STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Mr. W. Jeffrey Pardue, Director of Environmental Services
Florida Power Corporation
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733

Air Permit No. 0970014-003-AC (PSD-FL-268)
Three New Simple Cycle Gas Turbines
Intercession City Plant
Osceola County, Florida

Enclosed is Final Permit No. 0970014-003-AC (PSD-FL-268). This permit authorizes Florida Power Corporation to add three new simple cycle General Electric Model 7EA combustion turbines with electrical generator sets (87 MW each) to the existing Intercession City plant. As noted in the Final Determination (attached), the Department made minor changes to the Final Permit at the requests of the applicant and EPA Region 4. 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 12/13/99 to the person(s) listed:

Mr. W. Jeffrey Pardue, FPC*
Mr. Scott Osborne, FPC
Mr. J. Michael Kennedy, FPC
Mr. Len Kozlov, DEP - Central District Office
Ms. Katy Forney, EPA Region 4
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

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.

12/13/99
(Clerk) (Date)

Z 031 391 899

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PS Form 3800, April 1995

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Mr. W. Jeffrey Pardue
Director of Envir. Services
FPC
PO Box 14042, MAC BB1A
St. Petersburg, Fl 33733

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PERMIT PROCESSING SCHEDULE

05/25/99	The Department received the application for this project.
06/02/99	The Department received additional pages of the application that were accidentally omitted.
06/16/99	The Department received air dispersion modeling files for the project.
06/22/99	The Department requested additional information to complete the application.
08/12/99	Received e-mail from NPS that NPS and FWS did not have any comments on this project.
08/02/99	The Department received additional information from the applicant.
09/15/99	The Department distributed an Intent to Issue Permit package that would authorize the addition of three new simple cycle General Electric Model 7EA combustion turbines with electrical generator sets (87 MW each) to the existing Intercession City Plant.
09/30/99	The applicant published the "Public Notice of Intent to Issue" in Osceola News-Gazette.
10/01/99	The Department's Office of General Counsel received a request from the applicant to extend the period of time in which to file a petition for an administrative hearing.
10/15/99	The Department received comments from the applicant (by fax) on the Draft Permit.
10/21/99	The Department received proof of publication from the applicant.
10/25/99	The Department met with the applicant's representatives in Tallahassee to discuss the applicant's comments on the Draft Permit.
10/25/99	The Department received comments from EPA Region 4 on the Draft Permit.
11/02/99	The Department granted the applicant's request and extended the time to file for an administrative hearing until December 15, 1999.
11/02/99	The Department e-mailed a response to the applicant's comments made in writing and presented at the 10/25/99 meeting.
11/16/99	The Department received additional information and comments from the applicant requesting continuous compliance with the NOx standard based on "lb/hour" only or increasing the ppmvd limit to 10 ppmvd.
12/03/99	The Department received additional information and comments from the applicant requesting continuous compliance with the NOx standard based on "10 ppmvd" with a 3-hour rolling average. Annual testing would demonstrate compliance with the lb/hr limit and the 9-ppmvd basis.
12/06/99	The Department and applicant agreed upon proposed revisions.
12/07/99	The applicant withdrew the request for an extension to file for an administrative hearing.

COMMENTS/REQUESTS FROM THE APPLICANT

Page 5, Specific Condition 3. Permitted Capacity. Request: Applicant requests additional text similar to that in recent Title V permits to clarify that the heat input values for gas and oil firing are only included for the purposes of determining capacity during testing, and that regular record keeping is not required. Applicant also requests a change in the text from "... an inlet air supply cooled to 59° F ..." to "... an inlet air temperature of 59° F ..." Response: The maximum heat input rate is based on the fuel heating value, inlet temperature, air pressure, relative humidity, and load. This requirement was retained with text added to clarify that compliance would be determined based on adjusted data compiled by the automated Speedtronic™ Control System corrected for these parameters. The text regarding inlet air temperature was revised.

Page 6, Specific Condition 6. Hours of Operation. Request: Based on EPA Region 4's comments, the applicant requests an additional restriction of no more than 1000 hours of oil firing per gas turbine per year and to retain the aggregate limits on operation for the three gas turbines combined. Response: The additional restriction was added and is believed to address EPA's concerns regarding costs. In consideration for increasing the NOx concentration for continuous compliance to 10 ppmvd, the aggregate allowable hours of fuel oil firing was reduced from 3000 to 2500 hours per consecutive 12 months. It is estimated that this will result in an overall decrease in annual NOx emissions.

Request: Applicant requests deletion of the requirement to limit operation below 50% load to less than two hours per unit cycle. Response: This conditions was moved to Specific Condition No. 3 and revised to read, "Operation below 50% of base load shall be limited to two (2) hours during any calendar day."

Page 7, Specific Condition 11. and 12. Emissions Controls. Request: Applicant requests insertion of text to clarify that operation of the DLN and water injection systems will be in accordance with the manufacturer's recommendations. Response: The condition was revised.

Request: Applicant requests deletion of the requirement to provide emissions performance versus load diagrams. Response: The following text was added to the condition requiring load diagrams, "Compliance with this requirement may be demonstrated by compiling data during the initial NSPS tests performed at various load conditions."

Request: Applicant strenuously objects to the requirement of developing a NOx reduction plan if a unit fires more oil than gas during a 12-month period. Response: Because hours of fuel oil firing were limited to no more than 1000 hours per gas turbine per year, this requirement was deleted.

Page 8, Specific Condition No. 15. Emissions Standards. Request: Applicant requests that all emissions standards be expressed solely in terms of a mass emissions rate (pounds per hour) using "ppm" only as the basis for the standard verified by annual testing. Applicant also requests replacing the text "3-hour test averages" for the CO, NOx, and VOC standards with a reference to the corresponding EPA test methods. Response: The Department retained "ppm" as the units for continuous compliance limits as well as the 3-hour test averages. Other changes to emissions standards are summarized for each specific condition below. This summary table was revised accordingly.

Page 8, Specific Condition No. 16. Carbon Monoxide. Request: Applicant requests that the CO concentration limit be expressed as "ppmvd" without correction to 15% oxygen. Response: Potential CO emissions from this project are nearly 250 tons per year. The correction to 15% oxygen is necessary to "fix" the emissions standard. In addition, the manufacturer's data indicates an expected oxygen concentration of 13.8% during normal operation. Measured CO emissions would only be corrected upward for oxygen contents greater than 15%. No change was made.

Request: Applicant requests that the requirement to reduce CO emissions from 25 ppmvd to 20 ppmvd be revised from "after the first 12 months after initial startup" to "after the first 12 months after initial compliance testing". Response: This request is reasonable and the condition was revised.

Page 8, Specific Condition No. 17. Nitrogen Oxides. Request: Applicant requests that the continuous NOx standard be specified in terms of "lb/hr" rather than "ppmvd". The applicant states a higher level of confidence with the mass emission rate as opposed to the emission concentration, particularly at lower loads. Response: The "ppmvd" standards are required to ensure complete utilization of the technical capabilities of the DLN system to minimize NOx emissions. For combustion turbines, units of "ppmvd" are the standard by which environmental regulating agencies compare BACT determinations, have been included in nearly all recently issued Department air permits, and are consistent with the federal NSPS Subpart GG. The Department contacted an operator of a similar unit to discuss operation of the General Electric Model 7EA. The operator indicated that the new "9 ppm" combustor liner for the Model 7EA performed very well on their existing unit and that a 9 ppmvd limit appeared achievable for operation of 8 to 10 consecutive hours of operation. The applicant provided one day of CEM data for an existing similar unit, which shows that emission levels as high as 10.5 ppmvd being reported. It should be noted that the data was for an older unit with a NOx emissions standard of 15 ppmvd, so it may not be "tuned" for 9 ppmvd. The Department also considered the reduction in oil firing from 3000 to 2500 total turbine hours.. The NOx emissions standard for gas firing was revised to:

- Based on annual test requirements: NOx emissions shall not exceed 32.0 pounds per hour and shall not exceed 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load.
- Based on continuous compliance by CEM: NOx emissions shall not exceed 10.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average.

In combination with the reduced oil limit, the Department believes that these changes maintain the integrity of the standards specified in the Draft Permit, satisfy EPA's comments regarding the appropriate averaging period, and result in a decrease in emissions. Therefore, no additional publication will be required.

Request: Applicant requests that the NOx limit for oil firing be revised from a 3-hour average to a 24-hour average, consistent with gas firing. Response: The Department established the 24-hour average for gas firing to allow for fluctuations in emissions resulting from load changes that may require a period of time for the DLN system to completely adjust. The Department required a 3-hour average for oil firing for two reasons: (1) NOx emissions from oil firing are nearly five times that of gas firing, and (2) the belief that the Speedtronic™ Gas Turbine Automatic Control System is technically capable adjusting the water injection rate to meet this shorter averaging period. So, the averaging period isn't really based on the fuel being fired, but the control methods being used and the corresponding emission rates. In addition, the air quality analysis was based on maximum *hourly* emissions when firing oil. As described above, the new NOx standard for continuous compliance was revised to a 3-hour average.

Page 9, Specific Condition No. 19. Volatile Organic Compounds. Request: Applicant requests that the VOC concentration limit be expressed as "ppmvw". Response: The VOC concentration limit was revised to "ppmvw", consistent with the manufacturer's data.

Page 9, Specific Condition 20. Excess Emissions Prohibited. Consistent with the averaging periods for the revised NOx standard, this condition was revised to reflect 3-hour averaging period.

Page 9, Specific Condition 21. Excess Emissions Allowed. Request: In accordance with the original language of Rule 62-210.700, F.A.C., applicant requests that this condition be revised to include the following text " ... unless specifically authorized by the Department for longer duration ... ". . Response: The Department notes that Rule 62-210.700(5), F.A.C. also states the following: " ... Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest." Based on the Department's earlier discussion, the operator of an existing similar General Electric Model 7EA noted the following startup/shutdown times:

- Firing primary nozzle followed by firing secondary nozzle at low to mid loads: 22 minutes
- Shutdown of fuel to primary nozzle and extinguishing primary flame: 20 minutes
- Change to full lean premix and stabilized operation: 10 minutes
- Shutdown: A complete shutdown of the gas turbine can be made in 15 minutes.

During startup, NOx emissions may spike to 140 ppmvd until stable lean premix firing is achieved. (Mass emission rates will not necessarily be higher due to reduced fuel consumption and lower loads.) In addition, the Department notes that the compliance status will be routinely known for only two standards: visible emissions (surrogate for particulate) and NOx emissions. Therefore, the excess emissions rule is not practicably applicable to the following pollutants:

- SAM/SO_2 because compliance is demonstrated by fuel specifications.
- CO and VOC because compliance is demonstrated by an annual stack test.

Based on the information specific to this unit, the Department will change the excess emissions condition to the following.

" Excess Emissions Allowed: Providing the permittee adheres to best operational practices to minimize the amount and duration of excess emissions, the following conditions shall apply:

(a) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for up to 2.0 hours in any 24-hour period.

(b) During startup, shutdown, and malfunction, the NOx CEM shall monitor and record NOx emissions. However, up to 2.0 hours of monitoring data during any 24-hour period may be excluded from the continuous NOx compliance demonstration as a result of startup, shutdown, and documented malfunctions. In case of malfunctions, the owner or operator shall notify the Compliance Authorities in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report."

The Department believes this revision more appropriately addresses excess emissions expected from the specific equipment under review.

Request: Applicant requests that the limit of one hour of excess emissions resulting from startup to simple cycle be removed: Response: This was a typographical error and was deleted.

Page 10, Specific Condition 22. Combustion Turbine Testing Capacity. Request: Applicant requests that the text "ambient temperature" be replaced with "inlet temperature". Response: The text was revised.

Page 11, Specific Condition 27(a) and (d). Performance Test Methods. Request: Applicant requests clarification of the phrase "annual 3-hour NOx limit". Response: References to the NOx limit were deleted as unnecessary.

Page 11, Specific Condition 30. Annual Performance Tests. Request: Applicant requests removal of the requirement to conduct annual visible emissions tests when firing natural gas. Response: The Department established the visible emissions standard as a surrogate BACT standard for regulating particulate matter when firing natural gas. The visible emissions test is necessary on at least an annual basis to determine compliance for the visible emissions and particulate matter BACT standards. No change was made.

Request: Applicant requests that annual tests for CO, NOx, and visible emissions when firing oil be required only when oil is fired for more than 400 hours per year per combustion turbine. Response: The condition was revised to: "If a combustion turbine operates more than 200 hours of oil firing during any federal fiscal year, the permittee shall schedule and conduct annual tests for CO, NOx, and visible emissions while firing distillate oil. Compliance with the NOx standards may be determined by the continuous monitor data collected during the required CO test. An annual performance test for VOC emissions is not required as long as the unit remains in compliance with the CO and visible emissions limits specified by this permit for oil firing."

Request: Applicant requests removal of the condition requiring compliance with the visible emissions standard as a surrogate for compliance with the VOC standard. Applicant believes that compliance with the CO standard is an adequate surrogate. Response: The Department included visible emissions as a surrogate for VOC emissions because compliance may be easily demonstrated on a more frequent basis. No change was made.

Page 11, Specific Condition 31. Tests Prior to Renewal. This condition was revised to clarify that all emissions performance tests, including VOC tests, shall be conducted during the year prior to renewal.

Page 12, Specific Condition 35. Continuous Monitoring Requirements. Request: Applicant requests removal of text requiring substitution of missing data in accordance with Title IV for demonstrating compliance with the emissions standards, revising the NOx limits to a mass emissions rate, and changing the NOx limit for oil firing from a 3-hour average to a 24-hour average. Response: The data substitution requirement was removed. Revised NOx limits and averaging periods were previously discussed.

Page 14, Specific Condition 39. Monthly Operations Summary. Request: Applicant requests that this condition be deleted. Response: The Department will revise "written log" to "written or electronic log" and add the following text: "Information may be recorded and stored as an electronic file, but must be available for inspection and/or printing at the request of the Compliance Authorities." The requirements to calculate and record the average monthly heat input and to record the fuel sulfur content were deleted as unnecessary. The condition was clarified to indicate that records shall be kept for each gas turbine, for the group of three gas turbines, for the previous month of operation, and for the previous 12 months of operation.

Appendix BD. Request: Applicant requests revising the BACT Determination consistent with other requested changes. Response: Minor revisions were made to the BACT determination based on the previously discussed changes.

COMMENTS FROM EPA REGION 4 (11/12/99)

1. EPA Comment: EPA states that the Department's cost analysis was appropriate in considering year-round operation given the flexibility to operate a given unit 8760 hours per year. EPA does not believe that hot SCR should be rejected based on the estimated cost effectiveness at this level of operation. EPA suggests that these concerns could be addressed if the Draft Permit was revised to limit hours of operation to: 3390 hours per year gas per turbine with no more than 1000 hours of gas firing per gas turbine per year. This is consistent with other recent determinations for intermittent, simple cycle combustion turbines in Region 4. Response: The Department disagrees with EPA's conclusion regarding cost effectiveness for hot SCR. However, the permit was revised to limit each gas turbine to no more than 1000 hours of gas firing per year and to reduce total oil firing to no more than 2500 hours per year for all three gas turbines. At this level, requiring a hot SCR system would result in an incremental cost estimate of nearly $10,000 per ton of NOx removed over the selected DLN system. The Department believes this addresses EPA's concerns.

2. EPA Comment: Because these units are intended to be "peaking units", EPA Region 4 comments that the 24-hour block averages should be revised to a shorter averaging period, such as a 3-hour block average. Response: The Draft Permit included a 24-hour block averaging period to provide for fluctuations in emissions resulting from load changes. Functioning as designed, the Speedtronic™ Control System requires sufficient time to adjust operation in response load changes and other input parameters. The applicant agreed to demonstrate compliance with the mass emissions rate and 9.0 ppmvd NOx limit based on annual testing at base load conditions. The applicant also agreed to a shorter averaging period for continuous compliance by CEM if the given a slightly higher limit of 10.0 ppmvd. In addition, the applicant agreed to reduce oil firing from 3000 to 2500 total turbine hours. The Department estimates that this more than offsets any potential increase in emissions and believes this addresses EPA's concern about the long averaging period.

3. EPA Comment: EPA comments that an opacity limit for PM/PM_{10} is acceptable, but that the emissions rate should be referenced. Response: The permit was revised to include a PM/PM_{10} emissions rate reference in the Emissions Summary Table as the basis for the opacity standard.

4. EPA Comment: EPA comments that automatic exemptions should not be granted for excess emissions. Response: Startup and shutdown is part of every process involving mechanical equipment. For nearly all combustion sources, startup and shutdown involves higher emissions than normal operations. The DLN system employed to control emissions requires a period of "warm-up" and staging before a full lean premix state is established that results in the very low NOx emissions. The permit was revised to define allowable excess visible emissions during startup and shutdown as 20% opacity. The condition was also changed to allow exclusion of up to 2 hours during any 24-hour period resulting from startup, shutdown or documented malfunctions. This condition is specified in accordance with Rule 62-210.700, F.A.C., as approved by the EPA in Florida's State Implementation Plan.

5. EPA Comment: EPA comments that there will be an increase in potential VOC emissions from the existing fuel oil tank as a result of this project. Response: The Department concurs, but estimates the potential emissions to be much less than 1 ton per year or about the same magnitude as "rounding error" for the total project emissions.

6. EPA Comment: EPA notes that the Department's estimated emissions rates for PM/PM_{10} are higher than the initial application and modeling analysis. Response: The Department based these higher rates on information provided by General Electric for the same model gas turbine for another project. For that project, the manufacturer reports that the back half of the EPA Method 5 train also contains PM_{10} – about the same quantity as the filter portion. In effect, this could double both the expected PM emissions as well as PM_{10} (assuming all particulate to be PM_{10}). The Department's staff meteorologist concluded that no additional requirements would be triggered as a result of these emissions, which were higher than originally modeled. However, after additional consideration, the Department revised the PM/PM_{10} estimates lower for two reasons: (1) Many permitted sources have PM test data with no analysis of the back half of the sample train, and (2) The Department is uncertain as to the accuracy or repeatability of this non-reference test method.

7. EPA Comment: EPA agrees with the Department's conditions limiting hours of operation as each gas turbine is installed. Response: No response is required.

8. EPA Comment: EPA primarily comments that oil firing may not always result in the worst-case scenario and that a larger receptor grid should have been used in the air quality analysis. Response: Again, these issues were discussed with the staff meteorologist. He confirmed EPA's comments, but concluded that no additional requirements would be triggered based on additional modeling.

9. EPA Comment: EPA comments that air quality impacts resulting from temporary emissions sources associated with the project should also be considered in the Additional Impacts Analysis, but would believes this would not alter the conclusion presented. Response: The Department concurs.

CONCLUSION

Although the Department considers these revisions to be important, it does not believe the changes to be substantial modifications that would require the publication of a new public notice. In fact, the revisions will result in a decrease in potential emissions. The final action of the Department is to issue the permit with the changes described above.

Department of Environmental Protection

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

Jeb Bush
Governor

David B. Struhs
Secretary

PERMITTEE:

Florida Power Corporation
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733

Authorized Representative:
Mr. W. Jeffrey Pardue, C.E.P.
Director, Environmental Services

ARMS Permit No.	0970014-003-AC
PSD Permit No.	PSD-FL-268
Facility ID No.	0970014
SIC No.	4911
Expires:	July 1, 2001

PROJECT AND LOCATION

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 hourly capacity of 897 megawatts (MW). The proposed project will add three simple cycle, dual-fuel, General Electric Model 7EA combustion turbines with electrical generator sets each having a maximum hourly capacity of 87 MW.

The project will be located at the existing FPC Intercession City Plant in Osceola County approximately 3.5 miles west of Intercession City. The address is 6525 Osceola Polk County Line Road, Intercession City, Florida 33848. The UTM coordinates are Zone 17, 446.3 km E, 3126.0 km N and the map coordinates are Latitude 28° 15' 38", Longitude 81° 32' 51".

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40 CFR 52.21. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

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, Director
Division of Air Resources Management

Date: 12/9/99

FACILITY DESCRIPTION

The existing facility is an electric power generating plant consisting of eleven combustion turbine peaking units (P1-P11). Units P1-P6 each consist of two gas turbines having a combined hourly capacity of 56.7 MW and firing No. 2 distillate oil. Units P7-P10 each consist of a General Electric Model 7EA gas turbine having an hourly capacity of 96.3 MW and firing natural gas or distillate oil. Unit P11 is a Siemens Model V84.3 having an hourly capacity of 171 MW and firing distillate oil.

NEW EMISSIONS UNITS

The proposed project will add the following new emissions units.

ARMS ID No.	EMISSION UNIT DESCRIPTION
018 019 020	**Peaking Units P12, P13, and P14**: Each peaking unit consists of a General Electric Model No. PG7121 7EA dual-fuel simple cycle combustion turbine with electrical generator set having a nominal hourly power production output of 87 MW. The units may employ an evaporative cooling system. 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.

REGULATORY CLASSIFICATION

The facility is a "major facility" with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD) of Air Quality because emissions of at least one pollutant exceed 250 tons per year. 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 CO, NOx, PM/PM_{10}, and SAM/SO_2 are significant and this permit establishes the Best Available Control Technology (BACT) for each pollutant.

The facility is not believed to be a Title III major source of hazardous air pollutants. The facility and project are subject to the applicable Title IV acid rain provisions. The facility is classified as a Title V "major" source of air pollution because emissions of at least one regulated air pollutant, such as CO, NOx, PM/PM_{10}, SO_2, and/or VOC exceeds 100 tons per year.

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

RELEVANT DOCUMENTS

- Permit application (05/25/99) and all related correspondence.
- Technical information on DLN-1 combustor technology by General Electric.
- Technical information on inlet air fogging by Caldwell Energy and Environmental, Inc.
- Calpuff modeling analysis performed by Golder Associates, Inc. (08/02/99).
- Written comments (10/15/99 and subsequent discussions) received from applicant.
- Written comments (10/25/99) received from EPA Region 4.
- Applicant requested (09/30/99) extension of time to file for an administrative hearing.
- OGC granted (11/09/99) request and extended filing period to 12/15/99.
- Applicant withdrew request (12/07/99) for extended filing period.

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 Central District Office, Florida Department of Environmental Protection, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767. The phone number is 407/894-7555 and the fax number is 407/897-2966.

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, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the 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, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 52.166(j)(4)]

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

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

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

12. Title V Permit: This permit authorizes construction of the permitted emissions 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 units.

ARMS EU ID No.	EMISSION UNIT DESCRIPTION
018 019 020	**Peaking Units P12, P13, and P14:** This permit authorizes the installation of three new peaking gas turbines. Each gas turbine consists of a General Electric Model No. PG7121 (7EA) dual-fuel, simple-cycle combustion turbine with electrical generator set. Each unit has a nominal hourly power production capacity of 87 MW. The new units may employ an evaporative cooling system and will use the existing infrastructure including natural gas connections, oil storage and auxiliary equipment. Dry low-NOx (DLN) combustion technology will control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will control NOx emissions when firing low sulfur distillate oil as a backup fuel. Combustion design and clean fuels will minimize emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC. Exhaust gases from each combustion turbine will exit a 56 feet high stack at approximately 1000°F with a volumetric flow rate of 1,436,000 acfm.

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}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). [Rule 62-212.400, F.A.C.]

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

   (a) **Subpart A, General Provisions**, 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 GG* 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: Each combustion turbine shall operate only in simple-cycle mode and generate a nominal 87 MW per hour of electrical power. Operation of each unit shall not exceed 885 mmBTU per hour of heat input from firing natural gas or 954 mmBTU per hour of heat input from firing low sulfur distillate oil. Operation below 50% of base load shall be limited to two (2) hours during any 24-hour period (day). The maximum heat inputs are based on the lower heating value (LHV) of each fuel, an inlet air temperature of 59°F, a relative humidity of 60%, an ambient air pressure of 14.7 psi, and 100% of base load. Therefore, heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Compliance shall be determined by data compiled from the Speedtronic™ Control System adjusted for these parameters. 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. Initial compliance with this requirement may be demonstrated by compiling data during the

initial NSPS tests performed at various load conditions. [Design, Rule 62-210.200, F.A.C. (Definition - Potential Emissions)]

4. Simple Cycle Operation Only: The combustion turbines 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 these units to combined cycle operation by installing a new heat recovery steam generator or connecting 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: Each combustion turbine shall be fired by pipeline natural gas containing no more than 1 grain of sulfur per 100 dry standard cubic feet of gas. As a backup fuel, each combustion turbine may be fired with No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Each unit shall be capable of accommodating either fuel. 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 following limits apply to this group of three combustion turbines.

   (a) **Installation of One Gas Turbine**: When one gas turbine is installed, the total turbine operating hours shall not exceed 3390 hours during any consecutive 12 months.

   (b) **Installation of Two Gas Turbines**: When two gas turbines are installed, the total turbine operating hours shall not exceed 6780 hours during any consecutive 12 months.

   (c) **Installation of Three Gas Turbines**: When all three gas turbines are installed, the total turbine operating hours shall not exceed 10,170 hours during any consecutive 12 months.

   (d) **Oil Firing**: Each gas turbine is limited to no more than 1000 turbine operating hours of oil firing during any consecutive 12 months. In addition, the group of three gas turbines is limited to no more than 2500 turbine operating hours of oil firing during any consecutive 12 months.

   Total turbine operating hours are the sum of operating hours when firing gas and operating hours when firing oil. The permittee shall install, calibrate, operate and maintain meters to measure and accumulate the amount of each fuel fired and hours of operation for each 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 turbines 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 for each unit. Each system shall be designed and operated to monitor and control the gas turbine combustion process and operating parameters including, but not limited to: 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 permittee shall employ "good operating practices" in accordance with the manufacturer's recommended operating procedures to control CO, NOx, and VOC emissions. Prior to the initial emissions performance tests, the dry low-NOx (DLN) combustors and Speedtronic™ control system on each gas turbine 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 a dry low-NOx (DLN) combustion system for each combustion turbine in accordance with the manufacturer's recommendations. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific DLN system as part of the Title V permit application. Compliance with this requirement may be demonstrated by compiling data during the initial NSPS tests performed at various load conditions. [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 for each combustion turbine in accordance with the manufacturer's recommendations. Each water injection system shall be maintained and adjusted to minimize NOx emissions. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific water injection system as part of the Title V permit application. Compliance with this requirement may be demonstrated by compiling data during the initial NSPS tests performed at various load conditions. [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 specified in this permit.

EU-018, 019, and 020: GE Model 7EA Combustion Turbines		
Pollutant	**Fuels and Controls[a]**	**Emission Standards[b]**
CO	Gas Firing W/DLN During First 12 Months After Initial Testing After First 12 Months After Initial Testing	 25.0 ppmvd @ 15% O_2, 3-hour test avg. 54.0 pounds per hour, 3-hour test avg. 20.0 ppmvd @ 15% O_2, 3-hour test avg. 43.0 pounds per hour, 3-hour test avg.
	Oil Firing W/Wet Injection	20.0 ppmvd @ 15% O_2, 3-hour test avg. 44.0 pounds per hour, 3-hour test avg.
NOx	Gas Firing W/DLN Compliance by Annual Testing at Base Load Continuous Compliance by CEM	 9.0 ppmvd @ 15% O_2, 3-hour test avg. 32.0 pounds per hour, 3-hour test avg. 10.0 ppmvd @ 15% O_2, 3-hour avg.
	Oil Firing W/Wet Injection Compliance by Annual Testing at Base Load Continuous Compliance by CEM	 42.0 ppmvd @ 15% O_2, 3-hour test avg. 167.0 pounds per hour, 3-hour test avg. 42.0 ppmvd @ 15% O_2, 3-hour avg.
PM/PM_{10}	Fuel Sulfur Specifications and Combustion Design	Visible emissions ≤ 10% opacity (PM estimated at 0.002 grains/dscf)
SAM/SO_2	Natural Gas Sulfur Specification	1 grain per 100 SCF of gas
	Low Sulfur Distillate Oil Sulfur Specification	0.05% sulfur by weight
VOC	Gas Firing W/Combustion Design	2.0 ppmvw as methane 2.0 pounds per hour
	Oil Firing W/Combustion Design	4.0 ppmvw as methane 5.0 pounds per hour

[a] Oil firing is limited to 1000 hours per year per gas turbine and 2500 hours per year for all three gas turbines combined. DLN means dry low-NOx controls.

[b] The mass emission limits (pounds per hour) were based on 100% base load, 59° F, and 60% relative humidity.

16. Carbon Monoxide (CO)

(a) **Gas Firing:** When firing natural gas in a combustion turbine during the first 12 months after initial emissions performance testing, 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. Thereafter, when firing natural gas in a 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.

(b) **Oil Firing**: When firing low sulfur distillate oil in a combustion turbine, CO emissions shall not exceed 44.0 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 a combustion turbine, NOx emissions shall not exceed 32.0 pounds per hour nor 9.0 ppmvd corrected to 15% oxygen based on an annual 3-hour compliance test average. In addition, NOx emissions shall not exceed 10.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average for data collected from the continuous NOx emissions monitor.

(b) **Oil Firing**: When firing low sulfur distillate oil in a combustion turbine, NOx emissions shall not exceed 167.0 pounds per hour nor 42.0 ppmvd corrected to 15% oxygen based on an annual 3-hour test average. In addition, NOx emissions shall not exceed 42.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average for data collected from the continuous NOx 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 rolling 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 a combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The permittee shall demonstrate compliance with this standard 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 a 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 a 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 3-hour averages compiled by the continuous NOx emissions monitor. [Rule 62-210.700, F.A.C.]

21. Excess Emissions Allowed: Providing the permittee adheres to best operational practices to minimize the amount and duration of excess emissions, the following conditions shall apply:

(a) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for up to 2.0 hours in any 24-hour period.

(b) During startup, shutdown, and malfunction, the NOx CEM shall monitor and record NOx emissions. However, up to 2.0 hours of monitoring data during any 24-hour period may be excluded from the continuous NOx compliance demonstration as a result of startup, shutdown, and documented malfunctions. In case of malfunctions, the owner or operator shall notify the Compliance Authorities in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report."

[Design 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 air inlet air temperature during the test (with 100 percent represented by a curve depicting heat input vs. air inlet 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. air inlet temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet 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".

(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."

(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 firing natural gas and for firing 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 emissions performance tests for CO, NOx, and visible emissions from each combustion turbine shall be conducted when firing natural gas. If 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. An annual performance test for VOC emissions is not required as long as the unit remains in compliance with the CO and visible emissions limits specified by this permit.

    If a combustion turbine operates more than 200 hours of oil firing during any federal fiscal year, the permittee shall schedule and conduct annual emissions performance tests for CO, NOx, and visible emissions when firing low sulfur distillate oil. For oil firing, compliance with the NOx standards may be determined by the continuous monitor data collected during the required CO test. An annual performance test for VOC emissions is not required as long as the unit remains in compliance with the CO and visible emissions limits specified by this permit for oil firing.

    Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). [Rule 62-297.310(7)(a)4., F.A.C.]

31. Tests Prior to Permit Renewal: Prior to renewing the air operation permit, the permittee shall also conduct emissions performance tests for CO, NOx, VOC, and visible emissions when firing natural gas and when firing low sulfur distillate oil. These tests shall be conducted within the 12-month period prior to renewing the air operation permit. For pollutants required to be tested annually, the permittee may submit the most recent annual compliance test to satisfy the requirements of this provision. [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 each 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 continuous emissions standards for NOx based on a 3-hour rolling average. The 3-hour 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 documented malfunction unless prohibited by 62-210.700 F.A.C.

(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: Unless otherwise specified, 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 1 grain 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 summarizing the previous month of operation and the previous 12 months of operation: hours of gas firing; million cubic feet of gas fired; hours of oil firing; and gallons of oil fired. The information shall be recorded for each gas turbine and for the group of three gas turbines. Information may be recorded and stored as an electronic file, but must be available for inspection and/or printing at the request of the Compliance Authority. [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. Quarterly Excess Emissions Reports: 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

Florida Power Corporation
FPC Intercession City Plant
Osceola County

Draft Permit No. 0970014-003-AC (PSD-FL-268)
Three New Simple-Cycle Peaking Combustion Turbines
New Emissions Units 018, 019, and 020

1.0 EXISTING FACILITY

The existing facility is an electric power generating plant consisting of eleven combustion turbine peaking units, identified by the applicant as P1 through P11. Units P1-P6 each consist of two gas turbines having a combined hourly capacity of 56.7 MW and firing No. 2 distillate oil. Units P7-P10 each consist of a General Electric Model 7EA gas turbine having an hourly capacity of 96.3 MW and firing natural gas or distillate oil. Unit P11 is a Siemens Model V84.3 having an hourly capacity of 171 MW and firing distillate oil.

Because emissions of at least one criteria pollutant are greater than 250 TPY, the existing facility is considered a "major facility" with respect to Rule 62-212.400, F.A.C. - Prevention of Significant Deterioration (PSD) of Air Quality. 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, Florida Power Corporation (FPC), proposes to add three new General Electric Model No. PG7121 7EA dual-fuel simple cycle combustion turbines with electrical generator sets having a nominal power production of 87 MW. The new units may employ an evaporative cooling system and 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. The applicant requested the operational flexibility of limiting total turbine operating hours for the three combined units to 10,170 hours per year. Of this total, no more than 3000 turbine hours per year would occur when firing low sulfur distillate oil. 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 56 feet high stack.

As a result of fuel combustion, this project will emit significant amounts of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), and sulfur dioxide (SO_2), and sulfuric acid mist (SAM), as well as minor amounts of 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}, SAM, 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 Technical Evaluation and Preliminary Determination that accompanies the Department's Intent to Issue Permit package.

3.0 APPLICATION PROCESSING SCHEDULE

05/25/99 The Department received a PSD air construction permit application.

06/22/99 The Department requested additional information.

08/02/99 The Department received additional information from the applicant; application complete.

09/15/99 The Department issued the Intent to Issue Permit package, including the preliminary BACT determination.

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.

The existing facility is considered a PSD major source of air pollution because current potential emissions of at least one criteria pollutant are greater than 250 tons per year. 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 in accordance with Rule 62-212.400, F.A.C. 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 Osceola 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 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	260 / 220[a]	100	Yes	Yes
NOx	365[b]	40	Yes	Yes
PM/PM_{10}	73[b]	15	Yes	Yes
SAM	9[b]	7	Yes	Yes
SO_2	95[b]	40	Yes	Yes
VOC	15[b]	40	No	No

[a] - "260" TPY is based on 25 ppmvd for gas during the first 12 months. "220" TPY is based on 20 ppmvd for gas firing after the first 12 months. Both calculations include 3000 hours per year of oil firing at 20 ppmvd.

[b] - Based on worst case of 7170 total turbine hours per year of gas firing and 3000 total turbine hours per year of oil firing and GE data. Final permit conditions vary. Assumes all particulate matter is PM_{10}.

Therefore, the proposed combustion turbine project is subject to PSD review and a Best Available Control Technology (BACT) determination for CO, NOx, PM/PM_{10}, SAM 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/PM_{10}, SAM 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 June 6, 1999;
- No comments were received from EPA Region 4;
- 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.
- 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.

"Hot" Selective Catalytic Reduction (SCR): Due to the temperature limitation of conventional SCR catalysts, manufacturers have developed specially formulated zeolite catalysts designed to further the reduction reaction at temperatures up to 1025°F which is within the range of the exhaust gas temperature (1000°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. For evaluation purposes, DLN for gas firing and wet injection for oil firing were combined to form a single control alternative. For this project, hot selective catalytic reduction (SCR) with ammonia injection is recognized as the top control option followed by dry low-NOx (DLN) combustor technology for gas firing combined with water injection for oil firing. The applicant reviewed hot SCR for the following additional adverse impacts.

Energy Impacts: Both the DLN combustor technology and water injection controls tend to increase power, which is the primary purpose of the project. Hot SCR would result in a pressure loss across the catalyst resulting in an energy penalty.

Environmental Impacts: The maximum predicted impacts of all control alternatives are considerably below the PSD increment for NOx of 25 ug/m^3 (annual average) and the NOx AAQS of 100 ug/m^3.

Economic Impacts: Installation of hot SCR was estimated as having capital cost of $3,605,475 and an annualized cost of $941,081 per year. A control efficiency of 60% would provide a NOx reduction of 73 tons per year, which results in an incremental cost of $12,890 per ton of NOx removed. This assumes NOx emissions of 9 ppmvd prior to control.

The applicant rejected SCR primarily based on unreasonable costs associated with controlling low NOx emissions achieved by the General Electric 7EA. Therefore, the applicant proposed the following as the best available controls:

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

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

The Department recognizes hot selective catalytic reduction (SCR) with ammonia injection as the top control option followed by dry low-NOx (DLN) combustor technology for gas firing combined with water injection for oil firing. However, the Department disagrees with many of the applicant's assumptions.

Energy Impacts: Installation of hot SCR *would* result in an energy penalty due to the pressure drop across the catalyst bed of perhaps 3.5 inches of water. Roughly, this equates to nearly 4 million kWh per year of potential lost power generation.

Environmental Impacts: The Department gives no consideration to the applicant's comment that NOx levels are already below the PSD significant impact levels and AAQS. This is considered only in the air quality analysis and not in making a BACT determination. However, hot SCR requires the injection of ammonia at slightly above the stoichiometric rate which inevitably results in ammonia "slip" or emissions of unreacted ammonia perhaps as much as 25 tons per year could slip by the hot SCR system. 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: The Department disagrees with the applicant's cost analysis. First, the applicant multiplied the costs from another project nearly twice the size of the proposed combustion turbine by 50% to estimate costs for hot SCR. Second, the applicant estimated NOx emission reductions were based on 2390 hours of gas firing and 1000 hours of oil firing. However, the applicant also requested a limit of 10,170 total turbine hours for the three combined units with up to 3000 hours of total oil firing to provide operational flexibility. So, hours of operation for any one turbine could be much higher because of the requested flexible limits. Therefore, the Department performed a cost analysis using a vendor quote from an ongoing project that also involves hot SCR applied to a General Electric Model 7EA combustion turbine. In addition, the Department believes it is conservative to consider 5760 hours of gas firing and 3000 hours of oil firing to estimate potential emission reductions. The following table summarizes the Department's analysis. The applicant reviewed SCR for the following additional adverse impacts.

Control Option	Fuel	Emissions Ton Per Year	Control Efficiency	Reduction TPY	Totals TPY	Cost per Ton of NOx Removed
Hot SCR	Gas	50	60%[a]	74	124	$10,008/ton NOx[b]
	Oil	34	60%	50		
DLN	Gas	124	Baseline	Baseline	Baseline	Baseline
Wet Injection	Oil	84	Baseline	Baseline		

Table Notes:

[a] Based on emissions from DLN-controlled level to SCR-controlled level. Assumes similar level of control for 7760 hr/yr of gas firing and 1000 hr/yr of 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 for a similar unit (Hardee Power Station, PSD-FL-140a).

These costs are the result of substantial costs related to installation, equipment, catalyst replacement, energy consumption, and ammonia usage. The Department rejects hot SCR based on unreasonable costs associated with controlling very low NOx emissions. The Department agrees with the applicant that DLN combustion technology for gas firing combined with wet injection for oil firing represent the Best Available Control Technology for this project. Therefore, the Department determines the following NOx BACT emission standards at baseload conditions.

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 BACT limits of 10.0 ppmvd @ 15% oxygen for gas firing and 42.0 ppmvd @ 15% oxygen for oil firing based on a 3-hour average. The slightly higher NOx concentration was specified in consideration for the shorter averaging period (requested by the EPA) and a reduction in oil firing from 3000 to 2500 total turbine hours of operation for all three gas turbines.

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. 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 about 2 inches of water. This equates to about 12.5 million kWh per year of potential lost power generation or nearly 1000 residential customers per year.

Environmental Impacts: The air quality impacts of a DLN system is well below the significant impact levels for CO. Further reduction of CO with an oxidation catalyst would not result in any additional environmental benefits or improved ambient air quality.

Economic Impacts: The applicant estimated the incremental, annualized cost of an oxidation catalyst with respect to a baseline defined as DLN with wet injection. A summary is provided below.

Control Option	Fuel	Controlled Emissions	Control Efficiency	Reduction TPY	Totals TPY	Cost per Ton of CO Removed[c]
Oxidation Catalyst	Gas	28	57%	37[a]	49.2	$5238/ton CO[b]
	Oil	9.8	57%	12.2[a]		
Combustion Design	Gas	65[c]	Baseline	Baseline	Baseline	Baseline
	Oil	22	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. Assumes 2390 hours of gas firing and 1000 hours of oil firing.

[b] Based on estimated installed capital cost of $960,566 and a total annualized cost of $257,717 per year. Costs were estimated based on a combustion turbine project nearly twice the size of the proposed units.

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

Gas Firing: Combustion design with a CO emissions standard of 25.0 ppmvd @ 15% oxygen; and

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

6.2.3 Department's CO BACT Determination

The Department recognizes an oxidation catalyst as the top control for CO emissions followed by DLN combustor technology. However, the Department disagrees with many of the applicant's assumptions as summarized below.

Energy Impacts: Installation of an oxidation catalyst *would* result in an energy penalty due to the pressure drop across the catalyst bed of about 1 to 2 inches of water.

Environmental Impacts: 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.

Economic Impacts: The Department disagrees with the use of a cost estimate for an oxidation catalyst involving a combustion turbine nearly twice the size of the units proposed. Therefore, the Department performed its own analysis, summarized in the following table.

Control Option	Fuel	Controlled Emissions[a]	Control Efficiency	Reduction TPY	Cost per Ton of CO Removed[b]
Oxidation Catalyst	Gas	24	90%	213[a]	$1519/ton CO[b]
Combustion	Gas	237	Baseline	Baseline	Baseline

Table Notes:

[a] Based on emissions from DLN-controlled level (25 ppmvd) to oxidation catalyst-controlled level. Department conservatively assumed 8760 hours of gas firing (worst-case) because applicant requested operational flexibility of a limit on total turbine hours for the three units and not individual limits.

[b] Based on estimated installed capital cost of $1,368,919 and a total annualized cost of $323,500 per year. Costs were estimated based on an ongoing combustion turbine project for unit similar to that proposed for this project (Hardee Power Station, PSD-FL-140a).

Based on this cost analysis, the Department believes that installation of an oxidation catalyst may be cost effective. The Department gives further consideration to the following items:

- 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.
- 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 contacted the applicant with the above information. The applicant indicated 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 Department discussed that an oxidation catalyst appeared cost effective assuming the proposed baseline emission rate of 25 ppmvd for gas firing. However, from the data reviewed, it seemed reasonable to expect much lower CO emissions. Reducing the baseline DLN CO limit from 25 ppmvd to 20 ppmvd (same as for oil firing) results in the following analysis.

Control Option	Fuel	Controlled Emissions[a]	Control Efficiency	Reduction TPY	Cost per Ton of CO Removed[b]
Oxidation	Gas	19	90%	170[a]	$1900/ton CO[b]
Combustion	Gas	189[c]	Baseline	Baseline	Baseline

Table Notes:

[a] Based on 90% control of emissions from DLN baseline level of 20 ppmvd by an oxidation catalyst system. Department assumed 8760 hours of gas firing (worst-case) because applicant requested operational flexibility of a limit on total turbine hours for the three units and not individual limits.

[b] Based on estimated installed capital cost of $1,368,919 and a total annualized cost of $323,500 per year. Costs were estimated based on an ongoing combustion turbine project with an identical unit as proposed for this project (Hardee Power Station, PSD-FL-140a).

At the requested CO emissions standard of 20/20 ppmvd for gas/oil firing, the Department believes that even an oxidation catalyst capable of 90% control efficiency is not cost effective, relative to the significant emissions rates for other regulated pollutants. In addition, this analysis was based on the conservative assumption that a given unit would operate 8760 hours per year. The Department offered to specify the option of installing an oxidation catalyst system or establishing a lower DLN CO emissions standard for this project. The applicant indicated that a CO standard of 25 ppmvd for the first 12 months of operation and 20 ppmvd thereafter would be reasonable. The applicant declined the option of installing an oxidation catalyst.

Therefore, the Department establishes that the good combustion characteristics of the General Electric Model 7EA and the lower emissions standard represent BACT for this project. The Department believes there is reasonable assurance that the proposed combustion turbine is capable of complying with the lower emissions standards of 20/20 ppmvd for gas/oil firing. 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 testing 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

Several available control technologies for particulate matter removal including centrifugal collectors, electrostatic precipitators, fabric filters, and wet scrubbers were identified. 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 25 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.

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 1 grain of sulfur per 100 SCF and distillate oil containing no more than 0.05% sulfur by weight. Limiting the sulfur content of the fuels also establishes the maximum potential SAM and SO_2 emissions. At these already very low levels, the control efficiency of an add-on technology would be unreasonably low and cost prohibitive.

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

Gas Firing: Pipeline quality natural gas containing no more than 1 grain of sulfur per 100 SCF, and

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

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

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

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

Gas Firing: The combustion turbine shall be fired primarily by pipeline natural gas containing no more than 1 grain of sulfur per 100 standard cubic feet of natural gas.

Oil Firing: The combustion turbine may be fired with No. 2 (or a superior grade) distillate fuel oil containing no more than 0.05% sulfur by weight.

In addition, for the group of three combustion turbines, the permit limits the hours of operation to:

(a) **Installation of One Gas Turbine**: When one gas turbine is installed, the total turbine operating hours shall not exceed 3390 hours during any consecutive 12 months.

(b) **Installation of Two Gas Turbines**: When two gas turbines are installed, the total turbine operating hours shall not exceed 6780 hours during any consecutive 12 months.

(c) **Installation of Three Gas Turbines**: When all three gas turbines are installed, the total turbine operating hours shall not exceed 10,170 hours during any consecutive 12 months.

(d) **Oil Firing**: Each gas turbine is limited to no more than 1000 turbine operating hours of oil firing during any consecutive 12 months. In addition, the group of three gas turbines is limited to no more than 2500 turbine operating hours of oil firing during any consecutive 12 months.

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

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

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

6.4 VOLATILE ORGANIC COMPOUNDS

Originally, the applicant indicated VOC emissions above the significant emissions rate of 40 tons per year. However, this was based on the manufacturer's estimated maximum *unburned hydrocarbon* emissions rates. For an identical combustion turbine, General Electric guarantees VOC emissions of less than 2 lb/hour for gas firing and 5 lb/hr for oil firing. This would result in potential project VOC emissions of only 15 tons per year, which is 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 (2.0 lb/hr), 3-hour test average

Oil Firing: 4.0 ppmvd measured as methane (5.0 lb/hr), 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-018, 019, and 020: GE Model 7EA Combustion Turbines		
Pollutant	**Controls**[b]	**Emission Standard**
CO	Gas Firing W/DLN, First 12 Months After Initial Startup	25.0 ppmvd @ 15% oxygen and 54.0 pounds per hour
	Gas Firing W/DLN, After First 12 Months After Initial Startup	20.0 ppmvd @ 15% oxygen and 43.0 pounds per hour
	Oil Firing W/Wet Injection	20.0 ppmvd @ 15% oxygen and 44.0 pounds per hour
NOx	Gas Firing W/DLN	9.0 ppmvd @ 15% oxygen and 32.0 pounds per hour 10.0 ppmvd @ 15% oxygen by CEM
	Oil Firing W/Wet Injection	42.0 ppmvd @ 15% oxygen and 167.0 pounds per hour 42.0 ppmvd @ 15% oxygen by CEM
PM/PM_{10}	Fuel Sulfur Specifications and Combustion Design	Visible emissions ≤ 10% opacity
SAM[a]/SO_2	Natural Gas Sulfur Specification	1 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 standards are synthetic (PSD) minor limits, not BACT limits.
[b] DLN means dry low-NOx controls.

7.2 BACT COMPLIANCE DEMONSTRATION

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

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

* Compliance shall be demonstrated for each fuel type.

7.3 BACT EXCESS EMISSIONS ALLOWED

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

21. 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 3-hour and 24-hour NOx averages for compliance determinations. [Rule 62-210.700, F.A.C.]

22. Excess Emissions Allowed: Providing the permittee adheres to best operational practices to minimize the amount and duration of excess emissions, the following conditions shall apply:

    (a) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for up to 2 hours in any 24-hour period.

    (b) During startup, shutdown, and malfunction, the NOx CEM shall monitor and record NOx emissions. However, up to 2 hours of monitoring data during any 24-hour period may be excluded from the continuous NOx compliance demonstration as a result of startup, shutdown, and documented malfunctions. In case of malfunctions, the owner or operator shall notify the Compliance Authorities in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report."

8.0 COMMENTS ON THE DRAFT

Comments on the Draft Permit and BACT Determination were received from the applicant and EPA Region 4. See the Final Determination for a summary of the comments and the Department's responses.

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:

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

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

Recommended By:

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

Date: 12/9/99

Approved By:

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

Date: 12/9/99

SECTION IV.

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: Howard L. Rhodes

THRU: Clair Fancy
Al Linero

FROM: Jeff Koerner

DATE: December 8, 1999

SUBJECT: Final Permit No. 0970014-003-AC (PSD-FL-268)
FPC Intercession City Power Plant
Three 87 MW Simple-Cycle Combustion Turbines

The Final Permit is attached for your approval and signature to add three new 87 MW, simple-cycle combustion turbine peaking units to the existing Intercession City plant located Osceola County approximately 3.5 miles west of Intercession City. BACT for NOx was determined to be dry low NOx combustor design. BACT for CO, PM, SAM, and SO_2 was determined to be combustor design, low sulfur fuel specifications, and restricted fuel oil firing. VOC emissions did not trigger a BACT determination. The Public Notice of Intent to Issue was published in the Osceola News-Gazette on September 30, 1999.

No comments were received from the public or National Park Service regarding the Draft Permit. The applicant and EPA Region 4 submitted written comments that resulted in minor changes as summarized in the attached Final Determination. The most significant change is the increase in the continuous NOx BACT limit for gas firing from 9.0 ppmvd @ 15% oxygen based on a 24-hour block average to 10.0 ppmvd @ 15% oxygen based on a rolling 3-hour average. EPA requested the shorter averaging period for the peaking units. The applicant requested a slightly higher NOx concentration in consideration for the shorter averaging period and a reduction in firing fuel oil from 3000 hours to 2500 hours (all units combined). The permittee is still required to demonstrate compliance with a limit of 9.0 ppmvd @ 15% oxygen based on an annual test at base load. The changes did not result in increased emissions.

I recommend your approval and signature. Day 90 is January 26, 2000. (The permitting clock was tolled for an additional 39 days because the applicant filed a request for an extension of time in which to file a petition for administrative hearing. The applicant withdrew this request on December 7, 1999.)

Attachments

CHF/AAL/jfk