FLORIDA

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE:

Florida Power and Light Company – Martin Plant
P.O. Box 176
Indiantown, FL 34956

Authorized Representative:
John M. Lindsay, Plant General Manager

ARMS Permit No.	0850001-008-AC
PSD Permit No.	PSD-FL-286
Facility ID No.	0850001
SIC No.	4911
Expires:	July 1, 2002

PROJECT AND LOCATION

This permit is issued pursuant to the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality. The permit authorizes installation at the existing power plant of two simple cycle, 170 MW combustion turbines with electrical generator sets fired primarily with natural gas.

The project will be constructed at the existing FPL Martin Power Plant located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The UTM coordinates are Zone 17, 543.1 km E, 2992.9 km N and the map coordinates are Latitude 27° 03' 13", Longitude 80° 33' 46".

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 Determinations
Appendix E	- Emissions Standards Summary
Appendix GC	- Construction Permit General Conditions
Appendix GG	- NSPS Subpart GG Requirements for Gas Turbines
Appendix XS	- CEMS Excess Emissions Report

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

Date: 7/21/00

Z 341 355 338

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1. Article Addressed to:

Mr. John M. Lindsay
Plant General Mgr.
FPL - Martin Plant
P. O. Box 176
Indiantown, FL 34956

COMPLETE THIS SECTION ON DELIVERY

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X Michael [illegible]
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STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Florida Power and Light Company
P.O. Box 176
Indiantown, FL 34956

Permit No. PSD-FL-286
Project No. 0850001-008-AC
Two New 170 MW Combustion Turbines
FPL Martin Power Plant
Martin County, Florida

Authorized Representative:
John M. Lindsay, Plant General Manager

Enclosed is Final Permit No. PSD-FL-286 for Project No. 0850001-008-AC. This permit authorizes FPL to construct two new 170 MW combustion turbines at FPL's Martin Power Plant located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. As noted in the Final Determination (attached), the Department made only minor changes to the Final Permit. 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.

CH Fancy
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 7/24/00 to the persons listed:

Mr. John M. Lindsay, FPL*
Mr. Richard G. Piper, FPL
Mr. Ken Kosky, Golder Associates
Mr. Buck Oven, PPSO
Mr. Isidore Goldman, SED
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.

Charlotte J. Hayes (Clerk) 7/24/00 (Date)

The Department distributed a public notice package on June 9, 2000 for a project that will add 340 MW of electric power generating capacity to the existing FPL Martin Power Plant located in the western part of unincorporated Martin County approximately seven miles north of Indiantown on State Road 710. The applicant, Florida Power and Light, proposes to install two simple cycle, 170 MW General Electric Model PG7241(FA) simple cycle combustion turbines with electrical generator sets. The Public Notice of Intent to Issue was published in the Stuart News on June 13, 2000. The Department received the proof of publication on June 19, 2000.

COMMENTS FROM THE PUBLIC, DISTRICT OFFICE, AND NPS

The Department received no comments from the public, the Department's Southeast District Office, or the National Park Service during the comment period.

COMMENTS FROM THE APPLICANT

On June 6, 2000, the Department received comments from the applicant in response to an earlier question regarding emissions of hazardous air pollutants, particularly formaldehyde. The applicant explained that the emission factor used in the initial application was based on a report from EPRI and was believed to be the most technically accurate for estimating HAP emissions from large utility combustion turbines. The applicant suggests that large combustion turbines are not appropriately represented in the newly finalized AP-42 emission factors. However, calculation of the potential HAP emissions based on the emission factor for operation greater than 80% of base load indicates that this project is not a major source of HAP emissions, in and of itself. The Department's separate analysis confirms this conclusion. The Department estimates potential emissions of 4.5 tons of formaldehyde per year and 7.4 tons of combined HAPs per year.

COMMENTS FROM EPA REGION 4

On May 19, 2000, EPA Region 4 provided the following comments regarding the initial Draft Permit for this project.

1. EPA requested that the Department verify the potential emissions estimate for formaldehyde.

   Response: The applicant responded as indicated above and the Department confirmed that this project is expected to be minor with respect to HAP emissions.

2. EPA stated that it has a policy regarding automatic exemptions for excess emissions due to startup and shutdown. BACT should apply during all normal operations of the equipment. Also, the permit condition allowing excess emissions is unclear regarding the exclusion of "two hourly averages" from the CEMS data.

   Response: The Department reviewed the operational design of the General Electric Model PG7241(FA) gas turbine. To achieve the lean, premix steady state operation resulting in single digit NOx emissions, the automated gas turbine control system stages the air and fuel mixtures in various combinations of combustors. For startup, this may result in higher pollutant concentrations for approximately 30 minutes, but might not result in higher mass emission rates because less fuel is typically fired during these periods. Shutdown generally lasts less than 20 minutes and may or may not result in higher emissions. Many control systems require a period of time to reach appropriate temperatures or other parameters before emission reductions can be guaranteed. The Department believes the permit condition is reasonable because of the short period of excess emissions allowed and because it is in the permittee's best interest to achieve steady state operation as soon as possible. In addition, the Department's rules provide this authority as approved by EPA in the State Implementation Plan. The condition has been revised to clarify the exclusion of CEM emissions data from the compliance determination.

3. EPA commented that the Department's revised cost analysis better reflected the true costs of installing a selective catalytic reduction system and an oxidation catalyst system.

   Response: No response necessary.

   In June, EPA Region 4 also provide verbal comments that a few other states were requiring initial performance tests for formaldehyde and other HAP emissions.

   Response: The Department notes this comment and may consider it for future projects.

CONCLUSION

The final action of the Department is to issue the final permit with the changes mentioned above and to correct minor typographical errors.

FACILITY DESCRIPTION

The existing FPL Martin Power Plant currently consists of four electrical generating units. Fossil fuel-fired steam electric generators Nos. 1 and 2 (800 MW each) were built in the 1970's and are fired with low sulfur residual oil and natural gas. Combined cycle units Nos. 3A, 3B, 4A, and 4B are General Electric Model 7F combustion turbines (170 MW each) plus heat recovery steam generators. Each pair of gas turbines (3A/3B and 4A/4B) shares a common steam-electrical turbine (160 MW each). Completion of the two new 170 MW simple cycle combustion turbines will bring the electric power generation to a nominal 2940 MW.

NEW EMISSIONS UNITS

The proposed project will add the following new emissions units.

ARMS ID No.	Emission Unit Description
011	Simple Cycle Unit No. 8A: A General Electric Model PG7241(FA) simple cycle combustion turbine with electrical generator set designed to produce a nominal 170 MW of direct power.
012	Simple Cycle Unit No. 8B: A General Electric Model PG7241(FA) simple cycle combustion turbine with electrical generator set designed to produce a nominal 170 MW of direct power.
13	Two Natural Gas Fuel Heaters: Each gas fuel heater is fired with a maximum heat input of 23.71 mmBTU per hour of natural gas.
14	Oil Storage Tank: 2.1 million-gallon storage tank supplies low sulfur distillate oil as a backup fuel to simple cycle combustion turbine Nos. 8A and 8B.

REGULATORY CLASSIFICATION

HAPs: Based on the Title V permit, the existing facility is a major source of hazardous air pollutants (Title III). This project is not, in and of itself, major for HAPs.

Acid Rain: The existing facility is subject to the acid rain provisions of the Clean Air Act (Title IV).

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

PSD Major Source: The existing facility is classified as a fossil fuel-fired steam electric plant, which is one of the source categories listed in Table 62-212.400-2, F.A.C. Because emissions of at least one pollutant exceed 100 tons per year, the existing facility is considered a major source of air pollution with respect to PSD. Therefore, each new project requires a PSD applicability review. For each potential emission increase greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C., a determination of Best Available Control Technology (BACT) is required. For this project, emissions of CO, NOx, PM/PM_{10}, and SO_2 are significant and subject to the BACT standards specified in this permit.

NSPS Sources: Emissions units are subject to the New Source Performance Standards in 40 CFR 60 for the gas turbines (Subpart GG) and the oil storage tank (Subpart Kb).

RELEVANT DOCUMENTS

- Permit application received on 02/19/00 and all related correspondence.
- Initial Draft Permit issued on May 5, 2000 and subsequent correspondence regarding revisions.

The following conditions apply to all emissions units and activities defined for this project.

GENERAL 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 Air Resources Section of the Southeast District Office, Florida Department of Environmental Protection, 400 North Congress Avenue, P.O. Box 15425, West Palm Beach, Florida 33416-5425. The phone number is 561/681-6600 and the fax number is 561/681-6755.

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 permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

6. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. .The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [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 routine operation of the permitted emissions units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. 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.]

EMISSIONS AND CONTROLS

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

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

15. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. These emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard. [Rule 62-210.700(4), F.A.C.]

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

TESTING REQUIREMENTS

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

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

19. Applicable Test Procedures

    (a) *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be 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)1. and 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.]

(c) *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C. [Rule 62-297.310(4)(d), F.A.C.]

20. 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.]

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

RECORDS

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

REPORTS

23. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test 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.].

24. 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.]

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

EU ID No.	Common Emission Unit Description
011 012	Simple Cycle Units Nos. 8A and 8B: Each unit consists of a General Electric Model PG7241(FA) combustion turbine, an electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an exhaust stack that is 80 feet tall and 20.5 feet in diameter, and associated support equipment. Natural gas is the primary fuel with very low sulfur distillate oil as a limited backup fuel. Emissions of CO, PM/PM_{10}, SO_2, and VOC are minimized by the efficient combustion of these clean fuels at high temperatures. NOx emissions are reduced by dry low-NOx (DLN) combustion technology during gas firing and by water injection during distillate oil firing. The capacities by fuel and method of operation are: *Natural Gas* • Normal Firing: At a compressor inlet air temperature of 35° F and firing 1860 mmBTU per hour of gas, each unit produces a maximum 182 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,461,000 acfm at 1095° F. • Power Augmentation (Steam Injection): At a compressor inlet air temperature of 59° F and firing 1800 mmBTU per hour of gas with approximately 116,000 pounds per hour of steam injection, each unit produces a maximum 180 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,380,000 acfm at 1115° F. • Peaking: At a compressor inlet air temperature of 35° F and firing 1920 mmBTU per hour of gas during peaking, each unit produces a maximum 190 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,488,000 acfm at 1110° F. *Distillate Oil*: At a compressor inlet air temperature of 35° F and firing 2000 mmBTU per hour of oil as a backup fuel, each unit produces a maximum 191 MW. The water injection rate for NOx control will be approximately 131,000 pounds per hour. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,539,000 acfm at 1075° F. Note: All heat input values are based on the higher heating values (HHV) of the fuels.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emissions units addressed in this section are subject to Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}) 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* are 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. Combustion Turbines: The permittee is authorized to install, tune, operate and maintain two new General Electric Model PG7241(FA) combustion turbines with electrical generator sets, each designed to produce a nominal 170 MW of electrical power. [Applicant Request; Design]

4. Permitted Capacity: The heat input rates (HHV) to each combustion turbine shall not exceed the following:

   (a) *Normal Gas Firing*: 1860 mmBTU per hour with a compressor inlet air temperature of 35° F and producing a maximum 182 MW.

   (b) *Gas Firing With Power Augmentation (Steam Injection)*: 1800 mmBTU per hour of natural gas with a compressor inlet air temperature of 59° F and producing a maximum 180 MW.

   (c) *Gas Firing With Peaking*: 1920 mmBTU per hour with a compressor inlet air temperature of 35° F and producing a maximum 190 MW.

   (d) *Distillate Oil Firing*: 2008 mmBTU per hour with a compressor inlet air temperature of 35° F and producing a maximum 191 MW.

   The heat input rates are based on the higher heating values (HHV) of 23,127 BTU/lb_m for natural gas and 19,490 BTU/lb_m for distillate oil. The permittee shall provide the manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Compliance shall be determined by data compiled from the automated gas turbine control system. This data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Design; Rule 62-210.200(PTE), F.A.C.]

5. Simple Cycle Operation Only: Each combustion turbine shall operate only in simple cycle mode. This restriction is based on the permittee's request, which formed the basis of the CO and NOx BACT determinations and resulted in the emission standards specified in this permit. Specifically, the CO and NOx BACT determinations eliminated several control alternatives based on technical considerations due to the elevated temperatures of the exhaust gas as well as costs related to operation as peaking units. Any request to convert these units to combined cycle operation or increase the allowable hours of operation shall be accompanied by a revised CO and NOx BACT analysis and the approval of the Department through a permit modification in accordance with Chapters 62-210 and 62-212, F.A.C. Note: The results of this analysis may validate the initial BACT determinations or result in the submittal of a full PSD permit application, new control equipment, and new emissions standards. [Applicant Request; Rules 62-210.300 and 62-212.400, F.A.C.]

6. Allowable Fuels: Each combustion turbine shall be designed and tuned for a primary fuel of pipeline-quality 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 low sulfur No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. No other fuels are authorized by this permit. It is noted that both limitations are much more stringent than the sulfur dioxide limitation in 40 CFR 60, NSPS Subpart GG and assures compliance with regulations 40 CFR 60.333 and 60.334 of this subpart. The permittee shall demonstrate compliance with the fuel sulfur limits by keeping the records specified in this permit. [Application; Rule 62-210.200(PTE), F.A.C.]

7. Alternate Gas Firing Methods of Operation

   (a) *Power Augmentation Mode*: In accordance with the manufacturer's recommendations, steam may be injected into each combustion turbine when firing natural gas to provide additional peaking power during periods of high electrical power demand. Each unit shall not exceed 400 hours of power augmentation during any consecutive 12 months. To qualify as "power augmentation mode", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. Power augmentation when firing distillate oil is prohibited.

   (b) *High Temperature Peaking Mode*: In accordance with the manufacturer's recommendations, each combustion turbine may be operated in a high temperature peaking mode when firing natural gas to provide additional power during periods of peak electrical power demands. Peaking is achieved through the automated gas turbine control system by allowing slightly higher exhaust temperatures, calculating a new combustion reference temperature for the peak load, and adjusting the fuel distribution between the fuel nozzles to maintain lean pre-mix firing. During the transfer from base load to peak load and during peak load operation, each unit will remain in the lean pre-mix steady state mode. Each unit shall not exceed 60 hours of peaking during any consecutive 12 months. To qualify as "peaking mode", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the peaking mode, the operator shall log the date, time, and new mode of operation. Peaking when firing distillate oil is prohibited.

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

8. Restricted Operation

   (a) *Gas Firing*: Each combustion turbine shall fire no more than 5,902,588,000 standard cubic feet of natural gas during any consecutive 12 months (equivalent to 3390 hours per year at the maximum firing rate for a compressor inlet air temperature of 59° F).

   (b) *Oil Firing*: Each combustion turbine shall fire no more than 7,358,350 gallons of distillate oil during any consecutive 12 months (equivalent to 500 hours per year at the maximum firing rate for a compressor inlet temperature of 59° F). If oil is fired, the natural gas consumption limit shall be reduced by 127.4 standard cubic feet of gas for every gallon of distillate oil fired.

   The permittee shall install, calibrate, operate and maintain a monitoring system for each combustion turbine to measure and accumulate the quantity of fuel and hours of operation for each method of operation. [Applicant Request; Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

9. 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 systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

EMISSIONS CONTROLS

10. Automated Control System: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, tune, operate, and maintain a Speedtronic™ automated 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: air/fuel distribution and staging, turbine speed, load conditions, exhaust temperatures, heat input, and fully automated startup and shutdown. [Design; 62-212.400(BACT), F.A.C.]

11. DLN Combustion Technology: In accordance with the manufacturer's recommendations, the permittee shall install, tune, operate and maintain the General Electric dry low-NOx combustion system (DLN 2.6 or better) to control NOx emissions from each gas turbine . [Design; Rule 62-212.400(BACT), F.A.C.]

12. Tuning: Prior to the initial emissions performance tests for each gas turbine, the DLN 2.6 combustors and automated gas turbine control systems shall be tuned to optimize the reduction of CO, NOx, and VOC emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations to minimize these pollutant emissions. During tuning sessions, each combustion turbine shall be tuned for CO and NOx emissions performance of 9.0 ppmvd corrected to 15% oxygen or better. The permittee shall provide at least 5 days advance notice prior to any tuning session. [Design; Rule 62-212.400(BACT), F.A.C.]

EMISSIONS STANDARDS

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

13. Carbon Monoxide (CO)

    (a) *Gas Firing, Normal and Peaking*: When firing natural gas under normal operating conditions and in the high temperature peaking mode, CO emissions from each combustion turbine shall not exceed 32.0 pounds per hour and 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load.

    (b) *Gas Firing With Power Augmentation*: When firing natural gas and injecting steam to provide power augmentation, CO emissions from each combustion turbine shall not exceed 47.0 pounds per hour and 15.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at peak load.

    (c) *Distillate Oil Firing*: When firing low sulfur distillate oil as a backup fuel, CO emissions from each combustion turbine shall not exceed 68.0 pounds per hour and 20.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load.

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

14. Nitrogen Oxides (NOx)

    (a) *Gas Firing, Normal*: When firing natural gas under normal operating conditions, NOx emissions from each combustion turbine shall not exceed 66.0 pounds per hour and 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load. 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 NOx continuous emissions monitor.

    (b) *Gas Firing With Power Augmentation*: When firing natural gas and injecting steam to provide power augmentation, NOx emissions from each combustion turbine shall not exceed 82.0 pounds per hour and 12.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at peak load. In addition, NOx emissions shall not exceed 12.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average for data collected from the NOx continuous emissions monitor.

    (c) *Gas Firing With Peaking*: When firing natural gas with high temperature peaking, NOx emissions from each combustion turbine shall not exceed 105.0 pounds per hour and 15.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at peak load. In addition, NOx emissions shall not exceed 15.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average for data collected from the NOx continuous emissions monitor.

(d) *Distillate Oil Firing*: When firing low sulfur distillate oil as a backup fuel, NOx emissions from each combustion turbine shall not exceed 334.0 pounds per hour and 42.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load. 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 NOx continuous emissions monitor.

NOx emissions are defined as oxides of nitrogen measured as NO_2. The permittee shall demonstrate compliance by conducting performance tests and emissions monitoring in accordance with EPA Methods 7E, 20, and the requirements of this permit. [Rule 62-212.400(BACT), F.A.C.; 40 CFR 60.332]

15. Particulate Matter (PM/PM_{10}) and Sulfur Dioxide (SO_2)

(a) *Particulate Matter*: When firing natural gas under any method of operation, particulate matter emissions from each combustion turbine shall not exceed 9.0 pounds per hour based on a 3-hour test average conducted at base load. When firing distillate oil, particulate matter emissions from each combustion turbine shall not exceed 17.0 pounds per hour based on a 3-hour test average conducted at base load.

(b) *Fuel Specifications.* Emissions of PM, PM_{10}, and SO_2 shall be limited by the use of pipeline-quality natural gas containing no more than 1 grain per standard cubic feet as the primary fuel and restricted use of No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight as a backup fuel. The fuel specifications are work practice standards established as BACT limits for PM, PM_{10}, and SO_2 emissions. The permittee shall demonstrate compliance with the fuel sulfur limits by maintaining the records specified in this permit. [Rule 62-212.400(BACT), F.A.C.; 40 CFR 60.333]

(c) *VE Standard.* When firing natural gas or distillate oil, visible emissions from each combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The visible emissions limits are work practice standards established as BACT limits for PM and PM_{10} emissions. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. [Rule 62-212.400(BACT), F.A.C.]

16. Volatile Organic Compounds (VOC)

(a) *Gas Firing*: When firing natural gas under any method of operation, VOC emissions shall not exceed 3.0 pounds per hour and 1.5 ppmvw based on a 3-hour test average conducted at base load.

(b) *Distillate Oil Firing*: When firing distillate oil, VOC emissions shall not exceed 7.5 pounds per hour and 3.5 ppmvw based on a 3-hour test average conducted at base load.

The VOC standards are established as PSD-synthetic minor limits. VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Methods 25, 25A and the performance testing requirements of this permit. Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions. [Design; Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

17. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, power augmentation, high temperature peaking or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such

emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard. [Rule 62-210.700(4), F.A.C.]

18. Excess Emissions Allowed: For each combustion turbine, excess NOx and visible emissions during startup, shutdown, and documented malfunction shall be allowed, providing:

    (a) Operators employ best operational practices to minimize the amount and duration of excess emissions.

    (b) Operation below 50% of base load shall not exceed 120 minutes during any calendar day.

    (c) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for up to ten, 6-minute observation periods during any calendar day. Data for each observation period shall be exclusive for the ten periods.

    (d) During all startups, shutdowns, and malfunctions, the NOx CEM shall monitor and record NOx emissions. For each calendar day, up to two 1-hour monitoring averages may be excluded from the continuous NOx compliance demonstration for each combustion turbine due to excess NOx emissions resulting from startup, shutdown, and documented malfunction. For excess NOx emissions due to malfunction, the permittee 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. In addition, the Department may request a written summary report of the incident.

    (e) If the permittee provides at least 5 days advance notice prior to tuning in accordance with the manufacturer's recommendations, up to three 1-hour monitoring averages may be excluded from the continuous NOx compliance demonstration for each gas turbine due to excess NOx emissions resulting from tuning. *{Permitting Note: It is expected that no more than two tuning sessions would occur each year.}*

    [Design; Rule 62-210.700(1) and (5); Rule 62-4.130, F.A.C.]

EMISSIONS PERFORMANCE TESTING

19. 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.; 40 CFR 60.40a(b)]

20. 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 Rule 62-204.800, F.A.C.

    (a) EPA Method 5 or 17 - Determination of Particulate Matter Emissions from Stationary Sources

    (b) EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources

    (c) EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources

    (d) EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources

    (e) EPA Method 20 - Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

    (f) EPA Methods 25 or 25A - Determination of Volatile Organic Concentrations *{Note: EPA Method 18 may be conducted to account for the non-regulated methane fraction of the measured VOC emissions.}*

    No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [40 CFR 60, Appendix A; Rule 62-204.800, F.A.C.]

21. Initial Tests Required: Initial performance tests to demonstrate compliance with each emission standard for normal gas firing, gas firing with power augmentation, gas firing with high temperature peaking, and backup distillate oil firing shall be conducted within 60 days after achieving the maximum production rate, but not later than 180 days after initial operation of each emissions unit. Initial performance tests shall be conducted for CO, NOx, PM, VOC and visible emissions. Tests for CO, NOx, and VOC shall be conducted concurrently. Tests for PM and visible emissions shall be conducted concurrently. NOx performance tests shall be conducted in accordance with the requirements of 40 CFR 60, Subpart GG. For the initial performance tests, emissions data shall be presented in units of the BACT standards as well as the units specified in the Subpart GG emissions standard. [Rule 62-297.310(7)(a)1., F.A.C.; 40 CFR 60.335]

22. Annual Performance Tests: Annual performance tests shall be conducted for each combustion turbine to demonstrate compliance with CO, NOx, and visible emissions standards for normal gas firing, gas firing with power augmentation, and backup distillate oil firing. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). CO and NOx performance tests shall be conducted concurrently. If conducted at permitted capacity, NOx emissions data collected during the annual NOx continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the required annual performance test.

    (a) For each combustion turbine that fires distillate oil for less than 200 hours during the previous federal fiscal year, the annual performance tests when firing distillate oil for the current federal fiscal year of operation are not required.

    (b) For each combustion turbine that operates with power augmentation for less than 200 hours during the previous federal fiscal year, the annual performance tests when operating with power augmentation for the current federal fiscal year of operation are not required.

    [Rule 62-297.310(7)(a)4., F.A.C.]

23. Tests Prior to Permit Renewal: Prior to renewing air operation permits, performance tests shall be conducted for each combustion turbine to demonstrate compliance with the CO, NOx, PM, VOC and visible emissions standards for normal gas firing, gas firing with power augmentation, gas firing with high temperature peaking, and backup oil firing. Tests for CO, NOx, and VOC emissions shall be conducted concurrently. Tests for PM and visible emissions shall be conducted concurrently. All tests shall be conducted within the 12 months prior to renewing the air operation permit. [Rule 62-297.310(7)(a)3., F.A.C.]

24. Tests After Substantial Modifications: All performance tests required for initial startup shall also be conducted after any substantial modification and appropriate shakedown 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. This does not apply to routine maintenance. [Rules 62-297.310(7)(a)4. and 62-4.070(3), F.A.C.]

25. Combustion Turbine Testing Capacity

    (a) Initial performance tests shall be conducted in accordance with 40 CFR 60.8 and 40 CFR 60.335 for pollutants subject to New Source Performance Standards (NSPS) in Subpart GG for gas turbines.

    (b) Other required performance tests for compliance with standards specified in this permit shall be conducted with the combustion turbine operating at permitted capacity for each method of operation. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average compressor inlet air temperature during the test (with 100 percent represented by a curve depicting heat input vs. compressor 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. ambient 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.

(c) For performance tests conducted when gas firing under the power augmentation mode and under the high temperature peaking mode, the permittee shall document that the combustion turbine was operating under "peak load" for the given ambient conditions. For power augmentation, the steam injection rate shall be no less than 100,000 pounds of steam per hour.

[Rule 62-297.310(2), F.A.C.; 40 CFR 60.335]

CONTINUOUS MONITORING REQUIREMENTS

26. NOx CEMS: The permittee shall install, calibrate, operate, and maintain a CEMS to measure and record NOx and oxygen concentrations in each combustion turbine exhaust stack to meet the requirements of the Acid Rain program and to demonstrate compliance with the NOx standards specified in this permit. 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. The NOx monitoring devices shall comply with the certification requirements, quality assurance procedures, and all other provisions of the Acid Rain monitoring requirements of 40 CFR Part 75. A monitoring plan shall be provided to the Department's Emissions Monitoring Section, EPA Region 4, 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 the following information: CEM equipment specifications, manufacturer, model, type, calibration and maintenance needs, and the proposed location.

    (a) *Installation.* Each CEMS shall be installed, calibrated, and properly functioning prior to the initial performance tests. Each device shall comply with the applicable monitoring system requirements of 40 CFR 75.62.

    (b) *Data Collection.* Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Each valid 1-hour average shall be calculated using at least two valid data points at least 15 minutes apart.

    (c) *Data Reporting.* Data collected by the CEMS shall be used to demonstrate compliance with the emissions standards specified for each 3-hour average. Emissions shall be reported in units of ppmvd corrected to 15% oxygen for each hour of operation. The compliance averages shall be determined by calculating the arithmetic average of three valid 1-hour emission rates. When a monitoring system reports emissions in excess of the standards allowed by this permit, the permittee 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. Notification shall include either a written letter, a phone call, or a fax transmittal to the Compliance Authority. The Department may request a written report summarizing the excess emissions incident. The permittee shall also report excess emissions in a quarterly report as required by this permit.

    (d) *Data Exclusion for Compliance.* Unless prohibited by Rule 62-210.700(4), F.A.C., valid 1-hour monitoring averages shall not include periods of excess emissions due to startup, shutdown, documented malfunction, or the result of tuning as described and limited under Specific Condition 18 of this permit. Because such data may be excluded, the 3-hour average to determine compliance need not consist of *consecutive* 1-hour averages.

(e) *Alternate Methods of Operation.* Each 1-hour monitoring average consisting of any data collected during an alternate method of operation (oil firing, power augmentation, or peaking) shall be attributed entirely to the alternate method of operation. For each 3-hour average consisting of more than one method of operation, compliance shall be determined by prorating each emission standard based on the number of 1-hour averages represented. In event of a CEMS malfunction or occurrence of excess emissions while operating in the power augmentation or peaking modes, the permittee shall immediately cease power augmentation or peaking and revert to normal gas firing or shut down the combustion turbine.

[Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-212.400(BACT), and 62-297.520, F.A.C.; 40 CFR 60.7; 40 CFR 75]

RECORDS

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

(a) The permittee shall obtain data sheets from the vendor indicating the average sulfur content of the natural gas being supplied by the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or equivalent methods.

(b) The permittee shall obtain data sheets from the vendor indicating the quantity and sulfur content of the distillate oil for each shipment delivered. Methods for determining the sulfur content of distillate oil shall be ASTM D 2880-71 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), natural gas supplier data or the natural gas sulfur content referenced in 40 CFR 75 Appendix D. The analysis may be performed by the permittee, a service contractor retained by the permittee, 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 CFR 60.335 or 40 CFR 75 are used to determine the fuel sulfur content for compliance with the SO_2 standard in 40 CFR 60.333. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

28. Alternate Monitoring Plan: Subject to EPA approval, the following alternate monitoring may be used to demonstrate compliance with the monitoring requirements of 40 CFR 60, Subpart GG.

(a) Data collected from the NOx CEM shall be used in lieu of the water-to-fuel monitoring system required for reporting excess emissions in accordance with 40 CFR 60.334(c)(1) of NSPS, Subpart GG.

(b) 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.

(c) 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:

(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 the Authorized Representative, that commits to using a primary fuel of pipeline-supplied natural gas containing no more than 20 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 the 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]

29. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the hours of each mode of operation and the fuel consumption for each combustion turbine. The information shall be recorded in a written or electronic log and shall summarize the previous month of operation and the previous 12 months of operation. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three (3) days of a request from the Compliance Authority. [Rule 62-4.160(15), F.A.C.]

REPORTS

30. Quarterly Excess Emissions Reports: Following the NSPS format provided in Appendix XS of this permit, periods of startup, shutdown and malfunction shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. Within 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. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

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

EU ID No.	Emission Unit Description
13	Two Natural Gas Fuel Heaters: Each gas fuel heater is fired with a maximum heat input of 23.71 mmBTU per hour of natural gas.
14	Oil Storage Tank: 2.1 million-gallon storage tank supplies low sulfur distillate oil as a backup fuel to simple cycle combustion turbine Nos. 8A and 8B.

RULE APPLICABILITY

1. NSPS Subpart Kb Applicability: NSPS Subpart Kb applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(a)]

2. Exemption from Portions of NSPS Subpart Kb: Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, *except* for the record keeping requirements specified below. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.110b(c)]

PERFORMANCE RESTRICTIONS

3. Equipment: The permittee is authorized to install, operate, and maintain the following emissions units and supporting equipment: two gas fuel heaters fired solely with natural gas (23.71 mmBTU per hour) designed to heat the natural gas supplied to simple cycle combustion turbines 8A and 8B; and one 2.1 million gallon distillate oil storage tank designed to provide low sulfur distillate oil to simple cycle combustion turbines 8A and 8B. [Applicant Request]

4. Hours of Operation: The hours of operation for the gas fuel heaters and distillate oil storage tank are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

5. Good Combustion: Visible emissions of 5% opacity or less from the gas fuel heaters shall be an indicator of good combustion as determined by EPA Method 9. If visible emissions are greater than 5% opacity, the permittee shall investigate the cause, take appropriate corrective actions, and document the incident. This condition does not impose any initial or periodic testing. [Rules 62-4.070(3) and 62-210.700(4), F.A.C.; 40 CFR 60, Appendix A]

RECORDS

6. Records: For purposes of reporting in the Annual Operating Report, the permittee shall keep records sufficient to document the annual amount of natural gas fired in the gas fuel heaters and the annual throughput of distillate oil for the storage tank . [Rule 62-210.370(3), F.A.C.]

7. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage tank. Records shall be retained for the life of the facility. [Rule 62-204.800(7)(b)16., F.A.C.; 40 CFR 60.116b(a) and (b)]

SECTION IV.

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
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.

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

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

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

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

<u>New Permit Numbers</u>:

Example:	Permit No. 099-2222-001-AC or 099-2222-001-AV	
Where:	AC	- identifies the permit as an Air Construction Permit
	AV	- identifies the permit as a Title V Major Source Air Operation Permit
	099	- identifies the specific county that project is located in
	2222	- identifies the specific facility
	001	- identifies the specific permit project

<u>Old Permit Numbers</u>:

Example:	Permit No. AC50-123456 or AO50-123456	
Where:	AC	- identifies the permit as an Air Construction Permit
	AO	- identifies the permit as an Air Operation Permit
	123456	- identifies the specific permit project

FPL MARTIN POWER PLANT - MARTIN COUNTY
Project No. 0850001-008-AC (PSD-FL-286)
New EUs 011 - 014: Addition of Two New Simple-Cycle Gas Turbines

1.0 EXISTING FACILITY

The existing FPL Martin Power Plant currently consists of four electrical generating units. Fossil fuel-fired steam electric generators Nos. 1 and 2 (800 MW each) were built in the 1970's are fired with low sulfur residual oil and natural gas. Combined cycle Nos. 3A, 3B, 4A, and 4B are General Electric Model 7F combustion turbines (170 MW each) plus heat recovery steam generators. Each pair (3A/3B and 4A/4B) shares a common steam-electrical turbine (160 MW each). Completion of the two new 170 MW simple cycle combustion turbines will bring the electric power generation to a nominal 2940 MW.

2.0 PROJECT DESCRIPTION

The applicant, Florida Power and Light, proposes to install two new simple cycle combustion turbines, two gas-fired natural gas fuel heaters, a common distillate oil storage tank, and associated equipment at the existing FPL Martin Power Plant. Each combustion turbine consists of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, and an exhaust stack that is 60 feet tall and 22 feet in diameter. Each unit is designed to produce a nominal 170 MW of electrical power fired with natural gas as the primary fuel and low sulfur distillate oil as a backup fuel. The applicant proposes to limit use of the gas turbines as "peaking units" by restricting the allowable operation to no more than 3390 hours per year per unit. Of this total, no more than 500 hours per year would occur when firing low sulfur distillate oil as a backup fuel. In addition, the applicant requests approval for "power augmentation" and "peaking" as authorized high power modes of operation when firing natural gas. The high power modes result in higher CO and NOx emissions than those for normal gas firing and are discussed in more detail under the NOx BACT Determination. Of the allowable 3390 hours per year, no more than 500 hours per year would occur when operating in the high power modes. The applicant proposes dry low-NOx (DLN) combustion technology to control nitrogen oxide emissions and combustion design with clean fuels to minimize emissions of other pollutants.

As a result of fuel combustion, this project will emit emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Emissions of CO, NOx, PM/PM_{10}, and SO_2 exceed the Significant Emissions Rates established in Rule 62-212.400, F.A.C. for Prevention of Significant Deterioration (PSD) of Air Quality. Therefore, the Department must establish emissions standards that represent a determination of Best Available Control Technology (BACT) for these pollutants. The permit will also include emissions standards for VOC as a PSD-synthetic minor pollutant. This document presents a detailed description of the PSD applicability analysis and BACT determination. Additional information regarding the overall project, air quality impacts, and rule applicability are provided in the Technical Evaluation and Preliminary Determination that accompanied the Department's Intent to Issue Permit package.

An initial Intent to Issue Permit package was mailed to the applicant on May 5, 2000. The applicant requested several changes and provided additional supporting information. The primary changes were the addition of high temperature peaking for 60 hours per year, a reduction of power augmentation to 400 hours per year, revised stack dimensions, NOx compliance demonstrated with Acid Rain CEMS data, fuel consumption limits equivalent to hours of operation limits, addition of a particulate matter limit with testing, a visible emissions limit of 10% opacity for both gas and oil firing, and minor revisions to the maximum heat input and power output based on General Electric data. Revisions of the BACT determination are noted with the revision date.

3.0 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 or has the potential to emit:

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

The existing facility is classified as a fossil fuel-fired steam electric plant, which is one of the source categories listed in Table 62-212.400-2, F.A.C. Because potential emissions of at least one pollutant exceed 100 tons per year, the existing facility is considered a major source of air pollution with respect to PSD. For new projects at PSD major sources, each pollutant is reviewed for PSD applicability based on emissions 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 Martin 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 based on information provided by the applicant.

Pollutant	Project Potential Emissions[a] (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? Table 62-212.400-2, F.A.C.	Subject To BACT?
CO	170	100	Yes	Yes
NOx	423	40	Yes	Yes
PM	38	25	Yes	Yes
PM_{10}	38	15	Yes	Yes
SAM	5	7	No	No
SO_2	64	40	Yes	Yes
VOC	13	40	No	No

[a] - For each gas turbine, potential emissions were estimated by the applicant based on 2390 hours per year of normal gas firing, 500 hours per year of gas firing with high power mode, and 500 hours per year of distillate oil firing as a backup fuel. Potential emissions also include emissions from two gas fuel heaters and a distillate oil tank.

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}, and SO_2.

4.0 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 stated policy for pollution prevention.

5.0 PROJECT ANALYSIS AND BACT DETERMINATIONS

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

- The National Park Service made no adverse comments on the application;
- EPA Region 4 provided comments on the initial Draft Permit on May 19, 2000;
- DOE web site information on Advanced Turbine Systems Project;
- General Electric technical product literature regarding DLN emissions and the gas turbine control system;
- Englehard equipment cost quotes for a CO oxidation catalyst and selective catalytic NO_x reduction;
- Alternative Control Techniques Document – NO_x Emissions from Stationary Gas Turbines (1993);
- Proposed AP-42 changes to Section 3.1 for gas turbines (10/96 draft and 5/98 revision);
- Recently issued Department permits for the General Electric Model PG7241(FA) gas turbine;
- Goal Line Environmental Technology Website: http://www.glet.com; and
- Catalytica Website – www.catalytica-inc.com

In addition, the Department reviewed recent BACT determinations posted in EPA's RACT/BACT/LAER Clearinghouse for consistency. The following table provides a summary of the most recent determinations similar projects in the United States.

Brief Summary of Recent CO, NOx, and PM BACT Determinations for Similar Simple Cycle, Gas Fired Units

Project Location	Unit MW	Date	Technology	CO Limit ppmvd @ 15% O2	NOx Limit Ppmvd @ 15% O2	PM Limit	Comments
FPL Martin Plant, FL	170	04/00, D	DLN	9 15 w/PA	10, 3-hr CEMS 12 w/PA, 3-hr CEMS	5% Opacity	500 hr/yr oil firing 500 hr/yr PA mode
Palmetto Power, FL	170 MW WH 501FD	03/00, D	DLN	Initial: 25 (12 months) Final: 15	15, 3-hr CEMS	10% opacity	No oil firing
Desoto Power, FL	170 MW GE 7FA	03/00, D	DLN	12	9, 24-hr CEMS	10% opacity	1000 hr/yr oil firing
Shady Hills Pasco, FL	170 MW GE 7FA	01/00, P	DLN	12	9, 24-hr CEMS	10% opacity	1000 hr/yr oil firing
Vandolah Hardee, FL	170 MW GE 7FA	11/99, P	DLN	12	9, 24-hr CEMS	10% opacity	1000 hr/yr oil firing
Oleander Brevard, FL	170 MW GE 7FA	11/99, P	DLN	12	9, 24-hr CEMS	10% opacity	1000 hr/yr oil firing
JEA Baldwin, FL	170 MW GE 7FA	10/99, P	DLN	12	10.5, 24-hr CEMS	10% opacity	750 hr/yr oil firing
Reliant Osceola, FL	170 MW GE 7FA	11/99, P	DLN	10.5	10.5, 24-hr CEMS	10% opacity	750 hr/yr oil firing
TEC Polk Power, FL	165 MW GE 7FA	10/99, P	DLN	15	10.5, 24-hr CEMS	10% opacity	750 hr/yr oil firing
Dynegy Heard, GA	170 MW WH 501F	10/99, P	DLN	25	15	10% opacity	No oil firing
Tenaska Heard, GA	170 MW GE 7FA	12/98, P	DLN	15	15	Unknown	720 hr/yr oil firing
Calvert City, KY	170 MW GE 7FA	1999, D	WI	30, base load 90, other	25	Unknown	? hr/yr oil firing
Mid-GA Cogen	119 MW WH 501D5A	06/98, O	DLN, SCR	10	9	18 lb/hr	? hr/yr oil firing
Dynegy Reidsville, NC	180 MW WH 501F	06/99, P	DLN	25	Initial: 25 Final: 15 (by 2002)	6 lb/hr	1000 hr/yr oil firing
Lyondell Harris, TX	160 MW WH 501F	11/99, P	DLN	25	25	Unknown	No oil firing
Southern Energy, WI	175 MW GE 7FA	01/99, P	DLN	12	15, 1-hr 12, 24-hr	18 lb/hr	800 hr/yr oil firing
RockGen Cristiana, WI	175 MW GE 7FA	01/99, P	DLN	12	15, 1-hr 12, 24-hr	18 lb/hr	800 hr/yr oil firing
Lakeland, FL	250 MW WH 501G	07/98, P	DLN, HSCR	25	Initial: 25 Final: 9 (by 2002)	10% opacity	250 hr/yr oil firing

Abbreviations:

Manufacturer	Date	Controls	Other
GE – General Electric	D – Draft	DLN – Dry Low-NOx	LAER – Lowest Achievable Emission Rate
WH – Westinghouse	O – Operating	HSCR – Hot Selective Catalytic Reduction	CEMS – Continuous Emissions Monitoring System
ABB – Asea Brown Boyan	P – Permitted	SCR - Selective Catalytic Reduction	PA – Power Augmentation (Steam Injection)
		WI = Water or Steam Injection	

Notes. All data presented is for > 100 MW simple cycle units firing natural gas. The Lakeland project is permitted for combined cycle operation with separate limits for simple cycle mode. The remaining projects are restricted to intermittent simple cycle operation.

5.1 NITROGEN OXIDES (NOX)

{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 associated with combustion turbines, the primary pollutant of concern 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 in the range of 150 ppmvd @ 15% oxygen. The New Source Performance Standard (40 CFR 60, Subpart GG) regulating NOx emissions from stationary gas turbines is 75 ppmvd corrected to 15% oxygen and 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 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 due to the inherently lower thermal NOx portion. *Fuel-bound NOx* forms from the combustion of fuels containing bound nitrogen. This phenomenon is not important when combusting natural gas or distillate oil fuels, which contain negligible fuel-bound nitrogen.

Other factors that may also increase NOx emissions are combustion turbine loads and compressor inlet air conditions. In general, NOx emissions from gas turbines with dry low-NOx systems fluctuate during startup to approximately 50% to 70% of base load after which emissions begin to stabilize. This can be due to warming up a cold unit as well as the combustor air/fuel staging needed to achieve lean premix conditions suitable for dry low-NOx emissions. Higher NOx emissions also result from low ambient inlet temperatures. Cold air is denser than hot air, so the mass flow rate of air will be greater on a cold day than a hot day. Denser air requires more fuel combustion to raise the temperature of the higher mass, providing increased power production as well as emissions. Most new gas turbine projects take advantage of this concept by including evaporative coolers that will provide a slight power boost during warm weather. The evaporative coolers inject small amounts of water at high pressure which evaporate and cool the ambient compressor inlet air. Again, firing more fuel to raise the temperature of the higher mass increases power production nearer to 100% of base load. However, emissions increases are relatively small and the maximum emissions rate still occurs on the coldest predicted day, usually less than 32° F.

<u>Identification of Control Technologies</u>

The following technologies were identified as potentially applicable for the control of NOx from combustion turbines. A brief description of each technology is included with an estimated control efficiency based on an uncontrolled conventional gas turbine with NOx emissions of 150 ppmvd @15% O_2.

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. Wet injection results in 60% to 80% control efficiencies.

Dry Low-NOx Combustor Design (DLN): The U.S. Department of Energy has provided millions of dollars of funding to a number of combustion turbine manufacturers to develop inherently lower 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. Typically, this occurs 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. Due to the intricate air and fuel staging necessary for dry low-NOx combustor technology, the gas turbine control system becomes a very important component of the overall system. DLN systems result in control efficiencies of 80% to 95%. DLN technology research for oil firing continues.

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) with control efficiencies up to 98%.

"Hot" Selective Catalytic Reduction (SCR): Due to temperature limitations of conventional SCR catalysts, vendors have developed specially formulated catalysts designed to further the reduction reaction at temperatures up to 1025°F. Also, cooling air can be added to reduce the gas temperatures to the appropriate design range. Hot SCR can deliver NOx control efficiencies of 70% to 95%.

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. For boilers, SNCR has achieved control efficiencies in the 40% to 60% range.

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 with variable control efficiencies.

SCONOx™: This technology is a NOx and CO control system offered by Goal Line Environmental Technologies and ABB for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce CO and NOx emissions using an oxidation/absorption/regeneration cycle. The required operating temperature range is between 300°F and 700°F which requires a HRSG for use with a gas turbine. SCONOx™ can achieve control efficiencies in the 90% to98% range.

XONON™: This 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. This technology has been demonstrated, but will be specific to each manufacturer and model of gas turbine. It is anticipated that control efficiencies will be in the 80% to 95% range.

Applicant's Proposed NOx Controls

For a simple cycle gas turbine, the applicant recognized "hot" selective catalytic reduction as the top control option followed by dry low-NOx (DLN) combustion technology and water injection. For this project, General Electric guaranteed NOx emissions of 9 ppmvd @ 15% oxygen with DLN technology for gas firing and 42 ppmvd @ 15% oxygen for oil firing with water injection. The applicant estimated that hot SCR could reduce these emissions rates to 4 ppmvd @ 15% oxygen for gas firing with DLN and 16 ppmvd @ 15% oxygen for oil firing with water injection. However, the applicant makes the following claims regarding additional adverse impacts.

Energy Impacts: Hot SCR would result in a pressure loss across the catalyst resulting in an energy penalty of approximately 0.5%. Significant energy costs are associated with operating the hot SCR system. The lost energy would be equivalent to 370,000 mmBTU per year or about 37 mmCF per year of natural gas.

Environmental Impacts: The maximum predicted NOx concentrations resulting from DLN technology are well below the PSD increment of 25 ug/m^3 (annual average), the AAQS of 100 ug/m^3 and less than 20% of the significant impact level. Additional NOx reduction from requiring hot SCR would not be significant. Hot SCR would generate additional emissions of ammonia (> 47.7 tons per year per unit) and ammonium sulfates (>6.6 tons per year per unit). Power lost to the hot SCR system would have to be generated by other less efficient units resulting in increased emissions. CO_2 emissions would greatly increase as a result of hot SCR. Spent catalyst may have to be handled and treated as hazardous wastes. Ammonia handling and storage involves inherent risks and safety issues.

Economic Impacts: In a revised cost analysis, the applicant estimated that installation of hot SCR would result in capital costs of $5,189,813 and annualized costs of $1,640,906 per year. The applicant assumed a hot SCR system would remove an additional 127 tons of NOx per year (4 ppmvd @ 15% O_2 and 61% control efficiency) over a DLN only system at 10.5 ppmvd @15% O_2. This resulted in an incremental cost effectiveness for hot SCR of $12,943 per ton of NOx removed.

The applicant rejected hot SCR primarily based on unreasonable costs associated with controlling the low available tonnage of NOx emissions available from this project. This is primarily due to the inherently low emissions of the General Electric Model PG7241(FA) gas turbine as well as the applicant's request to restrict operation to that of a peaking unit (3390 hours per year). Therefore, the applicant proposed the following NOx limit as BACT for this project:

Applicant's Proposed NOx BACT

Normal Gas Firing Mode: 10.5 ppmvd @ 15% O_2 achieved by DLN technology

Gas Firing With a "High Power Mode": 15.0 ppmvd @ 15% O_2 achieved by DLN

Distillate Oil Firing Mode: 42.0 ppmvd @ 15% O_2 achieved by water injection

The applicant concludes by stating that DLN combustion provides the most cost effective alternative, is pollution preventing, results in low ambient impacts, and is consistent with recent BACT determinations for similar simple cycle combustion turbines made by Florida and other states.

Department's NOx BACT Determination (Revised 06/06/00)

The Department rejected several previously mentioned control options for the following reasons.

- *Conventional Selective Catalytic Reduction (SCR)* was rejected because the gas turbine exhaust temperature of 1100°F is above the design limit (850° F) for this technology.
- *Selective Non-Catalytic Reduction (SNCR)* was rejected because the gas turbine exhaust temperature of 1100°F is below the design limit (1600° F) for this technology.
- *Non-Selective Catalytic Reduction (NSCR)* was rejected because the oxygen content of the combustion turbine exhaust (13% to 15%) is above the design limit (3%) for this technology.
- *SCONOx*^{TM} was rejected because the gas turbine exhaust temperature of 1100°F is above the design limit (700° F) for new technology.
- *XONON*^{TM} because this emerging technology is model-specific and not yet commercially available for the General Electric Model PG7241(FA).

The Department also recognizes hot selective catalytic reduction (hot SCR) combined with dry low-NOx (DLN) combustion technology as the top control option followed DLN technology alone, and water injection for oil firing. However, the Department disagrees with several of the applicant's statements regarding adverse impacts.

Energy Impacts: 'Installation of hot SCR *would* result in a total energy penalty of approximately 0.5% mostly due to the pressure drop across the catalyst bed. For SCR systems, EPA (1993) bases energy consumption to operate the SCR system on the pressure drop, neglecting other energy costs.

Environmental Impacts: The Department gives no consideration to the applicant's comment that there is no environmental benefit from add-on controls because NOx levels are already below the PSD increments, significant impact levels and AAQS. Ambient impacts from the project are only considered in the air quality analysis and carry no weight in making a BACT determination. Hot SCR would result in some ammonia "slip" or emissions of unreacted ammonia. However, estimating ammonia, ammonia sulfate, and PM_{10} emissions based on 9-10 ppm is misleading. Manufacturers of SCR systems typically design and guarantee systems with a 9 to 10 ppm of ammonia slip, but this is based on the end of the catalyst life and is not representative of actual emissions. An operator would attempt to reduce ammonia slip whenever possible to reduce operating costs. Storage and handling of ammonia does present additional risks, but these risks can be safely managed as evidenced by the numerous existing SCR systems, industrial ammonia refrigeration systems, fertilizer plants, etc.

Economic Impacts: In general, the Department agrees that adding hot SCR to the General Electric Model PG7241(FA) gas turbine with DLN controls would result in a cost effectiveness in the range of $10,000 to $13,000 per ton of NOx removed. The high costs are partially the result of substantial expenses related to equipment, installation, maintenance, catalyst replacement, energy consumption, and ammonia usage. However, the Department also recognizes that the analysis is significantly influenced by three critical constraints: the applicant's request for simple cycle operation only, the applicant's request for restricted operation as peaking units (3390 hours per year per gas turbine), and the inherently low emissions of the General Electric Model PG7241(FA) gas turbine. Should the applicant ever request operation of these gas turbines as base load units, conversion to combined cycle operation, or the substitution of a another gas turbine model, it is essential that the NOx BACT determination be reevaluated.

Based on the above discussion, the Department also rejects hot SCR as not cost effective for the project as limited by the applicant's requests. Therefore, the dry low-NOx combustion technology designed into the General Electric Model PG7241(FA) is determined to represent the best available control technology for this project. Dry low NOx combustion is pollution preventing in nature, avoids emissions of several non-regulated pollutants such as ammonia, and is consistent with recent BACT determinations made in Florida and other states.

The Department evaluated the applicant's request for two "high power modes" of operation when firing natural gas, which included steam injection for power augmentation and raising the combustion reference temperature for additional peaking power. The high power modes can result in NOx emissions that are higher than the normal gas-firing mode. Initially, the Department accepted the request for limited steam injection, but rejected the request for high temperature peaking primarily due to the high number of operating hours requested, and the potential for degradation of the unit. However, as part of the request for a revised Draft Permit, the applicant provided additional information from General Electric regarding the emissions performance and adjustments made by the automated gas turbine control system to achieve high temperature peaking. Also, the applicant reduced the request for peaking to 60 hours per year and power augmentation to 400 hours per year, which results in no increase in annual emissions. High temperature peaking is expected to result in lower CO and VOC emissions.

After consideration of the new information provided, the Department establishes the following NOx standards as BACT for this project:

NOx BACT Determination

Normal Gas Firing: 9.0 ppmvd @ 15% O_2 based on a 3-hour initial and annual test average (to ensure that the units remain tuned for maximum NOx reduction). NOx emissions shall also not exceed 10.0 ppmvd @ 15% O_2 based on a 3-hour CEMS average achieved by DLN combustion. (The slightly higher continuous emissions limit with a short-term average was established to compensate for operation as a peaking unit. The mass emissions limit will be based on 10 ppmvd @15% O_2 and the most recent projects for the Model PG7241(FA) gas turbine.)

Gas Firing With Power Augmentation: 12.0 ppmvd @ 15% O_2 based on a 3-hour CEMS average achieved by DLN combustion. (A separate, short-term continuous emissions limit was established for operation in the power augmentation mode to allow maximum power generation during the hot summer months of high demand. Operation in this mode will be restricted to no more than 400 hours per year.)

Gas Firing With Peaking: 15.0 ppmvd @ 15% O_2 based on a 3-hour CEMS average achieved by DLN combustion. (A separate, short-term continuous emissions limit was established for operation in the peaking mode to provide limited short-term peaking power. Operation in this mode will be restricted to no more than 60 hours per year.)

Distillate Oil Firing: 42.0 ppmvd @ 15% O_2 based on a 3-hour CEMS average achieved by water injection. (DLN combustion technology is ineffective when firing distillate oil as a backup fuel. Operation when oil firing with water injection will be restricted to no more than 500 hours per year.)

Corresponding mass emission limits will also be established for each method of operation. The Department will include specific conditions in the permit to address the following items:

- Each combustion turbine shall operate only in simple cycle mode. Conversion to combined cycle operation will require a permit modification.
- Each combustion turbine shall operate no more than 3390 hours during any consecutive 12 months. Of the 3390 hours per year of allowable operation, the combustion turbine shall not fire oil for more than 500 hours during any consecutive 12 months. Of the 3390 hours per year of allowable operation, the combustion turbine shall not operate in the power augmentation mode for more than 400 hours during any consecutive 12 months. Alternatively, the Department may establish equivalent amounts of fuel consumption limits based on the maximum heat inputs at a compressor inlet air temperature of 59° F, which was the basis of the potential emissions for this project. To relax any of these conditions will require a permit modification.
- Each combustion turbine shall operate below 50% base load for no more than two hours per day.

This BACT determination is much more stringent than the standards of NSPS, Subpart GG. Compliance with the BACT emissions standards shall be demonstrated by conducting initial and annual performance tests in accordance with EPA Method 20. In addition, the permittee shall install, calibrate, operate, and maintain a certified NOx continuous emissions monitor (CEMS) to demonstrate continuous compliance with the BACT limits.

5.2 CARBON MONOXIDE (CO)

Discussion of CO Emissions

Emissions of carbon monoxide (CO) will result from incomplete fuel combustion while operating the combustion turbine. In general, CO emissions are inversely proportional to NOx emissions for gas turbines. However, new advanced combustor designs have also been able to lower CO emissions concurrently with NOx emissions. It is noted that General Electric has guaranteed CO emissions performance for the Model PG7241(FA) at 9.0 ppmvd @ 15% O_2 for several projects.

Applicant's Proposed CO BACT

The applicant identified two control options that are technically feasible and commercially available for combustion turbines: an oxidation catalyst and efficient combustor design. An oxidation catalyst consists of a noble metal catalyst section incorporated into the combustion turbine exhaust. The catalyst promotes oxidation of CO to carbon dioxide (CO_2) at much lower temperatures (650°F to 1150°F) than under normal conditions. The control efficiency is primarily a function of gas residence time and can exceed 90%. For this project, the exhaust gas temperature of 1100°F is in the proper design range. The applicant recognized an oxidation catalyst as the top control. However, the applicant asserts that an oxidation catalyst would result in 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 approximately 2 inches of water column. The lost energy is equivalent to approximately 11,000 mmBTU per year.

Environmental Impacts: The air quality impacts of a DLN system are well below the significant impact levels for CO. There is no additional environmental benefit gained by installing an oxidation catalyst. The air quality impacts of a DLN system alone are well below the PSD significant levels and less than 0.1% of the AAQS.

Economic Impacts: In a revised cost analysis, the applicant estimated that installation of an oxidation catalyst would result in capital cost of $1,673,295 per unit. The annualized cost was estimated to be $561,759 per year. It was assumed that the catalytic system could remove an additional 74 tons of CO per year (90% control efficiency) over a DLN only system at 12 ppmvd @ 15% O_2. This results in a cost effectiveness for the oxidation catalyst of $7595 per ton of CO removed. No such costs would be associated with the efficient combustion of the Model PG7241(FA) gas turbine.

The applicant rejected the oxidation catalyst as not being cost effective and not producing any measurable reductions in air quality impacts. The applicant proposed the following as the best available controls:

Applicant's Proposed CO BACT

Normal Gas Firing Mode: 12.0 ppmvd @ 15% O_2 achieved by DLN technology

Gas Firing With a "High Power Mode": 15.0 ppmvd @ 15% O_2 achieved by DLN

Distillate Oil Firing Mode: 20.0 ppmvd @ 15% O_2 achieved by water injection

Department's CO BACT Determination

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

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

Environmental Impacts: 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: In general, the Department agrees that the addition of an oxidation catalyst would result in a cost effectiveness in the range of $6000 to $8000. The high costs are partially the result of substantial expenses related to equipment, installation, maintenance, catalyst replacement, and energy consumption. Similar to the discussion for NOx controls, the Department recognizes that the cost analysis has been significantly constrained for this project by the applicant's requested operation.

The Department also rejects the addition of an oxidation catalyst as not being cost effective for the project as limited by the applicant's requests. Therefore, the Department establishes the following CO standards as BACT for this project:

CO BACT Determination

Gas Firing, Normal and Peaking: 9.0 ppmvd @ 15% O_2 based on a 3-hour initial and annual test average achieved by DLN combustion.

Gas Firing With Power Augmentation: 15.0 ppmvd @ 15% O_2 based on a 3-hour initial and annual test average achieved by DLN combustion.

Distillate Oil Firing: 20.0 ppmvd @ 15% O_2 based on a 3-hour initial and annual test average achieved by water injection.

Corresponding mass emission limits will also be established for each mode of operation. Compliance with the BACT emissions standards shall be demonstrated by conducting initial and annual performance tests in accordance with EPA Method 20. The Department will include the specific conditions identified under NOx controls to ensure that a switch to based loaded units, conversion to combined cycle operation, or substitution with a different make or model of gas turbine will trigger the appropriate permitting actions.

5.3 PARTICULATE MATTER (PM/PM_{10}) AND SULFUR DIOXIDE (SO_2)

Discussion of PM, PM_{10} and SO_2 Emissions

Emissions of particulate matter and sulfur dioxide will result from the combustion of the natural gas and low sulfur distillate fuel. Limited testing indicates that most of the particulate matter emitted from the combustion turbine will be less than 10 microns in diameter (PM_{10}). Particulate matter emissions increase with incomplete fuel combustion as well as with higher concentrations of ash, sulfur, and trace elements in the fuel. Sulfur dioxide emissions will increase with higher fuel sulfur contents. However, natural gas and very low sulfur distillate oil are clean fuels containing little ash, sulfur, or other contaminants.

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

The applicant indicated that a review of the EPA RACT/BACT/LAER Clearinghouse did not reveal any post-combustion controls were required for any gas/oil fired combustion turbine projects. Uncontrolled particulate matter emissions are estimated to be less than 0.01 grain per dscf of exhaust gas, which is typically specified as controlled emissions from a baghouse. The use of natural gas as the primary fuel and the restricted use (500 hours per year or less) of very low sulfur (0.05% sulfur by weight or less) distillate oil will result in very low emissions of SO_2.

Applicant's Proposal for PM, PM_{10}, and SO_2 BACT

Each combustion turbine shall be fired primarily with pipeline-quality natural gas containing no more than 1 grain of sulfur per 100 SCF. Low sulfur distillate oil containing no more than 0.05% sulfur by weight shall be fired only as a backup fuel for no more than 500 hours per year.

The applicant indicated that recent BACT determinations for large combustion turbine projects specified such clean fuels as BACT.

Department's PM, PM_{10}, and SO_2 BACT Determination (Revised 06/06/00)

The Department identifies several available control technologies for particulate matter removal including centrifugal collectors, electrostatic precipitators, fabric filters, and wet scrubbers. Similarly, there are scrubbers available to further reduce SO_2 emissions. The applicant proposes to fire pipeline-quality natural gas as the primary fuel and to fire a restricted amount of very low sulfur distillate oil as the backup fuel. The Department agrees that further control of particulate matter and sulfur dioxide emissions with one of these add-on control technologies would be cost prohibitive due to the very low uncontrolled emissions. The fuel sulfur contents proposed are clearly more stringent than the NSPS standard of 0.8% sulfur by weight. The specification of clean fuels constitutes a pollution prevention technique and is given favorable consideration in this case. In addition, a fuel specification for sulfur limits the maximum potential emissions that the gas turbine could emit. The Department establishes the following work practice standards as BACT for PM, PM_{10}, and SO_2.

PM, PM_{10}, and SO_2 BACT

EPA Region 4 commented that the BACT standard for particulate matter should include a mass emissions limit and at least an initial test. The applicant requested that the visible emissions rate for gas firing with the dual fueled combustion be raised to 10%. At this time, the Department is unable to adequately document that the measurement of particulate matter emissions from large gas turbines is technically infeasible. Therefore, the Department revised the initial Draft Permit to include the following standards.

Particulate Matter. When firing natural gas under any method of operation, particulate matter emissions from each combustion turbine shall not exceed 9.0 pounds per hour based on a 3-hour test average conducted at base load. When firing distillate oil, particulate matter emissions from each combustion turbine shall not exceed 17.0 pounds per hour based on a 3-hour test average conducted at base load. The permittee shall demonstrate compliance by conducting tests in accordance with EPA Method 5 (or 17, if applicable).

Fuel Specifications. Emissions of PM, PM_{10}, and SO_2 shall be limited by the use of pipeline-quality natural gas containing no more than 1 grain per standard cubic feet as the primary fuel and restricted use of No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight as a backup fuel. The fuel specifications are work practice standards established as BACT limits for PM, PM_{10}, and SO_2 emissions. Because the maximum potential SO_2 emissions are limited by the fuel sulfur specification, no emissions performance testing will be required. The permittee shall demonstrate compliance with the fuel sulfur limits by maintaining the records specified in this permit.

VE Standard. When firing natural gas or distillate oil, visible emissions from each combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The visible emissions limits are work practice standards established as BACT limits for PM and PM_{10} emissions. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit.

5.4 PSD SYNTHETIC MINOR LIMITS

Volatile Organic Compounds: VOC emissions result from incomplete combustion when firing natural gas and low sulfur distillate fuel oil. Large combustion turbines such as the Model PG7241(PA) offer high temperatures with very efficient combustion resulting in low levels of volatile organic compounds. Therefore, the Department establishes the following standards as PSD synthetic minor limits for VOC:

Gas Firing, All Modes: 1.5 ppmvw
Oil Firing, Backup Fuel: 3.0 ppmvw

Corresponding mass emission limits will also be established for each mode of operation. These standards limit the potential annual emissions of VOC to less than the Significant Emission Rate of 40 tons per year. Initial compliance with the VOC emissions standard shall be demonstrated by conducting performance tests in accordance with EPA Methods 25 or 25A. EPA Method 18 may be used as an optional method to account for the non-regulated methane fraction of the measured VOC emissions. Compliance shall also be demonstrated during the fiscal year prior to renewing each operation permit.

6.0 OTHER EMISSIONS UNITS

6.1 TWO NATURAL GAS FUEL HEATERS

Each fuel heater is fired with a maximum heat input of 23.71 mmBTU per hour of natural gas. For continuous operation, total emissions of PM/PM_{10}, SO_2 and VOC are each less than 1 ton per year and emissions of CO and NOx are each less than 10 tons per year. These emissions represent much less than 3% of the total controlled emissions for this project. For these small emissions units, the Department determines that efficient combustion and the firing of natural gas to be BACT.

6.2 OIL STORAGE TANK

A common storage tank (2.1 million gallon) supplies low sulfur distillate oil as a backup fuel to simple cycle combustion turbines Nos. 8A and 8B. Because VOC emissions are estimated to be less than 1 ton per year, the Department determines BACT to be the storage of only distillate fuel oil in this tank and compliance with NSPS Subpart Kb which requires the permittee to keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage tank. These records shall be retained for the life of the facility.

7.0 SUMMARY OF DEPARTMENT'S BACT DETERMINATION

7.1 BACT EMISSION LIMITS

The following table summarizes the BACT standards determined by the Department for this project. Similar limits will be specified as conditions of the permit.

EU-011 and 012: General Electric Model PG7241(FA) Combustion Turbines

Pollutant	*Fuel/Mode*	*Emission Standard*	*Compliance Method*
		BACT Emission Standard	
CO	Gas, Normal And Peaking	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 32.0 lb/hr, 3-hr test avg.	Base load: initial and annual tests
	Gas W/PA	15.0 ppmvd @ 15% O_2, 3-hr test avg. and 47.0 lb/hr, 3-hr test avg.	Peak load: initial and annual tests
	Oil	20.0 ppmvd @ 15% O_2, 3-hr test avg. and 68.0 lb/hr, 3-hr test avg.	Base load: initial and annual tests
NOx	Gas, Normal	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 66.0 lb/hr, 3-hr test avg.	Base load: initial and annual tests
		10.0 ppmvd @ 15% O2, 3-hr CEMS avg.	All loads, certified CEM data
	Gas W/PA	12.0 ppmvd @ 15% O_2, 3-hr test avg. and 82.0 lb/hr, 3-hr test avg.	Peak load: initial and annual tests
		12.0 ppmvd @ 15% O2, 3-hr CEMS avg.	All loads, certified CEM data

NOx (Cont'd)	Gas W/Peaking	15.0 ppmvd @ 15% O_2, 3-hr test avg. and 105.0 lb/hr, 3-hr test avg. 15.0 ppmvd @ 15% O2, 3-hr CEMS avg.	Peak load; initial/renewal tests All loads, certified CEM data
	Oil	42.0 ppmvd @ 15% O_2, 3-hr test avg. and 334.0 lb/hr, 3-hr test avg. 42.0 ppmvd @ 15% O_2, 3-hr CEMS avg.	Base load; initial and annual tests All loads, certified CEM data
SO_2, PM/PM_{10}	Gas, All Modes	PM ≤ 9.0 lb/hr 1 grain per 100 SCF of natural gas Visible emissions ≤ 10% opacity	Base load; initial/renewal tests Fuel records Base load; initial and annual tests
	Oil	PM ≤ 17.0 lb/hr Distillate oil with ≤ 0.05% sulfur by weight Visible emissions ≤ 10% opacity	Base load; initial/renewal tests Fuel records Base load; initial and annual tests
Synthetic Minor Emission Standard			
VOC	Gas, All Modes	1.5 ppmvw (as methane), 3-hr test avg. and 3.0 lb/hr (as methane), 3-hr test avg.	Base load; initial test and tests prior to renewal of operation permits
	Oil	3.5 ppmvw (as methane), 3-hr test avg. and 7.5 lb/hr (as methane), 3-hr test avg.	Base load; initial test and tests prior to renewal of operation permits

Note: PA means "power augmentation". The mass emission limits were based on 100% base load, maximum heat input, the fuel higher heating values, compressor inlet conditions of 35° F and 20% RH for normal gas and oil firing, and compressor inlet conditions of 80-95° F and 60% RH for gas firing with power augmentation.

According to the applicant, emissions data from General Electric was, "*... adjusted to reflect degradation when the units operate over time and performance improvements beyond that provided for by the manufacturer's guarantee.*" To account for this overall "degradation", the applicant increased the mass flow rate through the turbine by approximately 11%. This resulted in higher fuel consumption and predicted mass emission rates. However, the Department has reviewed many projects for peaking units as well as projects with power augmentation. The Department believes it is inappropriate to permit emissions increases that result from an applicant's choice to operate under conditions that will significantly degrade the unit such that the manufacturer will no longer guarantee emissions or performance. Therefore, the Department developed mass emission limits based on General Electric's maximum emissions performance estimates, similar limits in recent Department permits for the Model PG7241(FA) gas turbine, and the following conditions:

- For normal gas firing and backup oil firing, mass emission limits were based on operation at base load with a compressor inlet air temperature of 35° F.
- For gas firing with power augmentation, mass emissions limits were based on operation at base load with a compressor inlet air temperature of 95° F for NOx, and a compressor inlet temperature of 80° F for CO (worst-case scenarios).
- Information provided by the applicant did not suggest that the gas turbine would have problems complying with GE's guaranteed CO emissions level of 9 ppmvd @ 15% O_2 for normal gas firing.
- For normal gas firing, General Electric data indicates NOx emissions of 61 lb/hour (9 ppmvd @ 15% O_2) at 35° F. The Department allowed 10 ppmvd @ 15% O_2 with compliance demonstrated by CEMS data on a 3-hour block average as opposed to other Department permits containing long-term 24-hour block averages. The Department believes the slightly higher limit combined with the shorter averaging period better defines peaking operation. To account for the increase, the Department considered the following items in establishing the NOx mass emissions limit: the GE mass emission rate at 59° F is 59 lb/hour; the GE mass emission rate at 35° F is 61 lb/hour; and the mass emission limit for the recent Desoto Power project was 64 lb/hour.

The application indicates that recently issued PSD permits specify emissions limits similar to those requested by the applicant. In support of the Department's BACT determination, the following tables offer a comparison of the Department's emissions limits, the applicant's proposed emission limits, and the emission limits specified for a recent similar project (Desoto Power) consisting of General Electric Model PG7241(FA) gas turbines.

Comparison of FPL Martin With Desoto Power

Emissions Per Unit - Gas/Oil Firing

Pollutant	Department's TPY	Applicant's TPY	Desoto Power TPY
CO	67	82	86
NOx	183	208	252
PM/PM_{10}	17	19	20
SAM	< 3	< 3	4
SO_2	33	32	55
VOC	6	6	11

Emissions Per Unit - Gas Only (Including High Power Modes)

Pollutant	Department's TPY	Applicant's TPY	Desoto Power TPY
CO	56	79	72
NOx	113	144	109
PM/PM_{10}	15	17	17
SAM	< 1	< 1	< 1
SO_2	9	9	8
VOC	5	5	5

Comments:

It should be noted that the Desoto Power project allows up to 3390 hours per year of operation with no more than 1000 hours per year of oil firing. The higher emissions are the result of the increased oil firing. In addition, the Desoto Power project also allows up to 12 ppmvd of CO emissions, but did not permit power augmentation.

The gas only case is presented as more typical of actual operations. The Department's draft permit for the proposed FPL Martin project results in approximately 7 tons of NOx per year more than the Desoto Power project. About half of this is the result of limited power augmentation and about half from the slightly higher hourly emission limit. Lower CO emissions are the result of the 9 ppmvd limit established for the FPL Martin project compared to the 12 ppmvd limit specified for the Desoto Power project.

7.2 BACT EXCESS EMISSIONS ALLOWED

1. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, power augmentation, high temperature peaking or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard. [Rule 62-210.700(4), F.A.C.]

2. Excess Emissions Allowed: For each combustion turbine, excess NOx and visible emissions during startup, shutdown, and documented malfunction shall be allowed, providing:

   (a) Operators employ best operational practices to minimize the amount and duration of excess emissions.

   (b) Operation below 50% of base load shall not exceed 120 minutes during any calendar day.

   (c) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for up to ten, 6-minute observation periods during any calendar day. Data for each observation period shall be exclusive for the ten periods.

   (d) During all startups, shutdowns, and malfunctions, the NOx CEM shall monitor and record NOx emissions. For each calendar day, up to two 1-hour monitoring averages may be excluded from the continuous NOx compliance demonstration for each combustion turbine due to excess NOx emissions resulting from startup, shutdown, and documented malfunction. For excess NOx emissions due to malfunction, the permittee 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.

[Design: Rule 62-210.700(1) and (5); Rule 62-4.130, F.A.C.]

8.0 RECOMMENDATION AND APPROVAL

The permit project engineer is Jeff Koerner. 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 Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

Determination By:

Jeffery J. Koerner 7-18-00

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

Recommended By:

C H Fancy 7/21/00

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

Approved By:

C H Fancy 7/21/00

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

APPENDIX E - EMISSIONS STANDARDS SUMMARY

For informational purposes only, the following table summarizes the emissions standards specified in this permit. [Rules 62-212.400(BACT) and 62-4.070(3), F.A.C.]

EU-011 and 012: General Electric Model PG7241(FA) Combustion Turbines (8A and 8B)

Pollutant	*Fuel/Mode*	*Emission Standard*	*Compliance Method*
		BACT Emission Standard	
CO	Gas, Normal and Peaking	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 32.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
	Gas W/PA	15.0 ppmvd @ 15% O_2, 3-hr test avg. and 47.0 lb/hr, 3-hr test avg.	Peak load; initial and annual tests
	Oil	20.0 ppmvd @ 15% O_2, 3-hr test avg. and 68.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
NO_x	Gas, Normal	9.0 ppmvd @ 15% O_2, 3-hr test avg. and 66.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
		10.0 ppmvd @ 15% O_2, 3-hr avg.	All loads, certified CEM data
	Gas W/PA	12.0 ppmvd @ 15% O_2, 3-hr test avg. and 82.0 lb/hr, 3-hr test avg.	Peak load; initial and annual tests
		12.0 ppmvd @ 15% O_2, 3-hr avg.	All loads, certified CEM data
	Gas, Peaking	15.0 ppmvd @ 15% O_2, 3-hr test avg. and 105.0 lb/hr, 3-hr test avg.	Peak load; initial/renewal tests
		15.0 ppmvd @ 15% O_2, 3-hr avg.	All loads, certified CEM data
	Oil	42.0 ppmvd @ 15% O_2, 3-hr test avg. and 334.0 lb/hr, 3-hr test avg.	Base load; initial and annual tests
		42.0 ppmvd @ 15% O_2, 3-hr avg.	All loads, certified CEM data
PM/PM_{10}, SO_2	Gas, All Modes	PM ≤ 9.0 lb/hr 1 grain per 100 SCF of natural gas Visible emissions ≤ 10% opacity	Base load; initial/renewal tests Fuel records Base load; initial and annual tests
	Oil	PM ≤ 17.0 lb/hr Distillate oil with ≤ 0.05% sulfur by weight Visible emissions ≤ 10% opacity	Base load; initial/renewal tests Fuel records Base load; initial and annual tests
		Synthetic Minor Emission Standard	
VOC	Gas, All Modes	1.5 ppmvw (as methane), 3-hr test avg. and 3.0 lb/hr (as methane), 3-hr test avg.	Base load; initial/renewal tests
	Oil	3.5 ppmvw (as methane), 3-hr test avg. and 7.5 lb/hr (as methane), 3-hr test avg.	Base load; initial/renewal tests

Note: The mass emission limits for were based on the following:

- Gas Firing, Normal: At a compressor inlet air temperature of 35° F and firing 1860 mmBTU per hour of gas, each unit produces a maximum 182 MW.
- Power Augmentation (Steam Injection): At a compressor inlet air temperature of 59° F and firing 1800 mmBTU per hour of gas with approximately 116,000 pounds per hour of steam injection, each unit produces a maximum 180 MW.
- Peaking: At a compressor inlet air temperature of 35° F and firing 1920 mmBTU per hour of gas during peaking, each unit produces a maximum 190 MW.
- *Distillate Oil*: At a compressor inlet air temperature of 35° F and firing 2000 mmBTU per hour of oil as a backup fuel, each unit produces a maximum 191 MW.

Note: All heat input values are based on the higher heating values (HHV) of the fuels.

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 - NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

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 – QUARTERLY PERFORMANCE SUMMARY REPORT GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEMS

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

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

Reporting period dates: From ____________________ to ________________________

Company: ____

Emission Limitation: ____

Address: ____

Monitor Manufacturer and Model No.: ______________________________

Date of Latest CMS Certification or Audit: ______________________

Process Unit(s) Description: ________________________________

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

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

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

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

Note: *On a separate page, describe any changes since last quarter in CMS, process or controls.*

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

____
Name

____
Title

____ ____________________
Signature *Date*