shall be demonstrated by keeping records of the sulfur contents of the fuels delivered. Compliance with the visible emissions standard shall be demonstrated by conducting initial and annual performance tests in accordance with EPA Method 9.

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6.4 VOLATILE ORGANIC COMPOUNDS

Based on the manufacturer's guaranteed emissions rates, maximum VOC emissions will be less than 10 tons per year, well below the Significant Emissions Rate. Therefore, no BACT determination is required for this pollutant. However, the Department determines the following VOC emissions standards are necessary to ensure emissions levels are actually minor for purposes of this PSD review.

Gas Firing: 2.0 ppmvd measured as methane, 3-hour test average

Oil Firing: 4.0 ppmvd measured as methane, 3-hour test average

Initial compliance with the VOC emissions limits shall be demonstrated by conducting performance tests in accordance with EPA Methods 18, 25, and/or 25A. Thereafter, compliance with the VOC emissions rates shall be assumed if compliance is demonstrated for the emissions standards for carbon monoxide and visible emissions. Compliance shall also be demonstrated during the fiscal year prior to renewing each operation permit.

7.0 SUMMARY OF DEPARTMENT'S BACT DETERMINATION

7.1 BACT EMISSION LIMITS

Following are the BACT limits determined by the Department for this project. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, will be given in the specific conditions of the permit.

EU-004: GE Model 7EA Combustion Turbine

Pollutant	Controls[b]	Emission Standard
CO	Gas Firing W/DLN, First 12 Months After Initial Startup	25.0 ppmvd @ 15% oxygen 54.0 pounds per hour
	Gas Firing W/DLN, After First 12 Months After Initial Startup	20.0 ppmvd @ 15% oxygen 43.0 pounds per hour
	Oil Firing W/Wet Injection	20.0 ppmvd @ 15% oxygen 43.0 pounds per hour
NOx	Gas Firing W/DLN	9.0 ppmvd @ 15% oxygen 32.0 pounds per hour
	Oil Firing W/Wet Injection	42.0 ppmvd @ 15% oxygen 167.0 pounds per hour
PM/PM_{10}	Fuel Sulfur Specifications and Combustion Design	Visible emissions ≤ 10% opacity
SAM[a]/SO_2	Natural Gas Sulfur Specification	2 grain per 100 SCF of gas
	Low Sulfur Distillate Oil Sulfur Specification	0.05% sulfur by weight
VOC[a]	Gas Firing W/Combustion Design	2.0 ppmvd as methane 2.0 pounds per hour
	Oil Firing W/Combustion Design	4.0 ppmvd as methane 5.0 pounds per hour

[a] The VOC and SAM standards are synthetic (PSD) minor limits - not BACT limits.
[b] DLN means dry low-NOx controls. Oil firing is limited to 876 hours during any consecutive 12 months.

7.2 BACT COMPLIANCE DEMONSTRATION

Following is a brief summary of the methods required to demonstrate compliance with the BACT limits specified above.

Pollutant	Compliance Methods*
CO	EPA Method 10 for initial and annual tests concurrent with NOx.
NOx	EPA Method 20 for initial and annual tests concurrent with CO; continuous compliance shall be demonstrated with data from the certified continuous emissions monitor; annual RATA results may be substituted for annual tests if all capacity, notification, and reporting requirements are met.
PM/PM_{10}	EPA Method 9 for initial and annual visible emissions tests as a surrogate standard for PM/PM_{10}.
SO_2/SAM	Record keeping for the sulfur content of fuels delivered to the site.
VOC	Method 18, 25, or 25A for initial tests and prior to renewal of the operation permit, thereafter compliance is assumed IF compliance is maintained with the CO and VE standards.

* Compliance shall be demonstrated for each fuel type.

7.3 BACT EXCESS EMISSIONS ALLOWED

Pursuant to the Rule 62-210.700, F.A.C., excess emissions are permitted as follows.

Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, or malfunction of the combustion turbine shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions resulting from startup to simple cycle mode shall not exceed one (1) hour. In no case shall excess emissions from startup, shutdown, and malfunction exceed two hours in any 24-hour period. If excess emissions occur due to malfunction, the owner or operator shall notify the Compliance Authority within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. [Applicant Request, Vendor Data and Rule 62-210.700(1),(5), and (6), F.A.C.]

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. These emissions shall be included in the calculation of the 24-hour NOx averages for compliance determinations. [Rule 62-210.700(4), F.A.C.]

8.0 COMMENTS FROM NPS AND EPA REGION 4

8.1 NPS COMMENTS

The National Park Service commented that they were pleased to see the project proposed a new simple-cycle gas turbine that will meet a 9-ppmvd NOx limit when firing natural gas. NPS also agreed that there is little potential for this project to impact the Chassahowitza Class I Area due to low emissions and distance (130 km). The Department has no response.

8.2 EPA REGION 4 COMMENTS

The Department has the following response to EPA Region 4's comments.

1. EPA commented that the Department should also include the emission rate of 0.002 grains per dscf corresponding to the surrogate standard of 10% opacity. The Department established the surrogate standard because of the uncertainty of the test method measuring such low emissions.

However, the Department will include the emissions rate as a reference in the emissions standards summary table.

2. EPA commented on an inconsistency regarding the cost analysis for a CO oxidation catalyst. The Department was aware of the error and performed its own review of the cost effectiveness.

3. EPA commented that a similar DEP project (KUA Cane Island) allowed only one hour of excess emissions. In addition, EPA states that it is their policy not to grant automatic exemptions for excess emissions and that BACT applies during all normal operations. The Draft Permit includes conditions that limit excess emissions due to startup, shutdown, and malfunction to no more than 2 hours in any 24-hour period. In addition, the permit specifically limits excess emissions due to startup to no more than one hour in any 24-hour period. The Department justifies the periods of allowed excess emissions by a technical consideration of the physical operation of the combustor technology being employed. The dry-low NOx system requires a series of combustion stages to achieve the lean, premixed conditions that allow very low NOx emissions. During these relatively brief periods, emissions of CO and NOx are not yet stable. However, this is true for *many* combustion processes. The Department is authorized to grant these excess emissions conditions based on state Rule 62-210.700, F.A.C., as part of the EPA-approved State Implementation Plan.

4. EPA commented that the potential use of distillate oil would cause a small increase in the potential VOC emissions from the existing fuel storage tank. The Department agrees and will include the increased potential emissions in the state's database.

5. EPA notes that the OAQPS Cost Control Manual suggests an interest rate of 7% and not 7.5% as used by the applicant. The Department concurs.

6. EPA notes that SCR control efficiencies for NOx approach 90% and not the 61% used by the applicant. The Department notes that a 90% control efficiency for this project (9 ppmvd) would result in SCR-controlled emissions of less than 1 ppmvd. Due to problems with ammonia slip, catalyst fouling, and reagent stratification, the Department does not believe that this level of control is reliably measurable or consistently achievable. The Department concedes that a 90% control efficiency with SCR is possible when the uncontrolled NOx emissions are in the range of 25 ppmvd.

7. EPA recommended changing the applicant's proposed permit conditions using the phrase "tons per year" to "tons per consecutive 12 months". The Department is aware of the requirements regarding practicable enforceability. The Draft Permit includes such language when appropriate.

9.0 RECOMMENDATION AND APPROVAL

The permit project engineer and reviewing Professional Engineer is Jeff Koerner, P.E. The New Source Review Section recommends the above BACT determinations for this project. Additional details of this analysis may be obtained by contacting the project engineer at 850/414-7268 or the following address:

Department of Environmental Protection
Bureau of Air Regulation
New Source Review Section
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

DRAFT

Recommended By:

(DRAFT)

____

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

Date: ______________

Approved By:

(DRAFT)

____

Howard L. Rhodes, Director
Division of Air Resources Management

Date: ______________

APPENDIX GG - FEDERAL NEW SOURCE PERFORMANCE STANDARDS (NSPS)

40 CFR 60, SUBPART A - NSPS GENERAL PROVISIONS

This emissions unit is subject to the applicable portions of 40 CFR 60, 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
- 40 CFR 60.19, General Notification and Reporting Requirements

For copies of these requirements, please contact the Department's New Source Review Section.

40 CFR 60, SUBPART GG - STATIONARY GAS TURBINES

This emissions unit is subject to 40 CFGR 60, Subpart GG for stationary gas turbines adopted by reference in Rule 62-204.800(7)(b), F.A.C. The following conditions follow the original NSPS rule language and numbering scheme. Regulations that are not applicable were omitted for clarity. Because this emissions units is subject to an NSPS, it is also subject to the following federal provisions: 40 CFR 60, Subpart A, General Provisions for sources subject to an NSPS, adopted by reference in Rule 62-204.800(7)(d), F.A.C.; 40 CFR 60, Appendix A - Test Methods, Appendix B - Performance Specifications, Appendix C - Determination of Emission Rate Change, Appendix D - Required Emissions Inventory Information, Appendix F - Quality Assurance Procedures, adopted by reference in Rule 62-204.800(7)(e).

40 CFR 60.330 APPLICABILITY AND DESIGNATION OF AFFECTED FACILITY.

(a) The provisions of this subpart are applicable to all stationary gas turbines with a heat input at peak load equal to or greater than 10 million BTU per hour, based on the lower heating value of the fuel fired.

40 CFR 60.331 DEFINITIONS.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) <u>Stationary gas turbine</u> means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) <u>Simple cycle gas turbine</u> means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(d) <u>Combined cycle gas turbine</u> means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(f) <u>Ice fog</u> means an atmospheric suspension of highly reflective ice crystals.

(g) <u>ISO standard day conditions</u> means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) <u>Efficiency</u> means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) Peak load means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) Base load means the load level at which a gas turbine is normally operated.

(p) Gas turbine model means a group of gas turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

(q) Electric utility stationary gas turbine means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

60.332 STANDARD FOR NITROGEN OXIDES.

(a) On and after the date of the performance test required by Sec. 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b) of this section shall comply with one of the following, except as provided in paragraphs (e) of this section.

(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 = NO emission allowance for fuel-bound nitrogen as defined in the following table:

(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).

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

(f) Stationary gas turbines using water or steam injection for control of NOx emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

40 CFR 60.333 STANDARD FOR SULFUR DIOXIDE.

On and after the date on which the performance test required to be conducted by Sec. 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

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

40 CFR 60.334 MONITORING OF OPERATIONS.

(a) The owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water injection to control NOx emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to within +/- 5.0 percent and shall be approved by the Administrator.

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

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

(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.

(c) For the purpose of reports required under Sec. 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 Sec. 60.332 by the performance test required in Sec. 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 Sec. 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 Sec. 60.335(a).

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

(3) Ice fog. Each period during which an exemption provided in Sec. 60.332(g) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was

deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

40 CFR 60.335 TEST METHODS AND PROCEDURES.

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 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 Sec. 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 provided for in Sec. 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 Secs. 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:

$$NOx = (NOxo)\,(P_r/P_o)^{0.5}\,(e^{19(Ho-0.00633)})\,(288°K/T_a)^{1.53}$$

Where

NOx	=	emission rate of NOx at 15 percent oxygen and ISO standard ambient conditions, volume percent.
NOxo	=	observed NO<INF>x</INF> concentration, ppm by volume.
P_r	=	reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.
P_o	=	observed combustor inlet absolute pressure at test, mm Hg.
Ho	=	observed humidity of ambient air, g H<INF>2</INF>O/g air.
E	=	transcendental constant, 2.718.
T_a	=	ambient temperature, °K.

(2) The monitoring device of Sec. 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with Sec. 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.

(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.

(d) The owner or operator shall determine compliance with the sulfur content standard in Sec. 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference--see Sec. 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.

(e) To meet the requirements of Sec. 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.

SECTION IV.

APPENDIX XS - CEMS EXCESS EMISSIONS REPORT

FIGURE 1--SUMMARY REPORT--GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant *(Circle One)*: SO_2 NOx TRS H_2S CO Opacity

Reporting period dates: From ________________ to ________________

Company: ________________

Emission Limitation: ________________

Address: ________________

Monitor Manufacturer and Model No.: ________________

Date of Latest CMS Certification or Audit: ________________

Process Unit(s) Description: ________________

Total source operating time in reporting period [1]: ________________

Emission data summary [1]	CMS performance summary [1]
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] .... ____ % [2]	3. [Total CMS Downtime] x (100) / [Total source operating time] .... ____ % [2]

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

[2] 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 since last quarter in CMS, process or controls.

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

Name: ________________

Signature: ________________

Title: ________________

Date: ________________

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy, Chief, BAR

FROM: Jeff Koerner, New Source Review Section, BAR JK

DATE: August 30, 1999

SUBJECT: TECO Power Services
Hardee Power Station, Unit 2B
75 MW Simple Cycle Combustion Turbine Project (PSD-FL-140(A)

Attached is the public notice package for the installation of a new 75 MW gas-fired combustion turbine at the existing Hardee Power Station. The applicant, TECO Power Services, proposes to add one General Electric Model No. PG7121 7EA dual-fuel simple cycle combustion turbine with electrical generator set having a nominal power production of 75 MW. TECO Power Services identifies the new combustion turbine as "Unit 2B". The new unit will use the existing infrastructure including oil storage and support equipment.

Nitrogen Oxides (NO_X) emissions from the gas turbine will be controlled by dry low-NOx combustors capable of achieving emissions of 9 parts per million (ppm) by volume at 15 percent oxygen. Emissions of 42 ppm NOx will be achieved during the limited low sulfur distillate oil use (876 hours per year) by wet injection. Baseload carbon monoxide (CO) limits are 20 ppmvd corrected to 15% oxygen for gas and oil firing. For the first 12 months of operation, CO is limited to 25 ppmvd corrected to 15% oxygen for gas firing to allow for tuning the gas turbine. Emissions of volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter will be very low because of the inherently clean pipeline quality natural gas, limited fuel oil use and, especially, the design of the GE unit.

I recommend your approval of the attached Intent to Issue.

JFK

Attachments

Jeb Bush
Governor

Department of Environmental Protection

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

David B. Struhs
Secretary

P.E. Certification Statement

Permittee:

TECO Power Services
Hardee Power Station, Unit 2B
Hardee County, Florida

DEP File No. PSD-FL-140(A)

PPS No. PA89-25
Facility ID No. 0490015

Project type:

The applicant, TECO Power Services, proposes to add one General Electric Model No. PG7121 7EA dual-fuel simple cycle combustion turbine with electrical generator set having a nominal power production of 75 MW. TECO Power Services identifies the new combustion turbine as "Unit 2B". The new unit will use the existing infrastructure including oil storage and support equipment. Dry low-NOx (DLN) combustion technology will be used to control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will be used to control nitrogen oxide emissions when firing low sulfur distillate oil as a backup fuel for up to 876 hours per year. Combustion design and clean fuels will be used to minimize emissions of carbon monoxide, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds.

Baseload nitrogen oxides (NOx) limits are 9 ppmvd corrected to 15% oxygen for gas firing achievable by dry low-NOx technology and 42 ppmvd for oil firing controlled by water injection. Baseload carbon monoxide (CO) limits are 20 ppmvd corrected to 15% oxygen for gas and oil firing. For the first 12 months of operation, CO is limited to 25 ppmvd corrected to 15% oxygen for gas firing to allow for tuning the gas turbine.

Impacts due to the proposed project emissions are all less than the applicable significant impact limits corresponding to the nearest PSD Class I Area (Everglades National Park) and Class II areas.

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

Jeffery F. Koerner, P.E. — 8-28-99
Registration Number: 49441 — Date

Department of Environmental Protection
Bureau of Air Regulation, New Source Review Section
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Phone (850) 414-7268