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1. Article Addressed to:
Rick A. Bowen, Exe. V.P.
Palmetto Power, LLC
1000 Louisiana St.
Houston, TX 77002

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A. Received by (Please Print Clearly) B. Date of Delivery 6/7/00

C. Signature

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Street & Number Palmetto Power	
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Postage	$
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Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 6-5-00 0970073-001-AC 050-F1-277	

PS Form 3800, April 1995

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Palmetto Power L.L.C.
1000 Louisiana Street, Suite 5800
Houston, TX 77002

Authorized Representative:
Mr. Rick A. Bowen
Executive Vice President

Permit No. PSD-FL-277
Project No. 0970073-001-AC
Three New 170 MW Combustion Turbines
Palmetto Power L.L.C.
Osceola County, Florida

Enclosed is Final Permit No. PSD-FL-277 (Project No. 0970073-001-AC). This permit authorizes Palmetto Power L.L.C. to construct a new power generating plant consisting of three new 170 MW combustion turbines. The project will be located in Osceola County approximately a half-mile east of State Road 532 and a quarter mile south of the Orange/Osceola County border. As noted in the Final Determination (attached), the Department made only minor changes to the Final Permit. A copy of EPA Region 4's approval of the Custom Fuel Monitoring Schedule is also enclosed. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 6-5-00 to the person(s) listed:

Mr. Rick A. Bowen, Palmetto Power L.L.C.*
Ms. Starla Lacy, Dynegy
Mr. Ken Kosky, Golder Associates
Mr. Len Kozlov, DEP - Central District Office
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.

Kim Tober — 6-5-00

(Clerk) (Date)

The Department distributed a public notice package on March 28, 2000 for a project that will create a new 510 MW electric power generating plant located near State Road 532 in Osceola County approximately 30 miles southeast of Orlando. The applicant, Palmetto Power L.L.C., proposes to install three simple cycle, 170 MW Siemens/ Westinghouse Model W501FD combustion turbines with electrical generator sets. The Public Notice of Intent to Issue was published in The Orlando Sentinel for both the Osceola and Orange County editions on April 30, 2000.

COMMENTS AND CHANGES

The Department received no comments from the applicant, the public, the Department's Central District Office, or the National Park Service during the comment period. EPA Region 4 provided comments regarding the application, the BACT determination procedure and the Draft Permit. The comments are summarized below and the Department's responses are included following each comment.

1. Comment: EPA Region 4 suggested that the Department verify the emission factor used by the applicant to estimate formaldehyde emissions. New combustion turbine projects could trigger a case-by-case MACT determination for HAPs, particularly formaldehyde. The formaldehyde emission factor used by the applicant was two orders of magnitude less than draft AP-42 emission factors.

   Response: The Department requested supporting documentation for the emissions factor, but did not receive a response. The Department estimated emissions of hazardous air pollutants based on the EPA MACT data released at the end of April. Assuming 100% permitted operation at base load and maximum heat input for all three units when firing natural gas, the Department estimates 8.55 tons per year of total HAP emissions, of which 7.90 tons per year would be formaldehyde. The Department believes this estimate to be conservative and therefore, 112(g) is not triggered.

2. Comment: Region 4 commented that it is EPA policy that BACT standards apply during all normal operations. Startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the planning, design, and implementation of operating procedures for the process and control equipment. Region 4 quotes from an EPA policy memo that, "... it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods."

   Response: The Department agrees that it is inappropriate to apply blanket exemptions for excess emissions to all projects. However, the Department's excess emissions rule (Rule 62-210.700, F.A.C.,) has been approved by EPA in Florida's state implementation plan and prohibits most cases of excess emissions as follows:

   (4) Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.

   This portion of the rule allows the Department to document poor performance that is within the control of the operator and to require appropriate corrective actions. Another portion of Florida's excess emissions rule does allow limited periods of excess emissions under specific conditions:

   (1) Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

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1. Article Addressed to:

Rick A. Bowen, Exe. VP.
Palmetto Power, LLC
1000 Louisiana St.
Houston, TX 77002

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US Postal Service
Receipt for Certified Mail
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Sent to Rick Bowen	
Street & Number Palmetto Power	
Post Office, State, & ZIP Code Houston TX	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 6-5-00	
097CCT3-001-AC	
PSD-F1-277	

PS Form 3800, April 1995

The purpose of this rule is to allow particular, limited periods of excess emissions that are beyond the control of the operator. The rule requires the Department to scrutinize the available information and determine whether the best efforts were used to minimize the quantity and duration of excess emissions. With regard to a new project, excess emissions due to startup and shutdown should be evaluated for the particular piece of equipment under review and the period of allowable excess emissions adjusted accordingly. An additional portion of Florida's excess emissions rule provides for making these adjustments:

(5) Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest.

The final applicable portion of Florida's excess emissions rule allows excess emissions for valid documented malfunctions. The rule codifies the understanding that electrical and mechanical equipment will fail or malfunction from time to time, which may cause excess emissions. In fact, it may occasionally be necessary to continue operation through these periods in order to repair or correct the situation. The rule requires the following notification and reporting requirements as a safeguard to prevent abuse:

(6) In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.

The Department also notes that practical application of the excess emissions rule is only possible for emissions standards with compliance demonstrated by continuous monitor or some other readily verifiable method, such as visible emissions. For emissions standards with compliance demonstrated by an emissions performance test, the instantaneous compliance status is unknown and therefore the excess emissions rule does not apply. Also, emissions performance tests conducted during startup, shutdown, or malfunctions are not typically considered "normal operations" as defined by EPA's reference methods in 40 CFR 60, which would prevent the use of test results collected during such periods.

With regard to this specific project, the Department recognizes that CO and NOx emissions during startup of a combustion turbine will fluctuate because the dry low-NOx combustion technology requires separate stages of air and fuel mixing to realize the lower emissions achieved during lean premix. Similarly, CO and NOx emissions will also fluctuate during shutdown due to the instability of the process. CO and NOx emissions may exceed BACT concentration limits and, for brief instances, mass emission limits during startup and shutdown. However, the Department recognizes that the Siemens/Westinghouse Model 501FD will typically achieve lean premix operation in approximately 50 to 60 minutes. Shutdown may complete in 20 to 30 minutes. As drafted, the permit includes the following specific conditions (SC) related to excess emissions during startup, shutdown, and valid, documented malfunctions.

SC No. 4: Operation below 70% of base load shall not exceed two (2) hours during any 24-hour period.

SC No. 8: 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.

SC No 9: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment … 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 …

Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations.

SC No. 11: An automated gas turbine control system is required for each unit to monitor fuel distribution and staging, turbine speed, load conditions, combustion temperatures, heat input, and fully automated startup, shutdown, and cool-down. This information will be used to document valid "malfunctions".

SC No. 14: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly.

SC No. 21: 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 CO and NOx emissions standards.

SC No. 22: Providing the permittee adheres to best operational practices to minimize the amount and duration of excess emissions, the following conditions shall apply:

(a) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for up to 2 hours in any 24-hour period. [Design; Rule 62-210.700(1) and (5), F.A.C.]

(b) During all startups, shutdowns, and malfunctions, the continuous emissions monitors (CEMs) shall monitor and record emissions. However, up to 2 hours of monitoring data during any 24-hour period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions. In case of malfunctions, the permittee shall notify the Compliance Authorities within one working day. A full written report on the malfunctions shall be submitted in a quarterly report. [Design; Rules 62-210.700(1), (5), and 62-4.130, F.A.C.]

SC No. 37:

(a) Data Collection. CO and NOx 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.

(c) Data Reporting: 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. The Department may request a written report summarizing the excess emissions incident.

(d) Data Exclusion. Unless prohibited by 62-210.700 F.A.C., valid hourly emission rates shall not include periods of start up, shutdown, or documented malfunction as described under the excess emissions requirements of this permit.

SC No. 38: 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.

SC No. 40: Data collected from the NOx CEM shall be used to report excess emissions in accordance with 40 CFR 60.334(c)(1) of NSPS, Subpart GG.

SC No. 40: If excess CO, NOx or visible emissions occur 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. Following the NSPS format in 40 CFR 60.7, Subpart A, 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 thirty (30) days following each calendar quarter, the permittee shall submit a report on any periods of excess emissions that occurred during the previous calendar quarter to the Compliance Authority. This quarterly report shall follow the format provided in Appendix XS of this permit.

As indicated, this permit does require at least one continuous monitor for CO emissions because of to the lack of actual performance data. CO CEMS monitors are not typically required for simple cycle units with restricted operation. The Department believes the above measures are sufficient to prevent repeated misuse of the excess emissions rule by the permittee to avoid compliance issues.

3. Comment: EPA Region 4 concurred with the Department's evaluation of the cost effectiveness calculations for CO and NOx controls. Region 4 also notes that the cost effectiveness, in EPA's opinion, is very close to the range that has lead to requiring SCR for combined cycle projects. Region 4 also agrees that relaxing project constraints requested by the applicant (3750 hours/CT/year, emissions performance, and firing exclusively natural gas) may require the installation of additional controls such as SCR.

   Response: No response required.

4. Comment: EPA Region 4 suggests that the Department add the particulate matter emission rate in terms of pounds per hour, which is used in the PTE calculations.

   Response: The Department included a reference on page 7 of the permit in Specific Condition No. 16 that particulate matter emissions were estimated to be less than 0.001 grains per dscf. For particulate matter, the Department opted for fuel specifications and a visible emissions limit instead of a particulate matter emissions limit in pounds per hour. The primary reason was that the mass emissions from a large modern combustion turbine are widely recognized as being very low due to efficient combustion at high temperatures. In fact, for these units, the particulate matter concentration for gas firing is estimated to be:

   [(8.6 lb/hour) (hour/60 min) (7000 grains/lb)] / (750,000 dscf/min) = 0.0013 grains/dscf

   (0.08424 mg/dscf)

   This concentration is less than that typically found after control by a baghouse. This is due to the very efficient combustion of clean fuels and the large volume of filtered inlet air moved through these units. The definition of Best Available Control Technology provides for the following, "... If technological or economic limitations in the application of a measurement methodology to a particular emission unit would make an emissions limit infeasible, a design, equipment, work practice, operation standard, or combination thereof, may be prescribed. Also, the technology upon which the BACT emissions limit is based should be specified in the permit. These requirements should be written in the permit so that they are specific to the individual emission unit(s) subject to PSD review."

   The Department's rules require a minimum sampling volume of 25 dscf for an EPA Method 5 performance test. A gas turbine exhaust containing 0.08424 mg/dscf would result in a total PM catch of only 2.1 mg. EPA Method 5I was developed for very low particulate matter concentrations and is most effective for PM catches of 50 mg or less. This method states that PM catches between 1 and 3 mg are between the minimum detection limit and the practical quantitation limit and can have a high degree of uncertainty. When collecting such small samples, bias becomes an important issue so extreme caution must be used to assure clean sampling probes, low tare weight containers, well-controlled balance rooms, etc. Obviously, the sampling volume could be increased to collect a larger sample (> 3 mg), but the point is that the very low mass emissions provide some testing difficulties in addition to those associated with the high flow rates and velocities from gas turbines.

The Department believes that it is appropriate to substitute fuel specifications and a low visible emissions limit in lieu of a particulate matter standard for this specific project due to the very low expected emissions rates and problems encountered in testing. Little benefit is gained by confirming low emissions rates with an initial test. In fact, if a particulate matter emissions standard is specified, the Department's rules would require performance tests to be conducted at least initially and once every five years. The Department added the PM emission factor of 8.6 pounds per hour and the natural gas fuel specification to the emissions summary table listed in Specific Condition No. 16 of the final permit.

CONCLUSION

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

Department of

Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE:

Palmetto Power L.L.C.
1000 Louisiana Street, Suite 5800
Houston, TX 77002

Authorized Representative:
Mr. Rick A. Bowen
Executive Vice President

ARMS Permit No.	0970073-001-AC
PSD Permit No.	PSD-FL-277
Facility ID No.	0970073
SIC No.	4911
Expires:	July 1, 2002

PROJECT AND LOCATION

This permit is issued pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit). The proposed project authorizes the installation of three simple cycle, combustion turbines with electrical generator sets fired solely by natural gas. Each gas turbine is capable of producing a nominal 170 MW of electricity. The new electric power generating plant will provide a nominal 510 MW of electrical power.

The project will be located in Osceola County approximately a half-mile east of State Road 532 and a quarter mile south of the Orange/Osceola County border. The UTM coordinates are Zone 17, 508.3 km E, 3135.2 km N and the map coordinates are Latitude 28° 20' 40", Longitude 80° 54' 52".

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

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

Date: 6/2/00

SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

Completion of this project will result in a new electric power generating plant capable of providing a nominal 510 MW of electrical power.

NEW EMISSIONS UNITS

The proposed project will result in the following new emissions units.

ARMS ID No.	COMMON EMISSION UNIT DESCRIPTION
001 002 003	Three new Siemens/Westinghouse Model W501FD combustion turbines with electrical generator sets. Each unit will produce a maximum 196.2 MW of electrical power fired exclusively with natural gas. Dry low-NOx (DLN) combustion technology will control emissions of CO, NOx, and VOC. Each unit may employ an evaporative inlet air cooling system.

REGULATORY CLASSIFICATION

HAPs: This facility will not be a major source of hazardous air pollutants (Title III).

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

Title V Major Source: This facility is a Title V major source of air pollution because potential emissions of CO and NOx each exceed 100 tons per year.

PSD Major Source: This facility is a PSD major source of air pollution as defined in Rule 62-212.400, F.A.C. for Prevention of Significant Deterioration (PSD) of Air Quality because potential emissions of CO and NOx each exceed 250 tons per year. Therefore, each pollutant with potential emissions greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C. requires a PSD review and Best Available Control Technology (BACT) determination. For this project, emissions of CO, NOx, and PM/PM_{10} are significant and subject to the BACT standards specified in this permit.

NSPS Sources: The combustion turbines specified in this permit are also subject to regulation under the New Source Performance Standards for Stationary Gas Turbines, 40 CFR 60, Subpart GG.

RELEVANT DOCUMENTS

- Permit application received on 10/15/99 and all related correspondence
- Intent to Issue Permit package mailed on March 28, 2000
- Public Notice published in The Orlando Sentinel for both the Osceola and Orange County editions on April 30, 2000
- Proof of publication received May 22, 2000

GENERAL AND ADMINISTRATIVE REQUIREMENTS

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

2. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Air Resources Section of the Central District Office, Florida Department of Environmental Protection, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767. The phone number is 407/894-7555 and the fax number is 407/897-5963.

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 units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the 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 units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular 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.]

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

EU ID No.	COMMON EMISSION UNIT DESCRIPTION
001 002 003	Siemens/Westinghouse Model W501FD combustion turbine with electrical generator set: This unit produces a maximum 196.2 MW of electrical power at a heat input of 1981 mmBTU per hour when fired exclusively with natural gas. Dry low-NOx (DLN) combustor technology controls CO, NOx, and VOC emissions. Efficient combustion design and pipeline-quality natural gas minimize emissions of PM/PM_{10}, SAM, and SO_2. Exhaust gases exit a 50 feet tall stack that is 19 feet in diameter at approximately 1100°F with a volumetric flow rate of 2,522,120 acfm. During warm weather conditions, an evaporative cooling system reduces the ambient temperature of the compressor inlet air to provide additional power.

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), and particulate matter (PM/PM_{10}). [Rule 62-212.400, F.A.C.]
2. NSPS Requirements: Each combustion turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   (a) **Subpart A, General Provisions**, incuding:

   - 40 CFR 60.7, Notification and Record Keeping
   - 40 CFR 60.8, Performance Tests
   - 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
   - 40 CFR 60.12, Circumvention
   - 40 CFR 60.13, Monitoring Requirements
   - 40 CFR 60.19, General Notification and Reporting Requirements

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

PERFORMANCE RESTRICTIONS

3. Combustion Turbines: The permittee is authorized to install, tune, operate and maintain three new combustion turbines with electrical generator sets (Siemens/Westinghouse Model 501FD or equivalent). Each unit is designed to produce a maximum 196.2 MW of electrical power. [Applicant Request]
4. Permitted Capacity: The heat input to each combustion turbine from firing natural gas shall not exceed 1981 mmBTU per hour based on the following: 100% base load (196.2 MW); a higher heating value (HHV) of 23,299 BTU/lb_m for natural gas; a compressor inlet air temperature of 32° F; a compressor inlet air relative humidity of 50%. The permittee shall provide 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. Operation below 70% of base load shall not exceed two (2) hours during any 24-hour period. [Design, Rule 62-210.200, F.A.C. (Definition - PTE)]

5. Simple Cycle, Intermittent Operation Only: Each combustion turbine shall operate only in simple cycle mode not to exceed the permitted hours of operation allowed by this permit. 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 temperature of the exhaust gas as well as higher cost effectiveness due to the requested intermittent operation of 3750 hours per year. For any request to convert these units to combined cycle operation by installing/connecting to heat recovery steam generators or increasing the allowable hours of operation, the permittee shall submit a full PSD permit application complete with a new proposal of the best available control technology as if the units had never been built. [Rules 62-212.400(2)(g) and 62-212.400(6)(b), F.A.C.]

6. Allowable Fuels: Each combustion turbine shall only be fired with pipeline-quality natural gas containing no more than 1 grain of sulfur per 100 dry standard cubic feet of gas, monthly average. It is noted that this limitation is 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 limit by keeping the records specified in this permit. [Applicant Request, Rule 62-210.200, F.A.C. (Definition - PTE)]

7. Hours of Operation: Each combustion turbine shall operate no more than 3750 hours during any consecutive 12-month period. For each combustion turbine, the permittee shall install, calibrate, operate and maintain a monitoring system to measure and accumulate the amount of natural gas fired and the hours of operation. [Applicant Request; Rule 62-212.400, F.A.C. (BACT); Rule 62-210.200, F.A.C. (Definitions - PTE)]

8. 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; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

9. 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.]

EMISSIONS CONTROLS

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

11. Automated Control System: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, tune, operate, and maintain an ECONOPAC™ automated gas turbine control system (or equivalent) for each unit. Each system shall be designed and operated to monitor and control the gas turbine combustion process and operating parameters including, but not limited to: fuel distribution and staging, turbine speed, load conditions, combustion temperatures, heat input, and fully automated startup, shutdown, and cool-down. [Design; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

12. DLN Combustion Technology: To control NOx emissions, each combustion turbine shall include a dry low-NOx (DLN) combustion system designed for firing natural gas only. The DLN system shall be tuned, operated and maintained in accordance with the manufacturer's recommendations. [Design and Rule 62-212.400, F.A.C.]

13. Tuning: Prior to the initial emissions performance tests for each gas turbine, the dry low-NOx (DLN) 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. [Design, Rules 62-4.070 and 62-212.400, 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. Future Controls: If for any reason additional controls are necessary to comply with the BACT standards specified in this permit, the permittee shall submit a full PSD permit application to modify this permit. The application shall propose Best Available Control Technology for combustion turbines as if the project had never been constructed. [Rule 62-212.400(2)(g), F.A.C.]

EMISSIONS STANDARDS

16. Summary: The following table summarizes the emissions standards specified in this permit.

EU-001, 002, and 003: Siemens/Westinghouse Model 501 FD Combustion Turbines		
BACT Standards		
Pollutant	Control Method[a]	Emission Standard[c]
CO	*Initial*: DLN W/Gas Firing, First 12 Months[b]	25.0 ppmvd @ 15% oxygen, and 113.0 pounds per hour
	Final: DLN W/Gas Firing, After First 12 Months[b]	15.0 ppmvd @ 15% oxygen, and 68.0 pounds per hour
NOx	DLN W/Gas Firing,	15.0 ppmvd @ 15% oxygen, and 111.0 pounds per hour
PM/PM_{10}	DLN W/Gas Firing Fuel Specification	Visible emissions ≤ 5% opacity Natural gas only (≤ 1 grain per 100 scf) {The PM/PM_{10} emission factor is 8.6 lb/hour.}
PSD Synthetic Minor Standards		
SAM/SO_2	Fuel Sulfur Specification	1 grain per 100 SCF of natural gas
VOC	DLN W/Gas Firing	1.5 ppmvd @ 15% oxygen, as methane, and 3.7 pounds per hour, as methane

[a] "DLN" means dry low-NOx combustion technology.

[b] "First 12 months" means the 12-month period following initial performance testing, including the initial testing.

[c] The mass emission limits (pounds per hour) were based on 100% base load (196.2 MW), a heat input of 1981 mmBTU per hour (HHV) from firing natural gas, a higher heating value (HHV) for natural gas of 23,299 BTU/lbm, an ambient temperature of 32° F, a relative humidity of 50%, and no evaporative cooling.

17. Carbon Monoxide (CO):

(a) *During the first 12-months after initial performance testing and including initial performance testing*: CO emissions from each combustion turbine shall not exceed 113.0 pounds per hour and 25.0 ppmvd corrected to 15% oxygen based on a 3-hour performance test average. In addition, CO emissions shall not exceed 25.0 ppmvd corrected to 15% oxygen based on a 3-hour block average for data collected from any required CO continuous emissions monitor during this period.

(b) *Following the first 12 months after initial performance testing*: CO emissions from each combustion turbine shall not exceed 68.0 pounds per hour and 15.0 ppmvd corrected to 15% oxygen based on a 3-hour performance test average. In addition, CO emissions shall not exceed 15.0 ppmvd corrected to 15% oxygen based on a 3-hour block average for data collected from any required CO continuous emissions monitor.

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

18. Nitrogen Oxides (NOx): NOx emissions from each combustion turbine shall not exceed 111.0 pounds per hour and 15.0 ppmvd corrected to 15% oxygen based on a 3-hour performance test average. In addition, NOx emissions shall not exceed 15.0 ppmvd corrected to 15% oxygen based on a 3-hour block 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 and 20 and the requirements of this permit. [Rule 62-212.400, F.A.C. (BACT)]

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

(a) Fuel Specifications. Emissions of PM, PM_{10}, SAM, and SO_2 shall be limited by the exclusive use of pipeline-quality natural gas containing no more than 1 grain per standard cubic feet and good combustion techniques as specified in this permit. The permittee shall demonstrate compliance with the fuel sulfur limit by maintaining the records specified by this permit. The fuel specification is a work practice standard established as a BACT limit for PM/PM_{10} emissions [Rule 62-212.400, F.A.C. (BACT)] and as a synthetic minor limit for SAM/SO_2 emissions [Rule 62-4.070(3), F.A.C.].

(b) VE Standard. Visible emissions from each combustion turbine shall not exceed 5% opacity, based on a 6-minute average. This work practice standard is established as a BACT limit for PM/PM_{10} emissions. The permittee shall demonstrate compliance with this standard by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. [Rule 62-212.400, F.A.C. (BACT)]

20. Volatile Organic Compounds (VOC): VOC emissions shall not exceed 3.7 pounds per hour and 1.5 ppmvd corrected to 15% oxygen based on a 3-hour performance test average. The VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Methods 25 and/or 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. [Application, Design, Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

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

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

    (a) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for up to 2 hours in any 24-hour period. [Design; Rule 62-210.700(1) and (5), F.A.C.]

    (b) During all startups, shutdowns, and malfunctions, the continuous emissions monitors (CEMs) shall monitor and record emissions. However, up to 2 hours of monitoring data during any 24-hour period may be excluded from continuous compliance demonstrations as a result of startups, shutdowns, and documented malfunctions. In case of malfunctions, the permittee shall notify the Compliance Authorities within one working day. A full written report on the malfunctions shall be submitted in a quarterly report. [Design; Rules 62-210.700(1), (5), and 62-4.130, F.A.C.]

EMISSIONS PERFORMANCE TESTING

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

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

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

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

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

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

    (e) EPA Method 25 or 25A - Determination of Volatile Organic Concentrations. (EPA Method 18 may be conducted to account for the non-regulated methane portion of the VOC emissions.)

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

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

26. Initial Tests Required: Initial performance tests to demonstrate compliance with the emission standards specified in this permit shall be conducted within 60 days after achieving at least 90% of permitted capacity, but not later than 180 days after initial operation of the emissions unit. Initial performance tests shall be conducted for CO, NOx, VOC, and visible emissions from each combustion turbine. Initial NOx performance tests shall be conducted in accordance with the requirements of NSPS Subpart GG including testing at four separate load conditions (see Appendix GG). NOx emissions data shall also be converted into units of the NSPS emissions standard. Initial CO performance tests shall be conducted concurrently with all NOx performance tests required at the four load conditions. [Rule 62-297.310(7)(a)1., F.A.C.]

27. Annual Performance Tests: To demonstrate compliance with the emission standards specified in this permit, the permittee shall conduct annual performance tests for CO, NOx, and visible emissions from each combustion turbine. 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. CO and NOx performance tests shall be conducted concurrently. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). [Rule 62-297.310(7)(a)4., F.A.C.]

28. Tests Prior to Permit Renewal: Prior to renewing the air operation permit, the permittee shall conduct performance tests for CO, NOx, VOC, and visible emissions from each combustion turbine. These tests shall be conducted within the 12-month period prior to renewing the air operation permit. For pollutants required to be tested annually, the permittee may submit the most recent annual compliance test to satisfy the requirements of this provision. [Rule 62-297.310(7)(a)3., F.A.C.]

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

30. Combustion Turbine Testing Capacity: Initial performance tests shall be conducted in accordance with 40 CFR 60.8 and 40 CFR 60.335 for pollutants subject to a New Source Performance Standard (NSPS) in Subpart GG for stationary gas turbines. Other required performance tests for compliance with standards specified in this permit shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C. [Rule 62-297.310(2), F.A.C.]

31. 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.]

32. Applicable Test Procedures

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. [Rule 62-297.310(4)(a)1., F.A.C.]

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

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet. [Rule 62-297.310(4)(b), F.A.C.]

(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.]

33. 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.]

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

CONTINUOUS MONITORING REQUIREMENTS

35. NOx 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. 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 Performance Specifications 2 and 3 as defined in Appendix B of 40 CFR 60 and the Acid Rain monitoring requirements of 40 CFR Part 75. A monitoring plan shall be provided to the Department's Emissions Monitoring Section Administrator, 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 data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location. [Rule 62-212.400, F.A.C. (BACT) and 40 CFR 75]

36. CO CEMS: Because of the limited CO emissions data available for the Siemens/Westinghouse Model 501FD, the permittee shall install, calibrate, operate, and maintain a continuous emission monitoring system (CEMS) on the exhaust stack of the first installed and operated combustion turbine to measure and record CO and oxygen concentrations. 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 CO CEMS shall comply with the certification requirements, quality assurance procedures, and all other provisions of Performance Specifications 3 and 4 as defined in Appendix B of 40 CFR 60. The CO CEMS shall collect and report data during the 12-month period after initial performance testing to demonstrate compliance with the *initial* CO emissions standard. After the initial 12-month period, the permittee may request removal of the CO CEMS if subsequent monitoring data sufficiently demonstrates compliance with the *final* CO emissions standard. The monitoring data shall consist of at least the first 250 compliance periods (3-hour averages) following the 12-month period after initial performance testing. The permittee shall submit a report summarizing the compliance monitoring data and requesting approval from the Department to remove the CO CEM. The permittee shall only remove the CO CEMS after obtaining written approval from the Department. [Rule 62-212.400, F.A.C. (BACT)]

37. CO/NOx CEMS Data Requirements:

(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 60.7(a)(5), 40 CFR 60.13, and Appendix F of 40 CFR 60.

(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 block 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 a 3-hour block of valid hourly 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. 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 in specific condition 43 of this permit.

(d) Data Exclusion. Unless prohibited by 62-210.700 F.A.C., valid hourly emission rates shall not include periods of start up, shutdown, or documented malfunction as described under the excess emissions requirements of this permit.

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

COMPLIANCE DEMONSTRATIONS

38. 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.]

39. Fuel Records: The permittee shall demonstrate compliance with the fuel sulfur limit for natural gas specified in this permit by maintaining records of the sulfur content of the natural gas being supplied for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or equivalent methods. These methods shall be used to determine the sulfur content of the natural gas fired in accordance with any EPA-approved custom fuel monitoring schedule (see Alternate Monitoring Plan) or natural gas supplier data or the natural gas sulfur content referenced in 40 CFR 75 Appendix D. The analysis may be performed by the 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 40 CFR 60.333 SO_2 standard. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

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

(a) 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.

(b) Data collected from the NOx CEM shall be used to report excess emissions in accordance with 40 CFR 60.334(c)(1) of NSPS, Subpart GG.

(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 the following conditions are met.

(1) Each combustion turbine shall fire only pipeline-quality natural gas. No other fuels are permitted.

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

(3) 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 1 grain of sulfur per 100 SCF of gas (monthly average) pursuant to 40 CFR 75.11(d)(2).

(4) 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 with the use of pipeline natural gas as the exclusive fuel. Changing to a higher sulfur fuel or adding an alternate fuel would require a modification of this permit with SO_2 emissions accounted for as required pursuant to 40 CFR 75.11(d).

[40 CFR 60, Subpart GG and Applicant Request]

41. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the hours of operation and the million cubic feet of natural gas fired 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/or printing within at least one day of a request from the Compliance Authority. [Rule 62-4.160(15), F.A.C.]

REPORTS

42. 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.].

43. Quarterly Excess Emissions Reports: If excess CO, NOx or visible emissions occur 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. Following the NSPS format in 40 CFR 60.7, Subpart A, 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 thirty (30) days following each calendar quarter, the permittee shall submit a report on any periods of excess emissions that occurred during the previous calendar quarter to the Compliance Authority. This quarterly report shall follow the format provided in Appendix XS of this permit. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7]

44. 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.]

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.

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

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.

Facility Identification (ID) Number:

Example: Facility ID No. 099-0001
Where: 099 - 3 digit number that identifies the specific county location
0221 - 4 digit number that identifies the specific facility

New Permit Numbers:

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 - 3 digit number that the specific county location
2222 - 4 digit number that identifies the specific facility
001 - 3 digit sequential number identifies the specific permit project

Old Permit Numbers:

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 - 6 digit sequential number that identifies the specific permit project

Palmetto Power L.L.C.
Osceola County

Draft Permit No. 0970073-001-AC (PSD-FL-277)
New Facility With Three 170 MW Simple-Cycle Combustion Turbines
Emissions Units 001, 002, and 003

1.0 NEW FACILITY

Completion of this project will result in a new electric power generating plant capable of providing a nominal 510 MW of electrical power. The new facility is a PSD major source of air pollution as defined in Rule 62-212.400, F.A.C. for Prevention of Significant Deterioration (PSD) of Air Quality because potential emissions of carbon monoxide (CO) and nitrogen oxides (NOx) each exceed 250 tons per year. Therefore, each pollutant with potential emissions greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C. requires a PSD review and Best Available Control Technology (BACT) determination.

2.0 PROJECT DESCRIPTION

The applicant, Palmetto Power L.L.C., proposes to install three new Siemens/Westinghouse Model W501FD combustion turbines with electrical generator sets. Each unit will produce a nominal 170 MW of electrical power fired solely by natural gas and may employ an evaporative cooling system for the compressor inlet air. 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. At nominal capacity, exhaust gases from each combustion turbine will exit a 50 feet tall stack that is 19 feet in diameter at approximately 1100°F with a volumetric flow rate of 2,429,700 acfm.

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, and PM/PM_{10} 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 Department will also establish PSD-synthetic minor emissions standards for SAM, SO_2, and VOC. 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.

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:

- 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 project will be located in Osceola County, an area that is currently in attainment, or designated as unclassifiable, for all air pollutants subject to a National Ambient Air Quality Standard (AAQS). The project will create a new PSD major source of air pollution because potential emissions of CO and NOx each are each greater than 250 tons per year. For 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. The following table summarizes the potential emissions increases and PSD applicability for this new project.

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	613	100	Yes	Yes
NOx	602	40	Yes	Yes
PM	46	25	Yes	Yes
PM_{10}	46	15	Yes	Yes
SAM	5	7	No	No
SO_2	33	40	No	No
VOC	20	40	No	No

a - Potential emissions are based on the firing of natural gas 3750 hours per year, evaporative cooling at 85%, and ambient conditions at 59°F and 60% relative humidity. Assumes all PM emitted is PM_{10}.

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

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 is 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, the New Source Performance Standard (NSPS) regulating 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, NOx, PM and PM_{10}. The applicant proposed control strategies for these pollutants in the application for a PSD permit. Besides the information submitted by the applicant, the Department also relied on the following information:

- Comments from the National Park Service dated November 22, 1999;
- Comments from EPA Region 4 on the Draft Permit on April 28, 2000;
- DOE web site information on Advanced Turbine Systems Project;
- Siemens/Westinghouse technical product literature regarding DLN emissions, the gas turbine control system, and evaporative cooling;
- Englehard equipment cost quotes for a CO oxidation catalyst and selective catalytic NOx reduction;
- Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines (1993);
- Proposed AP-42 changes to Section 3.1 for gas turbines (10/96 draft and 5/98 revision);
- Permit No. 4911-149-0005-P-01-0 issued by the State of Georgia to Heard County Power L.L.C. for a similar project Heard County, Georgia;
- Goal Line Environmental Technology Website: http://www.glet.com;
- Dynegy Website – www.dynegy.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 Similarly Sized Units

Project Location	Unit MW	Date	Technology	CO Limit ppmvd @ 15% O2	NOx Limit Ppmvd @ 15% O2	PM Limit	Comments
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	15	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	
		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)

5.1.1 Discussion of NOx Emissions

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

A gas turbine is sometimes referred to a "heat engine". In operation, hot combustion gases are diluted with additional air from the compressor section and directed to the turbine section at temperatures up to 2350°F. During simple cycle operation, electrical power is produced directly from the hot expanding exhaust gases in the form of shaft horsepower. Because of the high temperatures 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 as well as 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 fuel oil, 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 tend to fluctuate during startup up to approximately 50% of base load after which emissions begin to stabilize. In some specific models, emissions do not stabilize until approximately 70% of base load. This can be due to warming up a cold unit as well as the combustor fuel staging needed to achieve lean premix conditions in dry low-NOx system.

Another factor that can cause higher NOx emissions is a low ambient inlet temperature. 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. The denser air requires more fuel combustion to raise the temperature of the higher mass, which leads to 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 naturally coldest day, approximately 32° F.

5.1.2 Identification of Control Technologies

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 a NOx emission rate of 150 ppmvd @15% oxygen.

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 with 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%.

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 the temperature limitation of conventional SCR catalysts, manufacturers have developed specially formulated zeolite catalysts designed to further the reduction reaction at temperatures up to 1025°F. In addition, 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. The control efficiency for this technology is unknown.

SCONOx™: SCONOx™ is a NOx and CO control system offered by ABB Alstom Power for 100 MW and larger combustion turbines. 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% to 98% range.

XONON™: XONON™ is an emerging technology that partially burns fuel in a low temperature pre-combustor and completes combustion in a catalytic combustor. The result is partial combustion with a lower temperature and NOx formation followed by flame-less catalytic combustion to further inhibit NOx formation. This technology is now commercially available, but only for selected manufacturer and models. It is anticipated that control efficiencies will be in the 80% to 95% range.

5.1.3 Applicant's Proposed NOx Controls

The applicant rejected the following control technologies:

- *Wet Injection (WI)*: The applicant rejects wet injection as not available for the Siemens/Westinghouse 501FD model with combustors designed to fire only natural gas. Apparently, wet injection is only available for the dual-fuel model.
- *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™* was rejected because the gas turbine exhaust temperature of 1100°F is above the design limit (700° F) for this technology.
- *XONON™* because this technology is model-specific and not yet commercially available for a Siemens/Westinghouse Model 501FD combustion turbine.

Of the control alternatives discussed, only DLN combustor technology and hot SCR remain as viable NOx controls for the project. Siemens/Westinghouse guaranteed NOx emissions of 15 ppmvd @ 15% oxygen with DLN technology for this project. The applicant estimated hot SCR might be able to reduce this emissions rate to 4.5 ppmvd @ 15% oxygen. Therefore, the applicant recognized hot selective catalytic reduction (SCR) with ammonia injection as the top control option, but identified the following 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%. The applicant also claims additional energy costs associated with a cooling fan, 3 days of capacity loss, a fuel escalation cost, and a 10% contingency for energy costs.

Environmental Impacts: The maximum predicted impacts of all control alternatives are considerably below the PSD increment for NOx of 25 ug/m^3 (annual average) and the NOx AAQS of 100 ug/m^3. Hot SCR would generate additional emissions of ammonia (> 40 TPY) and ammonium sulfates (> 3 TPY).

Power lost to the hot SCR system would have to be generated resulting in increased emissions. Spent catalyst may have to be handled and treated as hazardous wastes. Ammonia handling and storage involves inherent risks and safety issues.

Economic Impacts: Initially, the applicant estimated that installation of hot SCR would result in capital costs of $5,290,700 or approximately 12% of the cost of the gas turbine. The annualized cost was estimated to be $1,661,000 per year. The applicant assumed a hot SCR system would remove an additional 140 tons of NOx per year (70% control efficiency) over a DLN only system at 15 ppmvd @15% O_2. This resulted in an incremental cost effectiveness for hot SCR of $11,850 per ton of NOx removed.

The Department requested a revised cost analysis to include: treatment of the catalyst costs as part of the capital costs and annual costs and not a "recurring capital cost"; elimination of the additional energy costs; and NOx reduction to 3.5 ppmvd @ 15% O_2. The revised analysis indicated a capital cost of $6,937,423, annualized costs of $2,094,192, and a NOx reduction of 154 tons per year. This resulted in an incremental cost effectiveness of $13,635 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 due to the relatively low emissions of the Siemens/Westinghouse 501FD as well as the restricted intermittent operation (3750 hours per year) requested. Therefore, the applicant proposed the following NOx limit as BACT for this project:

Proposal: 15.0 ppmvd @ 15% oxygen achieved by DLN technology

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

5.1.4 Department's NOx BACT Determination

The Department also recognizes hot selective catalytic reduction (SCR) with ammonia injection as the top control option. However, the Department disagrees with many of the applicant's assumptions.

Energy Impacts: Installation of hot SCR *would* result in an energy penalty of approximately 0.5 percent due to the pressure drop across the catalyst bed. However, the Department disagrees with the other estimated energy costs. For SCR systems, EPA (1993) recommends excluding any fan electrical costs as negligible. The fuel escalation cost and 10% contingency for energy costs have no basis. The capacity loss for 3 days of outage should not be included because this work could be performed during the remaining 5010 hours the gas turbine will not be operating.

Environmental Impacts: The Department gives no consideration to the applicant's comment that NOx levels are already below the PSD significant impact levels and AAQS. Ambient impacts are considered only in the air quality analysis and not in making the 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 10 ppm is misleading. Manufacturers of SCR systems may 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. 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: The Department disagrees with the applicant's methodology used to determine cost effectiveness. The Department believes that the cost analysis should be consistently performed so that all projects are evaluated on the same basis. In 1993, EPA provided specific recommendations regarding a cost analysis for an SCR system. As examples to illustrate the differences, the Department estimated costs for two cases based on the EPA recommendations and a NOx emissions rate of 3.5 ppmvd @ 15% O_2 (which is a reduction of 154 tons of NOx per year).

Case 1: Based on the initial information provided by the applicant, the Department estimates a capital cost of approximately $4,770,000, an annualized cost of $1,525,000, and a cost effectiveness for hot SCR of $9900 per ton of NOx removed. Differences with the applicant's estimate include not treating catalyst costs as a "recurring capital cost", using a catalyst life of five years instead of three, not including "direct installation costs" in the basis of estimates for "indirect costs", lower ammonia costs, and exclusion of the miscellaneous energy costs.

Case2: Based on the revised information provided by the applicant, the Department estimates a capital cost of $6,200,000, an annualized cost of $1,725,000, and a cost effectiveness for hot SCR of $11,200 per ton of NOx removed. Differences with the applicant's estimate included using a catalyst life of five years instead of three, not including "direct installation costs" in the basis of estimates for "indirect costs", lower ammonia costs, and exclusion of the miscellaneous energy costs. The reason that this estimate is higher than the initial estimate is a much higher SCR capital equipment cost based on a revised vendor quote. Apparently, there is a significant cost increase with sizing the system to meet a NOx emissions standards of 3.5 ppmvd compared to 4.5 ppmvd.

The Department estimates the incremental cost effectiveness of a hot SCR system for this project to be in the range of $10,000 per ton of NOx removed. These costs are the result of substantial costs related to equipment, installation, maintenance, catalyst replacement, energy consumption, and ammonia usage. However, the Department also notes that this analysis is based on two critical constraints: the applicant's request for restricted intermittent operation (3750 hours per year) and that the DLN emissions rate will not exceed 15 ppmvd @ 15% oxygen (111 pounds of NOx per hour). To illustrate the effects of these parameters, the Department estimated the cost effectiveness for a hot SCR system (3.5 ppmvd @ 15% oxygen) for the following conditions.

- As the DLN emissions rate approaches 25 ppmvd @ 15% oxygen, the cost effectiveness can drop below $6000 per ton assuming restricted intermittent operation (3750 hours per year).
- As the hours of operation approach 8000 hours per year, the cost effectiveness can drop below $5000 per ton assuming a DLN emissions rate of 15 ppmvd @ 15% oxygen.
- Assuming a DLN emissions rate of 20 ppmvd @ 15% oxygen AND 8000 hours of operation per year, the cost effectiveness can drop below $4000 per ton.
- Assuming a DLN emissions rate of 25 ppmvd @ 15% oxygen AND 8000 hours of operation per year, the cost effectiveness can drop below $3000 per ton.

These other conditions are important to evaluate because the hot SCR technology is being rejected based on the restricted use of the gas turbines as well as the manufacturer's guarantee that it will deliver DLN combustor technology for this project with NOx emissions of 15 ppmvd @ 15% oxygen or less. Should either of these parameters change, the BACT determination must be reevaluated.

Another consideration of the Department was the proposed numerical emissions standard of 15 ppmvd @ 15% oxygen. BACT is defined as, "... an emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant." The Department is aware of gas turbine models from other manufactures that have demonstrated NOx emissions of less than 9 ppmvd @ 15% oxygen. It would be difficult to establish an emissions standard much higher than that proposed as "BACT" when other manufacturers are delivering units with emissions nearly half of the proposed BACT limit. The only reasonable assurance provided by the applicant was a guarantee by Siemens/Westinghouse that they would deliver a Model 501FD capable of meeting the proposed standard. No supporting data was presented to indicate that this unit has demonstrated such operation in the field. The manufacturer is currently developing seven air and fuel management programs intended to achieve sub-15 ppmvd NOx emissions before the end of 2000. Nevertheless, there is some concern regarding the ability of Siemens/Westinghouse to deliver a Model 501FD with DLN technology capable of achieving the BACT standard in accordance with the proposed schedule.

Based on the above discussion, the Department also rejects hot SCR as not being cost effective and establishes the following NOx standard as BACT for this project:

NOx BACT: NOx emissions shall not exceed 15.0 ppmvd @ 15% oxygen based on a 3-hour block average achieved solely by DLN technology. The following qualifications shall also apply:

1. Each combustion turbine shall operate only in simple cycle mode. To convert any unit to combined cycle operation, the permittee shall submit a full PSD permit application for a new determination of NOx BACT as if the project had not yet been built.
2. Each combustion turbine shall operate no more than 3750 hours during any consecutive 12 months. To relax this condition, the permittee shall submit a full PSD application for a new determination of NOx BACT as if the project had not yet been built.
3. Each combustion turbine shall be installed with combustors capable of firing only natural gas.
4. Except for up to two hours in any 24-hour period, each combustion turbine shall operate at 70% or more of base load.
5. If the actual NOx emissions are determined to be higher than the BACT limit, the permittee shall submit a full PSD application for a new determination of NOx BACT as if the project had not yet been built.

The Department believes that these additional conditions are necessary for this particular case because the manufacturer has yet to demonstrate continuous compliance with the "guaranteed" emissions standard. 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 Methods 7, 7E, and/or 20. In addition, the permittee shall install, calibrate, operate, and maintain a certified continuous NOx emissions monitor to demonstrate continuous compliance with the BACT limit.

5.2 CARBON MONOXIDE (CO)

5.2.1 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.

5.2.2 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 catalysts promote oxidation of CO to carbon dioxide (CO_2) at much lower temperatures (650°F to 1150°F) than possible for oxidation without the catalyst. 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 and reviewed this option for the following additional adverse impacts.

Energy Impacts: Installation of an oxidation catalyst would result in an energy penalty due to the pressure drop across the catalyst bed of approximately 0.2% of the power output as well as increased fuel costs.

Environmental Impacts: The air quality impacts of a DLN system are well below the significant impact levels for CO. The applicant asserts that no additional benefit is gained by installing an oxidation catalyst. The oxidation catalyst is not selective and would tend to convert SO_2 emissions to secondary sulfate emissions. Sulfates may gradually degrade the heat rate of the gas turbine.

Economic Impacts: In the revised cost analysis, the applicant estimated that installation of an oxidation catalyst would result in capital cost of $2,068,897 or approximately 5% of the cost of the gas turbine. The annualized cost was estimated to be $674,272 per year. It was assumed that the catalytic system could remove an additional 184 tons of CO per year (90% control efficiency) over a DLN only system at 25 ppmvd @ 15% O_2. This resulted in an incremental cost effectiveness for the oxidation catalyst of $3666 per ton of CO removed. The applicant asserts that the proposed CO emissions limit of 25 ppmvd is a result of the uncertainty associated with maintaining low CO and NOx emissions simultaneously. In support of this argument, the applicant states that recent tests for a "Westinghouse 'F' class turbine with DLN" showed emission rates of less than 10 ppmvd. Finally, the applicant contends that an actual CO emissions rate of 20 ppmvd would more than double the cost effectiveness.

The applicant rejected an oxidation catalyst based on the belief that it is not cost effective. The applicant proposed the following as the best available controls:

Proposal: CO emissions shall not exceed 25.0 ppmvd @ 15% oxygen based on the combustion design.

5.2.3 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 making the BACT determination. Also, it is unlikely that any measurable sulfate emissions would be converted due to an oxidation catalyst because of the exclusive use of natural gas for this project.

Economic Impacts: In general, the Department agreed with the applicant's cost estimate for installation of an oxidation catalyst. However, the Department performed an analysis to illustrate the effects of different assumptions and estimation techniques. The primary differences with the applicant's estimate was to base the "indirect costs" on only the "purchased equipment costs" and subtracting the catalyst costs from the capital costs when estimating the capital recovery costs. Both of these estimation techniques are recommended in EPA's OAQPS Cost Control Manual. The Department estimates a capital cost of approximately $1,918,000 and an annualized cost of $574,000 per year. It was assumed that the oxidation catalyst could remove an additional 184 tons of CO per year (90% control efficiency) over a DLN system at 25 ppmvd @ 15% O_2. This resulted in an incremental cost effectiveness for the oxidation catalyst of approximately $3100 per ton of CO removed.

Further consideration is given to the following items:

- The Department has issued several permits for similarly sized General Electric Model 7FA gas turbines with CO emissions standards of 15 ppmvd @ 15% oxygen. At least one permit has been issued with a CO limit for gas firing of 9 ppmvd @ 15% oxygen with compliance demonstrated by continuous CO emissions monitor.
- As the applicant indicated, the actual emissions from the Model 501FD are expected to be less than 10 ppmvd @ 15% oxygen based on the few available field tests. As emissions approach this level, the oxidation catalyst becomes cost prohibitive. The applicant provided no supporting information to suggest that actual CO emissions would be 25 ppmvd.
- The Department notes that as the hours of operation approach 8000 hours per year, the oxidation catalyst becomes much more cost effective.

The Department is reluctant to establish a CO emissions standard as "BACT" that may be two to three times the capability of the installed equipment. As previously discussed, BACT is an emissions standard that represents the maximum degree of reduction using available methods for the control of a given pollutant. An emissions standard of 25 ppmvd @ 15% oxygen does not represent the maximum degree of control for other currently available for similarly sized DLN combustion turbines. In fact, a substantial "cushion" has been added due to the uncertainty for this specific equipment model. Therefore, the Department establishes the following CO standard as BACT for this project:

<u>CO BACT</u>: For initial testing and the subsequent 12 months, CO emissions from each combustion turbine shall not exceed 25 ppmvd @ 15% oxygen based on a 3-hour average achieved solely with DLN combustion technology. Thereafter, CO emissions shall not exceed 15 ppmvd @ 15% oxygen based on a 3-hour average. The following qualifications shall also apply:

1. Each combustion turbine shall operate only in simple cycle mode. To convert any unit to combined cycle operation, the permittee shall submit a full PSD permit application for a new determination of CO BACT as if the project had not yet been built.
2. Each combustion turbine shall operate no more than 3750 hours during any consecutive 12 months. To relax this condition, the permittee shall submit a full PSD application for a new determination of CO BACT as if the project had not yet been built.
3. Each combustion turbine shall be installed with combustors capable of firing only natural gas.
4. Except for up to two hours in any 24-hour period, each combustion turbine shall operate at least 70% of base load.
5. If unable comply with the final CO limit after the initial 12 months of operation, the permittee shall submit a full PSD application for a new determination of CO BACT as if the project had not yet been built.

The Department believes that this is a reasonable compromise for a gas turbine model that has not yet been placed in normal operation nor demonstrated the capability to achieve CO emissions representative of current "best available control technology". The initial 12 months will allow a period of time to operate, tune and adjust the gas turbine and automated control system. Because emissions of CO for this model have not yet been demonstrated, the Department will require the following testing and monitoring conditions:

- The permittee shall conduct performance tests in accordance with EPA Method 10 concurrently with NOx performance tests or with valid NOx CEM data.
- The permittee shall conduct initial CO performance tests for each gas turbine at the four load conditions required by NSPS, Subpart GG.

- The permittee shall install, calibrate, certify, operate and maintain equipment to continuously monitor and record CO emissions on the first installed and operated combustion turbine. The permit may contain provisions for removal of the continuous monitor once compliance with the final CO BACT emissions standard is demonstrated.

The Department believes that these additional testing and monitoring conditions are necessary for this particular case because the manufacturer has yet to demonstrate actual CO emissions for the Model 501 FD. The proposed standard of 25 ppmvd @ 15% oxygen is not representative of BACT for CO from similarly sized gas turbines with DLN technology. The CO standard proposed by the applicant merely reflects a degree of "uncertainty" for this particular unit due to a lack of operational data.

5.3 PARTICULATE MATTER (PM/PM_{10})

5.3.1 Discussion of PM/PM_{10}

Emissions of particulate matter will result from the combustion of the natural gas. 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. However, pipeline-quality natural gas is a very clean fuel containing little measurable ash and typically less than 1 grain of sulfur per 100 SCF.

5.3.2 Applicant's Proposed PM/PM_{10} BACT

The applicant identified several available control technologies for particulate matter removal including centrifugal collectors, electrostatic precipitators, fabric filters, and wet scrubbers. Pipeline-quality natural gas containing less than 1 grain of sulfur per 100 SCF is proposed as the only fuel for this project. Siemens/Westinghouse guarantees particulate matter emissions of no more than 8.6 pounds per hour from the Model 501FD combustion turbine when fired exclusively with natural gas. Based on the design flow rate, this equates to approximately 0.001 grains per dry standard cubic feet of exhaust gas, which is difficult to control with add-on equipment as well as measure during a performance test. In fact, this level of emissions is more closely associated with concentrations expected *after* control by a high efficiency fabric filter.

The applicant also provided information collected from EPA's RACT/BACT/LAER Clearinghouse indicating low-sulfur, clean fuels to be the predominant PM BACT standard for combustion turbines. Typically, PM BACT is established as pipeline-grade natural gas containing negligible sulfur as the primary fuel. Therefore, the applicant proposed the following NOx limit as BACT for this project:

Proposal: Each combustion turbine shall be fired only with pipeline-quality natural gas containing no more than 1 grain of sulfur per 100 SCF. Visible emissions shall not exceed 10% opacity.

5.3.3 Department's PM/PM_{10} BACT Determination

The Department agrees with the applicant that add-on equipment would be cost prohibitive to control already very low emissions. The specification of clean fuels constitutes a pollution prevention technique and is given favorable consideration when possible. Also, the low emission rate combined with the high air flow rate from the gas turbine can lead to non-detectable results during performance testing with EPA Method 5. However, a properly operating combustion turbine fired with only natural gas should have no visible emissions. Therefore, the Department establishes the following as PM/PM_{10} BACT for this project:

PM/PM_{10} BACT: The Department establishes the following work practice standards as BACT for particulate matter.

1. *Fuel Specification*: Each combustion turbine shall fire only pipeline-quality natural gas containing no more than 1 grain of sulfur per 100 SCF, monthly average.
2. *Visible Emissions*: Visible emissions shall not exceed 5% opacity.

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

5.4 PSD SYNTHETIC MINOR LIMITS

Emissions of sulfuric acid mist, sulfur dioxide, and volatile organic compounds do not exceed the PSD significant emissions rates specified in Table 62-212.400-2, F.A.C. Therefore, emissions standards for these pollutants will be set to establish the synthetic minor source status of each pollutant.

5.4.1 Sulfuric Acid Mist (SAM) and Sulfur Dioxide (SO_2)

Gas turbines are subject to the following New Source Performance Standards for sulfur dioxide in 40 CFR 60, Subpart GG, which requires, "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". Emissions of sulfur dioxide and sulfuric acid mist are a function of the amount of fuel sulfur. It is estimated that less than 15% of the potential sulfur dioxide emissions would be in the form of sulfuric acid mist. The applicant proposes to fire only pipeline-quality natural gas containing no more than 1 grain per 100 SCF. This is approximately equivalent to 0.004% sulfur by weight. Clearly, limiting the sulfur content to this concentration is more stringent than the NSPS restriction and effectively reduces the potential emissions of sulfuric acid mist. Therefore, the Department proposes the following work practice standard as a PSD synthetic minor limit for SO_2 and SAM:

SO_2/SAM Standard: Each combustion turbine shall be fired only with pipeline-quality natural gas containing no more than 1 grain per 100 SCF, monthly average.

This limits potential annual emissions of SAM to 4.99 tons per year and emissions of SO_2 to 33.24 tons per year for the project. Compliance shall be demonstrated by keeping records of the fuel sulfur content of the natural gas delivered via the pipeline.

5.4.2 Volatile Organic Compounds

VOC emissions result from the firing of natural gas and are generally a function of the combustion efficiency. Combustion turbines firing natural gas offer high temperatures with efficient combustion resulting in very low levels of unburned hydrocarbons. Siemens/Westinghouse guarantees VOC emissions of no more than 1.5 ppmvd @ 15% oxygen (3.6 pounds per hour) for the Model 501FD combustion turbine when firing only natural gas. Therefore, the Department establishes the following standard as a PSD synthetic minor limit for VOC:

VOC Standard: 1.5 ppmvd @ 15% oxygen achievable with DLN technology

This limits potential annual emissions of VOC to 20.25 tons per year for the project. 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 to account for the non-regulated methane portion of the VOC emissions. Compliance shall also be demonstrated during the fiscal year prior to renewing each operation permit.

6.0 SUMMARY OF DEPARTMENT'S BACT DETERMINATION

6.1 BACT EMISSION LIMITS

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

EU-001, 002, and 003: Siemens/Westinghouse Model 501 FD Combustion Turbines		
	BACT Standards	
Pollutant	Controls[b]	Emission Standard
CO	*Initial*: DLN W/Gas Firing, First 12 Months[b]	25.0 ppmvd @ 15% oxygen, and 113.0 pounds per hour
	Final: DLN W/Gas Firing, After First 12 Months[b]	15.0 ppmvd @ 15% oxygen, and 68.0 pounds per hour
NOx	DLN W/Gas Firing,	15.0 ppmvd @ 15% oxygen, and 111.0 pounds per hour
PM/PM10	DLN W/Gas Firing Fuel Specifications	Visible emissions ≤ 5% opacity Natural gas only (< 1grain per 100 scf) {PM estimated < 0.001 grains per dscf}
	PSD Synthetic Minor Standards	
Pollutant	Controls[b]	Emission Standard
SAM[a]/SO2	Fuel Sulfur Specification	1 grain per 100 SCF of natural gas
VOC[a]	DLN W/Gas Firing	1.5 ppmvd @ 15% oxygen, as methane, and 3.7 pounds per hour, as methane

[a] DLN means dry low-NOx combustion technology.

[b] "First 12 months" means the 12-month period following initial testing, including the initial testing.

6.2 BACT COMPLIANCE DEMONSTRATION

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

Pollutant	**Compliance Methods***
CO	EPA Method 10 shall be conducted for initial and annual tests concurrent with NOx. The first installed combustion turbine shall demonstrate continuous compliance with data from a certified continuous CO emissions monitor. The permit will include provisions for removal of the CO monitor after sufficient demonstration of compliance with the final CO BACT emissions standard.
NOx	EPA Method 20 shall be conducted for initial and annual tests concurrent with CO. Continuous compliance shall be demonstrated with data from certified continuous NOx emissions monitors for each combustion turbine. The annual RATA results may be substituted for annual tests if all capacity, notification, and reporting requirements are met.
VE	EPA Method 9 shall be conducted for initial and annual visible emissions tests.
PM / PM10, SO2 / SAM	Record keeping of the fuel sulfur content of the natural gas delivered via the pipeline shall be used to demonstrate compliance with the fuel sulfur limits.
VOC	EPA Method 25 or 25A shall be conducted for initial tests and prior to renewal of each operation permit. EPA Method 18 may be conducted to account for the non-regulated methane portion of the VOC emissions.

6.3 BACT EXCESS EMISSIONS ALLOWED

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

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 for continuous compliance demonstrations. [Rule 62-210.700, F.A.C.]

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

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

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

[Design and Rules 62-4.130 and 62-210.700, F.A.C.]

7.0 RECOMMENDATION AND APPROVAL

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:

Jeffrey F. Koerner — 6-1-00

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

Recommended By:

C. H. Fancy — 6/2/00

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

Approved By:

Howard L. Rhodes — 6/2/00

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

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:

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

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, degrees Kelvin

(2) The monitoring device of Sec. 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with Sec. 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

(d) The owner or operator shall determine compliance with the sulfur content standard in Sec. 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference--see Sec. 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

(e) To meet the requirements of Sec. 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

SECTION IV.

APPENDIX XS - CEMS EXCESS EMISSIONS REPORT

FIGURE 1 – 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]	

[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.

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

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

____
Name

____
Title

______________________________ ____________________
Signature *Date*

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

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MAY 0 8 2000

MAY 11 2000

BUREAU OF AIR REGULATION

4APT-ARB

A. A. Linero, P.E.
Administrator
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJECT: Custom Fuel Monitoring Schedule Proposed for Palmetto Power, L.L.C located in Osceola County, Florida

Dear Mr. Linero:

This letter is in response to your March 27, 2000, request for approval of a custom fuel monitoring schedule for Palmetto Power, L.L.C which will operate three natural gas-fired simple cycle combustion turbines subject to 40 C.F.R. Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines. As requested, the natural gas custom fuel monitoring plan and use of acid rain nitrogen oxides (NO_x) continuous emission monitoring system (CEMS) for demonstrating compliance has been reviewed. Region 4 has concluded that the use of acid rain NO_x CEMS for demonstrating compliance, as described in Specific Conditions 35 and 37, is acceptable. Region 4 has also concluded that the natural gas custom fuel monitoring schedule proposed in Specific Condition 40 is acceptable.

According to 40 C.F.R. 60.334(b)(2), owners and operators of stationary gas turbines subject to Subpart GG are required to monitor fuel nitrogen and sulfur content on a daily basis if a company does not have intermediate bulk storage for its fuel. 40 C.F.R. 60.334(b)(2) also contains provisions allowing owners and operators of turbines that do not have intermediate bulk storage for their fuel to request approval of custom fuel monitoring schedules that require less frequent monitoring of fuel nitrogen and sulfur content.

Region 4 reviewed Specific Condition 40 which allows SO_2 emissions to be quantified using procedures in 40 C.F.R. 75 Appendix D in lieu of daily sampling as required by 40 C.F.R. 60.334(b). Since the specific limitations listed in the permit condition are consistent with previous determinations, we have concluded that the use of this custom fuel monitoring schedule is acceptable.

Additionally, Specific Condition 40 also addresses the potential for correcting results to ISO standard day conditions. The basis for this requirement is that, under the provisions of 40 C.F.R. 60.335(c), NO_x results from performance tests must be converted to ISO standard day conditions. As an alternative to continuously correcting results to ISO standard day conditions, Palmetto Power plans to keep records of the data needed to make this conversion, so that NO_x results could be calculated on an ISO standard day condition basis anytime at the request of the Environmental Protection Agency (EPA) or the Florida DEP. This approach is acceptable, since the construction permit contains NO_x limits that are more stringent than those in Subpart GG, and compliance with Subpart GG for these units would be a concern only in cases when a turbine is in violation of the NO_x limits in its permit.

Finally, Specific Conditions 37 and 40 involve the method used to monitor NO_x excess emissions. Under the provisions for 40 C.F.R. 60.334(c)(1), the operating parameters used to identify NO_x excess emissions for Subpart GG turbines are water-to-fuel injection rates and fuel nitrogen content. As an alternative to monitoring NO_x excess emissions using these parameters, Palmetto Power is proposing to use a NO_x CEMS that is certified for measuring NO_x emissions under 40 C.F.R. Part 75. Based upon the enclosed determination issued by EPA on March 12, 1993, NO_x CEMS can be used to monitor excess emissions from Subpart GG turbines if a number of conditions specified in the determination are met and included in the permit condition.

If you have any questions about the determination provided in this letter, please contact Katy Forney of the EPA Region 4 staff at 404-562-9130.

Sincerely,

Douglas Neeley

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

Enclosure

cc: J. Kearney, BAR
K. Kosky, Golden
R. Bowen, Palmetto
CD
NPS

March 12, 1993

MEMORANDUM

SUBJECT: Approval of the Use of NOx CEMS as an Alternative Method to the Water-fuel Ratio Monitoring under NSPS Subpart GG

FROM: John B. Rasnic, Director
Stationary Source Compliance Division
Office of Air Quality Planning and Standards

TO: Karl Mangels, Chief
New York Compliance Section
Air Compliance Branch, Region II

In response to your January 12, 1993, memorandum to Linda Lay, SSCD investigated the feasibility of our approval of your request. You asked SSCD to approve a request from East Syracuse Generating Company to allow the use of the NO_x continuous emission monitoring system (CEMS) as an alternative monitoring method to the continuous water-fuel ratio monitoring method.

East Syracuse Generating Company is to commence development of a 100 MW natural gas-fired cogeneration combustion turbine facility in the village of East Syracuse, New York. The facility is allowed to use a limited amount of low sulfur distillate oil as a backup fuel. To control the emissions of NO_x this turbine will use both water injection and selective catalytic reduction as required by the New York State Department of Environmental Conservation (NYSDEC). Since the NYSDEC permit conditions are more restrictive than the requirements of NSPS Subpart GG, East Syracuse is asking for a waiver from the following monitoring requirements:

1. Fuel sulfur monitoring
2. Fuel nitrogen monitoring
3. Continuous water-fuel ratio monitoring for Nox compliance.

You have already made determinations on the first two issues and asked SSCD to address only the third issue, use of NO_x CEMS, that is required by the State permit, instead of the water-fuel ratio monitoring method.

SSCD determined that the use of a NO_x CEMS can be allowed as an alternative monitoring method if the facility meets the following conditions:

1. Each turbine meets the emission limitation (STD) determined according to 40 CFR Part 60.332. The "Y" value for the applicable equation and supporting documentation should

be provided by the applicant and the limitation for NO_x emissions from pipeline quality natural gas should be fixed by EPA assuming the "F" value equals 0. The emission limitation shall be expressed in ppmv, dry, corrected to 15 percent 02.

2. Each N0x CEMS meets the applicable requirements of 40 CFR 560.13, Appendix B, and Appendix F for certifying, maintaining, operating and assuring quality of the system.

3. Each N0x CEMS must be capable of calculating NO_x emissions concentrations corrected to 15% 02 an IS0 conditions.

4. Monitor data availability shall be no less than 95 percent on the quarterly basis.

5. N0x CEMs should provide 4 data points for each hour and calculate a l-hour average.

6. Each owner or operator of a NO_x CEMS shall submit an excess emissions (calculated according to the requirements of paragraph 60.13(h)) and monitoring systems performance report and/or a summary report form to the Administrator on a quarterly basis, if excess emissions are determined, or semiannually. The report shall be postmarked by the 30th day following the end of each reporting period. Written reports shall include information required in paragraphs 60.7 (c) and 60.7 (d). This report shall also contain the content of nitrogen in fuel oil for each reporting period when oil is fired and a clearly calculated corresponding emission limitation (STD).

7. Recordkeeping requirements shall follow the requirements specified in 40 CFR 560.7.

In addition, to upgrade the EPA data, we recommend that the NO_x CEMS be used to demonstrate compliance with the emission limitation on a continuous basis and that the quarterly report include the NO_x mass emissions for the reported period as reported to the State.

If you have any questions, please call Zofia Kosim at 703-308-8733.

cc: Air, Pesticides, and Toxics Management Division Directors
Regions I and IV
Air and Waste Management Division Director
Region II
Air, Radiation, and Toxics Division Director
Region III
Air and Radiation Division Director
Region V
Air, Pesticides, and Toxics Division Director
Region VI
Air and Toxics Division Directors
Regions VII, VIII, IX, and X

Memorandum

Florida Department of
Environmental Protection

TO:	Howard L. Rhodes
THRU:	Clair Fancy Al Linero
FROM:	Jeff Koerner
DATE:	June 1, 2000
SUBJECT:	Project No. 0970073-001-AC (PSD Permit No. PSD-FL-277) Palmetto Power L.L.C. Three Nominal 170 MW Simple Cycle Combustion Turbines

The Final Permit is attached for your approval and signature for a project that will create a new 510 MW electric power generating plant located near State Road 532 in Osceola County approximately 30 miles southeast of Orlando. The permit authorizes the installation of three simple cycle, 170 MW Siemens/ Westinghouse Model W501FD combustion turbines with electrical generator sets. Each gas turbine is limited to no more than 3750 hours of operation per year and will be fired exclusively with natural gas. BACT for NOx emissions was determined to be dry low-NOx combustion technology. BACT for emissions of CO, PM/PM_{10}, SO_2, and VOC was determined to be the efficient combustion of a clean fuel.

The Public Notice of Intent to Issue was published in The Orlando Sentinel for both the Osceola and Orange County editions on April 30, 2000. No comments were received from the public or National Park Service regarding the Draft Permit. EPA Region 4 provided written comments prior to the publication date. Minor changes to the draft permit and the Department's response to EPA Region 4's comments are summarized in the attached Final Determination.

I recommend your approval and signature. Day 90 is July 13, 2000.

Attachments

CHF/AAL/jfk