Memorandum

Florida Department of Environmental Protection

BAR

TO: Howard L. Rhodes

THRU: Clair Fancy
Al Linero 10/5

FROM: Jeff Koerner JK

DATE: October 5, 1999

SUBJECT: Final PSD Permit No. PSD-FL-140A
TECO Hardee Power Station
75 MW Simple-Cycle Gas Turbine Project (Unit 2B)

Attached for approval and signature is the Final Permit for a project located at the Hardee Power Station, owned and operated by TECO Power Services. This project includes the addition of a 75 MW simple-cycle gas turbine, referred to as Unit 2B by the permittee, to an existing electrical generating plant. The Public Notice of Intent to Issue was published in the Tampa Tribune on September 4, 1999. No comments were received from the public, EPA, or the NPS regarding the Draft Permit. The applicant submitted comments that resulted in minor changes as summarized in the attached Final Determination.

I recommend your approval and signature.

Because this project is part of a modification to a Power Plant Siting Certification, there is no permit processing time clock.

Attachments

/jfk

Department of Environmental Protection

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

Jeb Bush
Governor

David B. Struhs
Secretary

NOTICE OF FINAL PERMIT

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

PSD Permit No. PSD-FL-140A
Hardee Power Station
Hardee County
New Gas Turbine, Unit 2B

Dear Mr. Ludwig:

Enclosed is Final Permit Number PSD-FL-140A. This permit authorizes TECO Power Services to construct a simple cycle, dual-fuel, General Electric Model 7EA combustion turbine with electrical generator set (75 MW). This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 10-8-99 to the person(s) listed:

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) 10-8-99 (Date)

FINAL DETERMINATION

TECO Power Services, Inc.
Hardee Power Station
PSD Permit No. PSD-FL-140A

The Department distributed a public notice package on August 30, 1999 to allow the applicant to construct a new 75 MW simple-cycle combustion gas turbine at the existing Hardee Power Station located approximately 3.5 miles north of State Road 62 on County Road 663 in Fort Springs, Hardee County, Florida. The Public Notice of Intent to Issue was published in the Tampa Tribune on September 4, 1999.

COMMENTS/CHANGES

The Department received no comments from the public regarding the Draft Permit.

The Department received no comments the EPA or the NPS regarding the Draft Permit.

The Department received comments from the applicant by letter dated 09/13/99 and faxed on the same date. The Department responded in writing to the applicant (09/14/99) and made minor revisions to the Draft Permit as a result of these comments. The DEP Power Plant Siting Office was notified by mail (and e-mail) on 09/16/99 of the minor revisions. The applicant's comments and the Department's response are summarized below.

Section II., Conditions No. 11 and 38(d)(1): The applicant requested the Department to revise the requirement to submit a Title IV application at least 24 months in advance of electrical production. The Department responded that this is a federal requirement that must be included in the permit. The Department also advised the applicant to contact the EPA Region 4 office regarding their proposed plans and submit the Title IV application as soon as possible.

Section III., Condition No. 4: The applicant requested that the Department delete this condition, which requires a revision of the BACT analysis if the permittee later requests a conversion of this emissions unit to combined-cycle operation. The applicant observed there was no appropriate rule citation. The Department's response is that the condition is a result of the information provided in the permit application indicating simple-cycle only operation. This information was the basis for rejecting available add-on control technologies in favor of a technology with a lesser control efficiency. The Department inadvertently omitted the rule citation, which is Rule 62-212.400(6)(b), F.A.C. referencing 40 CFR 52.166(j)(4). These regulations prevent an applicant from splitting projects in an effort to avoid PSD requirements. The Department stated that the applicant should revise the application and BACT analysis to include combined-cycle operation if this is the ultimate intent of this project, but the applicant declined stating that combined-cycle operation was only a conceivable future option. The Department did revise this condition to reflect that only a revised BACT analysis is required initially. A review of the revised BACT analysis may validate the original BACT determination; otherwise a full PSD permit application, new control equipment, and new emissions standards may be appropriate.

Section III., Condition No. 10: The applicant objected to the language that requires the permittee to "minimize pollutant emissions" and requested that this condition be changed to "comply with the specified emissions limitations". The Department revised this condition to require that the control systems be "maintained and tuned in accordance with the manufacturer's recommendations".

CONCLUSION

The final action of the Department is to issue the permit with the changes described above.

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 031 392 020

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

7. Date of Delivery
OCT 13 1999

5. Received By: *(Print Name)*

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

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

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

Thank you for using Return Receipt Service.

Z 031 392 020

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 Hardee	
Post Office, State, & ZIP Code Tampa Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
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Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 10-8-99 049015- 050-F1-14@a	

PS Form **3800**, April 1995

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

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:	May 1, 2001

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

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

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 to the existing facility.

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/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_x), 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

09/09/99	Received proof of Public Notice published in the 09/04/99 issue of the Tampa Tribune.
08-30-99	Distributed Intent to Issue Permit package.
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.

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 Blairstone 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. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 52.166(j)(4)]

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

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

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

12. Title V Permit: This permit authorizes construction of the permitted emissions 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. <u>BACT Determinations</u>: The combustion turbine 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. <u>NSPS Requirements</u>: 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. <u>Permitted Capacity</u>: 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 combustion turbine shall operate only in simple cycle mode. This requirement is based on the permittee's request, which formed the basis of the NOx BACT determination and resulted in the emission standards specified in this permit. Specifically, the NOx BACT determination eliminated several control alternatives based on technical considerations and costs due to the elevated temperatures of the exhaust gas. Any request to convert this unit to combined cycle operation by installing a new heat recovery steam generator or connecting this unit to an existing heat recovery steam generator shall require the permittee to perform a new NOx BACT analysis and the approval of the Department through a permit modification. The results of this analysis may validate the initial BACT determination or result in the submittal of a full PSD permit application, new control equipment, and new emissions standards. [Rule 62-212.400(6)(b), F.A.C.]

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 in accordance with the manufacturer's recommendations. [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 corrected to 15% oxygen 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 and 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 in terms of 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 Duration: 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 (or electronic) 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 or printed 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. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

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

Hardee Power Station Combustion Turbine Project (Unit 2B)
TECO Power Services
PSD-FL-140A 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.

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.
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.

08/30/99 The Department mailed the Intent to Issue Permit package to the applicant and affected parties.

09/04/99 The applicant published notice in the Tampa Tribune.

09/09/99 The Department received proof of the Public Notice.

09/16/99 The Department notified DEP's Power Plant Siting office of minor changes that would be made to the final permit.

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/PM10	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, NO_x, 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;
- 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.

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.

<u>"Hot" Selective Catalytic Reduction (SCR)</u>: 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.

<u>Selective Non-Catalytic Reduction (SNCR)</u>: 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.

<u>Non-Selective Catalytic Reduction (NSCR)</u>: 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.

<u>SCONOx™</u>: 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.

<u>XONON™</u>: 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	9.0	Baseline	Baseline	Baseline	Baseline
Wet Injection	Oil	42.0	Baseline	Baseline		

Table Notes:

[a] Based on emissions from DLN-controlled level to hot 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.

Hot 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 hot 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: Hot 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 hot 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 hot 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 hot 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.

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 CO Removed[c]
Oxidation Catalyst	Gas	2.0	90%	153.2[a]	170.2	$1900/ton CO[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, 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:

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

<u>Oil Firing</u>: 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 <u>Department's CO BACT Determination</u>

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 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.

<u>Gas Firing</u>: 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

<u>Oil Firing</u>: 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.

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

<u>Oil Firing</u>: 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 <u>Department's PM/PM_{10}, SAM, and SO_2 BACT Determination</u>

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 combustion design of the GE Model 7EA unit and the following fuel specifications.

<u>Gas Firing</u>: 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.

<u>Oil Firing</u>: 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.

<u>Visible Emissions</u>: 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.

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/PM10	EPA Method 9 for initial and annual visible emissions tests as a surrogate standard for PM/PM10.
SO2/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 also discovered this error when performing 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 or greater.

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

Recommended By:

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

Date: 10/6/99

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

Date: 10/6/99

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.

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) Stationary gas turbine 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) Simple cycle gas turbine 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) Combined cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(f) Ice fog means an atmospheric suspension of highly reflective ice crystals.

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

(h) Efficiency 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 NOx 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_2O/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.

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: Hamilton Oven, P.E. Administrator
DEP, Power Plant Siting Office

FROM: Jeff Koerner, New Source Review Section JK
DEP, DARM - Bureau of Air Regulation

DATE: September 16, 1999

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

I received and approved a request from the applicant to make some very minor changes to the following specific conditions in Section III of Draft Permit No. PSD-FL-140A.

#4. Revised to clarify that a revised BACT analysis is necessary which may require the submittal of a full PSD permit application. Also included the appropriate rule citation.

#10. Revised to clarify that maintenance and tuning of the unit is to be in accordance with the manufacturer's recommended schedule.

#16.(b) Added "corrected to 15% oxygen" for the CO limit which was inadvertently omitted.

#39. Added the capability of maintaining records in an electronic format that could be printed at the Department's request.

I have attached the complete revised pages so that they may be inserted into the original permit intact. The revisions are italicized and date of revision is included in the header. All of these changes are very minor and will be revised in the Department's Final Permit. The applicant published the PSD Public Notice in The Tampa Tribune on September 4, 1999. The 30-day PSD public comment period will expire on October 3, 1999. I have attached a copy of the Public Notice provided by the applicant.

Please contact me at 414-7268 if you have any questions.

JFK

Attachments

4. Simple Cycle Operation Only: *The combustion turbine shall operate only in simple cycle mode. This requirement is based on the permittee's request which formed the basis of the NOx BACT determination and resulted in the emission standards specified in this permit. Specifically, the NOx BACT determination eliminated several control alternatives based on technical considerations and costs due to the elevated temperatures of the exhaust gas. Any request to convert this unit to combined cycle operation by installing a new heat recovery steam generator or connecting this unit to an existing heat recovery steam generator shall require the permittee to perform a new, current NOx BACT analysis and the approval of the Department through a permit modification. The results of this analysis may validate the initial BACT determination or result in the submittal of a full PSD permit application, new control equipment, and new emissions standards.* [Rule 62-212.400(6)(b), F.A.C.]

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 *in accordance with the manufacturer's recommendations.* [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 *corrected to 15% oxygen* 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.

(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 *(or electronic)* 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 *or printed* 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

Best Available Copy

RECEIVED
SEP 0 7 1999
TECO Power Services

RECEIVED
SEP 09 1999
BUREAU OF AIR REGULATION

THE TAMPA TRIBUNE
Published Daily
Tampa, Hillsborough County, Florida

State of Florida }
County of Hillsborough } ss.

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

LEGAL NOTICE

in the matter of

PUBLIC NOTICE OF INTENT

was published in said newspaper in the issues of

SEPTEMBER 4, 1999

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

J Rosenthal

Sworn to and subscribed before me, this 7 day of SEPTEMBER, A.D. 19 99

Personally Known____or Product Identification______
Type of Identification Produced________________

(SEAL)

Susie Lee Slaton

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

NOTARY PUBLIC ★ STATE OF FLORIDA

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/PM10), sulfur dioxide (SO2). Dry low-NOx (DLN) combustion technology will be used to control nitrogen oxide emissions when firing (lle 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 Emisisons Rate
CO (First 12 months)	237	100
CO (After First 12 Months)	188	100
NOx	199	40
PM10	50	15
SO2	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 signification 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 com-

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 14-Sep-1999 03:32pm
From: Jeff Koerner TAL
KOERNER_J
Dept:
Tel No:

To: Paul Carpinone (carpin@ix.netcom.com)
To: Tom Davis (tdavis@ectinc.com)
To: Alvaro Linero TAL (LINERO_A)

Subject: Response to Requested Changes

Attached is the Department's response.

By Email

September 14, 1999

To: Paul Carpione, Director – Environmental
Hardee Power Partners

From: Jeff Koerner, New Source Review Section
Florida Department of Environmental Protection
Jeff.Koerner@dep.state.fl.us

Re: TECO Power Services, Hardee Power Station – Unit 2B
Draft Permit No. PSD-FL-140(a)

The Department received your faxed comments on the Draft Permit for Unit 2B at the Hardee Power Station. The following comments are in response to your requested changes.

Section II, Permit Condition No. 11 and Section III, Permit Condition No. 38(d)(1): The requirement to submit a Title IV application is a federal requirement pursuant to 40 CFR 72. The Department has no discretion to waive this federal requirement. I would recommend submittal of the Title IV application as soon as possible and discussing this issue with the EPA Region 4 office in Atlanta. If the Title IV application is submitted prior to issuance of the Final PSD Permit, the Department will include language in the permit to indicate that the requirement to submit a Title IV application has been met without commenting on the timeliness.

Section III, Permit Condition No. 4: The Department included this condition as a reminder that the Best Available Control Technology (BACT) determination relied upon specific information provided by the applicant regarding the intended plans for this unit. The purpose is to ensure that the integrity of the BACT process is maintained. For this project, conventional SCR was eliminated as not being technically feasible because the elevated temperature of the combustion turbine operating in simple cycle mode was beyond the acceptable operating range. In its place, hot SCR was evaluated – a much more costly option. Hot SCR was rejected due to unreasonable costs. The applicant indicated that there are no plans to operate this unit in combined cycle mode. The Department considers this statement at face value, but intends to obligate the applicant.

In addition, the current facility consists of several similar combustion turbines, some of which are combined cycle units. It is reasonable to anticipate that future demands may necessitate converting Unit 2B to combined cycle operation by connecting to an existing heat recovery steam generator (HRSG) or installing a new HRSG for this unit. Although no new emissions would result, the BACT determination must be revisited because of the substantial change to the original basis of the BACT determination. The condition *may not* result in any new controls, only that the BACT review process be properly followed. By including this condition, the Department intends to clarify this potential situation and clearly notify the applicant of this obligation. The purpose is to avoid confusion in order to streamline such a request for a modification. As you indicated, the rule citation was inadvertently omitted. This condition is based upon the following rule:

> **Rule 62-212.400(6)(b), F.A.C.**: "Phased Construction Projects - For phased construction projects, the determination of BACT shall be reviewed and modified in accordance with 40 CFR 51.166(j)(4), adopted and incorporated by reference in Rule 62-204.800, F.A.C."

The Department is considering the following changes to this permit condition.

4. Simple Cycle Operation Only: The combustion turbine shall operate only in simple cycle mode. This requirement is based on the permittee's request which formed the basis of the NOx BACT determination and resulted in the emission standards specified in this permit. Specifically, the NOx BACT determination eliminated several control alternatives based on technical considerations and costs due to the elevated temperatures of the exhaust gas. Any request to convert this unit to combined cycle operation by installing a new heat recovery steam generator or connecting this unit to an existing heat recovery steam generator shall require the permittee to perform a new, current NOx BACT analysis and the approval of the Department through a permit modification. The results of this analysis may validate the initial BACT determination or result in the submittal of a full PSD permit application, new control equipment, and new emissions standards. [Rule 62-212.400(6)(b), F.A.C.]

Note that this condition only prevents simple cycle operation until a new BACT analysis is performed and a corresponding permit modification is obtained. If the intent to operate this unit only in simple cycle mode has changed, please modify your PSD permit application accordingly.

Section III, Permit Condition No. 10: The Department fully expects the combustion turbine to operate at emissions levels below the permit limits. In fact, the permit limits contain a substantial margin above the actual expected emissions. However, as control systems age, they may degrade or require tuning to achieve optimal performance of the equipment. In addition, the poor operation of a unit may result in increased pollutant emissions. The Department believes that it is important properly maintain and operate the control equipment *in accordance with the manufacturer's recommendations*. The result will be reduced pollutant emissions and more successful compliance with the permit limits. This condition will remain unchanged.

If you have any further comments or questions, please contact me at 850/414-7268.

ORG 14.1

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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:

MR. Jeff Koerner, P.E.
Bureau of Air Regulation
New Source Review Section
Florida Department of Environmental Protection
Suite 4
111 South Magnolia Drive
Tallahassee, Florida 32301

4a. Article Number
Z 611 343 793

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

7. Date of Delivery

5. Signature (Addressee)

6. Signature (Agent)

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

Thank you for using Return Receipt Service.

PS Form **3811**, December 1991 ☆U.S. GPO: 1993—352-714 **DOMESTIC RETURN RECEIPT**

TECO POWER SERVICES

HARDEE POWER PARTNERS

By Fax

September 13, 1999

Mr. Jeff Koerner, P.E.
Bureau of Air Regulation
New Source Review Section
Florida Department of Environmental Protection
Suite 4
111 South Magnolia Drive
Tallahassee, Florida 32301

Re: TECO Power Services, Hardee Power Station – Unit 2B
FDEP File No. PSD-FL-140(a);

Dear Mr. Koerner:

We have received and reviewed the materials that you forwarded concerning the proposed Unit 2B addition at the Hardee Power Station. We appreciate the opportunity to provide comments on the permit conditions for the project and appreciate your willingness to share that material with us and to discuss our concerns. With a few exceptions, we are in agreement with the proposed permit documents and the specific conditions that relate to this project. We do have some comments on several conditions that we hope the Department will be in a position to address as their inclusion in the final permit will create significant problems for the project. These comments are addressed below.

General and Administrative Requirements -- Paragraph No. 11 of this section of the permit draft requires that a Title IV permit application for the project be filed at least 24 months prior to the date on which the new unit begins serving an electrical generator greater than 25 megawatts. We recognize that this requirement is contained in the Department's rules, and in the Environmental Protection Agency (EPA) regulations on this issue. For this project, however, the 24 month time frame is not applicable. Due to the shorter construction period for the type of facility that we are proposing, and based on the schedule that we are operating under presently, we would have to have submitted the Title IV permit application in May of this year in order to comply with this condition. This, of

HARDEE POWER PARTNERS, LTD.
P. O. BOX 111 TAMPA, FL 33601-0111
AN EQUAL OPPORTUNITY COMPANY

(813) 228-1330
FAX (813) 228-1308
HTTP://WWW.TECOPOWERSERVICES.COM

course, would have been prior to the time that we submitted the permit application that is presently under review.

We suggest that this condition be modified to reflect the construction schedule and the operation schedule under which we are proceeding. It would be reasonable to require that the Title IV permit application be submitted not later than January 1, 2000.

Performance Restriction – Paragraph No. 4 under this section provides that the permittee may request that the unit be operated in a combined cycle mode by installing a heat recovery steam generator, but that such a request would require modification of the permit, a full PSD permit application, and a new BACT review, apparently without regard to whether the proposed change in the method of operation would constitute a modification that would be subject to PSD review. This particular condition does not contain any citations to the regulations that would authorize its inclusion in the permit. We object to this condition and request that it be removed completely from the permit. Although we have no current firm plans for converting the facility into a combined cycle unit in the future, should the determination be made to do so, the proposal would be subjected to the regulatory analysis that is applicable and in place at the time. We see no need to prejudge the operation or to impose requirements now that may not be authorized, based upon the facts that are developed at the time any request to modify the facility is made. If a change is proposed and it does not trigger PSD review, there would be no basis for requiring the changed facility to undergo a new BACT analysis, as we understand it. This condition, therefore, appears not to be authorize by applicable regulations.

Emissions Controls – Paragraph No. 10 of this section contains a requirement that the operator employ good operating practices for the facility and that the system be tuned to optimize the reduction of certain pollutants and be maintained and tuned to minimize pollutant emissions. We certainly intend to operate the facility in a manner that ensures compliance with the emission limitations that are contained in the permit at all times. However, we believe that inclusion of such terms as "optimize" and "minimize" could lead to interpretational difficulties in the future. These terms could be construed to require that the facility be operated at levels below the emission limitations contained in the permit documents. We do not believe that this is the intent of the Department, and we request that these terms be deleted and that the condition be rewritten to refer to the emission limitations. We certainly have no objection to a requirement that the system be operated in such a manner as to ensure compliance with specified emission limitations contained in the permit.

Continuous Monitoring Requirements – Condition 38(d)(1) repeats the requirement that an acid rain permit be applied for 24 months before the beginning of commercial operation. As noted above, this time limit is not feasible based upon the construction and operation schedule for this unit. We request that it be changed to reflect the schedule for the project and further suggest that the application be required to be submitted prior to January 1, 2000.

We appreciate the opportunity to provide these comments and look forward to working with you to resolve these issues. We will be in contact with you to discuss the matter in more detail. In the meantime, if you have any questions, please give me a call.

Sincerely,

Paul L. Carpinone

Paul Carpinone
Director, Environmental

Cc: L.N. Curtin (H&K)
T. Davis (ECT)

FACSIMILE TRANSMITTAL

TECO POWER SERVICES

702 North Franklin
Tampa, FL 33602

MAILING ADDRESS:
P. O. Box 111
Tampa, FL 33601

Phone: (813) 228-1675
Fax: (813) 228-1360

PLEASE DELIVER IMMEDIATELY

TO: Mr. Jeff Koerner, P.E. 850-922-6979

FROM: Justino Morales

DATE: September 13, 1999

RE:

MESSAGE:

NUMBER OF PAGES (Including this cover page): 4
HARD COPY TO FOLLOW: YES
IF ANY PROBLEMS, CALL (813) 228-1675

HARDEE POWER PARTNERS

By Fax

September 13, 1999

Mr. Jeff Koerner, P.E.
Bureau of Air Regulation
New Source Review Section
Florida Department of Environmental Protection
Suite 4
111 South Magnolia Drive
Tallahassee, Florida 32301

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Sincerely,

Paul L. Carpinone

Paul Carpinone
Director, Environmental

Cc: L.N. Curtin (H&K)
T. Davis (ECT)

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:

Mr. Doug Neeley, Section Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA - Region IV
61 Forsyth Street
Atlanta, GA 30303

4a. Article Number
Z 333 618 132

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

7. Date of Delivery

5. Received By: *(Print Name)*

6. Signature: *(Addressee or Agent)*
X SEP - 1 1999

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 333 618 132

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

Sent to Neeley	
Street & Number EPA	
Post Office, State, & ZIP Code Atlanta GA	
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 Hardee P.S. 8-30-99 PSD-FL-140a P259-25	

PS Form **3800**, April 1995

Pollutant	Project Potential Emissions	PSD Significant Emisisons Rate
CO (First 12 months)	237	100
CO (After First 12 Months)	188	100
NOx	199	40
PM10	50	15
SO2	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 signification 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).

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. 32309-3000. 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 Deparement'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 interest 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
Telephone: 850/488-0114
Fax: 850/922-6979

Dept. of Environmental Protection
South District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8318
Telephone: (813) 744-6100
Fax: (813) 744-6084

TECO Power Services
702 North Franklin Street
Tampa, FL 33602
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.

4928 9/4/99

RECEIVED
SEP 07 1999
TECO Power Services

THE TAMPA TRIBUNE

Published Daily

Tampa, Hillsborough County, Florida

RECEIVED
SEP 09 1999
BUREAU OF AIR REGULATION

State of Florida }
County of Hillsborough } ss.

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

LEGAL NOTICE

in the matter of

PUBLIC NOTICE OF INTENT

was published in said newspaper in the issues of

SEPTEMBER 4, 1999

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

J. Rosenthal

Sworn to and subscribed before me, this 7 day of SEPTEMBER, A.D. 1999

Personally Known ____ or Product Identification ____
Type of Identification Produced ____

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

(SEAL)

Susie Lee Slaton

cc:

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 2E
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/PM10), sulfur dioxide (SO2). 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 Emissisons Rate
CO (First 12 months)	237	100
CO (After First 12 Months)	188	100
NOx	199	40
PM10	50	15
SO2	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 signification 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).

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. 32309-3000. 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 Deparement'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 interest 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
Telephone: 850/488-0114
Fax: 850/922-6979

Dept. of Environmental Protection
South District Office
3804 Coconut Palm Drive
Tampa, Florido 33619-8318
Telephone: (813) 744-6100
Fax: (813) 744-6084

TECO Power Services
702 North Franklin Street
Tampa, FL 33602
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.

4928 9/4/99

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. R. Douglas Neeley, Chief
Air, Radiation Technology Branch
US EPA Region IV
61 Forsyth Street
Atlanta, GA 30303

Re: PSD Review and Custom Fuel Monitoring Schedule
TECO Power Services' Hardee Power Station Unit 2B
PSD-FL-140(A) / PA89-25

Dear Mr. Neeley:

Enclosed is a copy of the Department's draft permit to construct Unit 2B for the Hardee Power Station in Hardee County, Florida. The Department's Intent to Issue package was already mailed to Mr. Gregg Worley of Region 4. This project consists of adding 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.

The project is subject to the Florida's Power Plant Siting procedure and will be a modification of PPS certification No. PA89-25.

Please send your written comments on or approval of the applicant's proposed custom fuel monitoring schedule. The plan is based on the letter dated January 16, 1996 from Region V to Dayton Power and Light. The Subpart GG limit on SO_2 emissions is 150 ppmvd @ 15% O_2 or a fuel sulfur limit of 0.8% sulfur. Neither of these limits could conceivably be violated by the use of pipeline quality natural gas which has a maximum SO_2 emission rate of 0.0006 lb/MMBtu (40 CFR 75 Appendix D Section 2.3.1.4). The sulfur content of pipeline quality natural gas in Florida has been estimated at a maximum of 0.003 % sulfur. Fuel oil will with a 0.05% sulfur content will be used. The requirements have been incorporated into the enclosed draft permit as Specific Conditions 37 and 38 and read as follows:

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]

Also, please comment on these conditions with respect to the use of the acid rain NOx CEMS for demonstrating compliance as well as reporting excess emissions. Typically NOx emissions will be less than 9 ppmvd @15% O_2 (gas) which is less than one-tenth of the applicable Subpart GG limit based on the efficiency of the unit. A CEMS requirement is stricter and more accurate than any Subpart GG requirement for determining excess emissions.

The Department recommends your approval of the custom fuel monitoring schedules and these NO_X monitoring provisions. We also request your comments on the Intent to Issue. If you have any questions on these matters please contact Jeff Koerner at 850/414-7268.

Sincerely,

for A. A. Linero, P.E., Administrator
New Source Review Section

AAL/jfk

Enclosures

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

August 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.

Ron Tober (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)*

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

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

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

Thank you for using Return Receipt Service.

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
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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.

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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}.

c - 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

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.

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

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.

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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.

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
NO_x	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}.

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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

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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,

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:

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

<u>Oil Firing</u>: 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.

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

<u>Oil Firing</u>: 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 <u>Department's PM/PM_{10}, SAM, and SO_2 BACT Determination</u>

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.

<u>Gas Firing</u>: 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.

<u>Oil Firing</u>: 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.

<u>Visible Emissions</u>: 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/PM10	EPA Method 9 for initial and annual visible emissions tests as a surrogate standard for PM/PM10.
SO2/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

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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: ______________

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) Stationary gas turbine 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) Simple cycle gas turbine 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) Combined cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(f) Ice fog means an atmospheric suspension of highly reflective ice crystals.

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

(h) Efficiency 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:

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

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

Department of
Environmental Protection

Jeb Bush
Governor

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 8-28-00

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

"Protect, Conserve and Manage Florida's Environment and Natural Resources"

Printed on recycled paper.

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 20-Aug-1999 11:10am
From: Jeff Koerner TAL
KOERNER_J
Dept: Air Resources Management
Tel No: 850/414-7268 GIC 069

To: Tom Davis (tdavis@ectinc.com)
To: Paul Carpinone (carpin@ix.netcom.com)

Subject: Hardee Power Station: New GE 7EA Combustion Turbine Project

Tom and Paul,

I received your updated information. For the DLN-1 combustor, it seems that GE is reluctant to guarantee CO emissions lower than 25 ppmvd when also guaranteeing a NOx emission standard of 9.0 ppmvd. I understand this is due to a few site-specific installations that had problems meeting a similar lower limit. However, GE was able to modify the combustor and meet the standard.

Although GE won't guarantee (yet) the lower CO emissions rates, the stack tests certainly suggest that emissions rates much lower than 25 ppmvd are achievable while meeting the 9 ppmvd standard. I believe your request to reduce CO emissions standard to 20 ppmvd is reasonable and makes the installation of an oxidation catalyst appear not quite cost effective in obtaining additional reductions. In consideration of possible problems during the initial installation including fine tuning the combustion turbine and perhaps modifying the combustor, I recommend the following specific permit condition.

12. Carbon Monoxide (CO)

(a) Dry-Low NOx Controls: 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) Water Injection: When firing low sulfur distillate oil in the combustion turbine, CO emissions shall not exceed 46.0 pounds per hour nor 20.0 ppmvd based on a 3-hour test average.

Please provide any comments.

Jeff

FACSIMILE TRANSMITTAL

TECO POWER SERVICES

702 North Franklin
Tampa, FL 33602

MAILING ADDRESS:
P. O. Box 111
Tampa, FL 33601

Phone: (813) 228-1675
Fax: (813) 228-1360

PLEASE DELIVER IMMEDIATELY

TO: Mr. Jeffery F. Koerner, P.E.

FROM: Paul L. Carpinone

DATE: August 18, 1999

RE: HARDEE Power STATION
CT 2B Project

MESSAGE:

Please call if you have any questions.

NUMBER OF PAGES (Including this cover page): 10
HARD COPY TO FOLLOW: YES
IF ANY PROBLEMS, CALL (813) 228-1675

POWER SERVICES **HARDEE POWER PARTNERS**

August 18, 1999

BY FAX

Mr. Jeffery F. Koerner, P.E.
Bureau of Air Regulation
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: FDEP File No. PSD-FL-140(a);
TECO Power Services - Hardee Power Station;
Simple-Cycle (SC) CT2B Power Project

Dear Mr. Koerner:

Per our conversation, Hardee Power Partners (HPP) hereby submits revised BACT summary sheets (see attached) based on achieving a lower carbon monoxide (CO) concentration of 20 ppmvd during natural gas-firing for the proposed CT2B combustion turbine at Hardee Power Station.

As discussed, HPP has requested from GE a lower guaranteed CO emission rate than the 25 ppmvd CO concentration specified in the submitted permit application for natural gas-firing. The basis for this request was the finding that similar GE 7EA gas turbines, equipped with a 9 ppm NOx tuned DLN-1 combustion system, could produce on average a lower CO concentration than the 25 ppm guarantee level. In response to this request, however, GE was not willing to provide a guarantee for a lower CO emission rate, but would be willing to tune the combustion system, at the expense of HPP, to a lower value while maintaining the 9 ppm NOx emission concentration level.

As a result, HPP is willing to accept a CO permit limit of 20 ppmvd during natural gas-firing, along with a revised permit condition that would allow CT2B to operate while modifications or corrections, if needed, are being implemented. The condition would apply in the event that the 20 ppmvd CO concentration level is exceeded during any annual compliance test. This condition is being requested as a contingency due to the time required by GE to manufacture and re-tune the combustion system to achieve a lower CO level than the guaranteed emission rate of 25 ppmvd, if such modifications become necessary. For your convenience, I have attached proposed permit language revisions that we believe will allow us to achieve a lower CO emissions rate for this combustion turbine.

Your continued expeditious processing of the Hardee Power Station CT2B permit application is appreciated. Please contact me at 813-228-4858, if there are any further questions.

Sincerely,

Paul L. Carpinone

Paul L. Carpinone
Director, Environmental

Attachments

cc: H. S. Oven, FDEP, Tallahassee
L. N. Curtin, H&K, Tallahassee
T. W. Davis, ECT, Gainesville

4. Professional Engineer Statement:

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

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

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

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

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

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

Thomas M. Davis 8/17/99

Signature Date

(seal)

* Attach any exception to certification statement.

Certification is applicable to August 1999 information submittal regarding the Hardee Power Station Simple-Cycle Combustion Turbine Project.

Table 5-12. Summary of CO BACT Analysis (Revised 8/99)

Control Option	Emission Impacts: Emission Rates (lb/hr)	Emission Rates (tpy)	Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Adverse Envir. Impact (Y/N)
Oxidation catalyst	4.3	18.9	170.2	1,368,919	323,438	1,900	4,484	Y	Y
Baseline	43.2	189.1	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: One GE PG7121 (7EA) CTG, 100-percent load for 7,884 hr/yr gas-firing and 876 hr/yr oil-firing.

Sources: GE, 1999.
ECT, 1999.

**Table 2. Hardee Power Station - CT2B (Revised 8/99)
CTG Operating Scenarios - General Electric PG7121(EA)
Natural Gas-Firing; Hourly Emission Rates**

Temp. (°F)	Case	Load (%)	PM/PM_{10}[1] (lb/hr)	PM/PM_{10}[1] (g/sec)	SO_2[2] (lb/hr)	SO_2[2] (g/sec)	H_2SO_4[3] (lb/hr)	H_2SO_4[3] (g/sec)	Lead[4] (lb/hr)	Lead[4] (g/sec)
32	1	100	5.0	0.63	5.7	0.72	0.655	0.0825	4.99E-04	6.29E-05
	2	75	5.0	0.63	4.6	0.58	0.526	0.0663	4.01E-04	5.05E-05
	3	65	5.0	0.63	4.2	0.53	0.486	0.0612	3.70E-04	4.66E-05
59	5	100	5.0	0.63	5.3	0.67	0.610	0.0768	4.65E-04	5.85E-05
	6	75	5.0	0.63	4.3	0.54	0.496	0.0624	3.78E-04	4.76E-05
	7	65	5.0	0.63	4.0	0.50	0.458	0.0577	3.49E-04	4.40E-05
95	9	100	5.0	0.63	4.8	0.60	0.550	0.0693	4.19E-04	5.28E-05
	10	75	5.0	0.63	4.0	0.50	0.454	0.0572	3.46E-04	4.36E-05
	11	65	5.0	0.63	3.7	0.46	0.420	0.0529	3.20E-04	4.03E-05
		Maximums	**5.0**	**0.63**	**5.7**	**0.72**	**0.655**	**0.0825**	**4.99E-04**	**6.29E-05**

Temp. (°F)	Case	Load (%)	NO_x (ppmvd)[5]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd)[5]	CO (lb/hr)	CO (g/sec)	VOC (ppmvd)[5]	VOC (lb/hr)	VOC (g/sec)
32	1	100	9.0	35.0	4.41	19.6	45.6	5.75	1.5	2.0	0.25
	2	75	9.0	28.0	3.53	24.1	45.0	5.67	1.4	1.6	0.20
	3	65	9.0	25.0	3.15	24.0	40.0	5.04	1.4	1.4	0.18
59	5	100	9.0	32.0	4.03	19.8	43.2	5.44	1.5	1.8	0.23
	6	75	9.0	26.0	3.28	24.2	42.0	5.29	1.5	1.4	0.18
	7	65	9.0	24.0	3.02	24.1	39.0	4.91	1.5	1.4	0.18
95	9	100	9.0	29.0	3.65	19.9	39.2	4.94	1.5	1.8	0.23
	10	75	9.0	24.0	3.02	24.0	39.0	4.91	1.5	1.4	0.18
	11	65	9.0	22.0	2.77	24.3	36.0	4.54	1.5	1.2	0.15
		Maximums	**9.0**	**35.0**	**4.41**	**24.3**	**45.6**	**5.75**	**1.5**	**2.0**	**0.25**

[1] Excludes sulfuric acid mist.
[2] Based on natural gas sulfur content of 2.0 gr/100 ft³.
[3] Based on 7.5% conversion of SO_2 to H_2SO_4.
[4] Natural gas combustion, Table 1.4-2, AP-42, March 1998.
[5] Corrected to 15% O_2.

Sources: ECT, 1999.
GE, 1999.

Table 6A. Hardee Power Station - CT2B (Revised 8/99)
CTG Operating Scenarios - General Electric PG7121(EA)
Annual Emission Rates - Criteria Pollutants

Source	Case	No. of CTGs	Annual Operations (hrs/yr)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT2B	5 - Gas	1	7,884	32.0	126.1	43.2	170.3	1.8	7.1
CT2B	5 - Oil	1	876	167.0	73.1	43.0	18.8	4.5	2.0
			Totals	N/A	199.3	N/A	189.1	N/A	9.1

Source	Case	No. of CTGs	Annual Operations (hrs/yr)	Emission Rates					
				PM/PM_{10}		SO_2		Lead	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT2B	5 - Gas	1	7,884	5.0	19.7	5.3	20.9	0.0005	0.0018
CT2B	5 - Oil	1	876	10.0	4.4	51.9	22.7	0.055	0.024
			Totals	N/A	24.1	N/A	43.7	N/A	0.026

1. CT2B operating with natural gas-firing at a 90.0% capacity factor; 7,884 hours/year at base load (Case 5).
2. CT2B operating with fuel oil-firing at a 10.0% capacity factor; 876 hours/year at base load (Case 5).
3. SO_2 rates based on natural gas sulfur content of 2.0 gr/100 ft^3.
4. SO_2 rates based on fuel oil sulfur content of 0.05 wt. percent.

Sources: GE, 1999.
ECT, 1999.
TPS, 1999.

Table 8.C. **Hardee Power Station - CT2B (Revised 8/99)**
CT Exhaust Data - General Electric PG7121(EA)
Natural Gas-Firing; Simple-Cycle

C. Correction of GE CO and VOC Concentrations to 15% O_2, dry

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			65 % Load		
	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F
Case	1	5	9	2	6	10	3	7	11
CO (ppmvd)	20.0	20.0	20.0	25.0	25.0	25.0	25.0	25.0	25.0
CO (15% O_2)	19.6	19.8	19.9	24.1	24.2	24.0	24.0	24.1	24.3
VOC (ppmvw)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
VOC (ppmvd)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
VOC (15% O_2)	1.5	1.5	1.5	1.4	1.5	1.5	1.4	1.5	1.5

Sources: ECT, 1999.
GE, 1999.

EXHIBIT A REVISED 8/18/99

PROPOSED MODIFICATIONS OF CONDITIONS OF CERTIFICATION
HARDEE POWER STATION UNIT 2B
PA 89-25

EMISSION LIMITS AND STANDARDS

17. The following table is a summary of the BACT determination and is followed by the applicable specific conditions. Values for NO_X are corrected to 15 % O_2 on a dry basis. These limits or their equivalent in terms of lb/hr or NSPS units, as well as the applicable averaging times, are followed by the applicable specific conditions [Rules 62-212.400, 62-204.800(7)(b) (Subpart GG), 62-210.200 (Definitions-Potential Emissions) F.A.C.]

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}, VE	Pipeline-Quality Natural Gas Good Combustion	10 Percent Opacity
VOC	As Above	2 ppmvd (Gas) 4 ppmvd (Fuel Oil)
CO	As Above	205 ppmvd (Gas) 20 ppmvd (Fuel Oil)
SO_2	Pipeline-Quality Natural Gas Low Sulfur Oil	2 gr S/100 ft^3 (Gas) 0.05% S (Fuel Oil)
NO_X	DLN, WI for F.O., limited fuel oil usage	9 ppmv (Gas) 42 ppmv (Fuel Oil) - 876 Hours/Year Max.

18. Nitrogen Oxides (NO_X) Emissions:

- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.
- While firing Natural Gas: The emission rate of NO_X in the exhaust gas shall not exceed 9 ppm @15% O_2 (at ISO conditions) on a 24 hr block average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 32 lb/hr and 9 ppm @15% O_2 to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- While firing Fuel oil: The concentration of NO_X in the exhaust gas shall not exceed 42 ppmvd at 15% O_2 on the basis of a 3 hr average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 167 lb/hr and 42 ppm @15% O_2 to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

19. Carbon Monoxide (CO) Emissions: The concentration of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on either natural gas or distillate fuel oil shall exceed neither 205 ppmvd nor 4354 lb/hr to be demonstrated by stack test using EPA Method 10. [Rule 62-212.400, F.A.C.] Should any annual test demonstrate that CO emissions exceed either 20 ppmvd or 43 lb/hr, the Permittee shall submit either a request for a permit modification or a compliance schedule to achieve the 20 ppmvd and 43 lb/hr CO emission limits within thirty days following

submittal of the annual test results to the Department. A compliance schedule, if submitted, shall describe the corrective action proposed to comply with the 20 ppmvd and 43 lb/hr CO emission limits and include milestone implementation dates. Final compliance with the applicable CO emission limits shall occur no later than 12 months from the date of Department approval of the permit modification request or compliance schedule.

TECO POWER SERVICES

HARDEE POWER PARTNERS

RECEIVED

AUG 19 1999

BUREAU OF AIR REGULATION

August 18, 1999

BY FAX

Mr. Jeffery F. Koerner, P.E.
Bureau of Air Regulation
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: FDEP File No. PSD-FL-140(a);
TECO Power Services - Hardee Power Station;
Simple-Cycle (SC) CT2B Power Project

Dear Mr. Koerner:

Per our conversation, Hardee Power Partners (HPP) hereby submits revised BACT summary sheets (see attached) based on achieving a lower carbon monoxide (CO) concentration of 20 ppmvd during natural gas-firing for the proposed CT2B combustion turbine at Hardee Power Station.

As discussed, HPP has requested from GE a lower guaranteed CO emission rate than the 25 ppmvd CO concentration specified in the submitted permit application for natural gas-firing. The basis for this request was the finding that similar GE 7EA gas turbines, equipped with a 9 ppm NOx tuned DLN-1 combustion system, could produce on average a lower CO concentration than the 25 ppm guarantee level. In response to this request, however, GE was not willing to provide a guarantee for a lower CO emission rate, but would be willing to tune the combustion system, at the expense of HPP, to a lower value while maintaining the 9 ppm NOx emission concentration level.

As a result, HPP is willing to accept a CO permit limit of 20 ppmvd during natural gas-firing, along with a revised permit condition that would allow CT2B to operate while modifications or corrections, if needed, are being implemented. The condition would apply in the event that the 20 ppmvd CO concentration level is exceeded during any annual compliance test. This condition is being requested as a contingency due to the time required by GE to manufacture and re-tune the combustion system to achieve a lower CO level than the guaranteed emission rate of 25 ppmvd, if such modifications become necessary. For your convenience,

HARDEE POWER PARTNERS, LTD.
P. O. BOX 111 TAMPA, FL 33601-0111
AN EQUAL OPPORTUNITY COMPANY

(813) 228-1330
FAX (813) 228-1308
HTTP://WWW.TECOPOWERSERVICES.COM

I have attached proposed permit language revisions that we believe will allow us to achieve a lower CO emissions rate for this combustion turbine.

Your continued expeditious processing of the Hardee Power Station CT2B permit application is appreciated. Please contact me at 813-228-4858, if there are any further questions.

Sincerely,

Paul L. Carpinone

Paul L. Carpinone
Director, Environmental

Attachments

cc: H. S. Oven, FDEP, Tallahassee
L. N. Curtin, H&K, Tallahassee
T. W. Davis, ECT, Gainesville

cc: File
SWD
NPS
EPA

4. Professional Engineer Statement:

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

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

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

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

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

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

Thomas W. Davis — Signature

Date 8/17/99

(seal)

* Attach any exception to certification statement.

Certification is applicable to August 1999 information submittal regarding the Hardee Power Station Simple-Cycle Combustion Turbine Project.

Table 5-12. Summary of CO BACT Analysis (Revised 8/99)

Control Option	Emission Impacts: Emission Rates (lb/hr)	Emission Impacts: Emission Rates (tpy)	Emission Impacts: Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Economic Impacts: Total Annualized Cost ($/yr)	Economic Impacts: Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Environmental Impacts: Adverse Envir. Impact (Y/N)
Oxidation catalyst	4.3	18.9	170.2	1,368,919	323,438	1,900	4,484	Y	Y
Baseline	43.2	189.1	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: One GE PG7121 (7EA) CTG, 100-percent load for 7,884 hr/yr gas-firing and 876 hr/yr oil-firing.

Sources: GE, 1999.
ECT, 1999.

Table 2. Hardee Power Station - CT2B (Revised 8/99)
CTG Operating Scenarios - General Electric PG7121(EA)
Natural Gas-Firing; Hourly Emission Rates

Temp. (°F)	Case	Load (%)	PM/PM_{10}[1] (lb/hr)	PM/PM_{10}[1] (g/sec)	SO_2[2] (lb/hr)	SO_2[2] (g/sec)	H_2SO_4[3] (lb/hr)	H_2SO_4[3] (g/sec)	Lead[4] (lb/hr)	Lead[4] (g/sec)
32	1	100	5.0	0.63	5.7	0.72	0.655	0.0825	4.99E-04	6.29E-05
	2	75	5.0	0.63	4.6	0.58	0.526	0.0663	4.01E-04	5.05E-05
	3	65	5.0	0.63	4.2	0.53	0.486	0.0612	3.70E-04	4.66E-05
59	5	100	5.0	0.63	5.3	0.67	0.610	0.0768	4.65E-04	5.85E-05
	6	75	5.0	0.63	4.3	0.54	0.496	0.0624	3.78E-04	4.76E-05
	7	65	5.0	0.63	4.0	0.50	0.458	0.0577	3.49E-04	4.40E-05
95	9	100	5.0	0.63	4.8	0.60	0.550	0.0693	4.19E-04	5.28E-05
	10	75	5.0	0.63	4.0	0.50	0.454	0.0572	3.46E-04	4.36E-05
	11	65	5.0	0.63	3.7	0.46	0.420	0.0529	3.20E-04	4.03E-05
		Maximums	**5.0**	**0.63**	**5.7**	**0.72**	**0.655**	**0.0825**	**4.99E-04**	**6.29E-05**

Temp. (°F)	Case	Load (%)	NO_x (ppmvd)[5]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd)[5]	CO (lb/hr)	CO (g/sec)	VOC (ppmvd)[5]	VOC (lb/hr)	VOC (g/sec)
32	1	100	9.0	35.0	4.41	19.6	45.6	5.75	1.5	2.0	0.25
	2	75	9.0	28.0	3.53	24.1	45.0	5.67	1.4	1.6	0.20
	3	65	9.0	25.0	3.15	24.0	40.0	5.04	1.4	1.4	0.18
59	5	100	9.0	32.0	4.03	19.8	43.2	5.44	1.5	1.8	0.23
	6	75	9.0	26.0	3.28	24.2	42.0	5.29	1.5	1.4	0.18
	7	65	9.0	24.0	3.02	24.1	39.0	4.91	1.5	1.4	0.18
95	9	100	9.0	29.0	3.65	19.9	39.2	4.94	1.5	1.8	0.23
	10	75	9.0	24.0	3.02	24.0	39.0	4.91	1.5	1.4	0.18
	11	65	9.0	22.0	2.77	24.3	36.0	4.54	1.5	1.2	0.15
		Maximums	**9.0**	**35.0**	**4.41**	**24.3**	**45.6**	**5.75**	**1.5**	**2.0**	**0.25**

1 Excludes sulfuric acid mist.
2 Based on natural gas sulfur content of 2.0 gr/100 ft^3.
3 Based on 7.5% conversion of SO_2 to H_2SO_4.
4 Natural gas combustion, Table 1.4-2, AP-42, March 1998.
5 Corrected to 15% O_2.

Sources: ECT, 1999.
GE, 1999.

Table 6A. Hardee Power Station - CT2B (Revised 8/99)
CTG Operating Scenarios - General Electric PG7121(EA)
Annual Emission Rates - Criteria Pollutants

Source	Case	No. of CTGs	Annual Operations (hrs/yr)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT2B	5 - Gas	1	7,884	32.0	126.1	43.2	170.3	1.8	7.1
CT2B	5 - Oil	1	876	167.0	73.1	43.0	18.8	4.5	2.0
			Totals	**N/A**	**199.3**	**N/A**	**189.1**	**N/A**	**9.1**

Source	Case	No. of CTGs	Annual Operations (hrs/yr)	Emission Rates					
				PM/PM_{10}		SO_2		Lead	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT2B	5 - Gas	1	7,884	5.0	19.7	5.3	20.9	0.0005	0.0018
CT2B	5 - Oil	1	876	10.0	4.4	51.9	22.7	0.055	0.024
			Totals	**N/A**	**24.1**	**N/A**	**43.7**	**N/A**	**0.026**

1. CT2B operating with natural gas-firing at a 90.0% capacity factor; 7,884 hours/year at base load (Case 5).
2. CT2B operating with fuel oil-firing at a 10.0% capacity factor; 876 hours/year at base load (Case 5).
3. SO_2 rates based on natural gas sulfur content of 2.0 gr/100 ft^3.
4. SO_2 rates based on fuel oil sulfur content of 0.05 wt. percent.

Sources: GE, 1999.
ECT, 1999.
TPS, 1999.

Table 8.C. Hardee Power Station - CT2B (Revised 8/99)
CT Exhaust Data - General Electric PG7121(EA)
Natural Gas-Firing; Simple-Cycle

C. Correction of GE CO and VOC Concentrations to 15% O_2, dry

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			65 % Load		
	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F
Case	1	5	9	2	6	10	3	7	11
CO (ppmvd)	20.0	20.0	20.0	25.0	25.0	25.0	25.0	25.0	25.0
CO (15% O_2)	19.6	19.8	19.9	24.1	24.2	24.0	24.0	24.1	24.3
VOC (ppmvw)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
VOC (ppmvd)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
VOC (15% O_2)	1.5	1.5	1.5	1.4	1.5	1.5	1.4	1.5	1.5

Sources: ECT, 1999.
GE, 1999.

EXHIBIT A REVISED 8/18/99

PROPOSED MODIFICATIONS OF CONDITIONS OF CERTIFICATION
HARDEE POWER STATION UNIT 2B
PA 89-25

EMISSION LIMITS AND STANDARDS

17. The following table is a summary of the BACT determination and is followed by the applicable specific conditions. Values for NO_X are corrected to 15 % O_2 on a dry basis. These limits or their equivalent in terms of lb/hr or NSPS units, as well as the applicable averaging times, are followed by the applicable specific conditions [Rules 62-212.400, 62-204.800(7)(b) (Subpart GG), 62-210.200 (Definitions-Potential Emissions) F.A.C.]

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}, VE	Pipeline-Quality Natural Gas Good Combustion	10 Percent Opacity
VOC	As Above	2 ppmvd (Gas) 4 ppmvd (Fuel Oil)
CO	As Above	20~~5~~ ppmvd (Gas) 20 ppmvd (Fuel Oil)
SO_2	Pipeline-Quality Natural Gas Low Sulfur Oil	2 gr S/100 ft^3 (Gas) 0.05% S (Fuel Oil)
NO_X	DLN, WI for F.O., limited fuel oil usage	9 ppmv (Gas) 42 ppmv (Fuel Oil) - 876 Hours/Year Max.

18. Nitrogen Oxides (NO_X) Emissions:

- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.
- While firing Natural Gas: The emission rate of NO_X in the exhaust gas shall not exceed 9 ppm @15% O_2 (at ISO conditions) on a 24 hr block average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 32 lb/hr and 9 ppm @15% O_2 to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- While firing Fuel oil: The concentration of NO_X in the exhaust gas shall not exceed 42 ppmvd at 15% O_2 on the basis of a 3 hr average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 167 lb/hr and 42 ppm @15% O_2 to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

19. Carbon Monoxide (CO) Emissions: The concentration of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on either natural gas or distillate fuel oil shall exceed neither 20~~5~~ ppmvd nor 43~~54~~ lb/hr to be demonstrated by stack test using EPA Method 10. [Rule 62-212.400, F.A.C.] Should any annual test demonstrate that CO emissions exceed either 20 ppmvd or 43 lb/hr, the Permittee shall submit either a request for a permit modification or a compliance schedule to achieve the 20 ppmvd and 43 lb/hr CO emission limits within thirty days following

submittal of the annual test results to the Department. A compliance schedule, if submitted, shall describe the corrective action proposed to comply with the 20 ppmvd and 43 lb/hr CO emission limits and include milestone implementation dates. Final compliance with the applicable CO emission limits shall occur no later than 12 months from the date of Department approval of the permit modification request or compliance schedule.

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

AUG 1 1 1999

RECEIVED

AUG 16 1999

BUREAU OF AIR REGULATION

4 APT-ARB

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

SUBJ: Application to Modify Certification for Hardee Power Partners, Ltd.
Hardee Power Station PA 89-25 located in Wauchula, FL

Dear Mr. Linero:

Thank you for sending an application to modify Hardee Power station as well as proposed modifications to the Conditions of Certification dated June 4, 1999, for the above referenced facility. The application is for a proposed installation of one simple cycle combustion turbine (CT) with a nominal generating capacity of 75 MW. The CT will combust pipeline quality natural gas as its primary fuel and distillate fuel oil as a backup fuel. As proposed, the turbine will be allowed to operate 8,760 hours per year with up to 876 hours per year firing fuel oil. Emissions from the proposed project are above the thresholds requiring Prevention of Significant Deterioration (PSD) review for nitrogen oxides (NO_X), carbon monoxide (CO), sulfur dioxide (SO_2) and particulate matter (PM/PM_{10}).

The combustion turbine proposed for the facility is a General Electric (GE) Model PG7121 (EA) unit (frequently referred to as a GE 7EA turbine). The proposed best available control technology (BACT) for NO_X emissions is use of a dry low-NO_X (DLN) combustor. Based on our review of the application, we have the following comments:

1. The proposed BACT limit, found on page 5-11, for particulate matter (PM_{10}) is 10% opacity of visible emissions. This visible emissions opacity limit is proposed as a surrogate for a BACT limit for particulate matter emissions rate. It is acceptable to use the 10% opacity limit as a surrogate for monitoring and recordkeeping; however, the permit conditions also should list the corresponding emission rate (i.e., 0.002 gr/dscf).

2. For your information, there is an inconsistency in the permit application regarding the $/ton cost of CO oxidation catalyst control. On page 5-17, in section 5.4.3, the cost effectiveness of oxidation catalyst control for CO emissions is listed as $1,644 per ton of CO removed. However, in table 5-12 (pg. 5-21), cost effectiveness is listed as $1,551 per ton of CO removed.

3. As indicated on page 2-4 of the permit application, Hardee Power is requesting allowable excess emissions due to startup, shutdown or malfunction for up to 4 hours in any 24-hour period. This proposal is inconsistent with FDEP's preliminary determination for Kissimmee Utility's Cane Island Power Park (January 1999) which only allowed excess emissions from a simple cycle combustion turbine for 1 hour in any 24-hour period. Additionally, Hardee Power will operate the new combustion turbine as part of their baseload operation. Therefore, the reduced number of startups and shutdowns should minimize the need for allowable excess emissions. Finally, it is the Environmental Protection Agency's (EPA's) policy (see January 28, 1993 memo from John B. Rasnic to Region 1) that BACT applies during all normal operations and that automatic exemptions should not be granted for excess emissions. Startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the planning, design, and implementation of operating procedures for the process and control equipment. Accordingly, it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods.

4. The new combustion turbine, which will fire No. 2 fuel oil as backup fuel, has the potential to increase the throughput of the existing fuel oil storage tank. Any increase in VOC emissions from the additional use should be taken into account when calculating the potential to emit of VOC emissions. We realize the VOC emissions increase will be small and do not expect it to cause any applicability changes; however, as a matter of completeness, this increase in emissions should be included in all PTE calculations.

5. In the SCR cost analysis, an interest rate of 7.5 percent was used to calculate a capital recovery factor. This interest rate may be appropriate for Hardee Power Station; however, it should be noted that the OAQPS Control Cost Manual uses an interest rate of 7 percent.

6. The cost analysis for SCR uses NO_X emissions of 9 ppm as the baseline and calculates the cost effectiveness of using SCR with controlled NO_X emissions at an assumed level of 3.5 ppm. In other words, the applicant does not base tons per year reduced on a specific control efficiency value. We note that the applicant's approach yields a control efficiency of about 61 percent, which is at the low end of the control efficiencies we have previously seen for SCR control.

7. If you plan to use any portion of the applicant's proposed permit conditions, we recommend the phrase "per year" be changed to "per consecutive 12 months."

Thank you for the opportunity to comment on the Hardee Power Station permit application. If you have any questions regarding these comments, please direct them to either Katy Forney at 404-562-9130 or Jim Little at 404-562-9118.

Sincerely,

Douglas Neeley

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

cc: J. Koerner, BAR
T. Davis, ECT
B. Oven, PPS
NPS
SWD

Author: Kim Pierce at REGION4 Bridgette
Date: 8/12/99 2:12 PM
Priority: Urgent
TO: Karen Cody
Subject: TA RETURNED WITHOUT ACTION- FOR KIM PIERCE

FYI.

Forward Header

Subject: TA RETURNED WITHOUT ACTION- FOR KIM PIERCE
Author: Barbara Grant at REGION4
Date: 8/12/1999 2:09 PM

Bridgett,

I received a RUSH TA for Kim stating that she was using a POV for traveling to Lagrange. When you use POV, you must justify it in block 10E on the TA.

Please pick up the document immediately and make adjustments then return to Budget's in box to be restamped and processed.

Thanks, bjg

ARMS Data Related to GE Model 7EA CT's

8-12-99

Gainesville Regional Utilities – Deerhaven Station

ARMS ID No. 001-0006

EU #006, GE 7001EA, 74MW SCCT

Test Data:

NOx Allowable: 15ppmvd (gas)

NOx Measured: 7.9 ppmvd 3/1/96

8.6 ppmvd 3/4/96

7.25 ppmvd 6/2/97

6.7 ppmvd 5/28/98

CO Allowable: Unknown

CO Measured: 7.1 ppmvd

Kissimmee Utility Authority – Cane Island Power Partners

ARMS ID No. 097-0043

EU-002, GE 7EA (7111EA), 75MW CCCT (Al Linero verified)

Test Data:

NOx Allowable: 25 ppmvd

NOx Measured: 10.5 ppmvd 11-13-95

CO Allowable: 20 ppmvd

CO Measured: 9.7 ppmvd 11-13-95

8.5 ppmvd 6-4-96

Fax Cover Sheet

8-11-99

TO: Jeff Koerner

from: Katy Forney

RE: Hardee Power Station

Here you go Jeff. Call me w/ Questions

Katy

404-562-9130

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

4 APT-ARB

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

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Sincerely,

Douglas Neeley

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

ECT

Environmental Consulting & Technology, Inc.

RECEIVED

JUL 23 1999

BUREAU OF AIR REGULATION

July 22, 1999
ECT No. 990462-0100

SENT BY OVERNIGHT MAIL ON 7/22/99

Mr. Jeffery F. Koerner, P.E.
Bureau of Air Regulation
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

**Re: Florida Department of Environmental Protection (FDEP)
File No. PSD-FL-140(a); PA89-25
TECO Power Services; Hardee Power Station; CT2B Power Project**

Dear Mr. Koerner:

On behalf of TECO Power Services (TPS), the following responses are provided to the items raised in your July 15, 1999 correspondence:

Item 1. Combustor Type and Description

The proposed combustion turbine CT2B, a General Electric (GE) PG7121 7EA unit, will be equipped with GE's DLN-1 combustor technology. GE technical literature describing the DLN-1 combustor technology is included as Attachment I.

Item 2. Combustion Control System Description

The GE 7EA unit will be controlled by means of GE's SPEEDTRONIC™ Mark V gas turbine control system. GE technical literature describing the Mark V control system is provided as Attachment II.

Item 3. Manufacture Emission Guarantees

A written guarantee of NO_x and CO emissions from the combustion turbine manufacturer (GE) is provided as Attachment III. Performance curves illustrating NO_x and CO emissions as a function of load are included in the GE technical literature provided in Attachment I.

3701 Northwest
98[TH] Street
Gainesville, FL
32606

(352)
332-0444

FAX (352)
332-6722

Item 4. Emissions Test Data for a Similar GE 7EA Unit

A copy of stack test results for a similar GE 7EA unit (i.e., dual-fuel, DLN-1 combustor unit) is provided as Attachment IV. These test results were obtained from two GE 7EA units located at the Panda-Brandywine Cogeneration Facility in Brandywine, Maryland.

Item 5. Dispersion Modeling Output Files

It is understood that electronic copies of the dispersion modeling output files are no longer required.

As advised in my e-mail message to you today, Table 7-13 (dispersion modeling summary) of the submitted application inadvertently indicated the unadjusted model results (i.e., based on a nominal 10.0 g/s emission rate) rather than the adjusted model results. Accordingly, Attachment V provides a revised version of Table 7-13. Note that the correct, adjusted model results are considerably lower than the unadjusted concentrations.

Your continued expeditious processing of the TECO Power Services Hardee Power Station CT2B project will be appreciated. Please contact me at 352/332-6230, Ext.351, if there are any further questions.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Thomas W. Davis

Thomas W. Davis, P.E.
Principal Engineer

Attachments

cc: Mr. Paul Carpinone, P.E., TPS
Mr. Lawrence Curtin, Holland & Knight

CC: EPA
NPS
Buck Oven, PPS
SD
File

ATTACHMENT I

GE DLN-1 COMBUSTOR TECHNICAL LITERATURE

DRY LOW NO_x COMBUSTION SYSTEMS FOR GE HEAVY-DUTY GAS TURBINES

L.B. Davis
GE Power Systems
Schenectady, NY

ABSTRACT

State-of-the-art emissions control technology for heavy-duty gas turbines is reviewed with emphasis on the operating characteristics and field experience of Dry Low NO_x(DLN) combustors for E- and F- technology machines. The lean premixed DLN systems for gas fuel have demonstrated their ability to meet the ever-lower emission levels required today. Lean premixed technology has also been demonstrated on oil fuel and is also discussed.

INTRODUCTION

The regulatory requirements for low emissions from gas turbine power plants have increased during the past 10 years. Environmental agencies throughout the world are now requiring even lower rates of emissions of NO_x and other pullutants from both new and existing gas turbines. Traditional methods of reducing NO_x emissions from combustion turbines (water and steam injection)are limited in their ability to reach the extremely low levels required in many localities. GE's involvement in the development of both the traditional methods (References 1 through6) and the newer Dry Low NO_x(DLN) technology (References 7 and 8) has been well-documented. This paper focuses on DLN.

Since the commercial introduction of GE's DLN combustion systems for natural-gas-fired heavy-duty gas turbines in 1991, systems have been installed in more than 145 machines, from the most modern F technology (firing temperature class of 2400 F/1316 C) to field retrofits of older machines. As of August 1996, these machines have operated more than one million hours with DLN; more than 290,000 hours have been in the F technology. To meet marketplace demands, GE has developed DLN products broadly classified as either DLN-1, which was developed for E-technology (2000 F/1093C firing temperature class) machines, or DLN-2, which was developed specifically for the F technology machines and is also being applied to the EC, G and H machines.

Development of these products has required an intensive engineering effort involving both GE Power Systems and GE Corporate Research and Development. This collaboration will continue as DLN is applied to the G and H machines and combustor development for Dry Low NO_x on oil ("dry oil") continues.

This paper presents the current status of DLN-1 technology and experience, including dry oil, and of DLN-2 technology and experience. Background information about gas turbine emissions and emissions control is contained in the Appendix.

DRY LOW NO_X SYSTEMS

Dry Low NO_X Product Plan

Figure 1 shows GE's Dry Low NO_x product offerings for its new and existing machines in three major groupings. The first group includes the MS3000, MS5000 and MS6001B products. The 6B DLN-1 is the technology flagship product for this group and, as can be noted, is available to meet 9 ppm NO_x requirements. Such low NO_x emissions are generally not attainable on lower firing temperature machines such as the MS3000s and MS5000s because carbon monoxide (CO) would be excessive.

The second major group includes the MS7000B/E, MS7001EA and MS9001E machines with the 9 ppm 7EA DLN-1 as the flagship product. The dry oil program focuses initially on this group.

The third group combines all of the DLN-2 products and includes the FA, EC, G and H machines, with the 7FA product as the flagship.

As shown in Figures 2 and 3, most of these products are capable of power augmentation and of peak firing with increased NO_x emissions. With gas fuel, power augmentation with steam is in the premixed mode for both DLN-1 and DLN-2 systems. Power augmentation with water is in the lean-lean mode for DLN-1 and in the premixed mode for DLN-2.

The GE DLN systems integrate a staged premixed combustor, the gas turbine's SPEEDTRONICTM controls and the fuel and associated systems. There

Turbine Model	Gas NO$_x$ (ppmvd)	Gas CO (ppmvd)	Gas Diluent	Distillate NO$_x$ (ppmvd)	Distillate CO (ppmvd)	Distillate Diluent
MS3002 (J) - RC	33	25	Dry	Not Available		
MS3002 (J) - SC	42	50	Dry			
MS5001P	42	50	Dry	65	20	Water
MS5001R	42	50	Dry	65	20	Water
MS5002C	42	50	Dry	65	20	Water
MS6001B	25	15	Dry	42	20	Water
	9	25	Dry	42	30	Water/Steam
MS7001B/E Conv.	25	25	Dry	42	30	Water
MS7001EA	25	15	Dry	42	20	Water
	15	25	Dry	42	30	Water/Steam
	9	25	Dry	42	30	Water/Steam
MS9001E	35	15	Dry	42	20	Water
	25	25	Dry	42	20	Water
	25	25	Dry	90	20	Dry
MS6001FA	25	15	Dry	42/65	20	Water/Steam
MS7001FA	25	15	Dry	42/65	20	Water/Steam
	9	9	Dry	42/65	30	Water/Steam
MS7001H	25	15	Dry	42/65	20	Water/Steam
	9	9	Dry	42/65	30	Water/Steam
MS9001EC	25	15	Dry	42/65	20	Water/Steam
MS9001FA	25	15	Dry	42/65	20	Water/Steam
MS9001H	25	15	Dry	42/65	20	Water/Steam

Notes: 1. No$_x$ levels are at 15% oxygen. Ambient range 30 F/-1 C to 100 F/30 C

GT24717E

Figure 1. Dry Low No$_x$ product plan

are two principal measures of performance. The first is meeting the emission levels required at base load on both gas and oil fuel and controlling the variation of these levels across the load range of the gas turbine.

The second measure is system operability, with

Turbine Model	NO$_x$ @15% O$_2$ (ppmvd)	Operating Mode	Diluent	Maximum Diluent/Fuel	NO$_x$ at Max D/F (ppmvd)	CO Max D/F (ppmvd)
MS6001(B)	9	Premix	Steam	2.5/1	9	25
		Lean-Lean	Steam	2.5/1	25	15
	25	Premix	Steam	2.5/1	25	15
		Lean-Lean	Water	1.5/1	25	15
		Lean-Lean	Steam	2.5/1	25	15
MS7001(EA)	9	Premix	Steam	2.5/1	9	25
		Lean-Lean	Water	1.5/1	25	15
		Lean-Lean	Steam	2.5/1	25	15
	25	Premix	Steam	2.5/1	25	15
		Lean-Lean	Water	1.5/1	25	15
		Lean-Lean	Steam	2.5/1	25	15
MS7001(FA)	25	Premix	Steam	2.1/1	25	15

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Figure 2. DLN power augmentation summary - gas fuel

	NO_x-Base (ppmvd)	NO_x-Peak (ppmvd)	CO-Base (ppmvd)	CO-Peak (ppmvd)
MS6001(B)	9 25	18 50	25 15	6 4
MS7001(EA)	9 25	18 50	25 15	6 4
MS7001(FA)	25	35	15	6
MS9001(E)	25	40	15	6

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Figure 3. DLN peak firing summary - gas fuel

emphasis placed on the smoothness and reliability of combustor mode changes, ability to load and unload the machine without restriction, capability to switch from one fuel to another and back again, and system response to rapid transients (e.g., generator breaker open events or rapid swings in load). GE's design goal is to make the DLN system operate so the gas turbine operator does not know whether a DLN or conventional combustion system is installed (i.e., its operation is "transparent to the user"). As of August 1996, a significant portion of the DLN design and development effort has focused on system operability.

Design of a successful DLN combustor for a heavy-duty gas turbine also requires the designer to develop hardware features and operational methods that simultaneously allow the equivalence ratio and residence time in the flame zone to be low enough to achieve low NO_x, but with acceptable levels of combustion noise (dynamics), stability at part load operation and sufficient residence time for CO burn-out, hence the designation of DLN combustion design as "four-sided box" (Figure 4).

A scientific and engineering development program by GE's Corporate Research and Development Center, Power Systems business and Aircraft Engine business has focused on understanding and controlling dynamics in lean premixed flows. The objectives have been to:

- Gather and analyze machine and laboratory data to create a comprehensive dynamics data base
- Create analytical models of gas turbine combustion systems that can be used to understand dynamics behavior
- Use the analytical models and experimental methods to develop methods to control dynamics

As of August 1996, these efforts have resulted in a large number of hardware and control features that limit dynamics, plus analytical tools that are used to predict system behavior. The latter are particularly useful in correlating laboratory test data from full scale combustors with actual gas turbine data.

DLN-1 System

DLN-1 development began in the 1970s with the goal of producing a dry oil system to meet the United States Environmental Protection Agency's New Source Performance Standards of 75 ppmvd NO_x at 15% O_2. As noted in Reference 7, this system was tested on both oil and gas fuel at Houston Lighting & Power in 1980 and met its emission goals. Subsequent to this, DLN program goals changed in response to stricter environmental regulations and the pace of the program accelerated in the late 1980s.

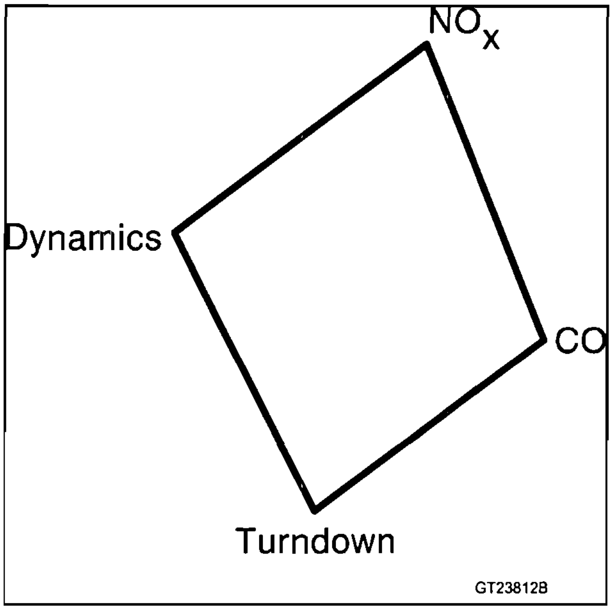

Figure 4. DLN technology - a four-sided box

DLN-1 Combustor

The GE DLN-1 combustor (shown in cross section in Figure 5 and described in Reference 8) is a two-stage premixed combustor designed for use with natural gas fuel and capable of operation on liquid fuel. As shown, the combustion system includes four major components: fuel injection system, liner, venturi and cap/centerbody assembly.

These components form two stages in the combustor. In the premixed mode, the first stage thoroughly mixes the fuel and air and delivers a uniform, lean, unburned fuel-air mixture to the second stage.

The GE DLN-1 combustion system operates in four distinct modes, illustrated in Figure 6, during pre-mixed natural gas or oil fuel operation:

Mode	Operating Range
Primary	Fuel only to the primary nozzles. Flame is in the primary stage only. This mode of operation is used to ignite, accelerate and operate the machine over low- to mid-loads, up to a preselected combustion reference temperature.
Lean-Lean	Fuel to both the primary and secondary nozzles. Flame is in both the primary and secondary stages. This mode of operation is used for intermediate loads between two pre-selected combustion reference temperatures.
Secondary	Fuel to the secondary nozzle only. Flame is in the secondary zone only. This mode is a transition state between lean-lean and premix modes. This mode is necessary to extinguish the flame in the primary zone, before fuel is reintroduced into what becomes the primary premixing zone.
Premix	Fuel to both primary and secondary nozzles. Flame is in the secondary stage only. This mode of operation is achieved at and near the combustion reference temperature design point. Optimum emissions are generated in premix mode.

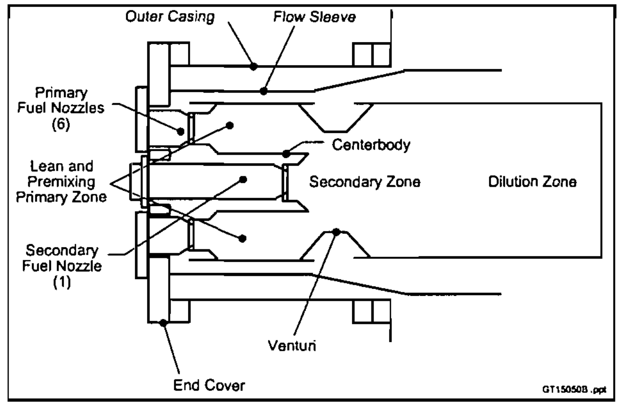

Figure 5. DLN-1 combustor schematic

The load range associated with these modes varies with the degree of inlet guide vane modulation and, to a smaller extent, with the ambient temperature. At ISO ambient, the premix operating range is 50% to 100% load with IGV modulation down to 42 Degrees, and 75% to 100% load with IGV modulation down to 57 Degrees. The 42 Degrees IGV minimum requires an inlet bleed heat system.

If required, both the primary and secondary fuel nozzles can be dual-fuel nozzles, thus allowing automatic transfer from gas to oil throughout the load range. When burning either natural gas or distillate oil, the system can operate to full load in the lean-lean mode (Figure 6) and in the pre-mixed. Power augmentation with water is the most common reason.

The spark plug and flame detector arrangements in a DLN-1 combustor are different from those used in a conventional combustor. Since the first stage must be re-ignited at high load in order to transfer from the

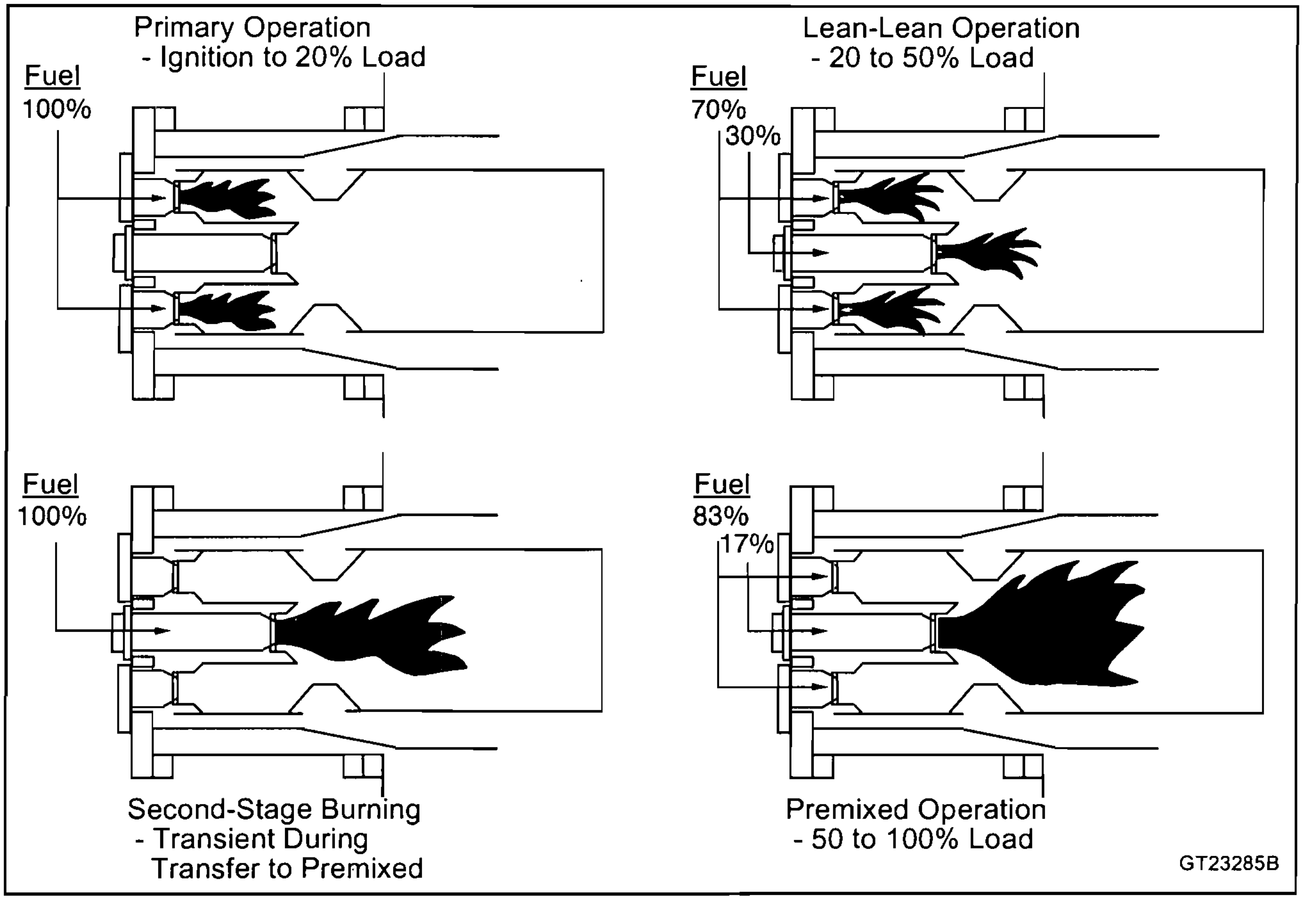

Figure 6. Fuel-staged Dry Low NOx operating modes

premixed mode back to lean-lean operation, the spark plugs do not retract. One plug is mounted in a primary zone cup in each of two combustors. The system uses flame detectors to view the primary stage of selected chambers (similar to conventional systems), and secondary flame detectors that look through the centerbody and into the second stage.

The primary fuel injection system is used during ignition and part load operation. The system also injects most of the fuel during premixed operation and must be capable of stabilizing the flame. For this reason, the DLN-1 primary fuel nozzle is similar to GE's MS7001EA multi-nozzle combustor with multiple swirl-stabilized fuel injectors. The GE DLN-1 system uses five primary fuel nozzles for the MS6001B and smaller machines and six primary fuel nozzles for the larger machines. This design is capable of providing a well-stabilized diffusion flame that burns efficiently at ignition and during part load operation.

In addition, the multi-nozzle fuel injection system provides a satisfactory spatial distribution of fuel flow entering the first-stage mixer. The primary fuel-air mixing section is bound by the combustor first-stage wall, the cap/centerbody and the forward cone of the venturi. This volume serves as a combustion zone when the combustor operates in the primary and lean-lean modes. Since ignition occurs in this stage, crossfire tubes are installed to propagate flame and to balance pressures between adjacent chambers. Film slots on the liner walls provide cooling, as they do in a standard combustor.

In order to achieve good emissions performance in premixed operation, the fuel-air equivalence ratio of the mixture exiting the first-stage mixer must be very lean. Efficient and stable burning in the second stage is achieved by providing continuous ignition sources at both the inner and outer surfaces of this flow. The three elements of this stage comprise a piloting flame, an associated aerodynamic device to force interaction between the pilot flame and the inner surface of the main stage flow, and an aerodynamic device to create a stable flame zone on the outer surface of the main stage flow exiting the first stage.

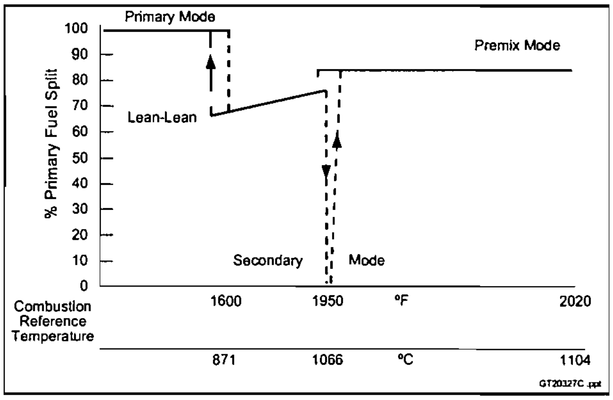

Figure 7. Typical Dry Low Nox fuel gas split schedule

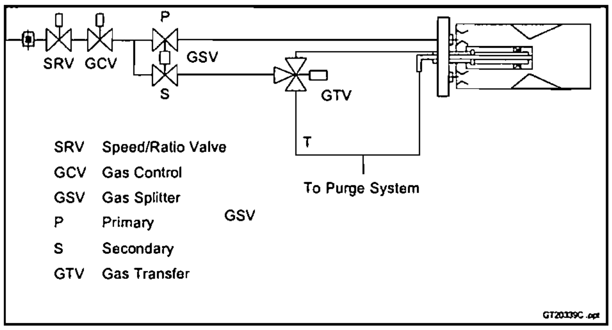

Figure 8. DLN-1 gas fuel system

The piloting flame is generated by the secondary fuel nozzle, which premixes a portion of the natural gas fuel and air (nominally, 17% at full-load operation) and injects the mixture through a swirler into a cup where it is burned. This flame is stabilized by burning an even smaller amount of fuel (less than 2% of the total fuel flow) as a diffusion flame in the cup. The secondary nozzle, which is mounted in the cap centerbody, is simple and highly effective for creating a stable flame.

A swirler mounted on the downstream end of the cap/centerbody surrounds the secondary nozzle. This creates a swirling flow that stirs the interface region between the piloting flame and the main-stage flow and ensures that the flame is continuously propagated from the pilot to the inner surface of the fuel-air mixture exiting the first stage. Operation on oil fuel is similar except that all of the secondary oil is burned in a diffusion flame in the current dry oil design.

The sudden expansion at the throat of the venturi creates a toroidal recirculation zone over the downstream conical surface of the venturi. This zone, which entrains a portion of the venturi cooling air, is a stable burning zone that acts as an ignition source for the main stage fuel-air mixture. The cone angle

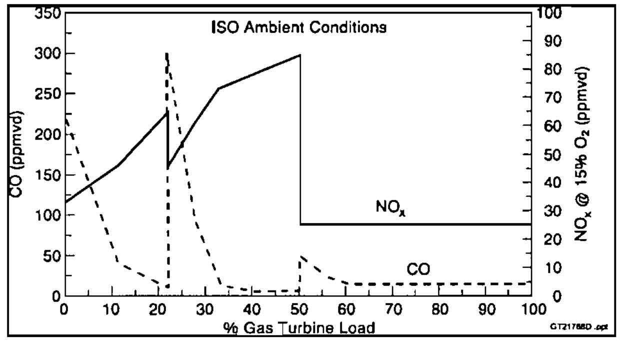

Figure 9. MS7001EA/MS9001E DLN-1 combustion system performance on natural gas fuel

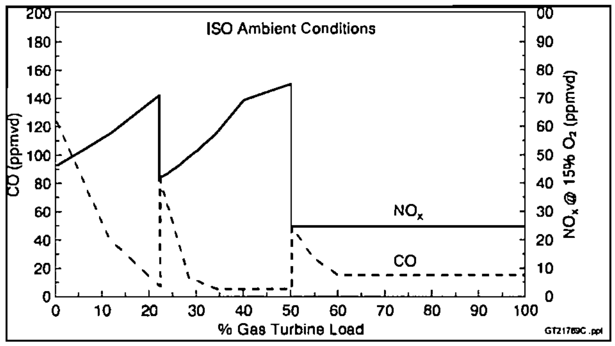

Figure 10. MS6001B DLN-1 emissions performance on natural gas fuel

and axial location of the venturi cooling air dump have significant effects on the efficacy of this ignition source. Finally, the dilution zone (the region of the combustor immediately downstream from the flame zone in the secondary) provides a region for CO burnout and for shaping the gas temperature profile exiting the combustion system.

DLN-1 Controls and Accessories

The gas turbine accessories and control systems are configured so that operation on a DLN-equipped turbine is essentially identical to that of a turbine equipped with a conventional combustor. This is accomplished by controlling the turbines in identical fashions, with the exhaust temperature, speed and compressor discharge pressure establishing the fuel flow and compressor inlet guide vane position.

A turbine with a conventional diffusion combustor that uses diluent injection for NO_x control will use an underlying algorithm to control steam or water injection. This algorithm will use top level control variables (exhaust temperature, speed, etc.) to establish a steam-to-fuel or water-to-fuel ratio to control NO_x.

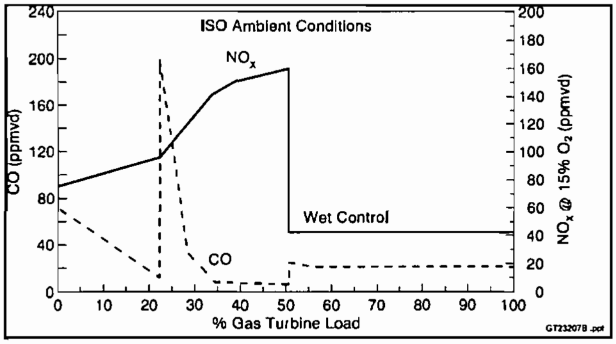

Figure 11. MS7001EA/MS9001E DLN-1 combustion system performance on distillate oil

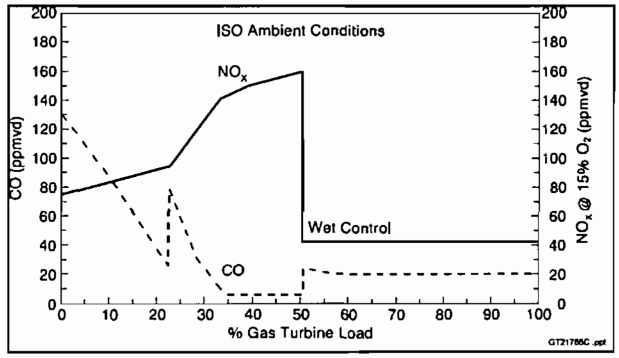

Figure 12. MS6001B DLN-1 emissions performance on distillate oil fuel

In a similar fashion, the same variables are used to divide the total turbine fuel flow between the primary and secondary stages of a DLN combustor. The fuel division is accomplished by commanding a calibrated splitter valve to move to a set position based on the calculated combustion reference temperature (Figure 7). Figure 8 shows aschematic of the gas fuel system for a DLN-equipped turbine.

The only special control sequences required are concerned protection of the turbine during a generator breaker-open trip, or flashback, from the second stage to the first stage during premixed operation. When either the breaker opens at load or flashback is sensed by ultraviolet flame detectors looking into the first stage, the splitter valve is commanded to move to a pre-determined position. In the case of a flashback, the control system can execute an automatic sequence to return to premixed, full-load operation.

DLN-1 Emissions

The emissions performance of the GE DLN system can be illustrated as a function of load for a given ambient temperature and turbine configuration. Figures 9 and 10 show the NO_x and CO emissions from typical MS7001EA and MS6001B DLN systems designed for 9 ppmvd NO_x and 25 ppm CO when operated on natural gas fuel. Note that in premixed operation, NO_x is generally highest at higher loads and CO only approaches 25 ppm at lower premixed loads.

Figures 11 and 12 show NO_x and CO emissions for the same systems operated on oil fuel with water injection for NO_x control, rather than premixed oil. These figures are for units equipped with inlet bleed heat and extended IGV modulation. NO_x and CO emissions from the DLN combustor at loads less than 20% of base load are similar to those from standard combustion systems. This result is expected because both systems are operating as diffusion flame combustors in this range. Between 20% and 50% load, the DLN system is operated in the lean-lean mode, and the flow split between the primary fuel nozzles and secondary nozzle is varied to give the decreasing NO_x characteristic shown.

From 50%to 100%load, the DLNsystem operates as a lean premixed combustor. As shown in Figures 9 through 12, NO_x emissions are significantly reduced, while CO emissions are comparable to those from the standard system.

DLN-1 Experience

GE's first DLN-1 system was tested at Houston Lighting & Power in 1980 (Reference 7). A prototype DLN system using the combustor design discussed above was tested on an MS9001E at the Electricity Supply Board's (ESB) Northwall Station in Dublin, Ireland, between October 1989 and July 1990. A comprehensive engineering test of the prototype DLN combustor, controls and associated systems was conducted with NO_x levels of 32 ppmvd (at 15% O_2) obtained at base load. The results were incorporated into the design of prototype systems for the MS7001E and MS6001B.

The 7E DLN-1 prototype was tested at Anchorage Municipal Light and Power (AMLP) in early 1991 and entered commercial service shortly afterward. Since then, development of advanced combustor configurations have been carried out at AMLP. These results have been incorporated into production hardware.

The MS6001B prototype system was first operated at Jersey Central Power & Light's Forked River Station in early 1991. A series of additional tests culminated in the demonstration of a 9 ppm combustor at Jersey Central in November 1993.

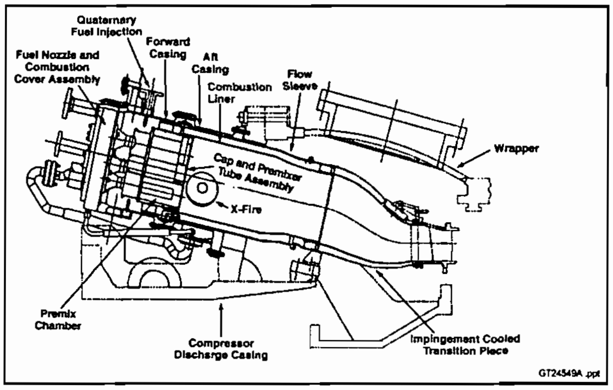

Figure 13. DLN-2 combustion system

As of August 1996, 28 MS6001B machines are equipped with DLN-1 systems. In total, they have accumulated more than 370,000 hours of operation. There are, in addition, four MS7001E, eight MS7001B-E, 26 MS7001EA, 18 MS9001E, one MS5001P and three MS3002J DLN-1 machines that have collectively operated for more than 350,000 hours. Excellent emission results have been obtained in all cases, with single-digit NO_x and COachieved on several MS7001EAs. Several MS7001E/EA machines have the capability to power augment with either massive water or steam injection.

Starting in early 1992, eight MS7001F machines equipped with GE DLN systems were placed in service at Korea Electric Power Company's Seoinchon site. These F technology machines have achieved better than 55% (gross) efficiency in combined-cycle operation, and the DLN systems are currently operating between 30 and 40 ppmvd NO_x on gas fuel (the guarantee level is 50 ppmvd). These units have operated for more than 150,000 hours. Four additional F technology DLN-1 systems have been commissioned at Scottish Hydro's Keadby site and at National Power's Little Barford site. These 9F machines have operated more than 20,000 hours at less than 60 ppm NO_x.

The combustion laboratory testing and field operation have shown that the DLN-1 system can achieve single digit NO_x and CO levels on E technology machines operating on gas fuel. Current DLN-1 development activity focuses on four goals:

- Application of single-digit technology to the MS6001B, MS7001EA and MS9001E
- Application of DLN-1 technology for retrofitting existing field machines (including MS3002s and MS5000s, some of which will require upgrade before DLN retrofit)

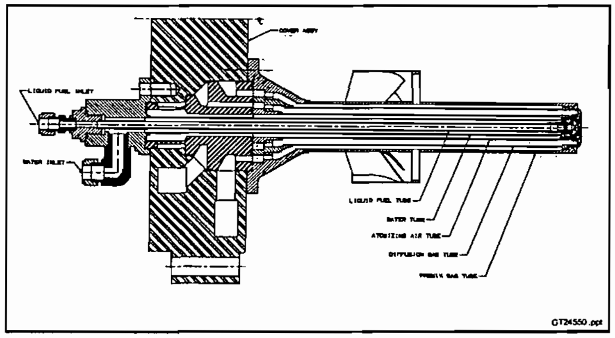

Figure 14. Cross-section of a DLN-2 fuel nozzle

- Completing the development of steam and water power augmentation as needed by the market
- Completing the development of dry oil DLN-1 products.

DLN-2 SYSTEM

As F-technology gas turbines became available in the late 1980s, studies were conducted to establish what type of DLN combustor would be needed for these new higher firing temperature machines. Studies concluded that that air usage in the combustor (e.g., for cooling) other than for mixing with fuel would have to be strictly limited. A team of engineers from GE Power Generation, GE Corporate Research and Development and GE Aircraft Engine proposed a design that repackaged DLN-1 premixing technology but eliminated the venturi and centerbody assemblies that require cooling air.

The resulting combustor is called DLN-2, which is the standard system for the 6FA, 7FA, 9FA, 9EC, 7G, 7H, 9G and 9H machines. Fourteen combustors are installed in the 7FA and 9EC, 18 in the 9FA, and six in the 6FA. These combustors, for all but the 7FA, are not scaled, but are full-size 9FA combustors; the 7FA is slightly smaller.

DLN-2 Combustion System

The DLN-2 combustion system shown in Figure 13 is a single-stage dual-mode combustor that can operate on both gaseous and liquid fuel. On gas, the combustor operates in a diffusion mode at low loads (< 50% load), and a premixed mode at high loads (> 50% load). While the combustor can operate in the diffusion mode across the load range, diluent injection would be required for NO_x abatement. Oil operation on this combustor is in the diffusion mode

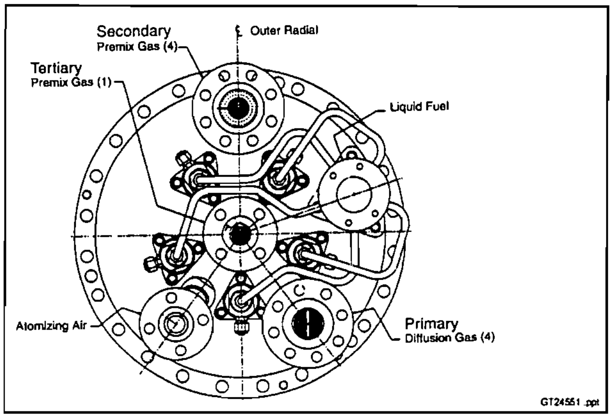

Figure 15. External view of DLN-2 fuel nozzles mounted

across the entire load range, with diluent injection used for NO_X control.

Each DLN-2 combustor system has a single burning zone formed by the combustor liner and the face of the cap. In low emissions operation, 90% of the gas fuel is injected through radial gas injection spokes in the premixer, and combustion air is mixed with the fuel in tubes surrounding each of the five fuel nozzles. The premixer tubes are part of the cap assembly. The fuel and air are thoroughly mixed, flow out of the five tubes at high velocity and enter the burning zone where lean, low- NO_x combustion occurs. The vortex breakdown from the swirling flow exiting the premixers, along with the sudden expansion in the liner, are mechanisms for flame stabilization. The DLN-2 fuel nozzle/premixer tube arrangement is similar in design and technology to the secondary nozzle/centerbody of a DLN-1. Five nozzle/premixer tube assemblies are located on the head end of the combustor. A quaternary fuel manifold is

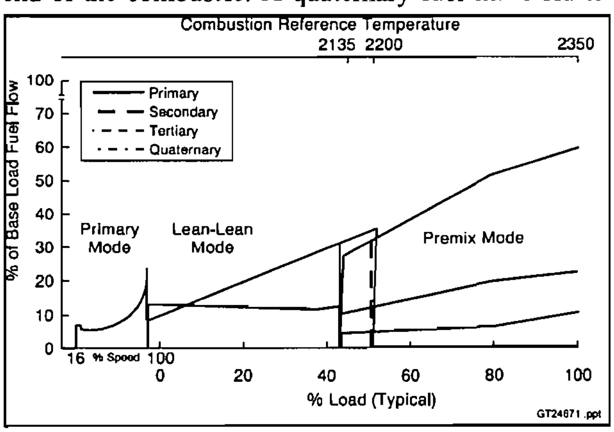

Figure 16. Fuel flow scheduling associated with DLN-2 operation

located on the circumference of the combustion casing to bring the remaining fuel flow to casing injection pegs located radially around the casing.

Figure 14 shows a cross-section of a DLN-2 fuel nozzle. As noted, the nozzle has passages for diffusion gas, premixed gas, oil and water. When mounted on the end cover, as shown in Figure 15, the diffusion passages of four of the fuel nozzles is fed from a common manifold, called the primary, that is built into the end cover. The premixed passage of the same four nozzles are fed from another internal manifold called the secondary. The premixed passages of the remaining nozzle are supplied by the tertiary fuel system; the diffusion passage of that nozzle is always purged with compressor discharge air and passes no fuel.

Figure 15 shows the fuel nozzles installed on the combustion chamber end cover and the connections for the primary, secondary and tertiary fuel systems. DLN-2 fuel streams are:

- Primary fuel – fuel gas entering through the diffusion gas holes in the swirler assembly of each of the outboard four fuel nozzles
- Secondary fuel – premix fuel gas entering through the gas metering holes in the fuel gas injector spokes of each of the outboard four fuel nozzles
- Tertiary fuel – premix fuel gas delivered by the metering holes in the fuel gas injector spokes of the inboard fuel nozzle
- The quaternary system – injects a small amount of fuel into the airstream just upstream from the fuel nozzle swirlers

The DLN-2 combustion system can operate in several different modes.

Primary

Fuel only to the primary side of the four fuel nozzles; diffusion flame. Primary mode is used from ignition to 81% corrected speed.

Lean-Lean

Fuel to the primary (diffusion) fuel nozzles and single tertiary (premixing) fuel nozzle. This mode is used from 81% corrected speed to a preselected combustion reference temperature. The percentage of primary fuel flow is modulated throughout the range of operation as a function of combustion reference temperature. If necessary, lean-lean mode can be operated throughout the entire load range of the turbine. Selecting "lean-lean base on" locks out premix operation and enables the machine to be taken to base load in lean-lean.

Premix Transfer

Transition state between lean-lean and premix modes. Throughout this mode, the primary and secondary gas control valves modulate to their final position for the next mode. The premix splitter valve is also modulated to hold a constant tertiary flow split.

Piloted Premix

Fuel is directed to the primary, secondary and tertiary fuel nozzles. This mode exists while operating with temperature control off as an intermediate mode between lean-lean and premix mode. This mode also exists as a default mode out of premix mode and, in the event that premix operating is not desired, piloted premix can be selected and operated to base load. Primary, secondary and tertiary fuel split are constant during this mode of operation.

Premix

Fuel is directed to the secondary, tertiary and quaternary fuel passages and premixed flame exists in the combustor. The minimum load for premixed operation is set by the combustion reference temperature and IGV position. It typically ranges from 50% with inlet bleed heat on to 65% with inlet bleed heat off. Mode transition from premix to piloted premix or piloted premix to premix, can occur whenever the combustion reference temperature is greater than 2200 F/1204 C. Optimum emissions are generated in premix mode.

Tertiary Full Speed No Load (FSNL)

Initiated upon a breaker open event from any load greater than 12.5%. Fuel is directed to the tertiary nozzle only and the unit operates in secondary FSNL mode for a minimum of 20 seconds, then transfers to lean-lean mode.

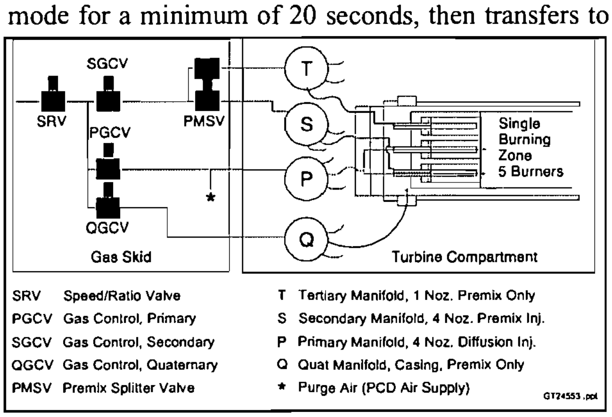

Figure 17. DLN-2 gas fuel system

Figure 16 illustrates the fuel flow scheduling associated with DLN-2 operation. Fuel staging depends on combustion reference temperature and IGV temperature control operation mode.

DLN-2 Controls and Accessories

The DLN-2 control system regulates the fuel distribution to the primary, secondary, tertiary and quaternary fuel system. The fuel flow distribution to each combustion fuel system is a function of combustion reference temperature and IGV temperature control mode. Diffusion, piloted premix and premix flame are established by changing the distribution of fuel flow in the combustor. The gas fuel system (Figure 17) consists of the gas fuel stop/ratio valve, primary gas control valve, secondary gas control valve premix splitter valve and quaternary gas control valve. The stop/ratio valve is designed to maintain a predetermined pressure at the control valve inlet.

The primary, secondary and quaternary gas control valves regulate the desired gas fuel flow delivered to the turbine in response to the fuel command from the SPEEDTRONICTM controls.

The premix splitter valve controls the fuel flow split between the secondary and tertiary fuel system.

DLN-2 Emissions Performance

Figures 18 and 19 show the emissions performance for a DLN-2 equipped 7FA/9FA for gas fuel and for oil fuel with water injection.

DLN-2 Experience

The first DLN-2 systems were placed in service at Florida Power and Light's Martin Station with com-

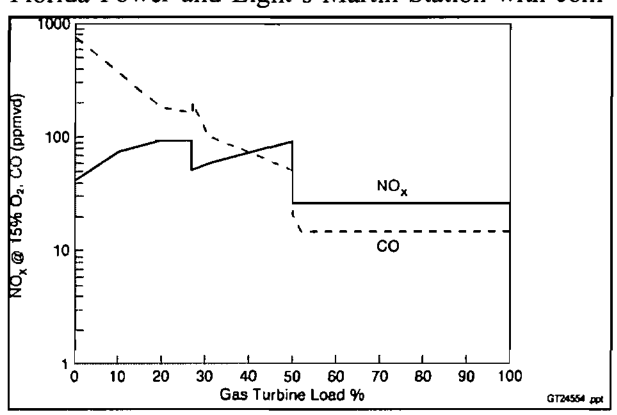

Figure 18. Emissions performance for DLN-2-equipped 7FA/9FA for gas fuel

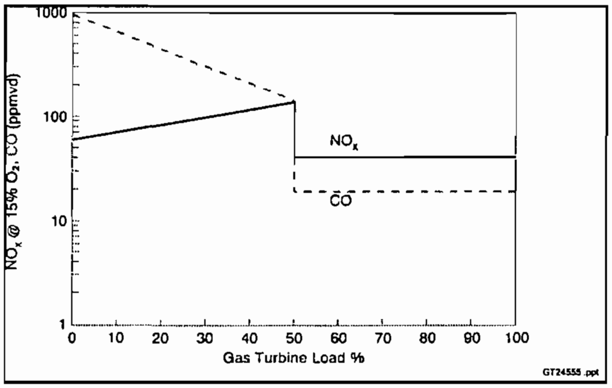

Figure 19. Emissions performance for DLN-2-equipped 7FA/9FA for oil fuel with water injection

missioning beginning in September 1993, and the first two (of four) 7FA units entering commercial service in February 1994. During commissioning, quaternary fuel was added and other combustor modifications were made to control dynamic pressure oscillations in the combustor.

As of August 1996, 23 DLN-2 7FA and 17 9FA units are in commercial service. They have accumulated more than 150,000 hours of operation. Of these units, 11 are dual-fuel units, and the remainder are gas-only.

CONCLUSION

GE's Dry Low NO_x Program continues to focus on the development of systems capable of the extremely low NO_x levels required to meet today's regulations and to prepare for more stringent requirements in the future. New unit production needs and the requirements of existing machines, are being addressed. GE DLN systems are operating on more than 145 machines and have accumulated more than one million service hours. More than 200 DLN systems have been either put into service, shipped or placed on order. GE is the only manufacturer with F technology machines operating below 25 ppmvd.

APPENDIX

Gas Turbine Combustion Systems

A gas turbine combustor mixes large quantities of fuel and air and burns the resulting mixture. In concept the combustor is comprised of a fuel injector and a wall to contain the flame. There are three fundamental factors and practical concerns that complicate the design of the combustor: equivalence ratio, flame stability, and ability to operate from ignition through full load.

Equivalence ratio

A flame burns best when there is just enough fuel to react with the available oxygen. With this stoichiometric mixture (equivalence ratio of 1.0) the flame temperature is the highest and the chemical reactions are the fastest, compared to cases where there is either more oxygen ("fuel lean," < 1.0) or less oxygen ("fuel rich," > 1.0) for the amount of fuel present.

In a gas turbine, the maximum temperature of the hot gases exiting the combustor is limited by the tolerance of the turbine nozzles and buckets. This temperature corresponds to an equivalence ratio of 0.4 to 0.5 (40 to 50% of the stoichiometric fuel flow). In the combustors used on modern gas turbines, this fuel-air mixture would be too lean for stable and efficient burning. Therefore, only a portion of the compressor discharge air is introduced directly into the combustor reaction zone (flame zone) to be mixed with the fuel and burned. The balance of the airflow either quenches the flame prior to the combustor discharge entering the turbine or to cool the wall of the combustor.

Flame Stability

Even with only part of the air being introduced into the reaction zone, flow velocities in the zone are higher than the turbulent flame speed at which a flame propagates through the fuel-air mixture. Special mechanical or aerodynamic devices must be used to stabilize the flame by providing a low velocity region. Modern combustors employ a combination of swirlers and jets to achieve a good mix and to stabilize the flame.

Operational Stability

The combustor must be able to ignite and to support acceleration and operation of the gas turbine over the entire load range of the machine. For a single-shaft generator-drive machine, speed is constant under load and, therefore, so is the airflow for a fixed ambient temperature. There will be a five- or six-to-one turndown in fuel flow over the load range, and a combustor whose reaction zone equivalence ratio is optimized for full load operation will be very lean at the lower loads. Nevertheless, the flame must be sta-

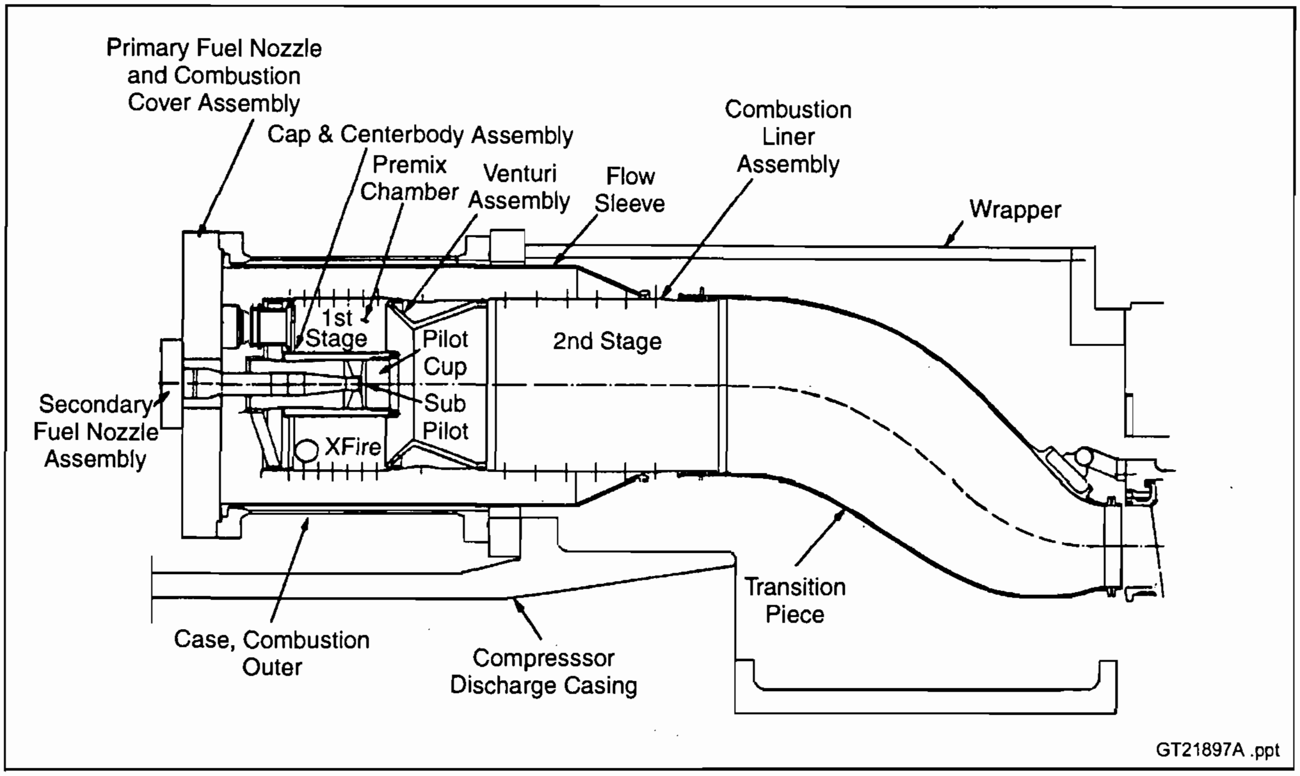

Figure A1. MS7001EA Dry Low Nox combustion chamber

ble and the combustion process must be efficient at all loads.

GE uses multiple-combustion chamber assemblies in its heavy-duty gas turbines to achieve reliable and efficient turbine operation. As shown in Figure A-1, each combustion chamber assembly comprises a cylindrical combustor, a fuel injection system and a transition piece that guides the flow of the hot gas from the combustor to the inlet of the turbine. Figure A-2 illustrates the multiple-combustor concept.

There are several reasons for using the multiple-chamber arrangement instead of large silo-type combustors:

- The configuration permits the entire turbine to be factory assembled, tested and shipped without interim disassembly
- The turbine inlet temperature can be better controlled, thus providing for longer turbine life with reduced turbine cooling air requirements
- Smaller parts can be handled more easily during routine maintenance
- Smaller transition pieces are less susceptible to damage from dynamic forces generated in the combustor; furthermore, the shorter combustion system length ensures that acoustic natural frequencies are higher and less likely to couple with the pressure oscillations in the flame
- Smaller combustors generate less NO_x because of much better mixing and shorter residence time
- As turbine inlet temperatures have increased to improve efficiency, the size of the combustors has decreased to minimize cooling requirements, as in aircraft gas turbine combustors
- Small can-type combustors can be completely developed in the laboratory through a combination of both atmospheric and full-pressure, full-flow tests. Therefore, there is a higher degree of confidence that a combustor will perform as designed across all load ranges before it is installed and tested in a machine.

Gas Turbine Emissions

The significant products of combustion in gas turbine emissions are:

- Oxides of nitrogen (NO and NO_2, collectively called NO_x)
- Carbon monoxide (CO)
- Unburned hydrocarbons or UHCs (usually expressed as equivalent methane (CH_4) particles and arise from incomplete combustion)

• Oxides of sulfur (SO_2 and SO_3) particulates.

Unburned hydrocarbons include both volatile organic compounds (VOCs), which contribute to the formation of atmospheric ozone, and compounds, such as methane, that do not.

There are two sources of NO_x emissions in the exhaust of a gas turbine. Most of the NO_x is generated by the fixation of atmospheric nitrogen in the flame, which is called thermal NO_x. Nitrogen oxides are also generated by the conversion of a fraction of any nitrogen chemically bound in the fuel (called fuel-bound nitrogen or FBN). Lower-quality distillates and low-Btu coal gases from gasifiers with hot gas cleanup carry various amounts of fuel-bound nitrogen that must be taken into account when emissions calculations are made. The methods described below to control thermal NO_x emissions are ineffective in controlling the conversion of FBN to NO_x.

Thermal NO_x is generated by a chemical reaction sequence called the Zeldovich Mechanism (Reference 6). This set of well-verified chemical reactions postulates that the rate of generation of thermal NO_x is an exponential function of the temperature of the flame. The amount of NO_x generated is a function of the flame temperature and of the time the hot gas mixture is at flame temperature. This turns out to be a linear function of time. Thus, temperature and residence time determine thermal NO_x emissions levels and are the principal variables that a gas turbine designer can adjust to control emission levels.

For a given fuel, since the flame temperature is a unique function of the equivalence ratio, the rate of NO_x generation can be cast as a function of the equivalence ratio. Figure A-3, shows that the highest rate of NO_x production occurs at an equivalence ratio of 1.0, when the temperature is equal to the stoichiometric, adiabatic flame temperature.

To the left of the maximum temperature point (Figure A-3), more oxygen is available (the equivalence ratio is less than 1.0) and the resulting flame temperature is lower. This is a fuel-lean operation. Since the rate of NO_x formation is a function of temperature and time, it follows that some difference in NO_x emissions can be expected when different fuels are burned in a given combustion system. Since distillate oil and natural gas have approximately a 100F/38 C flame temperature difference, a significant difference in NO_x emissions can be expected if reaction zone equivalence ratio, water injection rate, etc. are equal.

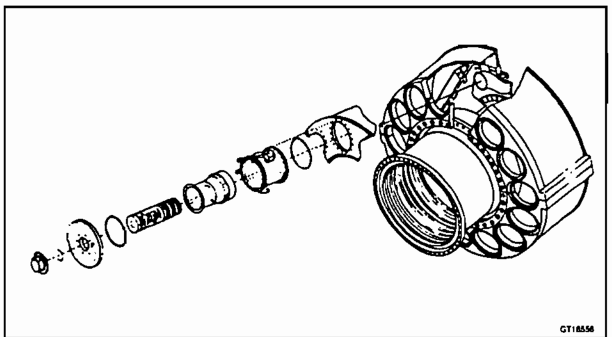

Figure A2. Exploded view of combustion chamber

As shown in Figure A-3, the rate of NO_x production dramatically decreases as flame temperature decreases (i.e., the flame becomes fuel lean). This is because of the exponential effect of temperature in the Zeldovich Mechanism and is the reason why diluent injection (usually water or steam) into a gas turbine combustor flame zone reduces NO_x emissions. For the same reason, very lean dry combustors can be used to control emissions. This is desirable for reaching the lower NO_x levels now required in many applications.

There are two design challenges associated with very lean combustors. First, care must be taken to ensure that the flame is stable at the design operating point. Secondly, a turndown capability is necessary since a gas turbine must ignite, accelerate, and operate over the load range. At lower loads, as fuel flow to the combustors decreases, the flame will be very lean and will not burn well, or it can become unstable and blow out.

In response to these challenges, combustion system designers use staged combustors so a portion of the flame zone air can mix with the fuel at lower loads or during startup. The two types of staged combustors are fuel-staged and air-staged (Figure A-4). In its simplest and most common configuration, a fuel-staged combustor has two flame zones; each receives a constant fraction of the combustor airflow. Fuel flow is divided between the two zones so that at each machine operating condition, the amount of fuel fed to a stage matches the amount of air available.

An air-staged combustor uses a mechanism for diverting a fraction of the airflow from the flame zone to the dilution zone at low load to increase turndown. These methods can be combined.

Emissions Control Methods

There are three principal methods for controlling gas turbine emissions:

- Injection of a diluent such as water or steam into the burning zone of a conventional (diffusion flame) combustor
- Catalytic clean-up of NO_x and CO from the gas turbine exhaust (usually used in conjunction with the other two methods)
- Design of the combustor to limit the formation of pollutants in the burning zone by utilizing "lean-premixed" combustion technology.

The last method includes both DLN combustors and catalytic combustors. GE has considerable experience with each of these three methods.

Since September 1979, when regulations required that NO_x emissions be limited to 75 ppmvd (parts per million by volume, dry), more than 300 GE heavy-duty gas turbines have accumulated more than 2.5 million operating hours using either steam or water-injection to meet or exceed these required NO_x emissions levels. The amount of water required to accomplish this is approximately one-half of the fuel flow. However, there is a 1.8% heat-rate penalty associated with using water to control NO_x emissions for oil-fired simple-cycle gas turbines. Output, increases by approximately 3%, making water (or steam) injection for power augmentation economically attractive in some circumstances (such as peaking applications).

Single-nozzle combustors that use water or steam injection are limited in their ability to reduce NO_x levels below 42 ppmvd on gas fuel and 65 ppmvd on oil fuel. GE developed multi-nozzle quiet combustors (MNQC) for the MS7001EA and MS7001FA capable of achieving 25 ppmvd on gas fuel and 42 ppmvd on oil, using either water or steam injection. Since October 1987, more than 26 MNQC-equipped MS7001s that use water or steam injection have been placed in service. One unit that uses steam injection has operated nearly 50,000 hours at 25 ppmvd NO_x(at 15% O_2).

Frequent combustion inspections and decreased hardware life are undesirable side effects that can result from the use of diluent injection to reduce NO_x emissions from combustion turbines. For applications that require NO_x emissions below 42 ppmvd (or 25 ppmvd in the case of the MS7001EA or MS7001FA MNQC), or to avoid the significant cycle efficiency penalties incurred when water or steam injection is used for NO_x control, one of the other two principal

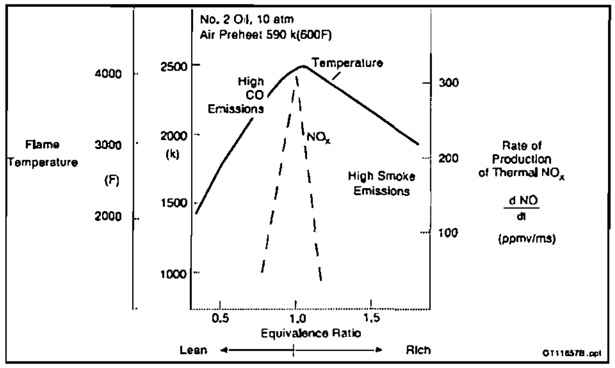

Figure A3. Rate of thermal Nox production

methods of NO_x control mentioned above must be used.

Selective catalytic reduction (SCR) converts NO and NO_2 in the gas turbine exhaust stream to molecular nitrogen and oxygen by reacting the NO_x with ammonia in the presence of a catalyst. Conventional SCR technology requires that the temperature of the exhaust stream remain in a narrow range (550 F to 750 F or 288 C to 399 C) and is restricted to applications with a heat recovery system installed in the exhaust. The SCR is installed at a location in the boiler where the exhaust gas temperature has decreased to the above temperature range. New high-temperature SCR technology is being developed that may allow SCRs to be used for applications without heat recovery boilers.

For an MS7001EA gas turbine, an SCR designed to remove 90% of the NO_x from the gas turbine exhaust stream has a volume of approximately 175 cubic meters and weighs 111 tons. It is comprised of

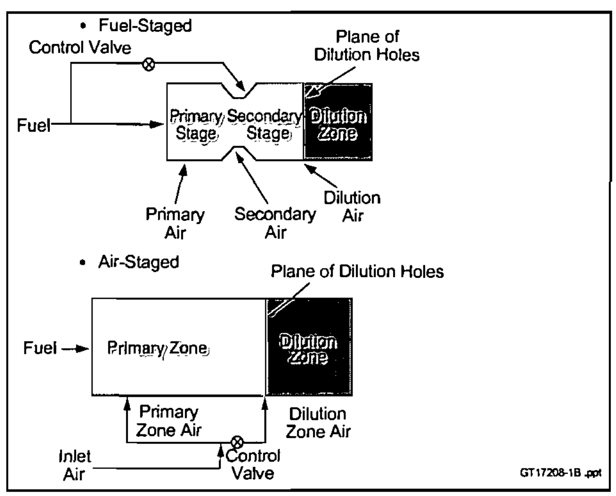

Figure A4. Staged combustors

segments stacked in the exhaust duct. Each segment has a honeycomb pattern with passages that are aligned in the direction of the exhaust gas flow. A catalyst, such as vanadium pentoxide, is deposited on the surface of the honeycomb.

SCR systems are sensitive to fuels containing more than 1,000 ppm of sulfur (light distillate oils may have up to 0.8% sulfur). There are two reasons for this sensitivity: first, sulfur poisons the catalyst being used in SCRs.

Secondly, the ammonia will react with sulfur in the presence of the catalyst to form ammonium bisulfate, which is extremely corrosive, particularly near the discharge of a heat recovery boiler. Special catalyst materials that are less sensitive to sulfur have been identified, and there are some theories as to how to inhibit the formation of ammonium bisulfate. This, however, remains an open issue with SCRs.

More than 100 GE units have accumulated more than 100,000 operating hours with SCRs installed. Twenty of the units are in Japan; others are located in California, New Jersey, New York and several other eastern U.S. states. Units operating with SCRs include MS9000s, MS7000s, MS6000s, LM2500s and LM5000s.

Lean premixed combustion is the basis for achieving low emissions from Dry Low NO_x and catalytic combustors. GE has participated in the development of catalytic combustors for many years. These systems use a catalytic reactor bed mounted within the combustor to burn a very lean fuel-air mixture. They have the potential to achieve extremely low emissions levels without resorting to exhaust gas cleanup. Technical challenges in the combustor and in the catalyst and reactor bed materials must be overcome in order to develop an operational catalytic combustor. GE has development programs in place with both ceramic and catalyst manufacturers to address these challenges. GE does not believe commercial systems employing this technology will be available in the near term.

REFERENCES

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7. Washam, R. M., "Dry Low NO_x Combustion System for Utility Gas Turbine," ASME Paper 83-JPGC-GT-13, Sept. 1983.
8. Davis, L. B., and Washam, R. M., "Development of a Dry Low NO_x Combustor," ASME Paper No. 89-GT-255, June 1989.

LIST OF FIGURES

ATTACHMENT II

GE MARK V CONTROL SYSTEM TECHNICAL LITERATURE

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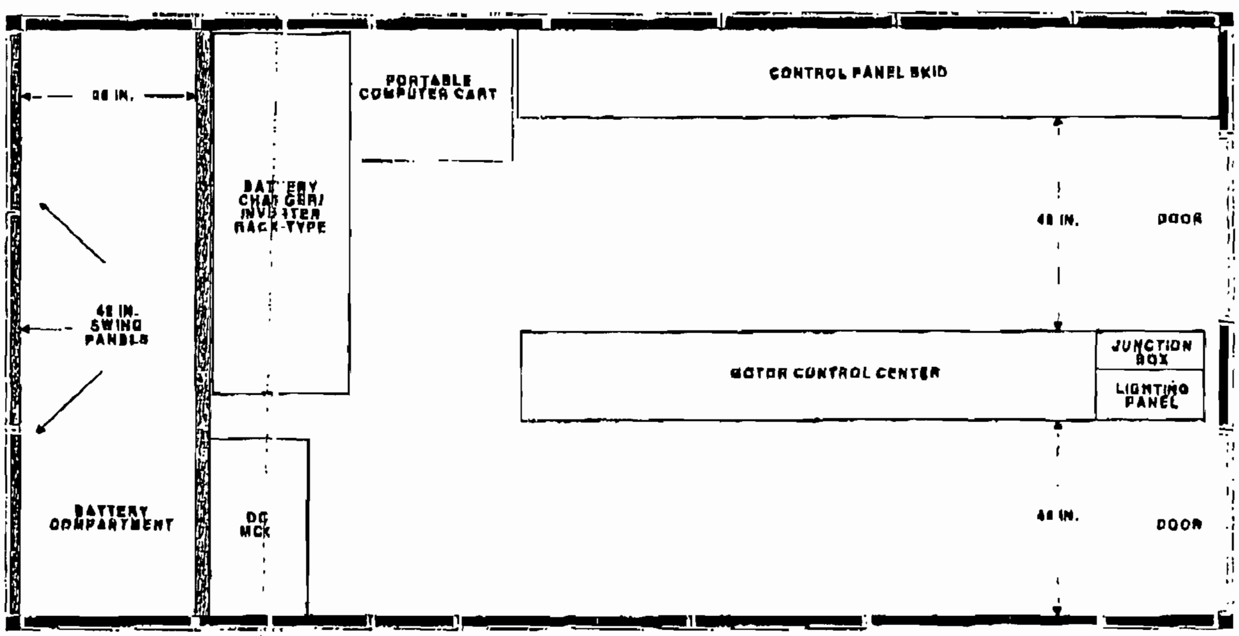
common skid and located in the PEECC. The customer control local interface <I> is also located in the PEECC. In addition to the control systems, the PEECC also houses the gas turbine motor control centers and batteries, rack and charger (s). The arrangement of the equipment is shown in the typical compartment layout below.

Packaged Electronic and Electrical Control Compartment (PEECC)
(Typical)



3.4.2 Gas Turbine Control System

The SPEEDTRONIC™ Mark V gas turbine control system is a state-of-the-art Triple Modular Redundant (TMR) microprocessor control system. The core of this system is the three separate but identical controllers called <R>, <S>, and <T>. All critical control algorithms, protective functions, and sequencing are performed by these processors. In so doing, they also acquire the data needed to generate outputs to the turbine. Protective outputs are routed through the <P> protective module consisting of triple redundant

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processors <X>, <Y>, and <Z>, which also provide independent protection for certain critical functions such as overspeed.

The three control processors, <R>, <S>, and <T>, acquire data from triple-redundant sensors as well as from dual or single sensors. All critical sensors for continuous controls, as well as protection, are triple-redundant. Other sensors are dual or single devices fanned out to all three control processors. The extremely high reliability achieved by TMR control systems is due in considerable measure to the use of triple sensors for all critical parameters.

3.4.2.1 Electronics

All of the microprocessor-based controls have a modular design for ease of maintenance. Each module or controller contains up to five cards, including a power supply. Multiple microprocessors reside in each controller which distribute the processing for maximum performance. Individual microprocessors are dedicated to specific I/O assignments, application software communications, etc., and the processing is performed in a real-time, multi-tasking operating system. Communications between the controller's five cards is accomplished with ribbon cables and gas-tight connectors. Communication between individual controllers is performed on high-speed Arcnet links.

3.4.2.2 Shared Voting

Software Implemented Fault Tolerance (SIFT) and hardware voting are utilized by the SPEEDTRONIC Mark V TMR control system. At the beginning of each computing time frame, each controller independently reads its sensors and exchanges this data with the data from the other two controllers. The median value of each analog input is calculated in each controller and then used as the resultant control parameter for that controller. Diagnostic algorithms monitor a predefined deadband for each analog input to each controller, and if one of the analog inputs deviates from this deadband, a diagnostic alarm is initiated to advise maintenance personnel.

Contact inputs are voted in a similar manner. Each contact input connects to a single terminal point and is parallel wired to three contact input cards. Each card optically isolates the 125 or 24 V dc input, and then a dedicated 80196 processor in each card time stamps the input to within 1 ms resolution. These signals are then transmitted to the <R>, <S>, and <T> controllers for voting and execution of the application software. This technique eliminates any single point failure in the software voting system. Redundant contact inputs for certain functions such as low lube oil pressure are connected to three separate terminal points and then individually voted. With this SIFT technique, multiple failures of contact or analog inputs can be accepted by the control system without causing an erroneous trip command from any of the three controllers as long as the failures are not from the same circuit.

Another form of voting is accomplished through hardware voting of analog outputs. Three coil servos on the valve actuators are separately driven from each controller, and the position feedback is provided by three LVDTs. The normal position of each valve is the average of the three commands from <R>, <S>, and <T>. The resultant averaging circuit has sufficient gain to override a gross failure of any controller, such as a controller output being driven to saturation. Diagnostics monitor the servo coil currents and the D/A converters in addition to the LVDTs.

3.4.2.3 PC Based Operator Interface

The operator interface, <I>, consists of a PC, color monitor, cursor positioning device, keyboard, and printer. The keyboard is primarily used for maintenance such as editing application software or alarm messages. While the keyboard is not necessary, it is convenient for accessing displays with dedicated function keys and adjusting setpoints by entering a numeric value rather than issuing a manual raise/lower command. Setpoint and logic commands require an initial selection which is followed by a confirming execute command.

The operator interface can be used as the sole interface or as a local maintenance work station with all operator control and monitoring coming from communication links with a plant distributed control system (DCS).

3.4.2.4 Direct Sensor Interface

Input/output (I/O) is designed for direct interface to turbine and generator devices such as thermocouples, RTDs and vibration sensors, flame sensors, and proximity probes. Direct monitoring of these sensors eliminates the cost and potential reliability factors associated with interposing transducers and instrumentation. All of the resultant data is visible to the operator from the SPEEDTRONIC Mark V operator interface.

In addition, the communication link enables the resultant data to be visible from a plant Distributed Control System (DCS) system.

3.4.2.5 Built–In Diagnostics

The control system has extensive built–in diagnostics and includes "power–up", background and manually initiated diagnostic routines capable of identifying both control panel, sensor, and output device faults. These faults are identified down to the board level for the panel, and to the circuit level for the sensor or actuator component. On–line replacement of boards is made possible by the triply redundant design and is also available for those sensors where physical access and system isolation are feasible.

3.4.2.6 Generator Interface and Control

The primary point of control for the generator is though the operator interface. However, the control system is integrated with the EX2000BR brushless excitation system over an Arcnet local area network (LAN). The SPEEDTRONIC Mark V is used to control megawatt output and the EX2000BR is used to control megavar output. The generator control panel is used to provide primary protection for the generator. This protection is further augmented by protection features located in the EX2000BR and the SPEEDTRONIC Mark V.

3.4.2.7 Synchronizing Control and Monitoring

Automatic synchronization is performed by the <X>, <Y>, and <Z> cards in conjunction with the <R>, <S>, and <T> controllers. The controllers match speed and voltage and issue a command to close the breaker based on a predefined breaker closure time. Diagnostics monitor the actual breaker closure time and self–correct each command.

Another feature of the system is the ability to synchronize manually via the operator interface instead of using the traditional synchroscope on the generator protective panel. Operators can choose one additional mode of operation by selecting the monitor mode, which automatically matches speed and voltage, but waits for the operator to review all pertinent data on the CRT display before issuing a breaker close command.

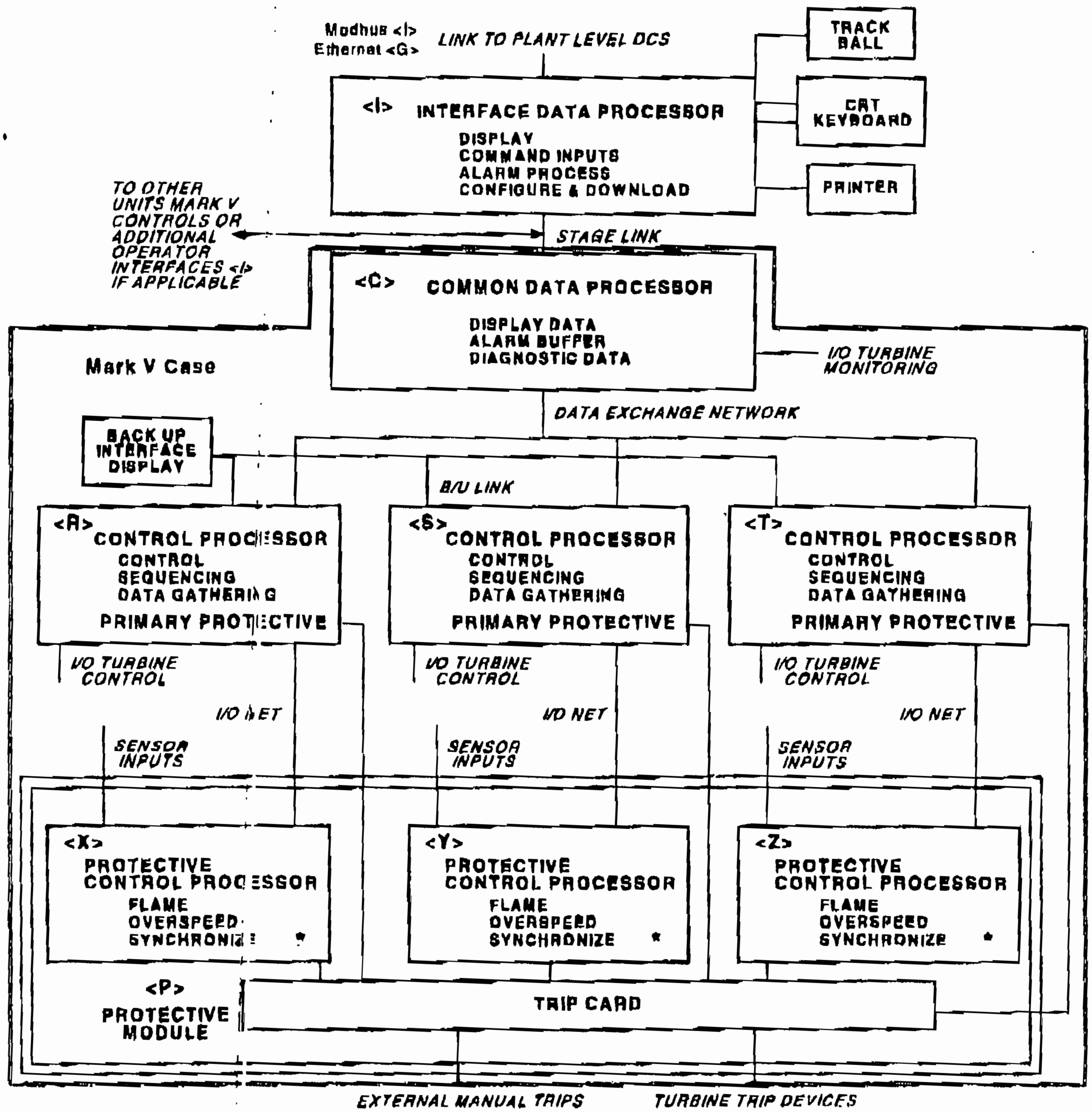
3.4.2.8 Architecture

The SPEEDTRONIC Mark V control configuration diagram depicts several advantages for increased reliability and ease of interface. For example:

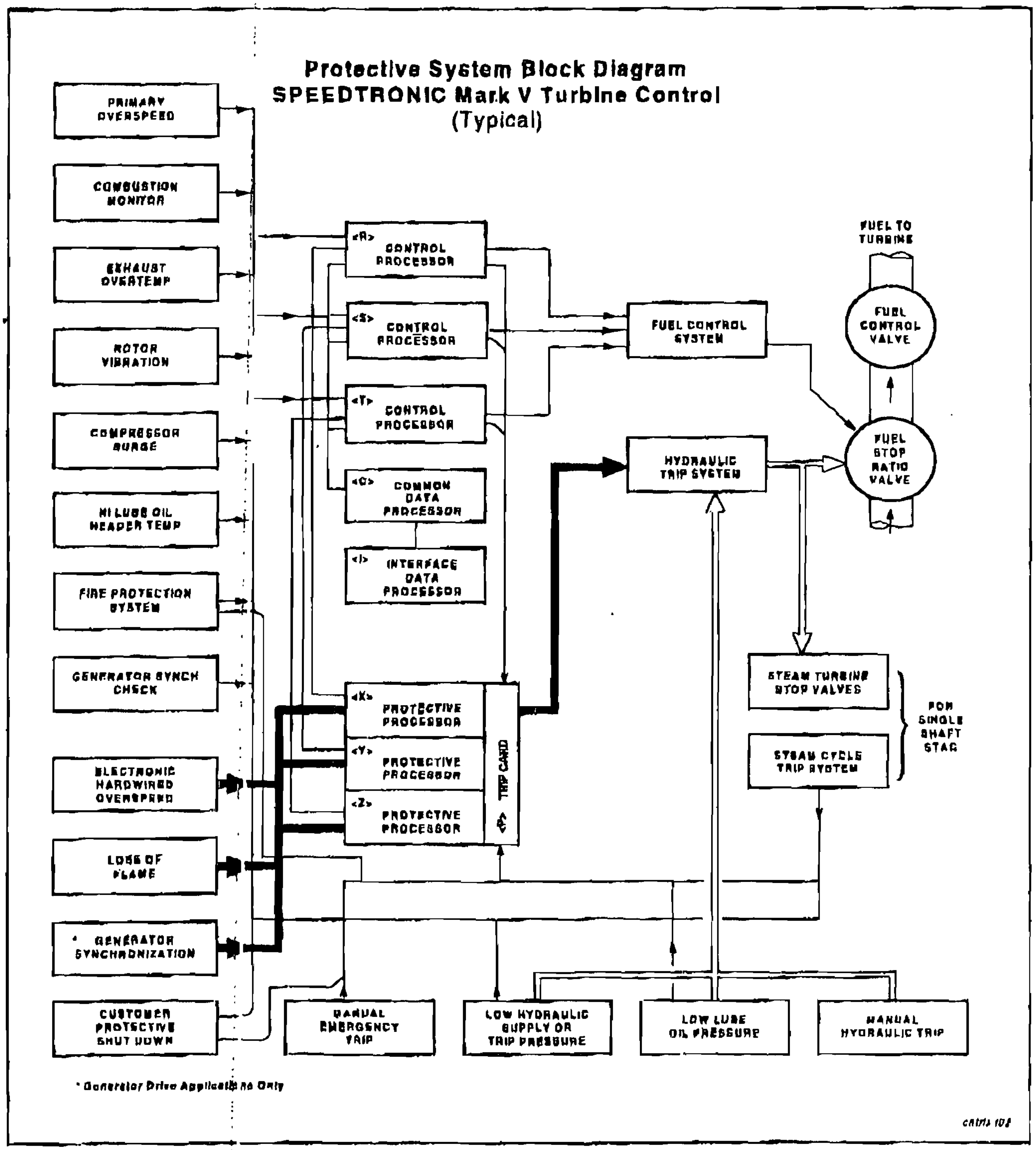
- Multiple unit control from a single <I>
- Back–up display wired directly to <R>, <S>, and <T> controllers
- PC interface to plant DCS system
- Hard wire protective signal from <R> <S> <T> controllers
- Additional protective processors <X>, <Y>, <Z>

The protective block diagram shows the built in redundancy/reliability of the SPEEDTRONIC Mark V control system. For example, if there is an overspeed condition requiring a trip of the unit, the first line of defense would be the primary overspeed protection via the <R>, <S>, and <T> controllers. All three trip signals then pass to the <P> protective module trip card where two out of three voting occurs prior to sending the automatic fuel supply trip signal. The secondary overspeed protection is via the <X>, <Y>, and <Z> protective control processor cards which similarly send their independent trip signals to the <P> protective module trip card for voting.

**Standard SPEEDTRONIC Mark V Control Configuration
(Typical)**



* Generator Drive Applications Only



Protective System Block Diagram
SPEEDTRONIC Mark V Turbine Control
(Typical)

ATTACHMENT III

GE EMISSIONS GUARANTEE

GE Power Systems
Global Power Plant Systems
General Electric Company
One River Road, Schenectady, NY 12345
518-385-0183

July 22, 1999

Eric Booth
Enron Engineering & Construction Company
333 Clay Street, Suite 400
Houston, TX 77002-7361

Subject: TECO Power Services
Emissions Guarantees

Dear Eric:

The General Electric dual fuel fired PG7121 EA Combustion Gas Turbine, purchased for TECO Power Services Hardee Power Station CT-2B has guaranteed emissions of NOx at 9 ppm (@15% O2) and CO at 25 ppm while operating on natural gas fuel, between 65 and 100%load, corrected to 59°F and 60% relative humidity. It is expected that the gas turbine will not exceed these emission levels over the life of the unit, as long as GE's maintenance practices are followed.

In addition, there have been at least seven 7EA gas turbines with DLN-1, Dual Fuel combustion systems, that have proven to meet guarantees of 9 PPM NOx and 25 PPM CO in the last five years.

Sincerely,

Jeff Darst

Jeff Darst
Project Manager

cc: W Turnipseed, NEPCO
DW Ross, TECO Power Services
TECO002

ATTACHMENT IV

GE 7EA CT STACK TEST RESULTS

ENTROPY, INC.

Specialists in Air Emissions Technology

P.O. Box 12291 • Research Triangle Park, North Carolina 27709-2291
(919) 781-3550 • (800) 486-3550 • Fax (919) 787-8442

VOLUME 1

TEXT AND APPENDIX A

PERFORMANCE AND COMPLIANCE TESTING

REFERENCE NO. 15533

PANDA-BRANDYWINE COGENERATION FACILITY

BRANDYWINE, MARYLAND

EMISSIONS TESTING FOR:

CARBON MONOXIDE

NITROGEN OXIDES

PARTICULATE

SULFUR DIOXIDE

SULFURIC ACID MIST

TOTAL HYDROCARBONS

RAYTHEON ENGINEERS & CONSTRUCTORS
PO NO SCT 96.05 PROJECT NO 8346001
REQN OR TASK SCT 96.05 RECEIVED 11/06/96
TAG NO ____ FILE NO 2
☒ FOR INITIAL REVIEW ☐ FOR REVIEW OF REVISION
☐ W/COMMENT-RELEASED FOR FAB WITH COMMENT INCORP. FINAL REQUIRED
☐ NO COMMENT-RELEASED FOR FAB-FINAL REQUIRED
☐ NOT RELEASED FOR FAB - REVISE & RESUBMIT FOR REVIEW
☒ FINAL-NO RETURN REQ'D ☐ FOR INFO-NO RETURN REQ'D
BY RDH DATE 11.6.96
REVIEW DOES NOT RELIEVE SELLER FROM RESPONSIBILITY FOR COMPLIANCE WITH THE CONTRACT DOCUMENTS.

UNIT NOS. 1 AND 2

PERFORMED FOR: RAYTHEON ENGINEERS AND CONSTRUCTORS

SEPTEMBER AND OCTOBER 1996

REPORT CERTIFICATION

EI Reference Number 15533

The sampling and analysis performed for this report were carried out under my direction and supervision, and I hereby certify that, to the best of my knowledge, the test report is authentic and accurate.

Signature: William H Harris

Date: 11/5/96

William H. Harris
Project Director
Client Services Division

Table of Contents

VOLUME 1

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List of Tables and Figures

1.0 INTRODUCTION

1.1 Background

An emissions sampling and analytical program was conducted on Units 1 and 2 at the Panda-Brandywine Cogeneration Facility. Performance testing was performed according to The Air and Radiation Management Administration of the Maryland Department of the Environment Case No. 8488 and methods from the United States Environmental Protection Agency (US EPA) 40 CFR, Part 60, Appendix A. Compliance testing was conducted according to the procedures of 40 CFR, Part 60, Subpart GG.

All testing was performed in strict conformance with specifications stipulated in EPA Reference Methods 1, 2, 3A, 4, 5, 6C, 7E, 8, 10, 19, 20, and 25A. Fuel sampling and analysis were conducted according to the applicable ASTM methods.

1.2 Outline of Test Program

Tables 1-1 through **1-4** are test logs for Unit Nos. 1 and 2. The test logs present the test fuel, sampling locations, sampling objectives, sampling methods, test dates, and run numbers for the test program. Several runs utilized volumetric air flow rates and/or flue gas composition data from other runs.

1.3 Test Participants

Table 1-5 lists the personnel involved in the test program.

TABLE 1-1
TEST LOG
UNIT NO. 1 STACK - NATURAL GAS
SEPTEMBER 1996

Test Condition	Sampling Objective	Test Method	Test Date	Run Numbers	Flue Gas Composition	Volumetric Air Flow Rate
PERFORMANCE TESTS						
Natural Gas	O_2/CO_2, SO_2, NO_x, CO, & THC	EPA 3A, 6C, 7E, 10, & 25A	9/26 9/26 9/26	1-NG-CEM-1 1-NG-CEM-2 1-NG-CEM-3	1-NG-CEM-1 1-NG-CEM-2 1-NG-CEM-3	1-NG-M5/8-1 1-NG-M5/8-2 1-NG-M5/8-3
	Particulate, SO_2, SO_3, & H_2SO_4	EPA 5 & 8	9/26 9/26 9/26	1-NG-M5/8-1 1-NG-M5/8-2 1-NG-M5/8-3	1-NG-CEM-1 1-NG-CEM-2 1-NG-CEM-3	NA
COMPLIANCE TESTS						
Natural Gas 100% Load	O_2/CO_2 & NO_x	EPA 20	9/26 9/26 9/26	1-NG-100-1 1-NG-100-2 1-NG-100-3	1-NG-30-1 1-NG-30-2 1-NG-30-3	Fuel Analysis & Process Data
Natural Gas 75% Load	O_2/CO_2 & NO_x	EPA 20	9/26 9/26 9/26	1-NG-75-1 1-NG-75-2 1-NG-75-3	1-NG-30-1 1-NG-30-2 1-NG-30-3	Fuel Analysis & Process Data
Natural Gas 50% Load	O_2/CO_2 & NO_x	EPA 20	9/27 9/27 9/27	1-NG-50-1 1-NG-50-2 1-NG-50-3	1-NG-30-1 1-NG-30-2 1-NG-30-3	Fuel Analysis & Process Data
Natural Gas 30% Load	O_2/CO_2 & NO_x	EPA 20	9/27 9/27 9/27	1-NG-30-1 1-NG-30-2 1-NG-30-3	1-NG-30-1 1-NG-30-2 1-NG-30-3	Fuel Analysis & Process Data

TABLE 1-2
TEST LOG
UNIT NO. 1 STACK - NO. 2 FUEL OIL
OCTOBER 1996

Test Condition	Sampling Objective	Test Method	Test Date	Run Numbers	Flue Gas Composition	Volumetric Air Flow Rate
PERFORMANCE TESTS						
No. 2 Fuel Oil	O_2/CO_2, SO_2, NO_x, CO, & THC	EPA 3A, 6C, 7E, 10, & 25A	10/09	1-O-CEM-1	1-O-CEM-1	1-O-M5/8-1
			10/09	1-O-CEM-2	1-O-CEM-2	1-O-M5/8-2
			10/09	1-O-CEM-3	1-O-CEM-3	1-O-M5/8-3
	Particulate, SO_2, SO_3, & H_2SO_4	EPA 5 & 8	10/09	1-O-M5/8-1	1-O-CEM-1	NA
			10/09	1-O-M5/8-2	1-O-CEM-2	
			10/09	1-O-M5/8-3	1-O-CEM-3	
COMPLIANCE TESTS						
No. 2 Fuel Oil 100% Load	O_2/CO_2 & NO_x	EPA 20	10/09	1-O-100-1	1-O-100-1	Fuel Analysis & Process Data
			10/09	1-O-100-2	1-O-100-2	
			10/09	1-O-100-3	1-O-100-3	
No. 2 Fuel Oil 75% Load	O_2/CO_2 & NO_x	EPA 20	10/09	1-O-75-1	1-O-75-1	Fuel Analysis & Process Data
			10/09	1-O-75-2	1-O-75-2	
			10/09	1-O-75-3	1-O-75-3	
No. 2 Fuel Oil 50% Load	O_2/CO_2 & NO_x	EPA 20	10/09	1-O-50-1	1-O-50-1	Fuel Analysis & Process Data
			10/09	1-O-50-2	1-O-50-2	
			10/09	1-O-50-3	1-O-50-3	
No. 2 Fuel Oil 30% Load	O_2/CO_2 & NO_x	EPA 20	10/09	1-O-30-1	1-O-30-1	Fuel Analysis & Process Data
			10/09	1-O-30-2	1-O-30-2	
			10/09	1-O-30-3	1-O-30-3	

TABLE 1-3
TEST LOG
UNIT NO. 2 STACK - NATURAL GAS
SEPTEMBER 1996

Test Condition	Sampling Objective	Test Method	Test Date	Run Numbers	Flue Gas Composition	Volumetric Air Flow Rate
PERFORMANCE TESTS						
Natural Gas	O_2/CO_2, SO_2, NO_x, CO, & THC	EPA 3A, 6C, 7E, 10, & 25A	9/25 9/25 9/25	2-NG-CEM-1 2-NG-CEM-2 2-NG-CEM-3	2-NG-CEM-1 2-NG-CEM-2 2-NG-CEM-3	2-NG-M5/8-1 2-NG-M5/8-2 2-NG-M5/8-3
	Particulate, SO_2, SO_3, & H_2SO_4	EPA 5 & 8	9/25 9/25 9/25	2-NG-M5/8-1 2-NG-M5/8-2 2-NG-M5/8-3	2-NG-CEM-1 2-NG-CEM-2 2-NG-CEM-3	NA
COMPLIANCE TESTS						
Natural Gas 30% Load	O_2/CO_2 & NO_x	EPA 20	9/27 9/27 9/27	2-NG-30-1 2-NG-30-2 2-NG-30-3	2-NG-30-1 2-NG-30-2 2-NG-30-3	Fuel Analysis & Process Data
Natural Gas 50% Load	O_2/CO_2 & NO_x	EPA 20	9/27 9/27 9/27	2-NG-50-1 2-NG-50-2 2-NG-50-3	2-NG-30-1 2-NG-30-2 2-NG-30-3	Fuel Analysis & Process Data
Natural Gas 75% Load	O_2/CO_2 & NO_x	EPA 20	9/27 9/27 9/27	2-NG-75-1 2-NG-75-2 2-NG-75-3	2-NG-30-1 2-NG-30-2 2-NG-30-3	Fuel Analysis & Process Data
Natural Gas 100% Load	O_2/CO_2 & NO_x	EPA 20	9/27 9/27 9/27	2-NG-100-1 2-NG-100-2 2-NG-100-3	2-NG-30-1 2-NG-30-2 2-NG-30-3	Fuel Analysis & Process Data

TABLE 1-4
TEST LOG
UNIT NO. 2 STACK - NO. 2 FUEL OIL
OCTOBER 1996

Test Condition	Sampling Objective	Test Method	Test Date	Run Numbers	Flue Gas Composition	Volumetric Air Flow Rate
PERFORMANCE TESTS						
No. 2 Fuel Oil	O_2/CO_2, SO_2, NO_x, CO, & THC	EPA 3A, 6C, 7E, 10, & 25A	10/10 10/10 10/10	2-O-CEM-1 2-O-CEM-2 2-O-CEM-3	2-O-CEM-1 2-O-CEM-2 2-O-CEM-3	2-O-M5/8-1 2-O-M5/8-2 2-O-M5/8-3
	Particulate, SO_2, SO_3, & H_2SO_4	EPA 5 & 8	10/10 10/10 10/10	2-O-M5/8-1 2-O-M5/8-2 2-O-M5/8-3	2-O-CEM-1 2-O-CEM-2 2-O-CEM-3	NA
COMPLIANCE TESTS						
No. 2 Fuel Oil 30% Load	O_2/CO_2 & NO_x	EPA 20	10/14 10/14 10/14	2-O-30-1 2-O-30-2 2-O-30-3	2-O-30-1 2-O-30-2 2-O-30-3	Fuel Analysis & Process Data
No. 2 Fuel Oil 50% Load	O_2/CO_2 & NO_x	EPA 20	10/14 10/14 10/14	2-O-50-1 2-O-50-2 2-O-50-3	2-O-50-1 2-O-50-2 2-O-50-3	Fuel Analysis & Process Data
No. 2 Fuel Oil 75% Load	O_2/CO_2 & NO_x	EPA 20	10/14 10/14 10/14	2-O-75-1 2-O-75-2 2-O-75-3	2-O-75-1 2-O-75-2 2-O-75-3	Fuel Analysis & Process Data
No. 2 Fuel Oil 100% Load	O_2/CO_2 & NO_x	EPA 20	10/10 10/10 10/10	2-O-100-1 2-O-100-2 2-O-100-3	2-O-100-1 2-O-100-2 2-O-100-3	Fuel Analysis & Process Data

TABLE 1-5
TEST PARTICIPANTS
UNIT NOS. 1 AND 2
SEPTEMBER AND OCTOBER 1996

Raytheon Engineers and Constructors	Jeff Jacobsohn Test Coordinator
	Al Vaught Test Observer
Entropy, Inc.	William H. Harris Project Director
	Julie R. Ruff Project Manager
	James E. Daley Sampling Team Leader
	Michael S. Riedel Sampling Team Leader
	Danny L. Speer Sampling Team Leader

2.0 SUMMARY OF RESULTS

2.1 Presentation

Tables 2-1 and **2-2** present the performance test results versus the permitted limits for Unit No. 1 and Unit No. 2, respectively. The compliance test results for Unit No. 1 are presented in **Tables 2-3** and **2-4** and Unit No. 2 compliance test results are presented in **Tables 2-5** and **2-6**. Detailed test results are presented in Volume 1, **Appendix A**; field data is given in Volume 2, **Appendix B**; and analytical data can be found in Volume 2, **Appendix C**.

2.2 Cyclonic Flow Checks

A cyclonic flow check was performed at each sampling location to determine if any cyclonic flow existed. Average yaw angles of < 3 ° were measured, indicating acceptable locations with respect to EPA Method 1 requirements.

2.3 Compliance (EPA Method 20) Tests

Each combustion turbine was tested according to the requirements of Subpart GG of 40 CFR, Part 60. These requirements included the determination of exhaust gas NO_x concentrations (ppm NO_x corrected for dilution to 15% O_2) and in terms of pounds NO_x (as NO_2) per hour at four load conditions. To measure the NO_x emissions on a pound per hour basis, average exhaust gas flow rates were calculated for each run using EPA Method 19 and fuel flow rate and heat content information.

The correction of NO_x concentration to ISO standard ambient conditions (59 °F temperature, 0.00633 g H_2O/g air absolute humidity) prescribed under Subpart GG was not applied, since these parameters are accounted for in the NO_x control water injection algorithm. The Speedtronic Mark V control system automatically adjusts water injection rates, based on current ambient conditions and operating load, to limit NO_x concentrations to levels expected when operating at the current load under ISO standard conditions. Further correction to ISO conditions would have been redundant.

TABLE 2-1
PERFORMANCE TEST RESULTS VERSUS PERMITTED LIMITS
UNIT NO. 1 STACK
SEPTEMBER AND OCTOBER 1996

	Rep 1	Rep 2	Rep 3	Average	Permit Limit
NATURAL GAS					
Concentration, ppmvd @ 15% O_2					
Nitrogen Oxides as NO_2	7.2	7.9	7.7	7.6	9
Emission Rate, lb/hr					
Carbon Monoxide	23.3	19.8	16.6	19.9	59.00
Nitrogen Oxides as NO_2	28.1	29.8	28.9	28.9	35.0
Particulate	2.79	0.666	2.45	1.97	7.0
Sulfur Dioxide (EPA 5/8)	20.0	23.0	17.8	20.3	29.0
Sulfur Dioxide (EPA 6C)	0.5	0.5	0.0	0.3	29.0
Sulfuric Acid Mist	1.87	1.16	2.71	1.91	3.0
Total Hydrocarbons as C	0.22	1.19	1.07	0.83	2.0
NO. 2 FUEL OIL					
Concentration, ppmvd @ 15% O_2					
Nitrogen Oxides as NO_2	47.9	40.2	40.2	42.8	54
Emission Rate, lb/hr					
Carbon Monoxide	0.0	0.0	0.5	0.2	71.0
Nitrogen Oxides as NO_2	194.6	168.0	163.9	175.5	239.0
Particulate	3.06	3.68	9.90	5.55	15.0
Sulfur Dioxide (EPA 5/8)	31.0	33.2	33.1	32.4	54.0
Sulfur Dioxide (EPA 6C)	25.2	29.9	28.6	27.9	54.0
Sulfuric Acid Mist	3.83	4.47	4.55	4.28	6.0
Total Hydrocarbons as C	1.78	1.57	1.11	1.49	5.00

TABLE 2-2
PERFORMANCE TEST RESULTS VERSUS PERMITTED LIMITS
UNIT NO. 2 STACK
SEPTEMBER AND OCTOBER 1996

	Rep 1	Rep 2	Rep 3	Average	Permit Limit
NATURAL GAS					
Concentration, ppmvd @ 15% O_2					
Nitrogen Oxides as NO_2	8.8	8.3	8.8	8.6	9
Emission Rate, lb/hr					
Carbon Monoxide	14.3	14.3	15.1	14.6	59.00
Nitrogen Oxides as NO_2	32.2	30.1	32.6	31.6	35.0
Particulate	2.67	3.99	1.33	2.66	7.0
Sulfur Dioxide (EPA 5/8)	16.5	23.2	21.0	20.2	29.0
Sulfur Dioxide (EPA 6C)	0.0	0.0	1.1	0.37	29.0
Sulfuric Acid Mist	2.38	1.91	3.72	2.67	3.0
Total Hydrocarbons as C	0.22	1.07	0.66	0.65	2.0
NO. 2 FUEL OIL					
Concentration, ppmvd @ 15% O_2					
Nitrogen Oxides as NO_2	46.3	46.6	45.0	46.0	54
Emission Rate, lb/hr					
Carbon Monoxide	0.7	0.0	0.0	0.2	71.0
Nitrogen Oxides as NO_2	182.2	192.0	192.5	188.9	239.0
Particulate	0.932	6.88	5.42	4.41	15.0
Sulfur Dioxide (EPA 5/8)	32.0	33.4	34.6	33.3	54.0
Sulfur Dioxide (EPA 6C)	8.6	12.7	16.3	12.5	54.0
Sulfuric Acid Mist	3.11	3.61	3.30	3.34	6.0
Total Hydrocarbons as C	1.08	1.27	1.17	1.17	5.00

TABLE 2-3
COMPLIANCE TEST RESULTS
UNIT NO. 1 STACK - NATURAL GAS
SEPTEMBER 1996

Natural Gas	Rep 1	Rep 2	Rep 3	Average	Permit Limit
100% LOAD (9/26/96)					
Sample Time	1815 - 1831	1848 - 1904	1912 - 1928		- -
Load, MW	77.28	77.28	77.27	77.28	- -
ppmvd NO_x	6.7	6.9	7.0	6.9	- -
ppmvd NO_x @ 15% O_2	6.8	7.0	7.1	7.0	9
Flow Rate, dscfh	2.89 E+07	2.89 E+07	2.89 E+07	2.89 E+07	- -
lb NO_x/hr	23.04	23.62	24.12	23.59	35.0
75% LOAD (9/26/96)					
Sample Time	1943 - 1959	2007 - 2023	2031 - 2047		- -
Load, MW	69.95	70.09	70.20	70.08	- -
ppmvd NO_x	7.5	7.4	7.4	7.4	- -
ppmvd NO_x @ 15% O_2	7.4	7.3	7.3	7.3	9
Flow Rate, dscfh	2.59 E+07	2.60 E+07	2.59 E+07	2.59 E+07	- -
lb NO_x/hr	23.06	22.92	22.78	22.92	35.0
50% LOAD (9/27/96)					
Sample Time	0730 - 0746	0754 - 0810	0818 - 0834		- -
Load, MW	65.57	65.45	64.96	65.33	- -
ppmvd NO_x	7.7	7.5	7.4	7.5	- -
ppmvd NO_x @ 15% O_2	7.8	7.6	7.5	7.6	9
Flow Rate, dscfh	2.56 E+07	2.52 E+07	2.50 E+07	2.53 E+07	- -
lb NO_x/hr	23.39	22.49	22.09	22.66	35.0
30% LOAD (9/27/96)					
Sample Time	0850 - 0906	0914 - 0930	0938 - 0954		- -
Load, MW	60.29	59.96	60.21	60.15	- -
ppmvd NO_x	7.7	7.9	7.7	7.8	- -
ppmvd NO_x @ 15% O_2	7.7	7.8	7.7	7.7	9
Flow Rate, dscfh	2.34 E+07	2.34 E+07	2.34 E+07	2.34 E+07	- -
lb NO_x/hr	21.62	21.94	21.46	21.67	35.0

TABLE 2-4
COMPLIANCE TEST RESULTS
UNIT NO. 1 STACK - NO. 2 FUEL OIL
OCTOBER 1996

No. 2 Fuel Oil	Rep 1	Rep 2	Rep 3	Average	Permit Limit
100% LOAD (10/09/96)					
Sample Time	0830 - 0846	1120 - 1136	1400 - 1416		- -
Load, MW	79.35	77.87	76.56	77.93	- -
ppmvd NO_x	50.5	43.3	41.2	45.0	- -
ppmvd NO_x @ 15% O_2	48.5	40.6	38.1	42.4	54
Flow Rate, dscfh	2.97 E+07	2.95 E+07	2.84 E+07	2.92 E+07	- -
lb NO_x/hr	179.12	152.45	139.37	156.98	239.0
75% LOAD (10/09/96)					
Sample Time	1611 - 1627	1633 - 1649	1655 - 1711		- -
Load, MW	70.01	70.06	70.18	70.08	- -
ppmvd NO_x	43.6	44.5	44.3	44.1	- -
ppmvd NO_x @ 15% O_2	40.8	41.4	41.0	41.1	54
Flow Rate, dscfh	2.61 E+07	2.61 E+07	2.61 E+07	2.61 E+07	- -
lb NO_x/hr	136.18	138.72	137.71	137.54	239.0
50% LOAD (10/09/96)					
Sample Time	1726 - 1742	1750 - 1812	1818 - 1834		- -
Load, MW	64.94	65.25	65.23	65.14	- -
ppmvd NO_x	44.9	44.5	43.4	44.3	- -
ppmvd NO_x @ 15% O_2	41.9	41.7	40.6	41.4	54
Flow Rate, dscfh	2.46 E+07	2.44 E+07	2.47 E+07	2.46 E+07	- -
lb NO_x/hr	132.04	129.80	127.70	129.85	239.0
30% LOAD (10/09/96)					
Sample Time	1844 - 1900	1906 - 1922	1928 - 1944		- -
Load, MW	60.37	60.22	60.27	60.29	- -
ppmvd NO_x	43.9	43.3	42.7	43.3	- -
ppmvd NO_x @ 15% O_2	41.9	41.4	40.9	41.4	54
Flow Rate, dscfh	2.34 E+07	2.35 E+07	2.35 E+07	2.35 E+07	- -
lb NO_x/hr	122.70	121.21	119.84	121.25	239.0

TABLE 2-5
COMPLIANCE TEST RESULTS
UNIT NO. 2 STACK - NATURAL GAS
SEPTEMBER 1996

Natural Gas	Rep 1	Rep 2	Rep 3	Average	Permit Limit
100% LOAD (9/27/96)					
Sample Time	1057 - 1113	1121 - 1137	1145 - 1201		- -
Load, MW	75.91	75.80	75.41	75.71	- -
ppmvd NO_x	8.9	8.8	8.9	8.9	- -
ppmvd NO_x @ 15% O_2	8.7	8.6	8.7	8.7	9
Flow Rate, dscfh	2.66 E+07	2.66 E+07	2.65 E+07	2.66 E+07	- -
lb NO_x/hr	28.10	27.98	27.96	28.01	35.0
75% LOAD (9/27/96)					
Sample Time	1215 - 1231	1239 - 1255	1303 - 1319		- -
Load, MW	70.25	70.07	70.19	70.17	- -
ppmvd NO_x	5.9	5.7	5.9	5.8	- -
ppmvd NO_x @ 15% O_2	5.9	5.8	6.1	5.9	9
Flow Rate, dscfh	2.56 E+07	2.56 E+07	2.55 E+07	2.56 E+07	- -
lb NO_x/hr	17.89	17.52	17.93	17.78	35.0
50% LOAD (9/27/96)					
Sample Time	1335 - 1351	1359 - 1415	1423 - 1439		- -
Load, MW	65.46	65.54	65.13	65.38	- -
ppmvd NO_x	6.6	6.9	7.0	6.8	- -
ppmvd NO_x @ 15% O_2	6.7	7.0	7.1	6.9	9
Flow Rate, dscfh	2.42 E+07	2.42 E+07	2.41 E+07	2.42 E+07	- -
lb NO_x/hr	19.12	19.80	20.17	19.70	35.0
30% LOAD (9/27/96)					
Sample Time	1454 - 1510	1518 - 1534	1542 - 1558		- -
Load, MW	60.47	59.87	60.30	60.21	- -
ppmvd NO_x	6.6	6.8	6.9	6.8	- -
ppmvd NO_x @ 15% O_2	6.6	6.8	6.9	6.8	9
Flow Rate, dscfh	2.25 E+07	2.24 E+07	2.24 E+07	2.24 E+07	- -
lb NO_x/hr	17.78	18.30	18.47	18.18	35.0

TABLE 2-6
COMPLIANCE TEST RESULTS
UNIT NO. 2 STACK - NO. 2 FUEL OIL
OCTOBER 1996

No. 2 Fuel Oil	Rep 1	Rep 2	Rep 3	Average	Permit Limit
100% LOAD (10/10/96)					
Sample Time	1200 - 1216	1445 - 1501	1730 - 1746		- -
Load, MW	78.78	78.71	79.14	78.88	- -
ppmvd NO_x	47.1	47.0	46.0	46.7	- -
ppmvd NO_x @ 15% O_2	44.8	45.4	43.9	44.7	54
Flow Rate, dscfh	2.83 E+07	2.83 E+07	2.90 E+07	2.85 E+07	- -
lb NO_x/hr	159.23	158.86	159.15	159.08	239.0
75% LOAD (10/14/96)					
Sample Time	1128 - 1144	1149 - 1205	1210 - 1226		- -
Load, MW	70.09	70.24	70.14	70.16	- -
ppmvd NO_x	48.4	49.9	49.1	49.1	- -
ppmvd NO_x @ 15% O_2	45.5	47.3	46.6	46.5	54
Flow Rate, dscfh	2.53 E+07	2.54 E+07	2.55 E+07	2.54 E+07	- -
lb NO_x/hr	146.14	151.04	149.40	148.86	239.0
50% LOAD (10/14/96)					
Sample Time	1013 - 1029	1034 - 1050	1056 - 1112		- -
Load, MW	65.03	64.93	65.01	64.99	- -
ppmvd NO_x	49.8	51.7	52.2	51.2	- -
ppmvd NO_x @ 15% O_2	46.5	48.0	48.5	47.7	54
Flow Rate, dscfh	2.35 E+07	2.36 E+07	2.35 E+07	2.35 E+07	- -
lb NO_x/hr	140.09	145.49	146.32	143.97	239.0
30% LOAD (10/14/96)					
Sample Time	0852 - 0908	0914 - 0930	0945 - 1001		- -
Load, MW	60.16	60.47	60.24	60.29	- -
ppmvd NO_x	50.0	48.8	52.3	50.4	- -
ppmvd NO_x @ 15% O_2	48.9	47.2	49.8	48.7	54
Flow Rate, dscfh	2.31 E+07	2.32 E+07	2.29 E+07	2.31 E+07	- -
lb NO_x/hr	137.60	135.41	143.32	138.78	239.0

ATTACHMENT V

REVISED TABLE 7-13

Table 7-13. ISCST3 Model Results—Maximum Criteria Pollutant Impacts

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Significant Impact ($\mu g/m^3$)
NO_x	Annual	0.011	1.0
CO	8-hour	0.7	500
	1-hour	5.2	2,000
PM	Annual	0.002	1.0
	24-hour	0.07	5.0
SO_2	Annual	0.003	1.0
	24-hour	0.23	5.0
	3-hour	1.74	25.0

Source: ECT, 1999.

INTEROFFICE MEMORANDUM

Date: 21-Jul-1999 09:45am
From: Tom Davis
tdavis@ectinc.com
Dept:
Tel No:

To: Jeff Koerner (Koerner_J@dep.state.fl.us)
CC: Chris Carlson (Carlson_C@dep.state.fl.us)

Subject: - no subject (01JDTLIQNZ609BVDS6) -

Jeff,

I have reviewed summary Table 7-13. Except for NO2, it looks like I used the unadjusted model results (based on a nominal 10.0 g/s emission rate) rather than the correct adjusted rates shown in Tables 7-5 through 7-12. Also, the 1- and 8-hr CO results were reversed. I will send you a corrected Table 7-13 with the response package to your 7/15/99 letter (probably going out to you today).

Tom Davis
Environmental Consulting & Technology, Inc.

Voice: (352) 332-6230, Ext. 351
Fax: (352) 332-6722

Z 333 618 198

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

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Street & Number TECO Hardee	
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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 050-Fl-140a	7-15-99

PS Form **3800**, April 1995

Fold at line over top of envelope to the right of the return address.

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
TECO Power Services
702 N. Franklin St.
Tampa, Fl 33602

4a. Article Number Z 333 618 198

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

7. Date of Delivery **JUL 19 1999**

5. Received By: *(Print Name)*

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

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

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

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

July 15, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Request for Additional Information
Permit No. PSD-FL-140(a)
TECO – Hardee Power Station (PA-89-25)
Modification to Construct Additional 75 MW Gas Turbine

Dear Mr. Ludwig:

On June 18, 1999, the Department's Bureau of Air Regulation received your application and complete fee for a PSD construction permit to add a 75 MW combustion turbine to the Hardee Power Station. Our review of the application is being conducted in parallel with the other Department programs as required by the Power Plant Siting Act. We will also provide a Sufficiency Review through the Office of Power Plant Siting.

The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. Specify the model of dry low-NOx, dual-fuel combustors that will be installed on the General Electric Model 7EA combustion turbine. Also, describe the combustion process using this specific combustor technology from startup to base load operation.
2. Specify the control system that will control the combustion process. What parameters are input to this control system? What processes and functions are controlled by this system?
3. Provide letter from the manufacturer stating that the guarantees for CO / NOx emissions (25 / 9 ppmvd at 15% oxygen) are for continuous operation with dual-fuel combustors. Also, provide manufacturer performance curves showing the CO and NOx emissions characteristics from startup to 100% base load for the combustion turbine.
4. Provide the test results summary (CO, NOx, and VOC) for a similarly designed, existing General Electric 7EA Model PG7121 conducted within the last two years.

5. Provide the modeling output files on computer diskette.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. A new certification statement by the authorized representative or responsible official must accompany material changes to the application. Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days. If there are any questions, please call me at 850/414-7268. Matters regarding modeling issues should be directed to Chris Carlson (meteorologist) at 850/921-9537.

Sincerely,

Jeffery F. Koerner

Jeffery F. Koerner, P.E.
New Source Review Section

JFK/jfk

cc: Mr. Thomas W. Davis, ECT
Mr. Paul L. Carpinone, TECO
Mr. Buck Oven, Siting Office
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS
Mr. Phil Barbaccia, SW District - DEP

INTEROFFICE MEMORANDUM

Date: 08-Jul-1999 06:19pm
From: Ellen_Porter
Ellen_Porter@nps.gov
Dept:
Tel No:

To: linero_a (linero_a@dep.state.fl.us)
To: koerner_j (koerner_j@dep.state.fl.us)
To: holladay_c (holladay_c@dep.state.fl.us)
CC: Don_Shepherd (Don_Shepherd@nps.gov)

Subject: Hardee Power Station

We are pleased to see that Hardee's new simple-cycle turbine will meet a NOx emission limit of 9 ppm when burning gas.

We agree that because of the distance of the project from Chassahowitzka (130 km) and the types and amounts of emissions (NOx=199 tpy; PM=24 tpy; SO2=44 tpy), there is low potential for impacts to the Class I area. We have no further comments.

FLORIDA
Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

June 24, 1999

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA – Region IV
61 Forsyth Street
Atlanta, Georgia 30303

Re: Hardee Power Station PA 89-25
Modification of Certification

Dear Mr. Worley:

Enclosed for your review and comment is an application for the above-mentioned project. The applicant proposes to install a General Electric Model PG7121 combustion gas turbine with electrical generator rated at 75 MW. The unit will operate in simple cycle mode and be fired primarily with natural gas and have low sulfur distillate oil as a backup. The proposed BACT emissions were 25/20 ppmvd of CO and 9/42 ppmvd of NOx for gas and oil firing.

Your comments can be forwarded to my attention at the letterhead address or faxed to the Bureau at 850/922-6979. If you have any questions, please contact Jeff Koerner at 850/414-7268.

Sincerely,

A. A. Linero, P.E.
Administrator
New Source Review Section

AAL/kt

Enclosures

cc: Jeff Koerner, BAR

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

June 24, 1999

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS-Air Quality Division
Post Office Box 25287
Denver, CO 80225

Re: Hardee Power Station PA 89-25
Modification of Certification

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for the above-mentioned project. The applicant proposes to install a General Electric Model PG7121 combustion gas turbine with electrical generator rated at 75 MW. The unit will operate in simple cycle mode and be fired primarily with natural gas and have low sulfur distillate oil as a backup. The proposed BACT emissions were 25/20 ppmvd of CO and 9/42 ppmvd of NOx for gas and oil firing.

Your comments can be forwarded to my attention at the letterhead address or faxed to the Bureau at 850/922-6979. If you have any questions, please contact Jeff Koerner at 850/414-7268.

Sincerely,

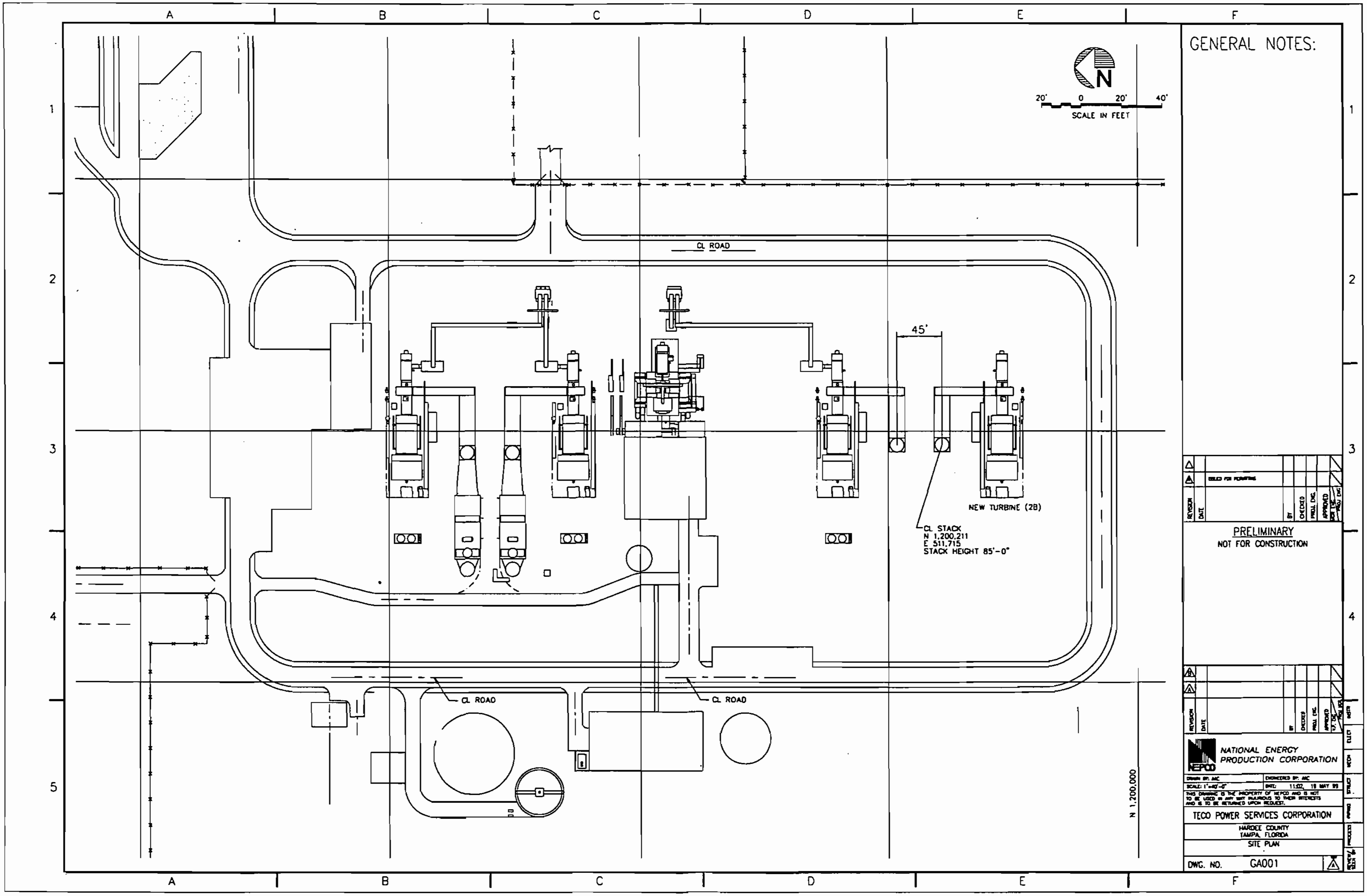
Jeff Koerner for

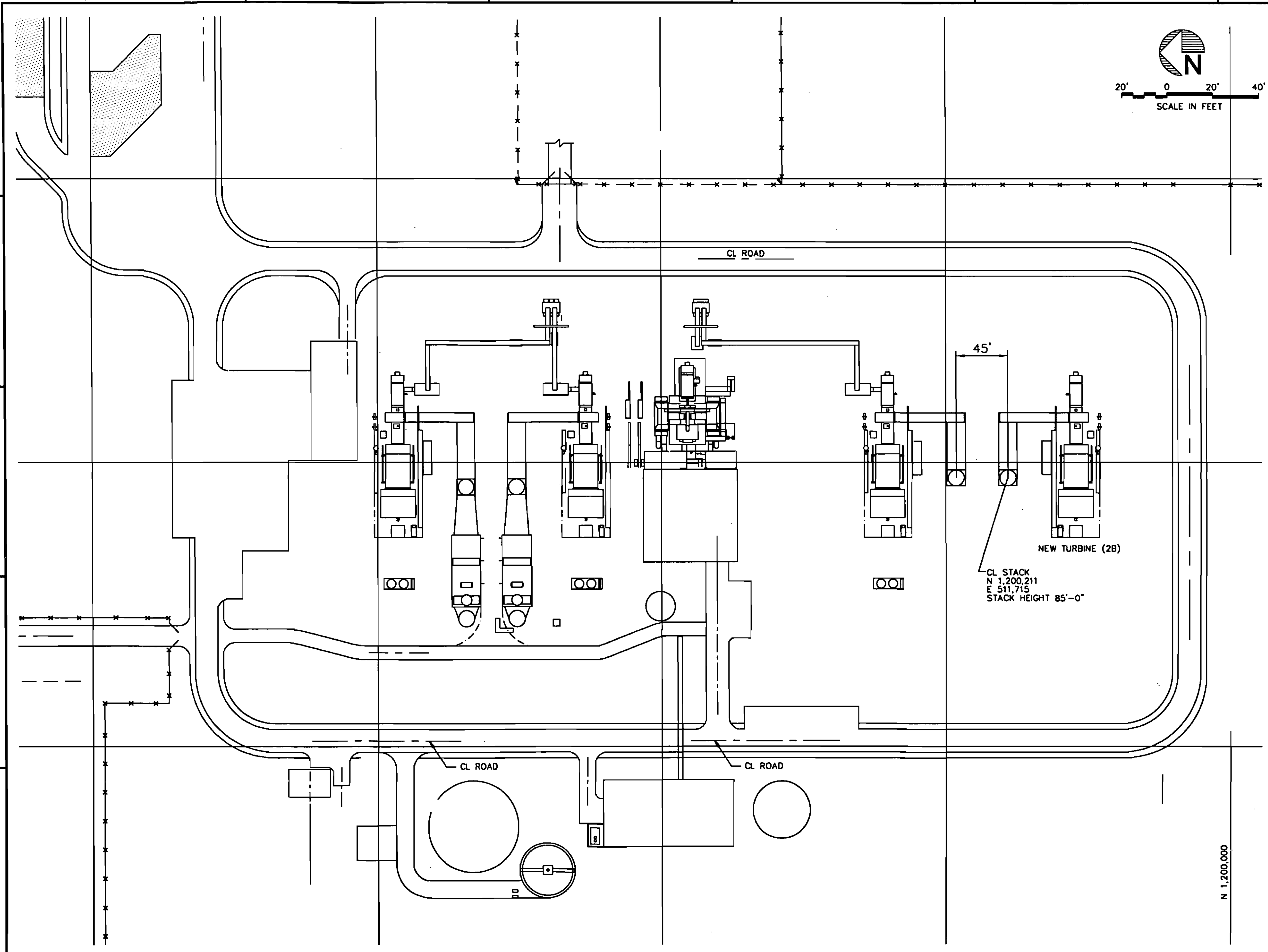
A. A. Linero, P.E.
Administrator
New Source Review Section

AAL/kt

Enclosures

cc: Jeff Koerner, BAR


GENERAL NOTES:
N
20' 0 20' 40'
SCALE IN FEET
CL ROAD
45'
NEW TURBINE (2B)
CL STACK
N 1,200,211
E 511,715
STACK HEIGHT 85'-0"
CL ROAD
CL ROAD
N 1,200,000
PRELIMINARY
NOT FOR CONSTRUCTION
REVISION
DATE
BY
CHECKED
PROJ. ENG.
APPROVED
NATIONAL ENERGY PRODUCTION CORPORATION
NEPCO
SCALE: 1"=40'-0"
DATE: 11:02, 19 MAY 99
THIS DRAWING IS THE PROPERTY OF NEPCO AND IS NOT TO BE USED IN ANY WAY INJURIOUS TO THEIR INTERESTS AND IS TO BE RETURNED UPON REQUEST.
TECO POWER SERVICES CORPORATION
HARDEE COUNTY
TAMPA, FLORIDA
SITE PLAN
DWG. NO. GA001



GENERAL NOTES:

ISSUED FOR PERMITTING

REVISION | DATE | BY | CHECKED | PROJ. ENG. | APPROVED

PRELIMINARY
NOT FOR CONSTRUCTION

NATIONAL ENERGY PRODUCTION CORPORATION

NEPCO

DRAWN BY: AAC | ENGINEERED BY: AAC

SCALE: 1"=40'-0" | DATE: 11:02, 19 MAY 99

THIS DRAWING IS THE PROPERTY OF NEPCO AND IS NOT TO BE USED IN ANY WAY INJURIOUS TO THEIR INTERESTS AND IS TO BE RETURNED UPON REQUEST.

TECO POWER SERVICES CORPORATION

HARDEE COUNTY
TAMPA, FLORIDA

SITE PLAN

DWG. NO. GA001

6-8-99

Meeting at Power Plant Siting Office

TECO
Hardie Power Station

- Near Seminole, Payne Creek
- Consultant - Jack Doolittle - ECT
- Want to add a 7E (GE) 75MW, simple cycle combustion turbine to existing plant (Unit 2-B?)
  - → Fired w/natural gas and oil backup fuel
  - → DLN on gas to NO_x ≤ 9 ppmvd, ≤ 25 ppmvd of CO
  - → water injection on oil to ≤ 42 ppmvd
  - → 876 hour/year of oil
  - → No new oil storage tank or cooling tower necessary
  - → Want up to 8760 hour/year on gas
  - → Dept. needs good information on "hot" SCR (have a bid in to Englehard)

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 031 392 020

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

7. Date of Delivery
OCT 13 1999

5. Received By: *(Print Name)*

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

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

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

Thank you for using Return Receipt Service.

Z 031 392 020

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 Hardee
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	10-8-99 0490015- PSO-FI-140a

PS Form **3800**, April 1995

ORB 14.1

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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:
Mr. Jeff Koerner, P.E.
Bureau of Air Regulation
New Source Review Section
Florida Department of Environmental Protection
Suite 4
111 South Magnolia Drive
Tallahassee, Florida 32301

4a. Article Number
Z 611 343 793

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

7. Date of Delivery

5. Signature (Addressee)

6. Signature (Agent)

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

Thank you for using Return Receipt Service.

PS Form **3811**, December 1991 ☆U.S. GPO: 1993—352-714 **DOMESTIC RETURN RECEIPT**

RECEIVED
SEP 07 1999
TECO Power Services

THE TAMPA TRIBUNE

Published Daily

Tampa, Hillsborough County, Florida

RECEIVED
SEP 09 1999
BUREAU OF AIR REGULATION

State of Florida }
County of Hillsborough } ss.

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

LEGAL NOTICE

in the matter of

PUBLIC NOTICE OF INTENT

was published in said newspaper in the issues of

SEPTEMBER 4, 1999

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

J Rosenthal

Sworn to and subscribed before me, this 7 day

of SEPTEMBER, A.D. 1999

Personally Known____or Product Identification______
Type of Identification Produced______________

(SEAL)

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

Susie Lee Slaton

cc:

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/PM10), sulfur dioxide (SO2). Dry low-NOx (DLN) combustion technology will be used to control nitrogen oxide emissions when firing (ile 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.

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
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- 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:

Mr. Doug Neeley, Section Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA - Region IV
61 Forsyth Street
Atlanta, GA 30303

4a. Article Number
Z 333 618 132

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

7. Date of Delivery

5. Received By: *(Print Name)*
JOYCE EVANS

6. Signature: *(Addressee or Agent)*
X SEP - 1 1999

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

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

Thank you for using Return Receipt Service.

Z 333 618 132

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

Sent to Neeley	
Street & Number EPA	
Post Office, State, & ZIP Code Atlanta GA	
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 Hardee P.S. 8-30-99 PSD-FL-140a PA 89-25	

PS Form **3800**, April 1995

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)*

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

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

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

Thank you for using Return Receipt Service.

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-Fl-140a
pa 89-25

PS Form **3800**, April 1995

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In Re: Hardee Power Partners Limited)
Hardee Power Station Unit 2B)
Modification of Conditions) OGC Case No. 99-1050
of Certification, PA89-25C)
Hardee County, Florida)

NOTICE OF INTENT TO ISSUE PROPOSED MODIFICATION OF POWER PLANT CERTIFICATION

The Florida Department of Environmental Protection (Department) hereby provides notice of an intent to modify Power Plant Certification Conditions issued pursuant to the Florida Electrical Power Plant Siting Act, § 403.501, *et seq.*, Florida Statutes (F. S.). A Proposed Final Order has been prepared in accordance with Rule 62-17.211(4), Florida Administrative Code, concerning the above referenced project. A copy of the proposed Final Order Modifying Conditions of Certification is attached.

On June 18, 1999, Hardee Power Partners Limited filed a request to modify the Conditions of Certification pursuant to § 403.516, F. S., and Condition XXI of the Conditions of Certification, which delegates authority to modify conditions to the Department. The Department has reviewed the requested modification of conditions of certification to allow the construction and operation of one additional nominal 75 megawatt, simple-cycle combustion turbine electrical power generation unit at the Hardee Power Partners Limited's Hardee Power Station in Hardee County, Florida. The combustion turbine will be fired primarily with pipeline quality natural gas and will use low-sulfur distillate fuel oil as a back-up fuel source. The addition of this unit also required a modification of Prevention of Significant Deterioration (PSD) Permit Number PSD-FL-140A. The final PSD permit with the modification addressing the addition of the new unit was issued on October 8, 1999. A copy of the proposed modifications is available from Steven L. Palmer, P.E., Siting Coordination Office, Department of Environmental Protection 2600 Blair Stone Road, M.S. 48, Tallahassee, Florida 32399-2400, (904) 487-0472.

POINT OF ENTRY

Pursuant to Section 403.516, F. S., and Rule 62-17.211(4), F.A.C., all parties to the certification proceeding have 45 days from the date of receipt of this notice in which to respond to the request. Failure to file a response constitutes a waiver of objection to the requested modification.

Any person who is not already a party to the certification proceeding and whose substantial interest is affected by the requested modification has 30 days from the date of publication of the public notice to object in writing. The written objection must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000.

If no objections are received, then a Final Order approving the modification shall be issued by the Department. If objections are raised and agreement cannot be subsequently reached, then pursuant to § 403.516(1)(c), F. S., the applicant may file a petition for modification seeking approval for those portions of the request for modification to which written objections were timely filed.

Mediation is not available in this proceeding.

CERTIFICATE OF SERVICE

I CERTIFY that a true and correct copy of the foregoing Intent to Issue Proposed Modification of Power Plant Certification was mailed to:

Lawrence N. Curtin, Esquire
Holland & Knight, L.L.P.
Post Office Drawer 810
Tallahassee, Florida 32303-0810
(For Hardee Power Partners, Ltd.)

William H. Green, Esquire
James S. Alves, Esquire
Hopping Green Sams & Smith, P.A.
Post Office Box 6526
Tallahassee, Florida 32314
(For Seminole Electric Cooperative, Inc.)

Michael P. Haymans, Esquire
Farr, Farr, Emerich, et al.
Post Office Box 511447
Punta Gorda, Florida 33951-1447
(For Slack and Katzen and Schmid)

Gary Alan Vorbeck
Hardee County Attorney
Vorbeck & Vorbeck, P.A.
207 East Magnolia Street
Arcadia, Florida 33821

Reneé Francis Lee, Esquire
Charlotte County Attorney
18500 Murdock Circle, Room 573
Port Charlotte, Florida 33948-1094

Mark Carpanini, Esquire
Office of the County Attorney
Polk County
Post Office Box 9005
Bartow, Florida 33831-9005

David E. Bruner, Esquire
Post Office Box 335
1645 Ludlow Road
Marco Island, Florida 34146
(For Southwest Florida Regional Planning Council)

Jim Yaeger, Esquire
Lee County Attorney
Post Office Box 398
Fort Myers, Florida 33902-0398

Ralph Artigliere, Esquire
Anderson & Artigliere
4927 Southfork Drive
Post Office Box 6839
Lakeland, Florida 33807-6839
(For Central Florida Regional Planning Council)

Emeline C. Acton, Esquire
Hillsborough County Attorneys Office
Post Office Box 1110
Tampa, Florida 33601-1110

Cari Roth, General Counsel
Department of Community Affairs
2555 Shumard Oak Boulevard
Tallahassee, Florida 32399-2100

John Fumero, Esquire
South Florida Water Management District
Post Office Box 24680
West Palm Beach, Florida 33416-4680

Ted Williams, Esquire
Manatee County Attorney
Post Office Box 1000
Bradenton, Florida 34206

David C. Hollomon, Esquire
Post Office Box 592
10 East Oak Street
Arcadia, Florida 34265-0592
(For City of Arcadia)

John McWhirter, Esquire
McWhirter and Reeves
Post Office Box 3350
Tampa, Florida 33601
(For Agrico Chemical Company)

James V. Antista, General Counsel
Florida Fish and Wildlife Conservation Commission
Bryant Building
620 South Meridian Street
Tallahassee, Florida 32399-1600

David LaCroix, Esquire
City Attorney
Post Office Box 512517
Punta Gorda, Florida 33951-2517
(For City of Cape Coral)

Robert V. Elias, Esquire
Division of Legal Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Thomas W. Reese, Esquire
2951 61st Avenue South
St. Petersburg, Florida 33712-4539
(For Manasota-88, Inc.)

Frank Anderson
Assistant General Counsel
Southwest Florida Water Management District
2379 Broad Street
Brooksville, Florida 34609-6899

Sheauching Yu, Assistant General Counsel
Department of Transportation
Haydon Burns Building, MS 58
605 Suwannee Street
Tallahassee, Florida 32399-0450

R.E. Ludwig, President
Hardee Power Partners, Ltd.
Post Office Box 111
Tampa, Florida 33601-0111

on this 5 day of May 2000.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

SCOTT A. GOORLAND
Senior Assistant General Counsel
Florida Bar No. 0066834

Douglas Building, MS 35
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In Re: Hardee Power Partners Limited Hardee Power Station Unit 2B Modification of Conditions of Certification, PA 89-25C Hardee County, Florida	))))))	OGC Case No. 99-1050

PROPOSED FINAL ORDER MODIFYING CONDITIONS OF CERTIFICATION

By a Final Order dated November 27, 1990, the Governor and Cabinet, sitting as the Siting Board, granted certification to co-applicants TECO Power Services Corporation, Tampa Electric Company, and Seminole Electric Cooperative, Inc. for the construction and operation of a combined-cycle power station known as the Hardee Power Station, including directly associated electrical transmission lines, a natural gas pipeline, and other directly associated facilities. 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, at the Polk and Hardee County lines in 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 Conditions of Certification were modified on August 12, 1991 to substitute Hardee Power Partners Limited for TECO Power Services Corporation as a responsible party under the conditions. The conditions were modified on October 28, 1991 to allow the use of steel instead of wood for transmission line structures in the Cecil M. Webb Wildlife Management Area in Charlotte County, Florida.

On June 18, 1999, Hardee Power Partners Limited filed a request to modify the Conditions of Certification pursuant to Section 403.516, Florida Statutes, and Condition XXI of the Conditions of Certification, which delegates authority to the Department to modify conditions. Hardee Power Partners Limited requested that the conditions be modified to allow the construction and operation of one additional 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 addition of this unit also required a modification of Prevention of Significant Deterioration (PSD) permit number PSD-FL-140A. The final PSD permit with the modification addressing the addition of the new unit was issued on October 8, 1999. 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 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 through a rectangular stack that is 85 feet in height. The applicant identifies the new combustion turbine as Unit 2B.

On July 12, 1999, all parties to the original proceeding were sent a Notice of Receipt of Proposed Modification of Power Plant Certification. On May 4, 2000, all parties to the original proceeding were furnished copies of the Notice of Intent to Issue Proposed Modification of Power Plant Certification and a copy of the proposed final order. On May 12, 2000, a Notice of Intent to Issue Proposed Modification of Power Plant Certification was published in the *Florida Administrative Weekly*. The notices specified that all parties to the original certification proceeding have 45 days from the issuance of the notice by mail to such party's last address of record in which to object to the requested modification. Failure of any of the parties to file a response constitutes a waiver of objection to the requested modification. The notices further specified that any person who is not already a party to the certification proceeding and whose substantial interest is affected by the requested modification has 30 days from the date of publication of the public notice to object in writing. If no objections are received, then a Final Order approving the modification shall be issued by the Department. If objections are raised and agreement cannot be subsequently reached, then pursuant to § 403.516(1)(c), F.S., the applicant may file a petition for modification seeking approval for those portions of the request for modification to which written objections were timely filed. No written objections to the proposed modifications have been received by the Department. Accordingly, in the absence of any timely objection,

IT IS ORDERED:

The proposed changes to the Hardee Power Station Conditions of Certification as described in the Department's May 4, 2000, Notice of Intent to Issue Proposed Modifications to Power Plant Certification are **APPROVED**. Pursuant to Section 403.516(1)(b), Florida Statutes, the Conditions of Certification for the Hardee Power Station are **MODIFIED** as follows:

I. GENERAL

A. Definitions

1. through 2. No change.

3. "DEP~~R~~" shall mean the Florida Department of Environmental Protection ~~Regulation~~.

4. No change.

~~5. "DNR" shall mean the Florida Department of Natural Resources.~~

6. through 7. renumber to 5. through 6.

7.~~8. "GFWFC"~~ "FWCC" shall mean the Florida ~~Game and Freshwater~~ Fish and Wildlife Conservation Commission.

9. through 23. Renumber to 8. through 22.

B. No change.

C. Applicable Rules

The construction and operation of the HPS shall be in accordance with these Conditions of Certification and all applicable provisions of at least the following regulations: Florida Statutes and the rules of the Department~~: Chapters 17-2, 17-3, 17-4, 17-5, 17-6, 17-7, 17-12, 17-21, 17-22, 17-25, 17-274, 17-302, and 17-610, Florida Administrative Code (F.A.C.)~~ or their successors as they are renumbered.

II. AIR (HPPL)

A. Emission Limitations for ~~HPS~~ Unit 1 and Unit 2A

The construction and operation of HPS shall be in accordance with all applicable provisions of Chapters ~~17-2~~ 62-204, 62-210, 62-256, 62-296, 62-701, and 62-704, F.A.C. In addition to the foregoing, HPS shall comply with the following Conditions of Certification as indicated.

1. through 7. No change.

8. a. through h. No change.

i. ASTM D 1072-80, D 3031-81, D 4084-82 or D 3246-81 for sulfur content of natural gas (I, and A if deemed necessary by ~~DER~~ DEP)

Other ~~DER~~ DEP approved methods may be used for compliance testing after prior Departmental approval.

9. through 11. No change.

12. The project shall comply with all the applicable requirements of Chapter ~~17-2~~ 62-204, 62-210, 62-256, 62-296, 62-701, and 62-704, Florida Administrative Code (F.A.C.) and the July 1, 1988, version of 40 CFR 60 Subpart GG, Gas Turbines.

13. Any change in the method of operation, fuels, equipment, or phase design, shall be submitted for approval to ~~DER~~ DEP's Bureau of Air Regulation.

14. through 15. No change.

16. If construction does not commence on the first three units within 18 months of issuance of this certification/permit, then the permittee shall obtain from ~~DER~~ DEP a review and, if necessary, a modification of the control technology and allowable emissions for the unit(s) on which construction has not commenced [40 CFR 52.21(r)(2)]. Units to be constructed in later phases of the project will be reviewed and limitations established under the supplementary review process of the Power Plant Siting Act.

17. Quarterly excess emission reports, in accordance with the July 1, 1988 version 40 CFR 60.7 and 60.334 shall be submitted to ~~DER~~ DEP's Southwest District office. Annual reports shall be submitted to the District office in accordance with Section 62-297.310(8), F.A.C. ~~Rule 17-2.700(7).~~

18. Literature of equipment selected shall be submitted as it becomes available. A CT-specific graph of the relationship between NOx emissions and water injection, and also another of ambient temperature and heat inputs to the CT shall be submitted to ~~DER~~ DEP's Southwest District Office and the Bureau of Air Regulation.

19. and 20. No change.

B. Emissions Limits for Unit 2B

1. Performance Restrictions

a. 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)]

b. 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)]

c. 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)]

d. 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 Department's Southwest District Office (SWDEP), 3804 Coconut Palm Drive, Tampa, FL 33619-8218, 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.]

2. Emissions Controls

a. 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)]

b. 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 in accordance with the manufacturer's recommendations. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

c. 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.]

d. 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.]

e. 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.]

f. 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.]

3. Emissions Standards

a. Emissions Standards Summary: The following table summarizes the emissions standards determined by the Department.

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.

b. Carbon Monoxide (CO)

(1) 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.

(2) 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 corrected to 15% oxygen based on a 3-hour test average.

(3) 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)]

c. Nitrogen Oxides (NOx)

(1) 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.

(2) 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.

(3) 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 and 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)]

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

(1) 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)]

(2) 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)]

e. Volatile Organic Compounds (VOC)

(1) 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.

(2) 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.

(3) The VOC emissions shall be measured and reported in terms of 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.]

4. Excess Emissions

a. 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.]

b. 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 SWDEP 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.]

5. Emissions Performance Testing

a. 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.]

b. 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.]

c. Applicable Test Procedures

(1) Required Sampling Time.

(a) 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.]

(b) 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.]

(2) 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.]

(3) 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.]

d. Determination of Process Variables

(1) 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.]

(2) 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.]

e. 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)]

f. 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.

(1) 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.

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

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

(4) 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.

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

(6) 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.

g. Test Notification: The permittee shall notify the SWDEP 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]

h. 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.]

i. 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.]

j 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.]

k. 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.]

l. 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.]

m. 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.]

6. Continuous Monitoring Requirements

a. 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.

(1) 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 SWDEP 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.

(2) 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 SWDEP 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].

7. Compliance Demonstrations

a. Records Duration: 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.]

b. Fuel Records

(1) 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 SO2 standard.

(2) 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.]

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

(1) 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.

(2) 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.

(3) 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.

(4) 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.

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

(b) 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);

(c) Each unit shall be monitored for SO2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

(d) 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, SO2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).
[40 CFR 60, Subpart GG, Applicant Request]

d. Monthly Operations Summary: By the fifth calendar day of each month, the owner or operator shall record the following information in a written (or electronic) 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 or printed at the Department's request. [Rule 62-4.160(15), F.A.C.]

8. Reports

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

b. Excess Emissions Reporting: If excess emissions occur due to malfunction, the owner or operator shall notify the SWDEP 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 SWDEP. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7]

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

III. SURFACE WATER DISCHARGES (HPPL)

Discharges into surface waters of the state during construction and operation of the project shall be in accordance with applicable provisions of Chapters ~~17-3, 17- 4, 17-302, 17-650, and 17-660~~, 62-302, 62-4, 62-302, 62-650, and 62-660, Florida Administrative Code, and the following Conditions of Certification:

A. Plant Effluents and Receiving Body of Water

1. through 6. No Change.

7. During the first 18 months, the Permittees shall monitor the cooling reservoir at the condenser cooling water intake for the following parameters in the manner prescribed. Upon completion of the 18 month monitoring period, the monitoring frequency may be decreased to once per year.

Parameter	Monitoring Requirements	
	Measurement Frequency	Sample Type

Total Dissolved Solids	1/month	grab
Turbidity (NTU)	1/month	grab
Ammonia Nitrogen	1/quarter	grab
Ammonia (un-ionized)	1/quarter	grab
Beryllium	1/quarter	grab
Cadmium	1/quarter	grab
Chlorophyll A	1/quarter	grab
Copper	1/quarter	grab
Cyanide	1/quarter	grab
Iron	1/quarter	grab
Lead	1/quarter	grab
Nitrogen, Total	1/quarter	grab
Nitrogen, Organic	1/quarter	grab
Mercury mg/L	1/quarter	grab
pH	1/quarter	grab
Selenium	1/quarter	grab
Silver	1/quarter	grab
Zinc	1/quarter	grab
Temperature	1/quarter	grab
TKN	1/quarter	grab
Ortho-phosphorus	1/quarter	grab
Total Phosphorus	1/quarter	grab

The results of the monitoring shall be submitted to the ~~DER~~ DEP Southwest District Office in Tampa within 45 days of collection. The Permittees shall maintain a summary of the results in the form of a yearly average for the life of the project. If any of the above parameters should reach 80% of the water quality criteria as contained in Chapter ~~17-302~~ 62-302, F.A.C., the Permittees shall notify the department. The department may then require sampling on a monthly basis in the reservoir and in Payne Creek and may approve mixing zones for parameters that exceed criteria.

8. through 9. No change.

10.a. through 10.c. No change.

d. It is necessary that there be an entity responsible for maintenance of the system ~~pursuant to Section 17-25.027 , FAC~~.

10.e. through 10f. No change.

11. No change.

12.a. No change.

12.b. Project discharge descriptions - Dewatering water, outfalls 001 or 002, includes all surficial groundwater extracted during all excavation construction on site for the purpose of installing structures, equipment, etc. Discharges to the storm water runoff sedimentation pond at a location to be depicted on an appropriate engineering drawing to be submitted to ~~DER~~ DEP and SWFWMD. Final discharge after treatment is to Payne Creek. The permittee shall report to ~~DER~~ DEP the date that construction dewatering is expected to begin at least one week prior to the commencement of dewatering.

12.c. No change.

13. Mixing Zones - The discharge of the following pollutants shall not violate the Water Quality Standards of Chapter ~~17-302~~ 62-302, F.A.C., beyond the edge of the designated mixing zones, which shall be 200 feet from the point of discharge (POD). For purposes of compliance monitoring, the following limitations shall apply at the POD.

Parameter	Limit at POD
Cadmium	2.6 ug/l

Cyanide	0.01 mg/l
Mercury	0.5 ug/l
Selenium	32.0 ug/l
Silver	0.8 ug/l
Gross alpha	22.2 pC/l
Radium 226	6.2 pC/l
Turbidity	31 NTU
Iron	---
Lead	---
Zinc	---

The Secretary of ~~DER~~ DEP may authorize alternative mixing zones for the above parameters in accordance with Condition XXI upon a demonstration that such mixing zone would not interfere with beneficial use of the creek.

14. Sanitary wastes from the HPS shall be collected and treated in an appropriately designed domestic wastewater treatment plant. The Permittee shall fill out the appropriate ~~DER~~ DEP application for a domestic wastewater treatment facility including the design specifications for the proposed facility and shall submit such application and specifications to the ~~DER~~ DEP Southwest District Office for approval at least 90 days prior to start of construction of that facility.

B. Water Monitoring Programs

1. No change.

2. Chemical Monitoring - The parameters described in Condition III.A shall be monitored during discharge as described in Condition III.A commencing with the start of construction or operation of the HPS and reported quarterly to the Southwest District Office.

IV. Ground Water

A. No change.

B. Well Criteria, Tagging and Wellfield Operating Plan

Leaking or inoperative well casings, valves, or controls must be repaired or replaced as required to put the system back in an operative condition acceptable to the SWFWMD. Failure to make such repairs will be cause for deeming the well abandoned in accordance with Chapter ~~17-21.532.200~~ 62-251, Florida Administrative Code, Chapter 373.309, Florida Statutes. Wells deemed abandoned will require plugging according to applicable regulations.

A SWFWMD-issued identification tag must be prominently displayed at each withdrawal site by permanently affixing such tag to the pump, headgate, valve or other withdrawal facility as provided by Section 40D-2, Florida Administrative Code. The HPS must notify the SWFWMD in the event that a replacement tag is needed.

C. through G. No change.

H. Ground Water Monitoring Requirements

After consultation with the ~~DER~~ DEP and SWFWMD, the permittee shall install a monitoring well network to monitor ground water quality horizontally and vertically through the aquifer above the Hawthorn Formation. Ground water quantity and flow directions will be determined seasonally at the site through the preparation of seasonal water table contour maps, based upon water level data obtained during the applicant's preoperational monitoring program. From these maps and the results of the detailed subsurface investigation of site stratigraphy, the water quality monitoring well network will be located. A ground water monitoring plan that meets the requirements of ~~Section 17-28.700(d)~~ Chapter 62-528, F.A.C., shall be submitted to the Department's Southwest District Office for review. Approval or disapproval of the ground water monitoring plan shall be given within 60 days of receipt. Ground water monitoring shall be required at HPS's sedimentation pond. Insofar as possible, the monitoring wells may be selected from the existing wells and piezometers used in the Permittee's preoperational monitoring program, provided that the wells' construction will not preclude their use. Existing wells will be properly sealed in accordance with Chapter ~~17-21~~ 62-521, F.A.C., whenever they are abandoned due to construction of facilities. The water samples collected from each of the monitor wells shall be collected immediately after removal by pumping of a quantity of water equal to at least three casing volumes. The water quality analyses shall be performed monthly during the year prior to commercial operation and quarterly thereafter. No sampling or analysis is to be initiated until receipt of written approval of a site-specific quality assurance project plan (QAPP) by the Department. Results shall be submitted to the ~~DER~~ DEP by the fifteenth (15th) day of the month following the month during which such analyses were performed. Testing for the following constituents is required around unlined ponds or storage areas:

TDS	Color	Cadmium	Arsenic
Conductance	Zinc	Chloride	Beryllium
pH	Copper	Iron	Radium 226
Redox	Nickel	Aluminum	Gross Alpha
Sulfate	Selenium	Chromium	
Sulfite	Lead	Mercury	

I. Zone of Discharge

The HPS shall meet the groundwater criteria of Chapter ~~17-3~~ 62-302, F.A.C. at the boundary of a mixing zone extending 100 feet from the outside toe of the cooling reservoir. A ground water monitoring program, as described in Condition IV.H, shall be implemented to verify compliance with these requirements. Such sampling program shall commence at least 12 months prior to start of commercial operation of the HPS.

J. through Q. No change.

V. Control Measures During Construction

A. No change

B. Environmental Control Program

Each permittee shall establish an environmental control program under the supervision of a qualified person to assure that all construction activities conform to good environmental practices and the applicable Conditions of Certification. A written plan for controlling pollution during construction shall be submitted to ~~DER~~ DEP within sixty days of issuance of the Certification. The plan shall identify and describe all pollutants and waste generated during construction and the methods for control, treatment and disposal. Each permittee shall notify the Department's Southwest District Office by telephone within 24 hours if possible if unexpected harmful effects or evidence of irreversible environmental damage are detected by it during construction, shall immediately report in writing to the Department, and shall within two weeks provide an analysis of the problem and a plan to eliminate or significantly reduce the harmful effects or damage and a plan to prevent reoccurrence.

C. Construction Dewatering Effluent

Should the permittee's dewatering operation create shoaling in adjacent water bodies, the permittee is responsible for removing such shoaling.

All offsite discharges resulting from dewatering activities must be in compliance with water quality standards required by ~~DER~~ DEP Chapters ~~17-3, 17-4, and 17-302~~ 62-302 and 62-4, F.A.C., or such standards as issued through a variance by ~~DER~~ DEP.

VI. through IX. No change.

X. CHANGE IN DISCHARGE (HPPL)

All discharges or emissions authorized herein to HPS shall be consistent with the terms and conditions of this certification. The discharge of any pollutant not identified in the application or any discharge more frequent than, or at a level in excess of, that authorized herein shall constitute a violation of this certification. Any anticipated facility expansions, production increases, or process modification which will result in new, different or increased discharges or expansion in steam generating capacity will require a submission of new or supplemental application to ~~DER~~ DEP's Siting Coordination Office pursuant to Chapter 403, F.S.

XI. NONCOMPLIANCE NOTIFICATION (HPPL)

If, for any reason, either permittee does not comply with or will be unable to comply with any limitation specified in this certification, the permittee shall notify the Deputy Assistant Secretary of ~~DER~~ DEP's Southwest District office by telephone as soon as possible but not later than the first ~~DER~~ DEP working day after the permittee becomes aware of said noncompliance, and shall confirm the reported situation in writing within seventy-two (72) hours supplying the following information:

XI. through XIII. No change.

XIV. RIGHT OF ENTRY (HPPL)

The Permittees shall allow ~~DER~~ DEP authorized representatives, upon the presentation of credentials:

A. through F. No change.

G. Moreover, the Permittees shall allow authorized representatives of ~~DER~~ DEP and other appropriate agencies, acting within the scope of their jurisdiction and authority, upon the presentation of credentials:

G.1. through G.2. No change.

XV. through XIX. No change.

XX. REVIEW OF SITE CERTIFICATION (HPS)

~~A.~~ The certification shall be final unless revised, revoked, or suspended pursuant to law. At least every five years from the date of issuance of this certification or any National Pollutant Discharge Elimination Control Act Amendments of 1972 for the plant units, the Department shall review all monitoring data, including groundwater quality monitoring data, that has been submitted to it or its agent(s) during the preceding five-year period for the purpose of determining the extent of the Permittee's compliance with the conditions of this certification of the environmental impact of this facility. The Department shall submit the results of its review and recommendations to the Permittees. Such review will be repeated at least every five years thereafter.

XXI. MODIFICATION OF CONDITIONS (HPS)

The conditions of this certification may be modified in the following manner:

A. The Siting Board pursuant to 403.516(1), Florida Statutes, hereby delegates to the Secretary of ~~DER~~ DEP the authority to modify, upon application by the Permittees and after notice and opportunity for hearing, any conditions pertaining to monitoring; sampling; mixing zone; zone of discharge; surface water, groundwater, and air effluent or emission limitations; variances or exemptions to water quality standards; and transmission lines.

B. All other modifications shall be made in accordance with Sections 403.516, Florida Statutes.

Replacement of any portion of the gas pipeline, transmission lines, or access roads constructed under this certification necessitated by emergency conditions shall not be considered a modification. A verbal report of any such emergency shall be made to ~~DER~~ DEP as soon as possible. Within 14 calendar days after correction of an emergency which would require the Permittees to perform an activity not in accordance with the Conditions of Certification, a report to the ~~DER~~ DEP shall be made outlining the details of the emergency and the steps taken for its temporary relief. The report shall be a written description of all of the work performed and shall set forth any pollution control measures or mitigative measures which were utilized or are being utilized to prevent pollution of waters, harm to sensitive areas, or alteration of archaeological or historical resources.

XXII. through XXV. No change.

XXVI. ENDANGERED AND THREATENED SPECIES (HPS)

Prior to start of construction, the permittee shall survey the site for endangered and threatened species of animal and plant life. Plant species on the endangered or threatened list shall be transplanted to an appropriate area if practicable. Gopher Tortoises and any commensals on the rare or endangered species list shall be relocated after consultation with the Florida Game and Fresh Water Fish Commission. A relocation program, as approved by the ~~FGFWFC~~ FWCC, shall be followed.

XXVII. DESIGN AND PERFORMANCE CRITERIA (HPS)

The power plant may be operated at up to 115% of the maximum electrical output at ISO conditions projected from design information without the need for modifying these conditions. Treatment or control facilities or systems installed or used to achieve compliance with the terms and conditions of this certification are not to be bypassed without prior ~~DER~~ DEP approval.

Moreover, the Permittees shall take all reasonable steps to minimize any adverse impacts resulting from noncompliance with any limitation specified in this certification, including, but not limited to, such accelerated or additional monitoring as necessary to determine the nature and impact of the noncomplying event.

XXVIII. No change.

XXIX. ROW DELINEATION AND COMPLIANCE VERIFICATION (HPS)

TPS is responsible for compliance with this General Condition with respect to the natural gas pipeline. TEC is responsible for compliance with this condition with respect to the Pebbledale transmission line. SECI is responsible for complying with this condition with respect to the Vandolah and Lee transmission lines.

At least 90 days prior to commencement of construction, three copies of blue-line reproductions of aerial photographs of at least 1:400 scale shall be submitted to ~~DER~~ DEP and one copy to each water management district (insofar as an area within its jurisdiction is involved) delineating the ROW routes selected, boundaries, preliminary pole and pad locations, and access roads. The Permittees shall notify all parties of such filing. These photographs shall be submitted prior to commencement of construction on the various segments of the linear facility; it is recommended that this information be submitted in segments rather than waiting until the entire ROW is acquired. ~~DER~~ DEP, the water management districts, and any other party who requests to do so shall have 30 days from receipt of notice to review the photographs and to call any apparent conflicts with the requirements of the Conditions of Certification to the Permittees' attention. However, this paragraph shall not operate to avoid the need for post-certification submittals and compliance reviews otherwise required by the Conditions of Certification.

If ~~DER~~ DEP or any substantially affected party has reason to believe that the construction of the linear facility and access roads within the Permittees' designated ROW cannot be accomplished in compliance with the Conditions of Certification, the Permittees shall be so notified in writing. Failure of such a notice to be served on Permittees within 30 days from the notice of filing of the various segments in the aerial photographs with ~~DER~~ DEP constitutes acknowledgment that construction of the linear facility and access roads can be accomplished in compliance with the Conditions of Certification within the designated ROW or the various segments of ROW submitted for review.

The acquisition of a particular ROW or the expenditure of funds toward acquisition of a particular ROW prior to post-certification review pursuant to this condition will be at the Permittees' risk, and no party will be estopped by such acquisition to seek disapproval of the construction of the linear facility or access roads within the ROW in accordance with these Conditions of Certification.

XXX. through XXXI. No change.

XXXII. Transmission Line and Pipeline ROWs

A. Construction

1. through 2. No change.

3. The Permittee shall consult with the Bureau of Wetland Resource Management prior to final determination of the access road locations, (including those not located on the ROW), tower locations, and construction techniques which are to be reflected on any post-certification review information submitals. At ~~DER~~ DEP's request, the Permittee shall conduct field inspection with staff of this agency.

4. Prior to clearing activities within any of the ROW associated with the various linear facilities, an ecological survey shall be conducted to identify the presence of threatened or endangered species (plant and animals) as defined in the application, likely to occur in the ROW based on range and habitat. This survey shall also identify the location of any wading bird colonies. Results of this survey shall be submitted to the ~~DER~~ DEP and the Florida Game and Freshwater Fish Commission (~~FGFWFC~~ FWCC) and the United States Fish and Wildlife Service

(USFWS). If any clearing activity will take place in or otherwise adversely affect jurisdictional wetlands, survey results will also be submitted to the appropriate water management district. If it is determined that any of these species will be affected by the construction of any of the linear facilities, the Permittee shall consult with ~~DER~~ DEP and ~~FGFWFC~~ FWCC to determine the appropriate steps to be take to avoid, minimize, mitigate or otherwise appropriately deal with, any adverse impacts within each agency's respective jurisdiction.

5. No change.

6. All materials used for any purpose related to the construction of the transmission lines or other linear facilities shall come from fill sources in compliance with applicable local ordinances. No fill materials shall be obtained from excavated wetlands within the ROW unless authorized by ~~DER~~ DEP and appropriate water management district in accordance with a mitigation plan submitted in compliance with certification.

7. The Permittee shall provide mitigation/compensation (M/C) for any wetland or open water habitat within the jurisdiction of ~~DER~~ DEP or WMD which is degraded or destroyed as a result of the construction of any portion of the transmission lines, natural gas pipelines or power plant facilities. M/C may include the creation of new wetland or open water habitat, the restoration of degraded habitat, the enhancement of functions and values provided by existing wetland or open water habitats, removal of exotics, or other activities found by the relevant agencies and appropriate local government to be in compliance with their applicable regulations. Prior to the elimination or degradation of any such wetland or open water habitat, the Permittee shall concurrently submit mitigation plans to ~~DER~~ DEP, Bureau of Wetland Resources Management and the appropriate water management district and receive approval of such plans. These mitigation plans shall, at a minimum, include the following:

a. No change.

b. A discussion and a detailed set of plan-view and cross-sectional drawings of the proposed M/C activities to be undertaken, including the location of all M/C areas and a description of the manner in which these areas will be created, restored or otherwise enhanced. Success standards will be determined based on the functional values of wetlands impacted and created. The Permittees will work with the appropriate agency staff to establish success criteria. The M/C plans proposed by Permittees shall be submitted concurrently to ~~DER~~ DEP and the appropriate water management district for review and compliance monitoring.

c. through d. No change.

8. M/C plans must be found to fully compensate for the functions and values provided by wetlands that will be degraded or eliminated. ~~DER~~ DEP and WMDs will work with the Permittee in the development of acceptable mitigation plans. The mitigation plans proposed by the Permittee shall be submitted for review and compliance monitoring to ~~DER~~ DEP and the appropriate water management district and such review shall be subject to the time constraints set forth in specific conditions XXXII.9, and XXXV. C, below, as appropriate.

9. For all construction activities in waters of the State where ~~DER~~ DEP has wetland resource protection jurisdiction pursuant to Chapter 402, Florida Statutes, the Permittees shall file with ~~DER~~ DEP, Office of Siting Coordination and Bureau of Wetland Resource Management the information described in Florida Administrative Code Rule ~~17-17.665 and 17-1.212(1), Section 3.2.2~~ 62-17.665 and Section 62-1.212(1).

a. ~~DER~~ DEP shall promptly review the submittal for completeness and sufficiency. If the submittal is found to be incomplete or insufficient, Permittee shall be so notified. Failure to issue such a notice within 30 days after filing of the submittal shall constitute a finding of completeness and sufficiency.

b. Within 90 days filing complete and sufficient information, ~~DER~~ DEP shall determine whether there is reasonable assurance of compliance with applicable substantive agency regulations as required by the Conditions of Certification if the plans are executed as filed. If it is determined that reasonable assurance has not been provided, the Permittee shall be notified with particularity and possible corrective measures suggested. Failure to notify

Permittee in writing within 90 days of receipt of a complete information submittal shall constitute a compliance verification.

c. If ~~DER~~ DEP does not object within the time period specified, Permittee may begin construction pursuant to the terms of the Conditions of Certification and the subsequently submitted construction details and ~~DER~~ DEP shall provide to the Corps of Engineers a letter indicating that the full requirements of this condition have been met and the water quality certification for the purposes of 33 USC Section 1341 is thereby conveyed.

d. No change.

10. Semi-annual narrative reports shall be submitted to ~~DER~~ DEP's Bureau of Wetlands Resource Management in Tallahassee and ~~DER~~ DEP's Southwest District Office, indicating the status of all construction activities within waters of the State. These reports shall be submitted until all construction in that respective area is complete. The reports include the following information:

a. through c. No change.

11. Upon completion of construction, the Permittee shall provide ~~DER~~ DEP with detailed engineering drawings which depict the pre and post construction contours in all areas in which construction occurred in waters of the State.

12. During construction all Brazilian Pepper, Australian Pine, and melaleuca in each ROW shall be removed or the trees cut and the stumps treated with an approved herbicide consistent with these conditions. A plan for removal and disposal of such exotic species which minimizes seed dispersal shall be developed by the Permittee in consultation with ~~DER~~ DEP. The Permittee shall abide by the plan.

13. Following construction, a plan for maintenance and control of Brazilian Pepper, Australian pine, and melaleuca within the ROWs shall be developed by the Permittee in consultation with ~~DER~~ DEP. The Permittee shall abide by the plan.

14. through 15. No change.

16. The Permittee shall be responsible for the correction of any water quality problems that result from the construction, operation and/or maintenance of works authorized under this certification. The Permittee will work with ~~DER~~ DEP to determine additional methods necessary to ensure that State Water Quality Standards are not violated as a result of construction.

17. through 18. No change.

19. No dewatering operation shall be allowed unless the Permittee can provide reasonable assurances to ~~DER~~ DEP that no adverse, off-site water resource impacts will occur as a result of the construction, operation, and/or maintenance of the project.

B. Operation

1. No change.

2. Only EPA approved herbicides may be used in waters of the State, or the use of other herbicides in any areas of the ROW shall only be allowed with the concurrence of ~~DER~~ DEP.

XXXIII. Mine Reclamation

A. General Conditions

1. No change.

2. In restoring drainage patterns, the ~~DNR~~ DEP and Agrico and its successors reserve the right to reexamine, in each stage of reclamation and restoration program application, the placement and configuration of the lakes, streams, wetlands, and watersheds which have been proposed in the conceptual plan, to assure that the natural functions of the lakes, streams, and wetlands are restored in accordance with the provisions of the then-existing standards and criteria of Chapter 16C-16, F.A.C.

B. through C. No change.

XXXIV. No change.

XXXV. Project Surface Water and Stormwater Management Facilities

A. General

1. through 5. No change.

6. Monitoring

Post-certification monitoring requirements may be determined and specified as a result of technical review of construction information, where necessary, to demonstrate compliance with water management district regulations. If monitoring data is required by SWFWMD or SFWMD in conjunction with post-certification review, it shall be submitted to the respective water management district and the ~~DER~~ DEP. Parameters to be monitored may include those listed in Chapter 17-302, Florida Administrative Code. Permittees also shall, if required, provide data to SWFWMD or SFWMD regarding: construction, operation, and maintenance of surface water management systems; NGVD levels; volumes and timing of water discharged, including total volume discharged during period of sampling and total discharges from the property. Environmental monitoring may also be required in conjunction with wetlands compensation/mitigation.

B. No change.

C. Project Information Requirements

1. through 3. No change.

4. The Permittee shall employ culverts or other appropriate techniques and implement suitable maintenance practices where necessary to comply with the applicable regulation of the applicable WMD or ~~DER~~ DEP and to maintain existing drainage patterns, hydroperiods, and sheetflow along the ROWs. The exact number, spacing, diameter, orientation, and length of culvert necessary to maintain existing hydrologic conditions and to maintain surface water flow conditions in the area shall be determined by the Permittees in consultation with applicable WMD or ~~DER~~ DEP based on site-specific information. This information shall be submitted to SFWMD or SWFWMD as applicable for approval prior to construction to ensure that the culverting or other appropriate techniques meets applicable standards within all affected wetlands areas.

XXXVI. Webb Wildlife Management Area

A. Parties to Agreement

Florida ~~Game and Fresh Water Fish~~ Fish and Wildlife Conservation Commission (Commission) and Seminole Electric Cooperative, Inc. (Seminole) are parties to the following agreement relating to the location of a ROW in the Cecil M. Webb Wildlife Management Area as generally depicted in Exhibit A.

B. through D. No change.

E. Joint Conditions

1. through 10. No change.

11. Seminole shall coordinate with the ~~FGFWFC~~ FWCC to assure that construction and maintenance of the transmission line and its right-of-way on the Webb Wildlife Management Area shall, to the extent practicable, be conducted in a manner which does not interfere with public hunting or other recreational use of the area. Activities occurring during established hunting seasons for construction and maintenance shall be coordinated in order to avoid interference with public use or hazards to area users or Seminole employees or agents.

12. No change.

XXXVII. through XLII. No change.

NOTICE OF RIGHTS

Any party to this Notice has the right to seek judicial review of the Order pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection, M. S. 35, Office of General Counsel, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000, and by filing a copy of the Notice of Appeal, accompanied by the applicable filing fee, with the appropriate district court of appeal. The Notice of Appeal must be filed within 30 days from the date that the Final Order is filed with the Department of Environmental Protection.

DONE AND ENTERED this __________ day of __________ 2000, in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

DRAFT

____

KIRBY B. GREEN, III
DEPUTY SECRETARY
Douglas Building
3900 Commonwealth Boulevard
Tallahassee, FL 32399-3000
Telephone: (850) 488-7131

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

____
DATE

CERTIFICATE OF SERVICE

I CERTIFY that a true and correct copy of the foregoing Final Order Modifying Conditions of Certification was mailed to:

Lawrence N. Curtin, Esquire
Holland & Knight, L.L.P.
Post Office Drawer 810
Tallahassee, Florida 32303-0810
(For Hardee Power Partners, Ltd.)

William H. Green, Esquire
James S. Alves, Esquire
Hopping Green Sams & Smith, P.A.
Post Office Box 6526
Tallahassee, Florida 32314
(For Seminole Electric Cooperative, Inc.)

Michael P. Haymans, Esquire
Farr, Farr, Emerich, et al.
Post Office Box 511447
Punta Gorda, Florida 33951-1447
(For Slack and Katzen and Schmid)

Gary Alan Vorbeck
Hardee County Attorney
Vorbeck & Vorbeck, P.A.
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(For City of Arcadia)

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McWhirter and Reeves
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Tampa, Florida 33601
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(For Manasota-88, Inc.)

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Florida Public Service Commission
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Frank Anderson
Assistant General Counsel
Southwest Florida Water Management District
2379 Broad Street
Brooksville, Florida 34609-6899

R.E. Ludwig, President
Hardee Power Partners, Ltd.
Post Office Box 111
Tampa, Florida 33601-0111

on this ____ day of ______________ 2000.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

DRAFT

____
SCOTT A. GOORLAND
Senior Assistant General Counsel
Florida Bar No. 0066834

Douglas Building, MS 35
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000
Telephone: (850) 488-9314

Z 333 618 198

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PS Form 3800, April 1995

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SENDER:

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- Attach this form to the front of the mailpiece, or on the back if space does not permit.
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3. Article Addressed to:
Richard Ludwig
TECO Power Services
702 N. Franklin St.
Tampa, Fl 33602

4a. Article Number
Z 333 618 198

4b. Service Type

- ☐ Registered
- ☒ Certified
- ☐ Express Mail
- ☐ Insured
- ☐ Return Receipt for Merchandise
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