STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Florida Power Corporation
P.O. Box 368
Intercession City, FL 33848
Authorized Representative:
Mr. Martin J. Drango, Plant Manager

Project No. 0970014-006-AC
PSD Permit No. PSD-FL-268A
Florida Power Intercession City Plant
Minor Modifications (Units P12-P14)

Enclosed is final air permit No. PSD-FL-268A, which: increases the maximum heat inputs and nominal power production for both gas and oil firing; revises the NOx compliance averaging period; clarifies the NOx CEMS data exclusion; and corrects the minimum observation period for a compliance visible emissions test. The existing facility is located in Osceola County approximately 3.5 miles west of Intercession City. The address is 6525 Osceola Polk County Line Road, Intercession City, Florida 33848. As noted in the Final Determination (attached), only minor changes were made to correct typographical errors. 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 (30) days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

for 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 1/30/02 to the persons listed:

Mr. Martin J. Drango, Florida Power Corp.*
Mr. Jamie Hunter, Florida Power Corp.
Mr. Scott Osbourn, ENSR
Mr. Len Kozlov, CD
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.

Victoria Gibson January 30, 200
(Clerk) (Date)

FINAL DETERMINATION

PERMITTEE

Florida Power Corporation
P.O. Box 368
Intercession City, FL 33848

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section
2600 Blair Stone Road, MS #5505
Tallahassee, Florida, 32399-2400

PROJECT

Project No. 0970014-006-AC
Air Permit No. PSD-FL-268A

The final permit modifies original air permit No. PSD-FL-268 to: increase the maximum heat inputs and nominal power production for both gas and oil firing; revise the NOx compliance averaging period from a 3-hour rolling average to a 24-hour block average of actual operating hours; clarify the permit conditions regarding data exclusion for the NOx continuous emissions monitoring system; and correct the minimum observation period for a compliance visible emissions test. The existing facility, Florida Power's Intercession City Plant, is located in Osceola County approximately 3.5 miles west of Intercession City. The address is 6525 Osceola Polk County Line Road, Intercession City, Florida 33848. The permittee is authorized to perform the minor upgrades on each existing gas turbine (P12-P14) to achieve the capacity increases. No other construction or modification is authorized.

NOTICE AND PUBLICATION

The Department distributed an "Intent to Issue Permit" package on December 19, 2001. The applicant published the "Public Notice of Intent to Issue" in The Osceola News-Gazette on December 22, 2001. The Department received proof of publication on January 16, 2002. No requests for administrative hearings were filed.

COMMENTS/CHANGES

No comments on the Draft Permit were received from the public, the Department's Central District Office, or the applicant. On the first page of the permit, the Department revised the description in the Statement of Basis to clarify that this action was a modification. The footers in the final permit and Appendices were revised to clarify the project and permit numbers. Other minor revisions included the correction of typographical errors.

CONCLUSION

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

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE:

Florida Power Corporation
P.O. Box 368
Intercession City, FL 33848

Authorized Representative:
Mr. Martin J. Drango, Plant Manager

Project No. 0970014-006-AC
PSD Permit No. PSD-FL-268A
Facility ID No. 0970014
SIC No. 4911
Expires: December 1, 2002

PROJECT AND LOCATION

This revised permit is issued pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit). This existing facility is an electric power generating plant with a nominal capacity of 1170 MW. The proposed project will add three simple cycle, dual-fuel, General Electric Model 7EA combustion turbines with electrical generator sets each having a maximum capacity of 91 MW.

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

STATEMENT OF BASIS

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

APPENDICES

The following Appendices are attached as part of this permit.

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

Howard L Rhodes

Howard L. Rhodes, Director
Division of Air Resources Management

Effective Date: January 30, 2002

FACILITY DESCRIPTION

The existing facility is an electric power generating plant consisting of fourteen combustion turbine peaking units (P1-P14). Units P1-P6 each consist of two gas turbines having a combined capacity of 56.7 MW and firing No. 2 distillate oil. Units P7-P10 each consist of a General Electric Model 7EA gas turbine having a capacity of 96.3 MW and firing natural gas or distillate oil. Unit P11 is a Siemens Model V84.3 having a capacity of 171 MW and firing distillate oil. Units P12-P14 each consist of a General Electric Model 7EA gas turbine with a nominal generating capacity of 91 MW when firing natural gas or distillate oil

PROPOSED PROJECT

The proposed project affects the following newly constructed emissions units.

ARMS ID NO.	EMISSION UNIT DESCRIPTION
018 019 020	**Peaking Units P12, P13, and P14**: Each peaking unit consists of a General Electric Model No. PG7121 7EA dual-fuel simple cycle combustion turbine with electrical generator set having a nominal power production output of 91 MW. The units may employ an evaporative cooling system. Dry low-NOx (DLN) combustion technology will be used to control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will be used to control nitrogen oxide emissions when firing the backup fuel of low sulfur distillate oil.

The proposed project modifies original air permit No. PSD-FL-268 to: increase the maximum heat inputs and nominal power production for both gas and oil firing; revise the NOx compliance averaging period from a 3-hour rolling average to a 24-hour block average of actual operating hours; clarify the permit conditions regarding data exclusion for the NOx continuous emissions monitoring system; and correct the minimum observation period for a compliance visible emissions test. The permittee is allowed to perform the minor upgrades on each existing gas turbine (P12-P14) to achieve the capacity increases. No other construction or modification is authorized.

REGULATORY CLASSIFICATION

The facility is a "major facility" with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD) of Air Quality because emissions of at least one pollutant exceed 250 tons per year. Therefore, each modification to this facility resulting in emissions increases greater than the Significant Emissions Rates specified in Table 62-212.400-2 also requires a PSD review and Best Available Control Technology (BACT) determination. For this project, emissions of CO, NOx, PM/PM_{10}, and SAM/SO_2 are significant and this permit establishes the Best Available Control Technology (BACT) for each pollutant.

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

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

RELEVANT DOCUMENTS

- Application received 11/26/01 and all related correspondence.
- Original air permit No. PSD-FL-268 issued 12/9/99.

GENERAL AND ADMINISTRATIVE REQUIREMENTS

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

2. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Central District Office, Florida Department of Environmental Protection, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767. The phone number is 407/894-7555 and the fax number is 407/897-2966.

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

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

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

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

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

8. BACT Determination: In conjunction with extension of the 18-month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 52.166(j)(4)]

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

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

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

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

This permit addresses the following new emissions units.

ARMS EU ID No.	Emission Unit Description
018 019 020	**Peaking Units P12, P13, and P14:** This permit authorizes the installation of three new peaking gas turbines. Each gas turbine consists of a General Electric Model No. PG7121 (7EA) dual-fuel, simple-cycle combustion turbine with electrical generator set. Each unit has a nominal power production capacity of 91 MW. The new units may employ an evaporative cooling system and will use the existing infrastructure including natural gas connections, oil storage and auxiliary equipment. Dry low-NOx (DLN) combustion technology will control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will control NOx emissions when firing low sulfur distillate oil as a backup fuel. Combustion design and clean fuels will minimize emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC. Exhaust gases from each combustion turbine will exit a 56 feet high stack at approximately 1000°F with a volumetric flow rate of 1,436,000 acfm.

APPLICABLE STANDARDS AND REGULATIONS

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

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

PERFORMANCE RESTRICTIONS

3. Permitted Capacity: Each combustion turbine shall operate only in simple-cycle mode and generate a nominal 91 MW of electrical power. Operation of each unit shall not exceed 905 mmBTU per hour of heat input from firing natural gas or 978 mmBTU per hour of heat input from firing low sulfur distillate oil. Excluding startup and shutdown, operation below 50% base load is prohibited. The maximum heat inputs are based on the lower heating value (LHV) of each fuel, an inlet air temperature of 59°F, a relative humidity of 60%, an ambient air pressure of 14.7 psi, and 100% of base load. Therefore, heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Compliance shall be determined by data compiled from the Speedtronic™ Control System adjusted for these parameters. Manufacturer's performance curves, corrected for site conditions or equations for correction to other ambient conditions, shall be provided to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Initial compliance with this requirement

may be demonstrated by compiling data during the initial NSPS tests performed at various load conditions. [Design, Rule 62-210.200(PTE), F.A.C.]

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

5. Allowable Fuels: Each combustion turbine shall be fired by pipeline natural gas containing no more than 1 grain of sulfur per 100 dry standard cubic feet of gas. As a backup fuel, each combustion turbine may be fired with No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Each unit shall be capable of firing natural gas. Compliance with the limits on fuel sulfur content shall be demonstrated by the record keeping requirements and/or the conditions of the Alternate Monitoring Plan specified in this permit. It is noted that these limitations are much more stringent than the NSPS sulfur dioxide limitation and assure compliance with 40 CFR 60.333 and 60.334. [Applicant Request, Rule 62-210.200(PTE), F.A.C.]

6. Hours of Operation: The following limits apply to this group of three combustion turbines.

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

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

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

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

   Total turbine operating hours are the sum of operating hours when firing gas and operating hours when firing oil. The permittee shall install, calibrate, operate and maintain meters to measure and accumulate the amount of each fuel fired and hours of operation for each combustion turbine. [Applicant Request; Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

7. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbines and pollution control devices in accordance with the guidelines and procedures established by each equipment manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

8. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the Compliance Authority as soon as possible, but at least within one (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the

problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

EMISSIONS CONTROLS

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

10. Combustion Controls: The permittee shall employ "good operating practices" in accordance with the manufacturer's recommended operating procedures to control CO, NOx, and VOC emissions. Prior to the initial emissions performance tests, the dry low-NOx (DLN) combustors and Speedtronic™ control system on each gas turbine shall be tuned to optimize the reduction of CO, NOx, and VOC emissions. Thereafter, these systems shall be maintained and tuned, as necessary, to minimize pollutant emissions. [Design, Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

11. DLN Combustion Technology: To control NOx emissions when firing natural gas, the permittee shall install, tune, operate and maintain a dry low-NOx (DLN) combustion system for each combustion turbine in accordance with the manufacturer's recommendations. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific DLN system as part of the Title V permit application. Compliance with this requirement may be demonstrated by compiling data during the initial NSPS tests performed at various load conditions. [Design, Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

12. Water Injection: To control NOx emissions when firing low sulfur distillate oil, the permittee shall install, calibrate and operate an automated water injection system for each combustion turbine in accordance with the manufacturer's recommendations. Each water injection system shall be maintained and adjusted to minimize NOx emissions. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific water injection system as part of the Title V permit application. Compliance with this requirement may be demonstrated by compiling data during the initial NSPS tests performed at various load conditions. [Design, Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

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

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

EMISSIONS STANDARDS

15. Emissions Standards Summary: The following table summarizes the emissions standards specified in this permit.

EU-018, 019, and 020: GE Model 7EA Combustion Turbines (P12, P13, and P14)

Pollutant	**Fuels and Controls**[a]	**Emission Standards**[b]
CO	Gas Firing W/DLN	20.0 ppmvd @ 15% O_2, 3-hour test avg. 43.0 pounds per hour, 3-hour test avg.
	Oil Firing W/Wet Injection	20.0 ppmvd @ 15% O_2, 3-hour test avg. 44.0 pounds per hour, 3-hour test avg.
NOx	Gas Firing W/DLN	
	Compliance by Annual Testing at Base Load	9.0 ppmvd @ 15% O_2, 3-hour test avg. 33.0 pounds per hour, 3-hour test avg.
	Continuous Compliance by CEM	10.0 ppmvd @ 15% O_2, 24-hour avg.
	Oil Firing W/Wet Injection	
	Compliance by Annual Testing at Base Load	42.0 ppmvd @ 15% O_2, 3-hour test avg. 169.0 pounds per hour, 3-hour test avg.
	Continuous Compliance by CEM	42.0 ppmvd @ 15% O_2, 24-hour avg.
PM/PM$_{10}$	Fuel Sulfur Specifications and Combustion Design	Visible emissions ≤ 10% opacity (PM estimated at 0.002 grains/dscf)
SAM/SO_2	Natural Gas Sulfur Specification	≤ 1 grain per 100 SCF of gas
	Low Sulfur Distillate Oil Sulfur Specification	0.05% sulfur by weight
VOC	Gas Firing W/Combustion Design	2.0 ppmvw as methane 2.0 pounds per hour
	Oil Firing W/Combustion Design	4.0 ppmvw as methane 5.0 pounds per hour

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

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

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

16. Carbon Monoxide (CO)

(a) **Gas Firing:** When firing natural gas in a combustion turbine, CO emissions shall not exceed 43.0 pounds per hour nor 20.0 ppmvd corrected to 15% oxygen based on a 3-hour test average.

(b) **Oil Firing**: When firing low sulfur distillate oil in a combustion turbine, CO emissions shall not exceed 44.0 pounds per hour nor 20.0 ppmvd based on a 3-hour test average.

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

17. Nitrogen Oxides (NOx)

(a) **Gas Firing**: When firing natural gas in a combustion turbine, NOx emissions shall not exceed 33.0 pounds per hour nor 9.0 ppmvd corrected to 15% oxygen based on an annual 3-hour compliance test average. In addition, NOx emissions shall not exceed 10.0 ppmvd corrected to 15% oxygen based on a 24-hour block average of all valid data collected from the continuous NOx emissions monitor during actual operation.

(b) **Oil Firing**: When firing low sulfur distillate oil in a combustion turbine, NOx emissions shall not exceed 169.0 pounds per hour nor 42.0 ppmvd corrected to 15% oxygen based on an annual 3-hour compliance test average. In addition, NOx emissions shall not exceed 42.0 ppmvd corrected to 15% oxygen based on a 24-hour block average of all valid data collected from the continuous NOx emissions monitor during actual operation. The permittee shall set up the automated control system for water injection to reduce NOx emissions below 42.0 ppmvd corrected to 15% oxygen.

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

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

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

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

19. Volatile Organic Compounds (VOC)

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

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

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

STARTUP, SHUTDOWN, AND MALFUNCTION

20. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. Such preventable emissions shall be included in the

calculation of the 24-hour averages compiled by the continuous NOx emissions monitor. [Rule 62-210.700, F.A.C.]

21. Alternate Standards and NOx CEMS Data Exclusion: The following permit conditions establish alternate standards or allow the exclusion of monitoring data for specifically defined periods of startup, shutdown, and documented malfunction of a gas turbine. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of emissions during such episodes.

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

   (b) **NOx CEMS Data Exclusion**: For the following identified operational periods, 1-hour NOx emissions rate values may be excluded from the 24-hour block compliance averages in accordance with the corresponding requirements.

      (1) *Startup, Shutdown, and Malfunction*: No more than 1 hourly emission rate value due to startup shall be excluded per cycle. No more than 1 hourly emission rate value due to shutdown shall be excluded per cycle. No more than 2 hourly emission rate values shall be excluded in a 24-hour period due to malfunction. No more than 4 hourly emission rate values shall be excluded in a 24-hour period due to all startups, shutdowns, and malfunctions. Note: A fuel-switch is not considered "startup".

      (2) *Tuning*: If the permittee provides at least five days advance notice prior to a major tuning session performed by the manufacturer's representative, hourly NOx emissions rate values during tuning may be excluded from the 24-hour block compliance averages. Data excluded due to tuning shall not count towards the limit on total excluded data in a 24-hour period. {Permitting Note: As an example, a major tuning session would occur after a combustor change-out. A tuning session may take a several hours each day over a few days. No more than two major tuning sessions would be expected during any year. Major tuning sessions are intended to return the unit to manufacturer's specifications for efficient operation and should result in lower actual emissions.}

As provided by the authority in Rule 62-210.700(5), F.A.C., the above requirements are established in lieu of the provisions of Rule 62-210.700(1), F.A.C. [Design; Rules 62-210.700(5), 62-4.130, and Rule 62-212.400(BACT), F.A.C.]

EMISSIONS PERFORMANCE TESTING

22. Combustion Turbine Testing Capacity: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average air inlet air temperature during the test (with 100 percent represented by a curve depicting heat input vs. air inlet temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. air inlet temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C. [Rule 62-297.310(2), F.A.C.]

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

24. Applicable Test Procedures

(a) **Required Sampling Time.**

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

2. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. [Rule 62-297.310(4)(a)2, F.A.C.]

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

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

25. Determination of Process Variables

(a) **Required Equipment.** The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. [Rule 62-297.310(5)(a), F.A.C.]

(b) **Accuracy of Equipment.** Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value. [Rule 62-297.310(5)(b), F.A.C.]

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

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

(a) **EPA Method 7E**, "Determination of Nitrogen Oxide Emissions from Stationary Sources".

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

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

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

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

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

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

29. Initial Tests Required: Initial compliance with the allowable emission standards specified in this permit shall be determined within 60 days after achieving the maximum permitted capacity, but not later than 180 days after initial operation of the emissions unit. Initial tests for emissions from the combustion turbine shall be conducted for CO, NOx, VOC, and visible emissions individually for firing natural gas and for firing low sulfur distillate oil. Initial NOx performance test data shall also be converted into the units of the corresponding NSPS Subpart GG emissions standards to demonstrate compliance (see Appendix GG). {Permitting Note: These initial tests are required after completing the minor upgrade to achieve increased heat inputs and power generation.} [Rule 62-297.310(7)(a)1, F.A.C.]

30. Annual Performance Tests: Annual emissions performance tests for CO, NOx, and visible emissions from each combustion turbine shall be conducted when firing natural gas. If conducted at permitted capacity, the annual NOx continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the annual compliance stack test. An annual performance test for VOC emissions is not required as long as the unit remains in compliance with the CO and visible emissions limits specified by this permit.

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

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

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

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

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

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

CONTINUOUS MONITORING REQUIREMENTS

35. NOx CEMS Requirements: For each gas turbine, the permittee shall install, calibrate, maintain, and operate continuous emissions monitors (CEMS) to measure and record emissions of nitrogen oxides (NOx) and oxygen (O_2) in a manner sufficient to demonstrate compliance with the standards of this permit. A monitor for carbon dioxide (CO_2) may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen.

(a) **Performance Specifications.** Each monitor shall be installed in a location that will provide emissions measurements representative of actual stack emissions. Each CEMS shall comply with the corresponding performance specifications that identify location, installation, design, performance, and reporting requirements.

(1) Each NOx monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NOx monitor shall be performed using EPA Method 7E or 20 as defined in Appendix A of 40 CFR 60. The NOx monitor shall have dual span capability with a low span (gas) no greater than 30 ppmvd corrected to 15% O_2 and a high span (oil) no greater than 200 ppmvd corrected to 15% O_2.

(2) Each O_2 (or CO_2) CEMS shall comply with Performance Specification 3 in Appendix B of 40 CFR 60. The O_2 reference method for the annual RATA shall be EPA Method 3A Appendix A of 40 CFR 60.

(b) **Data Collection.** Each CEMS shall be designed and operated to sample, analyze, and record emissions data evenly spaced over a 1-hour period during all periods of operation. Each 1-hour average shall be computed using at least one data point in each fifteen minute quadrant of the 1-hour block during which the unit combusted fuel. Notwithstanding this requirement, each 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes. All valid measurements or data points collected during a 1-hour block shall be used to calculate the 1-hour emission averages. If the NOx CEMS measures concentration on a wet basis, the permittee shall use approved methods for correction of measured emissions to a dry basis (0% moisture). The O_2 (or CO_2) CEMS shall express the 1-hour emission rate values in terms of "percent oxygen by volume". The NOx CEMS shall express the 1-hour emission averages in terms of "ppmvd corrected to 15% oxygen".

(c) **Compliance Averages.** Compliance with the 24-hour block NOx emissions standards shall be based on data collected by each required CEMS. The 24-hour block shall start at midnight of each operating day and consist of 24 consecutive 1-hour blocks. For purposes of determining compliance with the emission standards of this permit, missing data shall not be substituted. Instead the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. If a unit operates continuously throughout the day, the 24-hour block average shall be the average of 24 consecutive 1-hour emission averages. If a unit operates less than 24 hours during the day, the 24-hour block average shall be the average of the available valid 1-hour emission averages collected during actual operation If monitoring data is authorized for exclusion (due to startup, shutdown, malfunction, or tuning), the 24-hour block average shall be the average of the remaining valid 1-hour emission averages collected during actual operation. In cases of reduced operation or data exclusion, the compliance average will be based on less than 24, 1-hour emission averages. Upon completion of each 24-hour block, the permittee shall determine separate compliance averages for gas firing and oil firing. A 1-hour emissions average that includes any amount of oil firing shall only be included in the compliance average for oil firing. Upon a request from the Department, the NOx emission rate shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

(d) **Data Exclusion**. Except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each CEMS shall record emissions data at all times including episodes of startup, shutdown, and malfunction. Emissions data recorded during periods of startup, shutdown, or malfunction may only be excluded from the compliance averages in accordance with the requirements previously specified in this permit. To the extent practicable, the permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions. Data recorded during startup, shutdown or malfunction shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited. Excluded emissions data shall be summarized in the required quarterly report.

(e) **Reporting**: If a CEMS reports NOx emissions in excess of a standard, the permittee shall notify the Compliance Authority within one working day with a preliminary report 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 Compliance Authority may request a written summary report of the incident.

(f) **Monitor Availability**. Monitor availability shall not be less than 95% in any calendar quarter. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

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

COMPLIANCE DEMONSTRATIONS

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

37. Fuel Records

(a) Natural Gas: The permittee shall demonstrate compliance with the SO_2 standards of this permit and in 40 CFR 60.333 by complying with the requirements in 40 CFR 75 Appendix D.

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

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

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

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

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

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

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

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

(2) The permittee shall submit a monitoring plan, certified by signature of the Authorized Representative, that commits to using a primary fuel of pipeline supplied natural gas containing no more than 1 grain of sulfur per 100 SCF of gas pursuant to 40 CFR 75.11(d)(2);

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

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

[40 CFR 60, Subpart GG; Applicant Request]

39. Monthly Operations Summary: By the fifth calendar day of each month, the owner or operator shall record the following information in a written or electronic log summarizing the previous month of operation and the previous 12 months of operation: hours of gas firing; million cubic feet of gas fired; hours of oil firing; and gallons of oil fired. The information shall be recorded for each gas turbine and for the group of three gas turbines. Information may be recorded and stored as an electronic file, but

must be available for inspection and/or printing at the request of the Compliance Authority. [Rule 62-4.160(15), F.A.C.]

REPORTS

40. Emissions Performance Test Reports: A report indicating the results of the required emissions performance tests shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.]

41. Quarterly Excess Emissions Reports: If excess emissions occur due to malfunction, the owner or operator shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Following the NSPS format (40 CFR 60.7, Subpart A) periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the standards specified in this permit. Within thirty (30) days following each calendar quarter, the permittee shall submit a report on any periods of excess emissions that occurred during the previous calendar quarter to the Compliance Authority. This quarterly report shall follow the format provided in Appendix XS of this permit and summarize periods of excluded NOx emissions data. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7]

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

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
DB	Duct Burner
HRSG	Heat Recovery Steam Generator
DLN	Dry Low-NOx Combustion Technology
SCR	Selective Catalytic Reduction
OC	Oxidation Catalyst Technology for CO Control

RULE CITATIONS

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

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

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

Facility Identification (ID) Number:

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

New Permit Numbers:

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

Old Permit Numbers:

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

SECTION IV.

APPENDIX GC - CONSTRUCTION PERMIT GENERAL CONDITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

(a) Determination of Best Available Control Technology (X, initial permit);

(b) Determination of Prevention of Significant Deterioration (X, initial permit); and

(c) Compliance with New Source Performance Standards (X, initial permit).

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 BD - FINAL BACT DETERMINATION

Final BACT Determinations

In accordance with Rule 62-212.400, F.A.C., the Department determined that the following standards represent the Best Available Control Technology (BACT) for the simple cycle gas turbines. The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit for the original air construction permit (PSD-FL-268).

EU-018, 019, and 020: GE Model 7EA Combustion Turbines (P12, P13, and P14)

Pollutant	BACT Controls[b]	BACT Standard
CO	Gas Firing W/DLN Combustion	20.0 ppmvd @ 15% oxygen and 43.0 pounds per hour
	Oil Firing W/Combustion Design	20.0 ppmvd @ 15% oxygen and 44.0 pounds per hour
NOx	Gas Firing W/DLN Combustion	9.0 ppmvd @ 15% oxygen and 33.0 pounds per hour 10.0 ppmvd @ 15% oxygen by CEM
	Oil Firing W/Wet Injection	42.0 ppmvd @ 15% oxygen and 169.0 pounds per hour 42.0 ppmvd @ 15% oxygen by CEM
PM/PM_{10}	Fuel Sulfur Specifications and Combustion Design	Visible emissions ≤ 10% opacity
SAM[a]/SO_2	Natural Gas Sulfur Specification	1 grain per 100 SCF of gas
	Low Sulfur Distillate Oil Sulfur Specification	0.05% sulfur by weight
VOC[a]	Gas Firing W/Combustion Design	2.0 ppmvd as methane[a] 2.0 pounds per hour[a]
	Distillate Oil Firing W/Combustion Design	4.0 ppmvd as methane[a] 5.0 pounds per hour[a]

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

[b] DLN means dry low-NOx combustion design.

Revisions and Comments

The original PSD air construction permit was issued on December 9, 1999 and made the above final BACT determinations. In January of 2002, the Department issued a minor revision to the PSD permit that included a slight increase in the heat input rates for both gas and oil firing. This resulted in the following revisions to the NOx mass emissions standards: from 32.0 to 33.0 lb/hour for gas firing, and from 167.0 to 169.0 lb/hour for oil firing. In addition, the averaging period for the CEMS-based NOx emissions standards were revised from a 3-hour rolling average to a 24-hour block average of the actual operating hours to accommodate the multiple startups and fuel switching that occur at this plant. The BACT controls continue to be DLN combustion for gas firing and wet injection for oil firing. It is also noted that the original PSD air construction permit included a slightly higher CO limit for gas firing that applied during the initial CO performance tests and for the subsequent 12 months of operation. This higher standard was removed during the revision because it was no longer applicable.

APPENDIX GG - FEDERAL NEW SOURCE PERFORMANCE STANDARDS (NSPS)

40 CFR 60, SUBPART A - NSPS GENERAL PROVISIONS

This emissions unit is subject to the applicable portions of 40 CFR 60, Subpart A, General Provisions, including:

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

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

40 CFR 60, SUBPART GG - STATIONARY GAS TURBINES

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

40 CFR 60.330 APPLICABILITY AND DESIGNATION OF AFFECTED FACILITY.

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

40 CFR 60.331 DEFINITIONS.

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

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

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

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

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

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

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

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

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

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

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

60.332 STANDARD FOR NITROGEN OXIDES.

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

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = (0.0075)\frac{(14.4)}{Y} + F$$

Where:

STD = allowable NOx emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

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

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-Bound Nitrogen (Percent By Weight)	"F" (NOx Percent By Volume)
N < 0.015	0
0.015 < N < 0.1	0.04(N)
0.1 < N < 0.25	0.004 + 0.0067(N – 0.1)
N > 0.25	0.005

Where, N = the nitrogen content of the fuel (percent by weight).

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

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

40 CFR 60.333 STANDARD FOR SULFUR DIOXIDE.

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

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

40 CFR 60.334 MONITORING OF OPERATIONS.

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

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

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

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

(c) For the purpose of reports required under Sec. 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) Nitrogen oxides. Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with Sec. 60.332 by the performance test required in Sec. 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in Sec. 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under Sec. 60.335(a).

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

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

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

40 CFR 60.335 TEST METHODS AND PROCEDURES.

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in Sec. 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided for in Sec. 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in Secs. 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NOx) shall be computed for each run using the following equation:

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

Where

NOx = emission rate of NOx at 15 percent oxygen and ISO standard ambient conditions, volume percent.

$NOxo$ = observed NOx concentration, ppm by volume.

P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.

P_o = observed combustor inlet absolute pressure at test, mm Hg.

Ho = observed humidity of ambient air, g H_2O/g air.

E = transcendental constant, 2.718.

T_a = ambient temperature, °K.

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

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

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

fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

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

APPENDIX XS - CEMS EXCESS EMISSIONS REPORT

FIGURE 1. NSPS SUMMARY REPORT: GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

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

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

Reporting period dates: From ____________________ to ____________________

Company: ______________________________

Emission Limitation: ______________________________

Address: ______________________________

Monitor Manufacturer and Model No.: ______________________________

Date of Latest CMS Certification or Audit: ______________________________

Process Unit(s) Description: ______________________________

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

Emission data summary [1]	**CMS performance summary** [1]
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:
a. Startup/shutdown .... ____	a. Monitor equipment malfunctions .... ____
b. Control equipment problems .... ____	b. Non-Monitor equipment malfunctions . ____
c. Process problems .... ____	c. Quality assurance calibration .... ____
d. Other known causes .... ____	d. Other known causes .... ____
e. Unknown causes .... ____	e. Unknown causes .... ____
2. Total duration of excess emissions .... ____	2. Total CMS Downtime .... ____
3. [Total duration of excess emissions] x (100) / [Total source operating time] .... ____% [2]	3. [Total CMS Downtime] x (100) / [Total source operating time] .... ____ % [2]

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

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

Note: On a separate page, describe any changes since last quarter in CMS, process or controls. Also, summarize the periods of data excluded from the compliance averages due to startup, shutdown and malfunction.

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

Name: ______________________________

Signature: ______________________________

Title: ______________________________

Date: ____________________

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Martin J. Drango
Plant Manager
Florida Power Corporation
P. O. Box 368
Intercession City, FL 33848

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 2-5-02

C. Signature
X
☐ Agent
☐ Addressee

☒ D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7000 2870 0000 7028 3192

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

OFFICIAL USE

7000 2870 0000 7028 3192

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark
Here

Sent To
Martin J. Drango

Street, Apt. No.; or PO Box No.
PO Box 368

City, State, ZIP+ 4
Intercession City, FL 33848

PS Form 3800, May 2000 See Reverse for Instructions

Memorandum

Florida Department of
Environmental Protection

TO: Howard Rhodes

THRU: Clair Fancy
Al Linero aal 1/25 for CHF

FROM: Jeff Koerner

DATE: January 23, 2002

SUBJECT: Project No. 0970014-006-AC
Air Permit No. PSD-FL-268A
Florida Power Intercession City Plant
Minor Modifications for Units P12 to P14

The final permit is attached for your approval and signature. The permit authorizes minor modifications to Units P12 through P14 (simple cycle gas turbines) at Florida Power's Intercession City Plant, including: increases to the maximum heat inputs and nominal power production for both gas and oil firing; revision of the NOx compliance averaging period; clarification of NOx CEMS data exclusion; and correction of the minimum observation period for a compliance visible emissions test. The existing facility is located in Osceola County approximately 3.5 miles west of Intercession City.

The Department distributed an "Intent to Issue Permit" package on December 19, 2001. The applicant published the "Public Notice of Intent to Issue" in The Osceola News-Gazette on December 22, 2001. The Department received proof of publication on January 16, 2002. No requests for administrative hearings were filed.

Day #90 is April 5, 2002. I recommend your approval of the attached Final Permit for this project.

Attachments

HLR/CHF/AAL/jfk

Florida Power
A Progress Energy Company

RECEIVED
JAN 31 2002
BUREAU OF AIR REGULATION

January 2, 2002

Mr. Al Linero, P.E., Administrator
New Source Review Section
Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

Re: Intercession City Units P12 – P14
Project No. 0970014-006-AC
Draft Permit No. PSD-FL-268A
Public Notice – Proof of Publication

Please find enclosed the "proof of publication" for the public notice of the above referenced draft permit. The notice was published on December 22, 2001.

Please contact me if you have any questions or need additional information.

Sincerely,

Jamie Hunter
Project Technical Specialist
Environmental Services

jjh/JJH021

Enclosure

c(w/enc): Jeff Koerner, FDEP - Tallahassee
Martin Drango, IC44

PROOF OF PUBLICATION

FROM

Osceola News-Gazette

Kissimmee, Florida
OSCEOLA COUNTY

In the Matter of

Public Notice
Of Intent To Issue
Air Construction Permit
Draft Permit PSD-FL-268A

EIVED
JAN 0 2 2002
al Svcs
ent

Filed ...... day of ...., 20 .....
First Publication .. December 22, 2001
Last Publication ... December 22, 2001

Make Remittance to Osceola News-Gazette
Kissimmee, Florida

BEST AVAILABLE COPY

PUBLIC NOTICE OF INTENT
TO ISSUE AIR CONSTRUCTION PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Florida Power Corporation
Intercession City Power Plant
Project No. 0970014-006-AC
Draft Permit: PSD-FL-268A

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to the Florida Power Corporation to make minor modifications to the original PSD air construction permit for three simple cycle gas turbines installed at the Intercession City Power Plant. This plant is located in Osceola County approximatelt 3.5 miles west of Intercession City. The address is 6525 Osceola Polk County Line Road, Intercession City, Florida 33848. The applicant's authorized representative is Mr. Martin J. Drango, the Plant Manager. The applicant's mailing addreses is: P.O. Box 368, Intercession City, Florida 33848.

The original PSD permit authorized installation of three new simple cycle gas turbines at the Intercession city plant. The applicant requested changes to the original permit, primarily for a slight increase in the heat input rates and to clarify NOx compliance monitoring requirements. The heat input rates and NOx mass emission rates would increase by less than 3% of the current values. The draft permit authorizes those increases as well as the following changes: Revises the averaging period of CEMS-based NOx standards from a 3-hour rolling average to a 24-hour block average to accommodate multiple startups and fuel switching at this plant; clarify the continuous NOx monitoring conditions including the allowance for data exclusion; reduce the minimum observation period for compliance visible emissions test from 60 to 30 minutes; and clarify that the plant may provide the analysis of the fuel sulfur contest for distillate oil shipments in addition to an analysis from the fuel vendor.

Because the existing plant is a PSD-major source of air pollution, new projects are subject to the preconstruction review requirements for the Prevention of Significant Deterioration (PSD) of Air Quality in Rule 62-212.400, F.A.C. The proposed changes result in increased annual emissions of 6 tons of NOx per year and 2 tons of SO_2 per year. Annual emissions of other pollutants are not predicted to increase. These levels are well below the PSD significant emission rates defined in Table 62-212.400, F.A.C. Therefore, the project is not subject to PSD.

The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station # 5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, Florida Statues, before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at: 3900 Commonwealth Boulevard, Mail Station # 35, Tallahassee, Florida 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this Notice of Intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60 (3), F.S., must be filed within fourteen (14) days of publication of the Public Notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department for Notice of Agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent interventions will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address and telephone number of the petitioner, the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitionmer wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 A.M. to 5:00 P.M., Monday through Friday, except legal holidays at:

DEPARTMENT OF ENVIRONMENTAL PROTECTION
Bureau of Air Regulation
New Source Review Section
111 S. Magnolia Drive, Suite 4
Tallahassee, FL 32301
Telephone: (850) 488-0114
Fax #: (850) 922-6979

DEPARTMENT OF ENVIRONMENTAL PROTECTION
Central District Office
Air Resource Section
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: (407) 894-7555
Fax #: (407) 897-2966

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call (850) 488-0114, for additional information.

December 22, 2001

)F OF PUBLICATION

DA,
:EOLA

undersigned authority, personally
\utrey, who on oath says that he is
of the Osceola News-Gazette, a
spaper published at Kissimmee, in
lorida; that the attached copy of the
s published weekly in the regular
of said newspaper in the issues of:

...mber 22, 2001

....

ays that the Osceola News-Gazette
published in Kissimmee, in said
lorida, and that the said newspaper
een continuously published in said
Florida, each week and has been
dicals postage matter at the post
e, in said Osceola County, Florida,
year next preceding the first publi-
ned copy of advertisement; and affi-
at he has neither paid nor promised
any person, firm or corporation any discount, rebate,
commission or refund for the purpose of securing this
advertisement for publication in the said newspaper.

.....Dan L. Autrey..............

Sworn to and subscribed before me by Dan L. Autrey,

who is personally known to me, this ..22...day of

......December..... 2001....

Carol L. Gorrell.....
Carol L. Gorrell
(N.P. Seal)

OFFICIAL NOTARY SEAL
CAROL L GORRELL
COMMISSION NUMBER
CC970428
MY COMMISSION EXPIRES
OCT. 24,2004

PROOF OF PUBLICATION

STATE OF FLORIDA,
COUNTY OF OSCEOLA

Before me, the undersigned authority, personally appeared Dan L. Autrey, who on oath says that he is General Manager of the Osceola News-Gazette, a twice weekly newspaper published at Kissimmee, in Osceola County, Florida; that the attached copy of the advertisement was published weekly in the regular and entire edition of said newspaper in the issues of:

......December 22, 2001

....

Affiant further says that the Osceola News-Gazette is a newspaper published in Kissimmee, in said Osceola County, Florida, and that the said newspaper has heretofore been continuously published in said Osceola County, Florida, each week and has been entered as periodicals postage matter at the post office in Kissimmee, in said Osceola County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

.....Dan L. Autrey..............

Sworn to and subscribed before me by Dan L. Autrey,

who is personally known to me, this ..22.. day of

.....December...... 2001.....

Carol L Gorrell.....
Carol L. Gorrell
(N.P. Seal)

OFFICIAL NOTARY SEAL
CAROL L GORRELL
COMMISSION NUMBER
CC970428
MY COMMISSION EXPIRES
OCT. 24,2004

PROOF OF PUBLICATION

FROM

Osceola News-Gazette

Kissimmee, Florida
OSCEOLA COUNTY

In the Matter of

.....Public...Notice...

.Of Intent...To Issue.

Air. Construction Permit

Draft Permit. PSD-FL-268.A

Filed ...... day of December ...., 20 .....
First Publication ..December 22, 2001.
Last Publication ...December 22, 2001.

Make Remittance to Osceola News-Gazette
Kissimmee, Florida

PUBLIC NOTICE OF INTENT
TO ISSUE AIR CONSTRUCTION PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Florida Power Corporation
Intercession City Power Plant
Project No. 0970014-006-AC
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A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 A.M. to 5:00 P.M., Monday through Friday, except legal holidays at:

DEPARTMENT OF ENVIRONMENTAL PROTECTION
Bureau of Air Regulation
New Source Review Section
111 S. Magnolia Drive, Suite 4
Tallahassee, FL 32301
Telephone: (850) 488-0114
Fax #: (850) 922-6979

DEPARTMENT OF ENVIRONMENTAL PROTECTION
Central District Office
Air Resource Section
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: (407) 894-7555
Fax #: (407) 897-2966

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call (850) 488-0114, for additional information.

December 22, 2001

Florida Power
A Progress Energy Company

RECEIVED
FEB 04 2002
BUREAU OF AIR REGULATION

January 2, 2002

Mr. Al Linero, P.E., Administrator
New Source Review Section
Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

Re: Intercession City Units P12 – P14
Project No. 0970014-006-AC
Draft Permit No. PSD-FL-268A
Public Notice – Proof of Publication

Please find enclosed the "proof of publication" for the public notice of the above referenced draft permit. The notice was published on December 22, 2001.

Please contact me if you have any questions or need additional information.

Sincerely,

Jamie Hunter
Project Technical Specialist
Environmental Services

jjh/JJH021

Enclosure

c(w/enc): Jeff Koerner, FDEP - Tallahassee
Martin Drango, IC44

RECEIVED

FEB 04 2002

BUREAU OF AIR REGULATION

PROOF OF PUBLICATION

FROM

Osceola News-Gazette

Kissimmee, Florida
OSCEOLA COUNTY

In the Matter of

Public Notice
Of Intent To Issue
Air Construction Permit
Draft Permit PSD-FL-268A

EIVED

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Filed ...... day of ...., 20 .....
First Publication .. December 22, 2001.
Last Publication ... December 22, 2001.

Make Remittance to Osceola News-Gazette
Kissimmee, Florida

BEST AVAILABLE COPY

PUBLIC NOTICE OF INTENT
TO ISSUE AIR CONSTRUCTION PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTEC
Florida Power Corporation
Intercession City Power Plant
Project No. 0970014-006-AC
Draft Permit: PSD-FL-268A

The Department of Environmental Protection (Depa notice of its intent to issue an air construction permit t Power Corporation to make minor modifications to the ori construction permit for three simple cycle gas turbines in Intercession City Power Plant. This plant is located in O ty approximatelt 3.5 miles west of Intercession City. Th 6525 Osceola Polk County Line Road, Intercession 33848. The applicant's authorized representative is Mr. M go, the Plant Manager. The applicant's mailing addrese 368, Intercession City, Florida 33848.

The original PSD permit authorized installation of thre cycle gas turbines at the Intercession city plant. T requested changes to the original permit, primarily for a s in the heat input rates and to clarify NOx complianc requirements. The heat input rates and NOx mass e would increase by less than 3% of the current values. Th authorizes those increases as well as the following char the averaging period of CEMS-based NOx standards f rolling average to a 24-hour block average to accommo startups and fuel switching at this plant; clarify the cor monitoring conditions including the allowance for da reduce the minimum observation period for compliance sions test from 60 to 30 minutes; and clarify that the plan the analysis of the fuel sulfur contest for distillate oil shipr tion to an analysis from the fuel vendor.

Because the existing plant is a PSD-major source o new projects are subject to the preconstruction review for the Prevention of Significant Deterioration (PSD) of Rule 62-212.400, F.A.C. The proposed changes result annual emissions of 6 tons of NOx per year and 2 ton year. Annual emissions of other pollutants are not increase. These levels are well below the PSD signific rates defined in Table 62-212.400, F.A.C. Therefore, the subject to PSD.

The Department will issue the Final Permit with the at tions unless a response received in accordance with the cedures results in a different decision or significant chan conditions. The Department will accept written co requests for public meetings concerning the proposed pe action for a period of thirty (30) days from the date of pub Public Notice of Intent to Issue Air Construction Permit. ments and requests for public meetings should be pr Department's Bureau of Air Regulation at 2600 Blair Stor Station # 5505, Tallahassee, FL 32399-2400. Any writte filed shall be made available for public inspection. If writ received result in a significant change in the proposed a the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, Florida Statues, before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station # 35, Tallahassee, Florida 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this Notice of Intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60 (3), F.S., must be filed within fourteen (14) days of publication of the Public Notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department for Notice of Agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent interventions will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name

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website at
nmuseum.org.

More
MGM-

Th

PROOF OF PUBLICATION

STATE OF FLORIDA,
COUNTY OF OSCEOLA

Before me, the undersigned authority, personally appeared Dan L. Autrey, who on oath says that he is General Manager of the Osceola News-Gazette, a twice weekly newspaper published at Kissimmee, in Osceola County, Florida; that the attached copy of the advertisement was published weekly in the regular and entire edition of said newspaper in the issues of:

......December 22, 2001

....

Affiant further says that the Osceola News-Gazette is a newspaper published in Kissimmee, in said Osceola County, Florida, and that the said newspaper has heretofore been continuously published in said Osceola County, Florida, each week and has been entered as periodicals postage matter at the post office in Kissimmee, in said Osceola County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

....Dan L. Autrey..............

Sworn to and subscribed before me by Dan L. Autrey,

who is personally known to me, this ..22...day of

......December...... 2001....

Carol L. Gorrell.....
Carol L. Gorrell
(N.P. Seal)

OFFICIAL NOTARY SEAL
CAROL L GORRELL
COMMISSION NUMBER
CC970428
MY COMMISSION EXPIRES
OCT. 24,2004

BEST AVAILABLE COPY

PUBLIC NOTICE OF INTENT
TO ISSUE AIR CONSTRUCTION PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Florida Power Corporation
Intercession City Power Plant
Project No. 0970014-006-AC
Draft Permit: PSD-FL-268A

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to the Florida Power Corporation to make minor modifications to the original PSD air construction permit for three simple cycle gas turbines installed at the Intercession City Power Plant. This plant is located in Osceola County approximatelt 3.5 miles west of Intercession City. The address is 6525 Osceola, Polk County Line Road, Intercession City, Florida 33848. The applicant's authorized representative is Mr. Martin J. Drango, the Plant Manager. The applicant's mailing addreses is: P.O. Box 368, Intercession City, Florida 33848.

The original PSD permit authorized installation of three new simple cycle gas turbines at the Intercession city plant. The applicant requested changes to the original permit, primarily for a slight increase in the heat input rates and to clarify NOx compliance monitoring requirements. The heat input rates and NOx mass emission rates would increase by less than 3% of the current values. The draft permit authorizes those increases as well as the following changes: Revises the averaging period of CEMS-based NOx standards from a 3-hour rolling average to a 24-hour block average to accommodate multiple startups and fuel switching at this plant; clarify the continuous NOx monitoring conditions including the allowance for data exclusion; reduce the minimum observaiion period for compliance visible emissions test from 60 to 30 minutes; and clarify that the plant may provide the analysis of the fuel sulfur contest for distillate oil shipments in addition to an analysis from the fuel vendor.

Because the existing plant is a PSD-major source of air pollution, new projects are subject to the preconstruction review requirements for the Prevention of Significant Deterioration (PSD) of Air Quality in Rule 62-212.400, F.A.C. The proposed changes result in increased annual emissions of 6 tons of NOx per year and 2 tons of SO_2 per year. Annual emissions of other pollutants are not predicted to increase. These levels are well below the PSD significant emission rates defined in Table 62-212.400, F.A.C. Therefore, the project is not subject to PSD.

The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station # 5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, Florida Statues, before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

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A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station # 35, Tallahassee, Florida 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this Notice of Intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60 (3), F.S., must be filed within fourteen (14) days of publication of the Public Notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department for Notice of Agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent interventions will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitionmer wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 A.M. to 5:00 P.M., Monday through Friday, except legal holidays at:

DEPARTMENT OF ENVIRONMENTAL PROTECTION
Bureau of Air Regulation
New Source Review Section
111 S. Magnolia Drive, Suite 4
Tallahassee, FL 32301
Telephone: (850) 488-0114
Fax #: (850) 922-6979

DEPARTMENT OF ENVIRONMENTAL PROTECTION
Central District Office
Air Resource Section
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: (407) 894-7555
Fax #: (407) 897-2966

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call (850) 488-0114, for additional information.

December 22, 2001

OF OF PUBLICATION

DA,
EOLA

undersigned authority, personally
Autrey, who on oath says that he is
of the Osceola News-Gazette, a
spaper published at Kissimmee, in
lorida; that the attached copy of the
s published weekly in the regular
of said newspaper in the issues of:

mber 22, 2001

. . . .

ys that the Osceola News-Gazette
published in Kissimmee, in said
lorida, and that the said newspaper
en continuously published in said
Florida, each week and has been
dicals postage matter at the post
e, in said Osceola County, Florida,
year next preceding the first publi-
hed copy of advertisement; and affi-
at he has neither paid nor promised
any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Dan L. Autrey

Sworn to and subscribed before me by Dan L. Autrey,

who is personally known to me, this 22 day of

December 2001

Carol L. Gorrell
Carol L. Gorrell
(N.P. Seal)

OFFICIAL NOTARY SEAL
CAROL L GORRELL
COMMISSION NUMBER
CC970428
MY COMMISSION EXPIRES
OCT. 24,2004

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Martin J. Drango
Plant Manager
Florida Power Corporation
P. O. Box 368
Intercession City, FL 33848

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 2-5-02

C. Signature
X
☒ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7000 2870 0000 7028 3192

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

OFFICIAL USE

7000 2870 0000 7028 3192

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark
Here

Sent To
Martin J. Drango

Street, Apt. No.; or PO Box No.
PO Box 368

City, State, ZIP+ 4
Intercession City, FL 33848

PS Form 3800, May 2000 **See Reverse for Instructions**

Florida Power
A Progress Energy Company

RECEIVED
NOV 26 2001
BUREAU OF AIR REGULATION

November 21, 2001

Mr. Al Linero, P.E., Administrator
New Source Review Section
Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

Re: Intercession City Units P12 – P14
Application to Modify Permit ~~097001~~-003-AC/PSD-FL-268
0970014

Please find enclosed four copies of an application to modify the Intercession City PSD air permit. The main focus of this request is to incorporate an upgrade to these units in conjunction with routine warranty work that is planned. This upgrade results in an increase in the firing temperature of these peaking units in order to maximize output and optimize efficiency. In addition, modifications to the current permit language are requested to address concerns related to the NOx excess emissions requirements. The requested changes are necessary to address the somewhat unique operating scenarios demonstrated by these units, as well as clarify the interpretation of the NOx compliance demonstration methodology and associated reporting requirements.

Although the two issues above are the primary focus of this modification, there are also several minor issues that Florida Power would like to address at this time. These include a request to reduce the annual visible emissions test period from 60 minutes to 30 minutes, clarification that required fuel oil analysis may be provided by either the facility or the fuel vendor, and removal of language requiring that each of these units to be capable of accommodating both oil and gas fuels.

Please contact Jamie Hunter at (727) 826-4363 or me if you have any questions or need additional information.

Sincerely,

Martin J Drango

Martin Drango
Plant Manager/Responsible Official
Intercession City Plant

jjh/JJH019

Enclosures

c: Jeff Koerner, FDEP - Tallahassee ✓
Scott Osbourn, ENSR – St. Petersburg

PLANT OFFICE: 6525 Osceola Polk Line Road * P.O. Box 368 * Intercession City * Florida 33848 * 407-396-2111
A Progress Energy Company

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

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

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

Enclosed is Final Permit No. 0970014-003-AC (PSD-FL-268). This permit authorizes Florida Power Corporation to add three new simple cycle General Electric Model 7EA combustion turbines with electrical generator sets (87 MW each) to the existing Intercession City plant. As noted in the Final Determination (attached), the Department made minor changes to the Final Permit at the requests of the applicant and EPA Region 4. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 12/13/99 to the person(s) listed:

Mr. W. Jeffrey Pardue, FPC*
Mr. Scott Osborne, FPC
Mr. J. Michael Kennedy, FPC
Mr. Len Kozlov, DEP - Central District Office

Ms. Katy Forney, EPA Region 4
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Charlotte J. Hayes 12/13/99
(Clerk) (Date)

Z 031 391 899

US Postal Service

Receipt for Certified Mail

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

Sent to
Jeffrey Pardue

Street & Number
PO Box 14042

Post Office, State, & ZIP Code
St. Petersburg Fl 33733

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
12/13/99 - PSD-FI-2168
0970014-003-AC

PS Form **3800**, April 1995

Is your **RETURN ADDRESS** completed on the reverse side?

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

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

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

Consult postmaster for fee.

3. Article Addressed to:

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

4a. Article Number
Z 031 391 899

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

7. Date of Delivery ~~12/15/99~~ DEC 15 1999

5. Received By: *(Print Name)*

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

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

Thank you for using Return Receipt Service.

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

PERMIT PROCESSING SCHEDULE

05/25/99 The Department received the application for this project.

06/02/99 The Department received additional pages of the application that were accidentally omitted.

06/16/99 The Department received air dispersion modeling files for the project.

06/22/99 The Department requested additional information to complete the application.

08/12/99 Received e-mail from NPS that NPS and FWS did not have any comments on this project.

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

09/15/99 The Department distributed an Intent to Issue Permit package that would authorize the addition of three new simple cycle General Electric Model 7EA combustion turbines with electrical generator sets (87 MW each) to the existing Intercession City Plant.

09/30/99 The applicant published the "Public Notice of Intent to Issue" in Osceola News-Gazette.

10/01/99 The Department's Office of General Counsel received a request from the applicant to extend the period of time in which to file a petition for an administrative hearing.

10/15/99 The Department received comments from the applicant (by fax) on the Draft Permit.

10/21/99 The Department received proof of publication from the applicant.

10/25/99 The Department met with the applicant's representatives in Tallahassee to discuss the applicant's comments on the Draft Permit.

10/25/99 The Department received comments from EPA Region 4 on the Draft Permit.

11/02/99 The Department granted the applicant's request and extended the time to file for an administrative hearing until December 15, 1999.

11/02/99 The Department e-mailed a response to the applicant's comments made in writing and presented at the 10/25/99 meeting.

11/16/99 The Department received additional information and comments from the applicant requesting continuous compliance with the NOx standard based on "lb/hour" only or increasing the ppmvd limit to 10 ppmvd.

12/03/99 The Department received additional information and comments from the applicant requesting continuous compliance with the NOx standard based on "10 ppmvd" with a 3-hour rolling average. Annual testing would demonstrate compliance with the lb/hr limit and the 9-ppmvd basis.

12/06/99 The Department and applicant agreed upon proposed revisions.

12/07/99 The applicant withdrew the request for an extension to file for an administrative hearing.

COMMENTS/REQUESTS FROM THE APPLICANT

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

> " Excess Emissions Allowed: Providing the permittee adheres to best operational practices to minimize the amount and duration of excess emissions, the following conditions shall apply:
>
> (a) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for up to 2.0 hours in any 24-hour period.
>
> (b) During startup, shutdown, and malfunction, the NOx CEM shall monitor and record NOx emissions. However, up to 2.0 hours of monitoring data during any 24-hour period may be excluded from the continuous NOx compliance demonstration as a result of startup, shutdown, and documented malfunctions. In case of malfunctions, the owner or operator shall notify the Compliance Authorities in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report."

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

CONCLUSION

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

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE:

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

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

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

PROJECT AND LOCATION

This permit is issued pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit). This existing facility is an electric power generating plant with a nominal hourly capacity of 897 megawatts (MW). The proposed project will add three simple cycle, dual-fuel, General Electric Model 7EA combustion turbines with electrical generator sets each having a maximum hourly capacity of 87 MW.

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

STATEMENT OF BASIS

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

APPENDICES

The following Appendices are attached as part of this permit.

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

Howard L. Rhodes, Director
Division of Air Resources Management

Date: 12/9/99

"More Protection, Less Process"

FACILITY DESCRIPTION

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

NEW EMISSIONS UNITS

The proposed project will add the following new emissions units.

ARMS ID No.	EMISSION UNIT DESCRIPTION
018 019 020	**Peaking Units P12, P13, and P14**: Each peaking unit consists of a General Electric Model No. PG7121 7EA dual-fuel simple cycle combustion turbine with electrical generator set having a nominal hourly power production output of 87 MW. The units may employ an evaporative cooling system. Dry low-NOx (DLN) combustion technology will be used to control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will be used to control nitrogen oxide emissions when firing the backup fuel of low sulfur distillate oil.

REGULATORY CLASSIFICATION

The facility is a "major facility" with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD) of Air Quality because emissions of at least one pollutant exceed 250 tons per year. Therefore, each modification to this facility resulting in emissions increases greater than the Significant Emissions Rates specified in Table 62-212.400-2 also requires a PSD review and Best Available Control Technology (BACT) determination. For this project, emissions of CO, NOx, PM/PM_{10}, and SAM/SO_2 are significant and this permit establishes the Best Available Control Technology (BACT) for each pollutant.

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

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

RELEVANT DOCUMENTS

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

GENERAL AND ADMINISTRATIVE REQUIREMENTS

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

2. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Central District Office, Florida Department of Environmental Protection, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767. The phone number is 407/894-7555 and the fax number is 407/897-2966.

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

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

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

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

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

8. BACT Determination: In conjunction with extension of the 18 month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 52.166(j)(4)]

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

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

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

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

This permit addresses the following new emissions units.

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

APPLICABLE STANDARDS AND REGULATIONS

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

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

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

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

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

PERFORMANCE RESTRICTIONS

3. Permitted Capacity: Each combustion turbine shall operate only in simple-cycle mode and generate a nominal 87 MW per hour of electrical power. Operation of each unit shall not exceed 885 mmBTU per hour of heat input from firing natural gas or 954 mmBTU per hour of heat input from firing low sulfur distillate oil. Operation below 50% of base load shall be limited to two (2) hours during any 24-hour period (day). The maximum heat inputs are based on the lower heating value (LHV) of each fuel, an inlet air temperature of 59°F, a relative humidity of 60%, an ambient air pressure of 14.7 psi, and 100% of base load. Therefore, heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Compliance shall be determined by data compiled from the Speedtronic™ Control System adjusted for these parameters. Manufacturer's performance curves, corrected for site conditions or equations for correction to other ambient conditions, shall be provided to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Initial compliance with this requirement may be demonstrated by compiling data during the

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

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

5. Allowable Fuels: Each combustion turbine shall be fired by pipeline natural gas containing no more than 1 grain of sulfur per 100 dry standard cubic feet of gas. As a backup fuel, each combustion turbine may be fired with No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Each unit shall be capable of accommodating either fuel. Compliance with limits on fuel sulfur content shall be demonstrated by the record keeping requirements and/or the conditions of the Alternate Monitoring Plan specified in this permit. It is noted that these limitations are much more stringent than the NSPS sulfur dioxide limitation and assure compliance with 40 CFR 60.333 and 60.334. [Applicant Request, Rule 62-210.200, F.A.C. (Definition - Potential Emissions)]

6. Hours of Operation: The following limits apply to this group of three combustion turbines.

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

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

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

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

   Total turbine operating hours are the sum of operating hours when firing gas and operating hours when firing oil. The permittee shall install, calibrate, operate and maintain meters to measure and accumulate the amount of each fuel fired and hours of operation for each combustion turbine. [Applicant Request; Rule 62-212.400, F.A.C. (BACT); Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

7. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbines and pollution control devices in accordance with the guidelines and procedures established by each equipment manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

8. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the Compliance Authority as soon as possible, but at least within one (1) working day, excluding

weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

EMISSIONS CONTROLS

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

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

11. DLN Combustion Technology: To control NOx emissions when firing natural gas, the permittee shall install, tune, operate and maintain a dry low-NOx (DLN) combustion system for each combustion turbine in accordance with the manufacturer's recommendations. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific DLN system as part of the Title V permit application. Compliance with this requirement may be demonstrated by compiling data during the initial NSPS tests performed at various load conditions. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

12. Water Injection: To control NOx emissions when firing low sulfur distillate oil, the permittee shall install, calibrate and operate an automated water injection system for each combustion turbine in accordance with the manufacturer's recommendations. Each water injection system shall be maintained and adjusted to minimize NOx emissions. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific water injection system as part of the Title V permit application. Compliance with this requirement may be demonstrated by compiling data during the initial NSPS tests performed at various load conditions. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

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

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

EMISSIONS STANDARDS

15. Emissions Standards Summary: The following table summarizes the emissions standards specified in this permit.

EU-018, 019, and 020: GE Model 7EA Combustion Turbines		
Pollutant	**Fuels and Controls**[a]	**Emission Standards**[b]
CO	Gas Firing W/DLN	
	During First 12 Months After Initial Testing	25.0 ppmvd @ 15% O_2, 3-hour test avg. 54.0 pounds per hour, 3-hour test avg.
	After First 12 Months After Initial Testing	20.0 ppmvd @ 15% O_2, 3-hour test avg. 43.0 pounds per hour, 3-hour test avg.
	Oil Firing W/Wet Injection	20.0 ppmvd @ 15% O_2, 3-hour test avg. 44.0 pounds per hour, 3-hour test avg.
NOx	Gas Firing W/DLN	
	Compliance by Annual Testing at Base Load	9.0 ppmvd @ 15% O_2, 3-hour test avg. 32.0 pounds per hour, 3-hour test avg.
	Continuous Compliance by CEM	10.0 ppmvd @ 15% O_2, 3-hour avg.
	Oil Firing W/Wet Injection	
	Compliance by Annual Testing at Base Load	42.0 ppmvd @ 15% O_2, 3-hour test avg. 167.0 pounds per hour, 3-hour test avg.
	Continuous Compliance by CEM	42.0 ppmvd @ 15% O_2, 3-hour avg.
PM/PM10	Fuel Sulfur Specifications and Combustion Design	Visible emissions ≤ 10% opacity (PM estimated at 0.002 grains/dscf)
SAM/SO_2	Natural Gas Sulfur Specification	1 grain per 100 SCF of gas
	Low Sulfur Distillate Oil Sulfur Specification	0.05% sulfur by weight
VOC	Gas Firing W/Combustion Design	2.0 ppmvw as methane 2.0 pounds per hour
	Oil Firing W/Combustion Design	4.0 ppmvw as methane 5.0 pounds per hour

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

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

16. Carbon Monoxide (CO)

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

(b) **Oil Firing**: When firing low sulfur distillate oil in a combustion turbine, CO emissions shall not exceed 44.0 pounds per hour nor 20.0 ppmvd based on a 3-hour test average.

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

17. Nitrogen Oxides (NOx)

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

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

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

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

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

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

19. Volatile Organic Compounds (VOC)

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

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

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

EXCESS EMISSIONS

20. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup,

shutdown or malfunction, shall be prohibited. These emissions shall be included in the calculation of the 3-hour averages compiled by the continuous NOx emissions monitor. [Rule 62-210.700, F.A.C.]

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

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

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

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

EMISSIONS PERFORMANCE TESTING

22. Combustion Turbine Testing Capacity: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average air inlet air temperature during the test (with 100 percent represented by a curve depicting heat input vs. air inlet temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. air inlet temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C. [Rule 62-297.310(2), F.A.C.]

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

24. Applicable Test Procedures

    (a) **Required Sampling Time.**

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

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

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

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

25. Determination of Process Variables

(a) **Required Equipment.** The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. [Rule 62-297.310(5)(a), F.A.C.]

(b) **Accuracy of Equipment.** Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value. [Rule 62-297.310(5)(b), F.A.C.]

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

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

(a) **EPA Method 7E**, "Determination of Nitrogen Oxide Emissions from Stationary Sources".

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

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

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

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

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

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

29. Initial Tests Required: Initial compliance with the allowable emission standards specified in this permit shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days after initial operation of the emissions unit. Initial tests for emissions from the combustion turbine shall be conducted for CO, NOx, VOC, and visible emissions individually for firing natural gas and for firing low sulfur distillate oil. Initial NOx performance test data shall also be converted into the units of the corresponding NSPS Subpart GG emissions standards to demonstrate compliance (see Appendix GG). [Rule 62-297.310(7)(a)1., F.A.C.]

30. Annual Performance Tests: Annual emissions performance tests for CO, NOx, and visible emissions from each combustion turbine shall be conducted when firing natural gas. If conducted at permitted capacity, the annual NOx continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the annual compliance stack test. An annual performance test for VOC emissions is not required as long as the unit remains in compliance with the CO and visible emissions limits specified by this permit.

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

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

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

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

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

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

CONTINUOUS MONITORING REQUIREMENTS

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

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

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

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

COMPLIANCE DEMONSTRATIONS

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

37. Fuel Records

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

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

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

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

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

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

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

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

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

(2) The permittee shall submit a monitoring plan, certified by signature of the Authorized Representative, that commits to using a primary fuel of pipeline supplied natural gas containing no more than 1 grain of sulfur per 100 SCF of gas pursuant to 40 CFR 75.11(d)(2);

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

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

[40 CFR 60, Subpart GG, Applicant Request]

39. Monthly Operations Summary: By the fifth calendar day of each month, the owner or operator shall record the following information in a written or electronic log summarizing the previous month of operation and the previous 12 months of operation: hours of gas firing; million cubic feet of gas fired; hours of oil firing; and gallons of oil fired. The information shall be recorded for each gas turbine and for the group of three gas turbines. Information may be recorded and stored as an electronic file, but must be available for inspection and/or printing at the request of the Compliance Authority. [Rule 62-4.160(15), F.A.C.]

REPORTS

40. Emissions Performance Test Reports: A report indicating the results of the required emissions performance tests shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.].

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

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

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
DB	- Duct Burner
HRSG	- Heat Recovery Steam Generator
DLN	- Dry Low-NOx Combustion Technology
SCR	- Selective Catalytic Reduction
OC	- Oxidation Catalyst Technology for CO Control

RULE CITATIONS

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

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

Example: **[Rule 62-213.205, F.A.C.]**

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

Facility Identification (ID) Number:

Example: Facility ID No. 099-0001

Where:	099	- 3 digit number indicates that the facility is located in Palm Beach County
	0221	- 4 digit number assigned by state database identifies specific facility

New Permit Numbers:

Example: Permit No. 099-2222-001-AC or 099-2222-001-AV

Where:	AC	- identifies permit as an Air Construction Permit
	AV	- identifies permit as a Title V Major Source Air Operation Permit
	099	- 3 digit number indicates that the facility is located in Palm Beach County
	2222	- 4 digit number identifies a specific facility
	001	- 3 digit sequential number identifies a specific permit project

Old Permit Numbers:

Example: Permit No. AC50-123456 or AO50-123456

Where:	AC	- identifies permit as an Air Construction Permit
	AO	- identifies permit as an Air Operation Permit
	123456	- 6 digit sequential number identifies a specific permit project

APPENDIX BD
BACT DETERMINATION

Florida Power Corporation
FPC Intercession City Plant
Osceola County

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

1.0 EXISTING FACILITY

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

Because emissions of at least one criteria pollutant are greater than 250 TPY, the existing facility is considered a "major facility" with respect to Rule 62-212.400, F.A.C. - Prevention of Significant Deterioration (PSD) of Air Quality. Therefore, a PSD review and a Best Available Control Technology (BACT) determination is required for each pollutant that will experience an emissions increase greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C.

2.0 PROJECT DESCRIPTION

The applicant, Florida Power Corporation (FPC), proposes to add three new General Electric Model No. PG7121 7EA dual-fuel simple cycle combustion turbines with electrical generator sets having a nominal power production of 87 MW. The new units may employ an evaporative cooling system and will use the existing infrastructure including oil storage and support equipment. Dry low-NOx (DLN) combustion technology will be used to control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will be used to control nitrogen oxide emissions when firing low sulfur distillate oil. The applicant requested the operational flexibility of limiting total turbine operating hours for the three combined units to 10,170 hours per year. Of this total, no more than 3000 turbine hours per year would occur when firing low sulfur distillate oil. Combustion design and clean fuels will be used to minimize emissions of carbon monoxide, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. Emissions will exit the combustion turbine at through a 56 feet high stack.

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

3.0 APPLICATION PROCESSING SCHEDULE

05/25/99	The Department received a PSD air construction permit application.
06/22/99	The Department requested additional information.
08/02/99	The Department received additional information from the applicant; application complete.

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

4.0 PSD APPLICABILITY REVIEW

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

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

The existing facility is considered a PSD major source of air pollution because current potential emissions of at least one criteria pollutant are greater than 250 tons per year. Once a facility is classified as a PSD major source, new projects are reviewed for PSD applicability based on lower thresholds known as the Significant Emission Rates listed in Table 212.400-2, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each significant pollutant in accordance with Rule 62-212.400, F.A.C. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to implement BACT for several "significant" regulated pollutants.

This project will be located in Osceola County, an area that is currently in attainment, or designated as unclassifiable, for all air pollutants subject to a National Ambient Air Quality Standard (AAQS). The following table summarizes the potential emissions increases and PSD applicability for this new project.

Pollutant	Project Potential Emissions (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	Subject To BACT?
CO	260 / 220[a]	100	Yes	Yes
NOx	365[b]	40	Yes	Yes
PM/PM10	73[b]	15	Yes	Yes
SAM	9[b]	7	Yes	Yes
SO2	95[b]	40	Yes	Yes
VOC	15[b]	40	No	No

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

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

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

5.0 BACT DETERMINATION PROCEDURE

For projects subject to PSD review, it is the Department's responsibility to determine the Best Available Control Technology (BACT) for each regulated pollutant emitted in excess of a Significant Emission Rate. The BACT determination must be based on the maximum degree of emissions reduction that the Department determines is achievable through application of production processes and available methods, systems, and techniques for control of each such pollutant. The Department's determination is made on a case-by-case basis for each proposed project, taking into account energy, environmental and economic impacts. In addition to the information submitted by the applicant, the Department may rely upon other available information in making its BACT determination and shall also give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently directs that BACT should be determined using the "top-down" approach. In this approach, available control technologies are ranked in order of control effectiveness for the emissions unit under review. The most stringent control option is evaluated first and selected as BACT unless it is technically infeasible for the proposed project or rejected due to adverse energy, environmental or economic impacts. If the control option is eliminated, the next most stringent alternative is considered. This top-down approach continues until BACT is determined.

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

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

6.0 PROJECT ANALYSIS AND BACT DETERMINATIONS

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

- Comments from the National Park Service dated June 6, 1999;
- No comments were received from EPA Region 4;
- DOE web site information on Advanced Turbine Systems Project;
- Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines;
- General Electric technical product literature regarding the DLN-1 combustor design, CO/NOx performance curves vs. load, and the Speedtronic^{TM} Mark V Gas Turbine Control System.

- Emissions stack test results (September/October 1996) for a similar GE Model 7EA combustion gas turbine located at the Panda-Brandywine Cogeneration Facility in Brandywine, Maryland.
- Goal Line Environmental Technology Website: http://www.glet.com;
- TEC Website – www.teco-energy.com;
- Catalytica Website – www.catalytica-inc.com
- ARMS compliance data for similar General Electric 7EA units located at Gainesville Regional Utilities' Deerhaven Station and Kissimmee Utilities Authority's Cane Island Plant.

6.1 NITROGEN OXIDES (NOX)

6.1.1 Discussion of NOx Emissions

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

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

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

6.1.2 Applicant's Proposed NOx Controls

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

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

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

Conventional Selective Catalytic Reduction (SCR): This is an add-on control technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst bed to combine with NOx in a reduction reaction forming nitrogen and water. For this reaction to proceed satisfactorily, the exhaust gas temperature must be maintained between 450° F and 850°F. SCR is a commercially available, demonstrated control technology currently employed on several combined cycle combustion turbine projects capable of very low NOx emissions (< 3.5 ppmvd). However, conventional SCR is not technically feasible because the combustion turbine exhaust temperature of 1100°F is too high for standard catalysts and the oxidation reaction would not occur.

"Hot" Selective Catalytic Reduction (SCR): Due to the temperature limitation of conventional SCR catalysts, manufacturers have developed specially formulated zeolite catalysts designed to further the reduction reaction at temperatures up to 1025°F which is within the range of the exhaust gas temperature (1000°F) of this project. Typical NOx removal efficiencies for a hot SCR system would be 70% to 90% removal. Hot SCR is technically feasible for this project.

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

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

SCONOx™: SCONOx™ is a NOx and CO control system exclusively offered by Goal Line Environmental Technologies. Specialized potassium carbonate catalyst beds reduce CO and NOx emissions using an oxidation/absorption/regeneration cycle. The required operating temperature range is between 300°F and 700°F which requires a HRSG for use with a gas turbine. SCONOx™ is not technically feasible because the combustion turbine exhaust temperature of 1100°F is too high.

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

Of the control alternatives discussed, only DLN combustor technology, wet injection, and hot SCR remain as viable control options. For evaluation purposes, DLN for gas firing and wet injection for oil firing were combined to form a single control alternative. For this project, hot selective catalytic reduction (SCR) with ammonia injection is recognized as the top control option followed by dry low-NOx (DLN) combustor technology for gas firing combined with water injection for oil firing. The applicant reviewed hot SCR for the following additional adverse impacts.

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

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

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

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

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

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

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

6.1.3 Department's NOx BACT Determination

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

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

Environmental Impacts: The Department gives no consideration to the applicant's comment that NOx levels are already below the PSD significant impact levels and AAQS. This is considered only in the air quality analysis and not in making a BACT determination. However, hot SCR requires the injection of ammonia at slightly above the stoichiometric rate which inevitably results in ammonia "slip" or emissions of unreacted ammonia perhaps as much as 25 tons per year could slip by the hot SCR system. Ammonia may react with sulfur to generate up to additional 50% more PM_{10} emissions in the form of ammonium sulfates and bisulfates. Ammonia has been designated as an Extremely Hazardous Substance under federal SARA Title III regulations. Finally, the spent catalyst could be considered hazardous requiring handling and disposal subject to RCRA regulations.

Economic Impacts: The Department disagrees with the applicant's cost analysis. First, the applicant multiplied the costs from another project nearly twice the size of the proposed combustion turbine by 50% to estimate costs for hot SCR. Second, the applicant estimated NOx emission reductions were based on 2390 hours of gas firing and 1000 hours of oil firing. However, the applicant also requested a limit of 10,170 total turbine hours for the three combined units with up to 3000 hours of total oil firing to provide operational flexibility. So, hours of operation for any one turbine could be much higher because of the requested flexible limits. Therefore, the Department performed a cost analysis using a vendor quote from an ongoing project that also involves hot SCR applied to a General Electric Model 7EA combustion turbine. In addition, the Department believes it is conservative to consider 5760 hours of gas firing and 3000 hours of oil firing to estimate potential emission reductions. The following table summarizes the Department's analysis. The applicant reviewed SCR for the following additional adverse impacts.

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

Table Notes:

[a] Based on emissions from DLN-controlled level to SCR-controlled level. Assumes similar level of control for 7760 hr/yr of gas firing and 1000 hr/yr of oil firing.

[b] Based on estimated installed capital cost of $4,644,270 and a total annualized cost of $1,240,955 per year from the application and a vendor quote for a similar unit (Hardee Power Station, PSD-FL-140a).

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

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

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

This BACT determination is much more stringent than the standards of NSPS, Subpart GG. Compliance with the BACT emissions limiting standards shall be demonstrated by conducting initial and annual performance tests in accordance with EPA Method 20. Compliance shall be demonstrated with separate performance tests conducted for the firing of natural gas as well as for the firing of low sulfur distillate oil. In addition, a certified continuous emissions monitor shall be used to demonstrate compliance with BACT limits of 10.0 ppmvd @ 15% oxygen for gas firing and 42.0 ppmvd @ 15% oxygen for oil firing based on a 3-hour average. The slightly higher NOx concentration was specified in consideration for the shorter averaging period (requested by the EPA) and a reduction in oil firing from 3000 to 2500 total turbine hours of operation for all three gas turbines.

6.2 CARBON MONOXIDE (CO)

6.2.1 Discussion of CO Emissions

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

6.2.2 Applicant's Proposed CO BACT

The applicant identifies two control options that are technically feasible and commercially available for combustion turbines: an oxidation catalyst and combustion process design. Noble metal oxidation catalysts may be incorporated into the combustion turbine exhaust. These catalysts promote the oxidation of CO to carbon dioxide (CO_2) at much lower temperatures (650°F to 1150°F) than possible for oxidation without the catalyst. For this project, the exhaust gas temperature of 1100°F is in the proper design range and at this temperature, the control efficiency is primarily a function of gas residence time. An oxidation catalyst is recognized as the top control option and the applicant reviewed this option for the following additional adverse impacts.

Energy Impacts: Installation of an oxidation catalyst would result in an energy penalty due to the pressure drop across the catalyst bed of about 2 inches of water. This equates to about 12.5 million kWh per year of potential lost power generation or nearly 1000 residential customers per year.

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

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

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

Table Notes:

[a] Based on emissions from DLN-controlled level to oxidation catalyst-controlled level. Assumes similar level of control for gas or oil firing. Assumes 2390 hours of gas firing and 1000 hours of oil firing.

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

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

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

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

6.2.3 Department's CO BACT Determination

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

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

Environmental Impacts: The Department rejects the applicant's argument that the further reduction of CO emissions would have negligible ambient impacts. Ambient impacts are evaluated in the modeling analysis and are not considered in the BACT determination.

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

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

Table Notes:

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

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

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

- The Department is aware of two similar GE 7EA units permitted in Florida. The Gainesville Regional Utilities' Deerhaven Station operates a simple cycle peaking unit with a NOx limit of 15 ppmvd and a CO limit to remain under 100 tons per year. Stack tests indicate CO emissions of 7.1 ppmvd with NOx emissions at 7.9 ppmvd. Kissimmee Utilities Authority's Cane Island Plant operates a combined cycle unit with a CO limit of 20 ppmvd and a NOx emissions limit of 25 ppmvd. However, this unit has tested at a rate of 9.7 ppmvd for CO and 10.5 ppmvd for NOx.

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

The Department contacted the applicant with the above information. The applicant indicated that General Electric is unwilling to guarantee a lower CO limit due to some site-specific problems with other installations. However, GE was able to make specific modifications to the combustor to lower the CO emissions for these sites. The Department discussed that an oxidation catalyst appeared cost effective assuming the proposed baseline emission rate of 25 ppmvd for gas firing. However, from the data reviewed, it seemed reasonable to expect much lower CO emissions. Reducing the baseline DLN CO limit from 25 ppmvd to 20 ppmvd (same as for oil firing) results in the following analysis.

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

Table Notes:

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

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

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

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

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

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

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

6.3 PARTICULATE MATTER (PM/PM10), SULFURIC ACID MIST (SAM) AND SULFUR DIOXIDE (SO2)

6.3.1 Discussion of PM/PM10, SAM, and SO2 Emissions

Emissions of particulate matter, sulfur dioxide, and sulfuric acid mist will result from the combustion of the gas turbine fuels. Particulate matter emissions increase with incomplete fuel combustion as well as with higher concentrations of ash, sulfur, and trace elements in the fuel. Most of the particulate matter emitted from these types of processes will be less than 10 microns in diameter (PM10). Similarly, emissions of sulfur dioxide and sulfuric acid mist are a function of the amount of fuel sulfur. Gas turbines are subject to the following New Source Performance Standards for sulfur dioxide in 40 CFR 60, Subpart GG:

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

6.3.2 Applicant's Proposed PM/PM10, SAM, and SO2 BACT

Several available control technologies for particulate matter removal including centrifugal collectors, electrostatic precipitators, fabric filters, and wet scrubbers were identified. General Electric, the combustion turbine manufacturer, guarantees PM10 emissions for the Model 7EA unit of no more than 10 pounds per hour for natural gas firing and 25 pounds per hour for low sulfur distillate oil firing, including filterable and condensable fractions of the sampling train. Based on the design flow rate, this equates to approximately 0.002 grains per dry standard cubic feet of exhaust gas or roughly the emissions concentrations to be expected *after* control by a fabric filter. This level of emissions would be difficult to control with add-on equipment as well as measure during a performance test.

Wet or dry flue gas desulfurization and fuel treatment could be applied to this project to remove sulfur compounds. Although no cases of flue gas desulfurization applied to combustion turbines were identified, this option is technically feasible. Fuel treatment involves the desulfurization of natural gas and distillate oil by the fuel vendor prior to delivery to the user. For this project, the applicant has requested the use of pipeline quality natural gas containing less than 1 grain of sulfur per 100 SCF and distillate oil containing no more than 0.05% sulfur by weight. Limiting the sulfur content of the fuels also establishes the maximum potential SAM and SO2 emissions. At these already very low levels, the control efficiency of an add-on technology would be unreasonably low and cost prohibitive.

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

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

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

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

6.3.3 Department's PM/PM$_{10}$, SAM, and SO$_2$ BACT Determination

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

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

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

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

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

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

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

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

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

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

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

6.4 VOLATILE ORGANIC COMPOUNDS

Originally, the applicant indicated VOC emissions above the significant emissions rate of 40 tons per year. However, this was based on the manufacturer's estimated maximum *unburned hydrocarbon* emissions rates. For an identical combustion turbine, General Electric guarantees VOC emissions of less than 2 lb/hour for gas firing and 5 lb/hr for oil firing. This would result in potential project VOC emissions of only 15 tons per year, which is well below the Significant Emissions Rate. Therefore, no BACT determination is required for this pollutant. However, the Department determines the following VOC emissions standards are necessary to ensure emissions levels are actually minor for purposes of this PSD review.

Gas Firing: 2.0 ppmvd measured as methane (2.0 lb/hr), 3-hour test average

Oil Firing: 4.0 ppmvd measured as methane (5.0 lb/hr), 3-hour test average

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

7.0 SUMMARY OF DEPARTMENT'S BACT DETERMINATION

7.1 BACT EMISSION LIMITS

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

EU-018, 019, and 020: GE Model 7EA Combustion Turbines		
Pollutant	**Controls**[b]	**Emission Standard**
CO	Gas Firing W/DLN, First 12 Months After Initial Startup	25.0 ppmvd @ 15% oxygen and 54.0 pounds per hour
	Gas Firing W/DLN, After First 12 Months After Initial Startup	20.0 ppmvd @ 15% oxygen and 43.0 pounds per hour
	Oil Firing W/Wet Injection	20.0 ppmvd @ 15% oxygen and 44.0 pounds per hour
NOx	Gas Firing W/DLN	9.0 ppmvd @ 15% oxygen and 32.0 pounds per hour 10.0 ppmvd @ 15% oxygen by CEM
	Oil Firing W/Wet Injection	42.0 ppmvd @ 15% oxygen and 167.0 pounds per hour 42.0 ppmvd @ 15% oxygen by CEM
PM/PM10	Fuel Sulfur Specifications and Combustion Design	Visible emissions ≤ 10% opacity
SAM[a]/SO2	Natural Gas Sulfur Specification	1 grain per 100 SCF of gas
	Low Sulfur Distillate Oil Sulfur Specification	0.05% sulfur by weight
VOC[a]	Gas Firing W/Combustion Design	2.0 ppmvd as methane 2.0 pounds per hour
	Oil Firing W/Combustion Design	4.0 ppmvd as methane 5.0 pounds per hour

[a] The VOC standards are synthetic (PSD) minor limits, not BACT limits.
[b] DLN means dry low-NOx controls.

7.2 BACT COMPLIANCE DEMONSTRATION

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

Pollutant	**Compliance Methods***
CO	EPA Method 10 for initial and annual tests concurrent with NOx.
NOx	EPA Method 20 for initial and annual tests concurrent with CO; continuous compliance shall be demonstrated with data from the certified continuous emissions monitor; annual RATA results may be substituted for annual tests if all capacity, notification, and reporting requirements are met.
PM/PM10	EPA Method 9 for initial and annual visible emissions tests as a surrogate standard for PM/PM10.
SO2/SAM	Record keeping for the sulfur content of fuels delivered to the site.
VOC	Method 18, 25, or 25A for initial tests and prior to renewal of the operation permit, thereafter compliance is assumed if compliance is maintained with the CO and VE standards.

* Compliance shall be demonstrated for each fuel type.

7.3 BACT EXCESS EMISSIONS ALLOWED

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

21. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. These emissions shall be included in the calculation of the 3-hour and 24-hour NOx averages for compliance determinations. [Rule 62-210.700, F.A.C.]

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

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

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

8.0 COMMENTS ON THE DRAFT

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

9.0 RECOMMENDATION AND APPROVAL

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

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

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

Recommended By:

CH Fancy

12/8

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

Date: 12/9/99

Approved By:

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources Management

Date: 12/9/99

APPENDIX GC - CONSTRUCTION PERMIT GENERAL CONDITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

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

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

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

G.14 The permittee shall comply with the following:

(a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

(b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

(c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

APPENDIX GG - FEDERAL NEW SOURCE PERFORMANCE STANDARDS (NSPS)

40 CFR 60, SUBPART A - NSPS GENERAL PROVISIONS

This emissions unit is subject to the applicable portions of 40 CFR 60, Subpart A, General Provisions, including:

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

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

40 CFR 60, SUBPART GG - STATIONARY GAS TURBINES

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

40 CFR 60.330 APPLICABILITY AND DESIGNATION OF AFFECTED FACILITY.

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

40 CFR 60.331 DEFINITIONS.

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

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

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

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

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

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

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

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

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

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

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

60.332 STANDARD FOR NITROGEN OXIDES.

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

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = (0.0075)\frac{(14.4)}{Y} + F$$

Where:

STD = allowable NOx emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

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

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-Bound Nitrogen (Percent By Weight)	"F" (NOx Percent By Volume)
N < 0.015	0
0.015 < N < 0.1	0.04(N)
0.1 < N < 0.25	0.004 + 0.0067(N – 0.1)
N > 0.25	0.005

Where, N = the nitrogen content of the fuel (percent by weight).

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

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

40 CFR 60.333 STANDARD FOR SULFUR DIOXIDE.

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

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

40 CFR 60.334 MONITORING OF OPERATIONS.

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

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

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

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

(c) For the purpose of reports required under Sec. 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) Nitrogen oxides. Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with Sec. 60.332 by the performance test required in Sec. 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in Sec. 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under Sec. 60.335(a).

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

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

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

40 CFR 60.335 TEST METHODS AND PROCEDURES.

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in Sec. 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided for in Sec. 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in Secs. 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NOx) shall be computed for each run using the following equation:

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

Where

NOx = emission rate of NOx at 15 percent oxygen and ISO standard ambient conditions, volume percent.

NOxo = observed NOx concentration, ppm by volume.

P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.

P_o = observed combustor inlet absolute pressure at test, mm Hg.

Ho = observed humidity of ambient air, g H_2O/g air.

E = transcendental constant, 2.718.

T_a = ambient temperature, °K.

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

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

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

fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

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

APPENDIX XS - CEMS EXCESS EMISSIONS REPORT

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

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

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

Reporting period dates: From ____________ to ____________

Company: ____________

Emission Limitation: ____________

Address: ____________

Monitor Manufacturer and Model No.: ____________

Date of Latest CMS Certification or Audit: ____________

Process Unit(s) Description: ____________

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

Emission data summary [1]	**CMS performance summary** [1]
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:
a. Startup/shutdown .... ____	a. Monitor equipment malfunctions .... ____
b. Control equipment problems .... ____	b. Non-Monitor equipment malfunctions . ____
c. Process problems .... ____	c. Quality assurance calibration .... ____
d. Other known causes .... ____	d. Other known causes .... ____
e. Unknown causes .... ____	e. Unknown causes .... ____
2. Total duration of excess emissions .... ____	2. Total CMS Downtime .... ____
3. [Total duration of excess emissions] x (100) / [Total source operating time] .... ____% [2]	3. [Total CMS Downtime] x (100) / [Total source operating time] .... ___ % [2]

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

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

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

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

Name: ____________

Signature: ____________

Title: ____________

Date: ____________

Memorandum

Florida Department of
Environmental Protection

TO: Howard L. Rhodes

THRU: Clair Fancy CHF
Al Linero aal 12/8

FROM: Jeff Koerner JK

DATE: December 8, 1999

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

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

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

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

Attachments

CHF/AAL/jfk

RECEIVED
DEC 08 1999
BUREAU OF AIR REGULATION

THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the Matter of an
Application for Permit by:

Florida Power Corporation
One Power Plaza
St. Petersburg, FL 33733-4042
______________________________/

OGC No. 99-1673

DRAFT Permit No.: 0970014-003-AC; PSD-FL-268
Intercession City Plant
Osceola County

NOTICE OF WITHDRAWAL OF REQUEST FOR EXTENSION OF TIME

Florida Power Corporation (FPC), by and through undersigned counsel, hereby withdraws its Request for Extension of Time to file a petition for formal administrative proceedings in accordance with Chapter 120, Florida Statutes. FPC filed its Request for Extension of Time on September 30, 1999, in response to the "Intent to Issue Air Construction Permit" for the Intercession City Plant located in Osceola County, Florida, to negotiate certain changes in the proposed Prevention of Significant Deterioration air construction permit with the Department of Environmental Protection (Department). The Department granted the requested extension through December 15, 1999, by an order entered on November 3, 1999. FPC withdraws its Request because the Department has agreed to issue the final permit with changes negotiated with FPC, as reflected in the December 6, 1999 document attached as Exhibit A.

Respectfully submitted this 7th day of December, 1999.

HOPPING GREEN SAMS & SMITH, P.A.

Angela R. Morrison

Angela R. Morrison
Fla. Bar No. 0855766
Robert A. Manning
Fla. Bar No. 0035173
123 South Calhoun Street
Tallahassee, FL 32314
(850) 222-7500

Attorneys for FLORIDA POWER CORPORATION

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing has been furnished to the following by U.S. Mail on this 7th day of December, 1999:

✓ Clair H. Fancy, P.E.
Chief
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2600

Douglas Beason, Esq.
Office of General Counsel
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2600

Attorney

PERMIT PROCESSING SCHEDULE

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

COMMENTS/REQUESTS FROM THE APPLICANT

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

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would be determined based on adjusted data compiled by the automated Speedtronic™ Control System corrected for these parameters. The text regarding inlet air temperature was revised.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

- Firing primary nozzle followed by firing secondary nozzle at low to mid loads: 22 minutes
- Shutdown of fuel to primary nozzle and extinguishing primary flame: 20 minutes

- Change to full lean premix and stabilized operation: 10 minutes
- Shutdown: A complete shutdown of the gas turbine can be made in 15 minutes.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

1. EPA Comment: EPA states that the Department's cost analysis was appropriate in considering year-round operation given the flexibility to operate a given unit 8760 hours per year. EPA does not believe that hot SCR should be rejected based on the estimated cost effectiveness at this level of operation. EPA suggests that these concerns could be addressed if the Draft Permit was revised to limit hours of operation to: 3390 hours per year gas per turbine with no more than 1000 hours of gas firing per gas turbine per year. This is consistent with other recent determinations for intermittent, simple cycle combustion turbines in Region 4. Response: The Department disagrees with EPA's conclusion regarding cost effectiveness for hot SCR. However, the permit was revised to limit each gas turbine to no more than 1000 hours of gas firing per year and to reduce total oil firing to no more than 2500 hours per year for all three gas turbines. At this level, requiring a hot SCR system would result in an incremental cost estimate of nearly $10,000 per ton of NOx removed over the selected DLN system. The Department believes this addresses EPA's concerns.
2. EPA Comment: Because these units are intended to be "peaking units", EPA Region 4 comments that the 24-hour block averages should be revised to a shorter averaging period, such as a 3-hour block average. Response: The Draft Permit included a 24-hour block averaging period to provide for fluctuations in emissions resulting from load changes. Functioning as designed, the Speedtronic™ Control System requires sufficient time to adjust operation in response load changes and other input parameters. The applicant agreed to demonstrate compliance with the mass emissions rate and 9.0 ppmvd NOx limit based on annual testing at base load conditions. The applicant also agreed to a shorter averaging period for continuous compliance by

CEM if the given a slightly higher limit of 10.0 ppmvd. In addition, the applicant agreed to reduce oil firing from 3000 to 2500 total turbine hours. The Department estimates that this more than offsets any potential increase in emissions and believes this addresses EPA's concern about the long averaging period.

3. EPA Comment: EPA comments that an opacity limit for PM/PM_{10} is acceptable, but that the emissions rate should be referenced. Response: The permit was revised to include a PM/PM_{10} emissions rate reference in the Emissions Summary Table as the basis for the opacity standard.
4. EPA Comment: EPA comments that automatic exemptions should not be granted for excess emissions. Response: Startup and shutdown is part of every process involving mechanical equipment. For nearly all combustion sources, startup and shutdown involves higher emissions than normal operations. The DLN system employed to control emissions requires a period of "warm-up" and staging before a full lean premix state is established that results in the very low NOx emissions. The permit was revised to define allowable excess visible emissions during startup and shutdown as 20% opacity. The condition was also changed to allow exclusion of up to 2 hours during any 24-hour period resulting from startup, shutdown or documented malfunctions. This condition is specified in accordance with Rule 62-210.700, F.A.C., as approved by the EPA in Florida's State Implementation Plan.
5. EPA Comment: EPA comments that there will be an increase in potential VOC emissions from the existing fuel oil tank as a result of this project. Response: The Department concurs, but estimates the potential emissions to be much less than 1 ton per year or about the same magnitude as "rounding error" for the total project emissions.
6. EPA Comment: EPA notes that the Department's estimated emissions rates for PM/PM_{10} are higher than the initial application and modeling analysis. Response: The Department based these higher rates on information provided by General Electric for the same model gas turbine for another project. For that project, the manufacturer reports that the back half of the EPA Method 5 train also contains PM_{10} – about the same quantity as the filter portion. In effect, this could double both the expected PM emissions as well as PM_{10} (assuming all particulate to be PM_{10}). The Department's staff meteorologist concluded that no additional requirements would be triggered as a result of these emissions, which were higher than originally modeled. However, after additional consideration, the Department revised the PM/PM_{10} estimates lower for two reasons: (1) Many permitted sources have PM test data with no analysis of the back half of the sample train, and (2) The Department is uncertain as to the accuracy or repeatability of this non-reference test method.
7. EPA Comment: EPA agrees with the Department's conditions limiting hours of operation as each gas turbine is installed. Response: No response is required.
8. EPA Comment: EPA primarily comments that oil firing may not always result in the worst-case scenario and that a larger receptor grid should have been used in the air quality analysis. Response: Again, these issues were discussed with the staff meteorologist. He confirmed EPA's comments, but concluded that no additional requirements would be triggered based on additional modeling.
9. EPA Comment: EPA comments that air quality impacts resulting from temporary emissions sources associated with the project should also be considered in the Additional Impacts Analysis, but would believes this would not alter the conclusion presented. Response: The Department concurs.

CONCLUSION

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

(DRAFT 12/06/99)

PERMITTEE:

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

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

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

PROJECT AND LOCATION

This permit is issued pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit). This existing facility is an electric power generating plant with a nominal hourly capacity of 897 megawatts (MW). The proposed project will add three simple cycle, dual-fuel, General Electric Model 7EA combustion turbines with electrical generator sets each having a maximum hourly capacity of 87 MW.

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

STATEMENT OF BASIS

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

APPENDICES

The following Appendices are attached as part of this permit.

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

Howard L. Rhodes, Director
Division of Air Resources Management

Date: ____________

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FACILITY DESCRIPTION

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

NEW EMISSIONS UNITS

The proposed project will add the following new emissions units.

ARMS ID No.	EMISSION UNIT DESCRIPTION
018 019 020	**Peaking Units P12, P13, and P14**: Each peaking unit consists of a General Electric Model No. PG7121 7EA dual-fuel simple cycle combustion turbine with electrical generator set having a nominal hourly power production output of 87 MW. The units may employ an evaporative cooling system. Dry low-NOx (DLN) combustion technology will be used to control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will be used to control nitrogen oxide emissions when firing the backup fuel of low sulfur distillate oil.

REGULATORY CLASSIFICATION

The facility is a "major facility" with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD) of Air Quality because emissions of at least one pollutant exceed 250 tons per year. Therefore, each modification to this facility resulting in emissions increases greater than the Significant Emissions Rates specified in Table 62-212.400-2 also requires a PSD review and Best Available Control Technology (BACT) determination. For this project, emissions of CO, NOx, PM/PM_{10}, and SAM/SO_2 are significant and this permit establishes the Best Available Control Technology (BACT) for each pollutant.

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

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

RELEVANT DOCUMENTS

- Permit application (05/25/99) and all related correspondence.
- Technical information on DLN-1 combustor technology by General Electric.
- Technical information on inlet air fogging by Caldwell Energy and Environmental, Inc.
- Calpuff modeling analysis performed by Golder Associates, Inc. (08/02/99).
- Written comments (10/15/99 and subsequent discussions) received from applicant.
- Written comments (10/25/99) received from EPA Region 4.

GENERAL AND ADMINISTRATIVE REQUIREMENTS

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

2. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Central District Office, Florida Department of Environmental Protection, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767. The phone number is 407/894-7555 and the fax number is 407/897-2966.

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

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

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

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

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

8. BACT Determination: In conjunction with extension of the 18 month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 52.166(j)(4)]

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

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

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

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

This permit addresses the following new emissions units.

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

APPLICABLE STANDARDS AND REGULATIONS

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

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

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

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

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

PERFORMANCE RESTRICTIONS

3. Permitted Capacity: Each combustion turbine shall operate only in simple-cycle mode and generate a nominal 87 MW per hour of electrical power. Operation of each unit shall not exceed 885 mmBTU per hour of heat input from firing natural gas or 954 mmBTU per hour of heat input from firing low sulfur distillate oil. Operation below 50% of base load shall be limited to two (2) hours during any 24-hour period (day). The maximum heat inputs are based on the lower heating value (LHV) of each fuel, an inlet air temperature of 59°F, a relative humidity of 60%, an ambient air pressure of 14.7 psi, and 100% of base load. Therefore, heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Compliance shall be determined by data compiled from the Speedtronic^{TM} Control System adjusted for these parameters. Manufacturer's performance curves, corrected for site conditions or equations for correction to other ambient conditions, shall be provided to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Initial compliance

with this requirement may be demonstrated by compiling data during the initial NSPS tests performed at various load conditions. [Design, Rule 62-210.200, F.A.C. (Definition – Potential Emissions)]

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

5. Allowable Fuels: Each combustion turbine shall be fired by pipeline natural gas containing no more than 1 grain of sulfur per 100 dry standard cubic feet of gas. As a backup fuel, each combustion turbine may be fired with No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Each unit shall be capable of accommodating either fuel. Compliance with limits on fuel sulfur content shall be demonstrated by the record keeping requirements and/or the conditions of the Alternate Monitoring Plan specified in this permit. It is noted that these limitations are much more stringent than the NSPS sulfur dioxide limitation and assure compliance with 40 CFR 60.333 and 60.334. [Applicant Request, Rule 62-210.200, F.A.C. (Definition - Potential Emissions)]

6. Hours of Operation: The following limits apply to this group of three combustion turbines.

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

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

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

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

   Total turbine operating hours are the sum of operating hours when firing gas and operating hours when firing oil. The permittee shall install, calibrate, operate and maintain meters to measure and accumulate the amount of each fuel fired and hours of operation for each combustion turbine. [Applicant Request; Rule 62-212.400, F.A.C. (BACT); Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

7. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbines and pollution control devices in accordance with the guidelines and procedures established by each equipment manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

8. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the Compliance Authority as soon as possible, but at least within one (1) working day, excluding

weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

EMISSIONS CONTROLS

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

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

11. DLN Combustion Technology: To control NOx emissions when firing natural gas, the permittee shall install, tune, operate and maintain a dry low-NOx (DLN) combustion system for each combustion turbine in accordance with the manufacturer's recommendations. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific DLN system as part of the Title V permit application. Compliance with this requirement may be demonstrated by compiling data during the initial NSPS tests performed at various load conditions. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

12. Water Injection: To control NOx emissions when firing low sulfur distillate oil, the permittee shall install, calibrate and operate an automated water injection system for each combustion turbine in accordance with the manufacturer's recommendations. Each water injection system shall be maintained and adjusted to minimize NOx emissions. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific water injection system as part of the Title V permit application. Compliance with this requirement may be demonstrated by compiling data during the initial NSPS tests performed at various load conditions. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

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

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

EMISSIONS STANDARDS

15. Emissions Standards Summary: The following table summarizes the emissions standards specified in this permit.

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

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

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

16. Carbon Monoxide (CO)

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

(b) **Oil Firing**: When firing low sulfur distillate oil in a combustion turbine, CO emissions shall not exceed 44.0 pounds per hour nor 20.0 ppmvd based on a 3-hour test average.

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

17. Nitrogen Oxides (NOx)

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

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

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

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

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

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

19. Volatile Organic Compounds (VOC)

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

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

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

EXCESS EMISSIONS

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

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

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

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

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

EMISSIONS PERFORMANCE TESTING

22. Combustion Turbine Testing Capacity: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average 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.]

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

24. Applicable Test Procedures

   (a) **Required Sampling Time.**

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

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

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

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

25. Determination of Process Variables

(a) **Required Equipment.** The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. [Rule 62-297.310(5)(a), F.A.C.]

(b) **Accuracy of Equipment.** Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value. [Rule 62-297.310(5)(b), F.A.C.]

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

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

(a) **EPA Method 7E**, "Determination of Nitrogen Oxide Emissions from Stationary Sources".

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

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

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

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

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

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

29. Initial Tests Required: Initial compliance with the allowable emission standards specified in this permit shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days after initial operation of the emissions unit. Initial tests for emissions from the combustion turbine shall be conducted for CO, NOx, VOC, and visible emissions individually for firing natural gas and for

firing low sulfur distillate oil. Initial NOx performance test data shall also be converted into the units of the corresponding NSPS Subpart GG emissions standards to demonstrate compliance (see Appendix GG). [Rule 62-297.310(7)(a)1., F.A.C.]

30. Annual Performance Tests: Annual emissions performance tests for CO, NOx, and visible emissions from each combustion turbine shall be conducted when firing natural gas. If conducted at permitted capacity, the annual NOx continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the annual compliance stack test. An annual performance test for VOC emissions is not required as long as the unit remains in compliance with the CO and visible emissions limits specified by this permit.

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

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

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

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

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

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

CONTINUOUS MONITORING REQUIREMENTS

35. NOx CEM: The permittee shall install, calibrate, operate, and maintain a continuous emission monitoring system (CEMS) to measure and record NOx and oxygen concentrations in each combustion turbine exhaust stack. A monitor for carbon dioxide may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen. NOx data collected by the CEMS shall be used to demonstrate compliance with the continuous emissions standards for NOx based on a 3-hour rolling average. The 3-hour averages shall be determined by calculating the arithmetic average of all hourly emission rates for the respective averaging period. Each 1-hour average shall be expressed in

units of ppmvd corrected to 15% oxygen and calculated using at least two valid data points at least 15 minutes apart. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C.

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

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

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

COMPLIANCE DEMONSTRATIONS

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

37. Fuel Records

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

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

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

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

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

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

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

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

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

(2) The permittee shall submit a monitoring plan, certified by signature of the Authorized Representative, that commits to using a primary fuel of pipeline supplied natural gas containing no more than 1 grain of sulfur per 100 SCF of gas pursuant to 40 CFR 75.11(d)(2);

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

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

[40 CFR 60, Subpart GG, Applicant Request]

39. Monthly Operations Summary: By the fifth calendar day of each month, the owner or operator shall record the following information in a written or electronic log summarizing the previous month of operation and the previous 12 months of operation: hours of gas firing; million cubic feet of gas fired; hours of oil firing; and gallons of oil fired. The information shall be recorded for each gas turbine and for the group of three gas turbines. Information may be recorded and stored as an electronic file, but must be available for inspection and/or printing at the request of the Compliance Authorities. [Rule 62-4.160(15), F.A.C.]

REPORTS

40. Emissions Performance Test Reports: A report indicating the results of the required emissions performance tests shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.].

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

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

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OF COUNSEL
ELIZABETH C. BOWMAN

December 7, 1999

FAX COVER SHEET

Please deliver the following pages to:

Name:	Jeff Koerner	**Fax No.:**	922-6979
Firm:	DEP - DARM	**Phone No.:**	488-1344

Message:

Please find attached a copy of the Withdrawal of Request for Extension of Time, which was filed today for the Florida Power Corp. Intercession City plant.

The original, with exhibits, will follow via regular mail. If you have any questions, please feel free to give me a call. Thank you.

FROM: Angela Morrison

We are transmitting 5 **pages (including this cover sheet). If you do not receive all of the pages, please call (850) 222-7500 and ask for the Fax Desk.**

Client/Matter: FPC/132 (3881)

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OF COUNSEL
ELIZABETH C. BOWMAN

December 7, 1999

Via Hand Delivery

Ms. Kathy Carter, Clerk
Office of General Counsel
Florida Department of Environmental Protection
3900 Commonwealth Boulevard, Room 638
Tallahassee, FL 32399-3000

Re: Withdrawal of Request for Extension of Time
Permit No: 0970014-003-AC; PSD-FL-268, OGC No. 99-1673
Florida Power Corporation - Intercession City Plant

Dear Kathy:

Please find enclosed a Withdrawal of Request for Extension of Time regarding the above-referenced matter.

Thank you for your assistance. If you should have any questions or require any additional information, please do not hesitate to contact me at the above telephone number.

Sincerely,

HOPPING GREEN SAMS & SMITH, P.A.

Angela Morrison

Angela Morrison
Attorney for Gulf Power Company

ARM/gg
Enclosures

cc: Mr. Scott Osbourn, FPC (via fax and mail)
Mr. Jeff Koerner, DEP (via fax, w/out encl.)

THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the Matter of an
Application for Permit by:

Florida Power Corporation
One Power Plaza
St. Petersburg, FL 33733-4042

OGC No. 99-1673

DRAFT Permit No.: 0970014-003-AC; PSD-FL-268
Intercession City Plant
Osceola County

NOTICE OF WITHDRAWAL OF REQUEST FOR EXTENSION OF TIME

Florida Power Corporation (FPC), by and through undersigned counsel, hereby withdraws its Request for Extension of Time to file a petition for formal administrative proceedings in accordance with Chapter 120, Florida Statutes. FPC filed its Request for Extension of Time on September 30, 1999, in response to the "Intent to Issue Air Construction Permit" for the Intercession City Plant located in Osceola County, Florida, to negotiate certain changes in the proposed Prevention of Significant Deterioration air construction permit with the Department of Environmental Protection (Department). The Department granted the requested extension through December 15, 1999, by an order entered on November 3, 1999. FPC withdraws its Request because the Department has agreed to issue the final permit with changes negotiated with FPC, as reflected in the December 6, 1999 document attached as Exhibit A.

Respectfully submitted this 7th day of December, 1999.

HOPPING GREEN SAMS & SMITH, P.A.

Angela R. Morrison

Angela R. Morrison
Fla. Bar No. 0855766
Robert A. Manning
Fla. Bar No. 0035173
123 South Calhoun Street
Tallahassee, FL 32314
(850) 222-7500

Attorneys for FLORIDA POWER CORPORATION

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing has been furnished to the following by U.S. Mail on this 7th day of December, 1999:

Clair H. Fancy, P.E.
Chief
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2600

Douglas Beason, Esq.
Office of General Counsel
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2600

Attorney

Florida
Power
CORPORATION

Date: 12/2/99

To: Jeff Koerner

FAX #: (850) 922-6979

Phone #: ( )

From:

FAX #: (727) 826-4216

Phone #: (727)

3 Total number of pages including cover page.

Please notify ______________ at (727) 826 - __________ for any problems concerning the receipt of this FAX.

Comments:

Per my voice-mail attached is the NOx lb/hr curve, which will become part of the permit. I'll call you tomorrow to discuss.

One Power Plaza • 263 – 13th Avenue South • St. Petersburg • Florida 33701-5611
P.O. Box 14042 • St. Petersburg • Florida 33733-4042 • (727) 820-5151
A Florida Progress Company

Florida Power Corp – Intercession City

Date: 11/29/99

To: Scott Osborne 727-826-4216

From: Donald J. Cramer

RE: Data Submittal

Priority: [Urgent]

Scott,

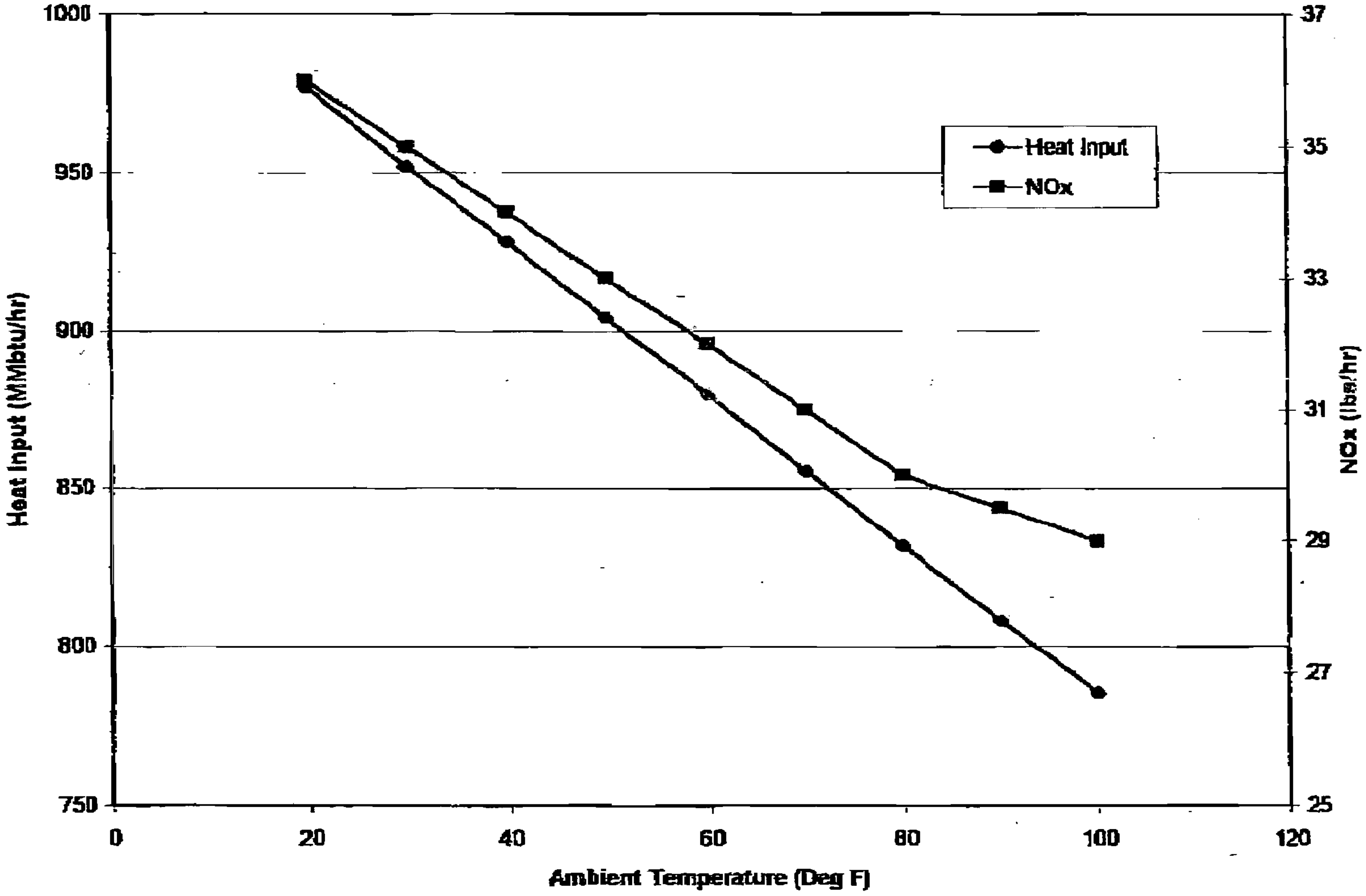
Attached is a plot of the NOx #/hr and heat input for the FPC 7EA's at Intercession City.

Please advise if you have any comments.

DJC

Attachments

PG7121 - Intercession City



INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 22-Nov-1999 04:06pm
From: Scott.H.Osbourn
Scott.H.Osbourn@fpc.com
Dept:
Tel No:

To: Jeff.Koerner (Jeff.Koerner@dep.state.fl.us)
CC: Aldazabal_Guillermo_A/goc_openmail (Aldazabal_Guillermo_A/goc_openmail@sv003.fpc.com)
CC: Kennedy_J-Michael/goc_openmail (Kennedy_J-Michael/goc_openmail@sv003.fpc.com)

Subject: Re: GE 7EAs

Jeff,

Please let us know your decision soon, as we would like to get this completed (as I'm sure that you would). I believe that our request for an extension of time expires on 11/30/99.

I'm not sure if you were able to locate any actual CEM data for GE7EA units, but Mike and I had some discussions with Larry Mattern at KUA. Their units are identical to those proposed for Intercession City. The data that he faxed us shows NOx values as high as 10.5 ppm during normal operation. I'm faxing these 3 pages to you today. Please call to discuss.

Scott

-----Original Message-----
From: Jeff.Koerner /internet/dd.RFC-822=Jeff.Koerner@dep.state.fl.us
[mailto:Jeff.Koerner@dep.state.fl.us]
Sent: Friday, November 19, 1999 11:30 AM
To: scott.osbourn /internet/dd.RFC-822=scott.osbourn@fpc.com
Cc: Jeff.Koerner /internet/dd.RFC-822=Jeff.Koerner@dep.state.fl.us
Subject: GE 7EAs
Sensitivity: Confidential

Scott,

I spoke with a 7EA operator and got some useful information on actual emissions. I also mentioned to EPA Region 4 that we were thinking of some
relief for the 9 ppm. I won't be able to discuss today, I have to go pick my
sick son up from school. I will call on Monday.

Jeff

Florida Power
CORPORATION

Date: 11/22/99

To: Jeff Koerner

FAX #: (850) 922-6979

Phone #: ( )

From: Scott Osborn

FAX #: (727) 826-4216

Phone #: (727) 826-4258

4 Total number of pages including cover page.

Please notify ____________ at (727) 826 - ____________ for any problems concerning the receipt of this FAX.

Comments:

Per my E-mail, attached is the CEM data for KUA.

One Power Plaza • 263 – 13th Avenue South • St. Petersburg • Florida 33701-5511
P.O. Box 14042 • St. Petersburg • Florida 33733-4042 • (727) 820-5151
A Florida Progress Company

Oxygen correction

Cane Island Unit 2 General Electric Frame 7 EA
September 26, 1999

Time	LOAD_2A	NOx/btu_2A #m	NOx/hr_2A #h	NOx_2A ppm	O2_2A %	Time	LOAD_2B	NOx/btu_2B #m	NOx/hr_2B #h	NOx_2B ppm	O2_2B %
12.00	0	0	0	0.3	21.11	12:00	0	0	0	5.1	20.78
12.01	0	0	0	0.3	20.21	12:01	0	0	0	6.1	20.83
12 02	0	0	0	8	17 35	12:02	0	0	0	0.5	20.98
12 03	0	0	0	10 3	17 3	12:03	0	0	0	8.1	20.82
12:04	0	0	0	22.7	18.05	12:04	0	0	0	4.1	21.07
12:05	0	0	0	21.6	18.2	12:05	0	0	0	0 1	21.22
12:06	0	0	0	22.5	17.82	12:06	0	0	0	0	21.22
12:07	0	0	0	11.2	18.99	12:07	0	0	0	0	21.19
12:08	5.19	0	0	20.7	19.06	12:08	1.6	0 046	2.5	3	20.39
12:09	9.02	0	0	22	18.8	12:00	8.63	0.136	8.2	8.4	19.36
12:10	13.76	0	0	26 6	18.45	12:10	13.82	0.137	8.4	11.4	19.05
12:11	18.54	0	0	33	18.14	12:11	16.05	0.19	11.3	19	18.67
12:12	22.64	0	0	37.9	17.83	12:12	22.55	0.248	15.2	28.2	18.34
12:13	22.83	0	0	45.1	17.66	12:13	22.98	0.278	17	35.8	17 99
12:14	21.01	0	0	45.9	17.72	12:14	21.2	0.318	19.4	43.2	17 83
12:15	18.1	0	0	43.3	17.90	12:15	17.94	0.337	20.5	45	17 88
12:16	18.09	0	0	39.3	18.06	12:16	18.01	0 346	21	42.9	18.1
12:17	18.36	0	0	39	18.06	12:17	18.23	0 323	19.8	38.8	18 19
12:18	22.67	0	0	39.3	17.91	12:18	22.25	0.317	19.3	38.3	18.13
12:19	28.11	0	0	44.8	17 51	12:19	27.7	0.309	18.6	39	18.05
12:20	30.56	0	0	54.1	17 21	12:20	30.44	0 313	19.1	44.2	17.7
12:21	32.95	0	0	60.1	17 06	12:21	34	0.346	21.1	53.8	17 39
12:22	35.58	0	C	68.9	16.8	12:22	35.45	0.363	22.1	59.4	17 19
12:23	39.52	0	C	72.3	16.65	12:23	39.35	0.356	21.7	62.7	16 9
12:24	40.2	0	C	85.3	16.38	12:24	40.08	0.35	21.3	64.9	16.69
12:25	38.78	0	C	88.8	16.36	12:25	40.19	0.398	24.3	77.1	16.51
12:26	43.84	0	C	84.8	16.26	12:26	38.28	0.424	148.3	81.9	16.5
12:27	41.09	0	0	53.1	16.51	12:27	41.53	0.396	174.5	76.8	16.49
12:28	47.3	0	0	38.9	16.16	12:28	47.03	0 272	174.2	53.5	16.62
12:29	52.97	0	0	45.9	15.55	12:29	52.71	0.22	151.3	46.1	16.37
12:30	59.14	0	0	81.3	14.77	12.30	57.98	0.221	168.4	61.6	15.87
12:31	64 63	0	0	80.4	14.8	12:31	62.41	0.233	172.4	61 5	15.21
12:32	70 66	0	0	18.7	14.84	12:32	70.27	-0.453	10.8	8.6	17.69
12:33	74 86	0	0	15	14.97	12:33	75.01	0.082	73.3	22	15.11
12:34	74.91	0	0	12 7	15.05	12 34	75.03	0.074	66.3	19.6	15.22
12:35	74.8	0	0	12.3	15.08	12:35	74.85	0.064	57.3	16.7	15.28
12.36	74.79	0	0	12.2	15.08	12:36	74.86	0.062	55.2	16	15.29
12 37	74.74	0	0	4.3	15.82	12 37	74.81	0.06	53.4	15.6	15 29
12:38	74.62	0	0	11.7	15.19	12:38	74 76	0.059	52.8	15.3	15.29
12:39	74 8	0	0	11.6	15 16	12.38	74.76	0.058	51.4	15	15.3
12:40	74 79	0	0	11.6	15 17	12:40	74.78	0.057	50.6	14.7	15.31
12:41	74.58	0	0	11 6	15 17	12:41	74.64	0.056	49.8	14.4	15.31
12.42	74.51	0	0	11 3	15 16	12:42	74.64	0.055	48.8	14.1	15.31
12:43	74.49	0	0	11 3	15.16	12:43	74.53	0.054	47.7	13.8	15.31
12:44	74.64	0	0	11.2	15.15	12:44	74.88	0.052	46	13.4	15.32
12:45	74.64	0	0	11 1	15.15	12:45	74.55	0.051	44.9	13.1	15.33
12:46	74.4	0	0	11.1	15.15	12:46	74.39	0.05	44.9	12.9	15.31
12:47	74.47	0	0	11	15.15	12:47	74.51	0.049	43.2	12.7	15 33
12:48	74.17	0	0	10 8	15.15	12:48	74.32	0.048	42.4	12.3	15.33
12:49	74 19	0	0	10 8	15.14	12.49	74.22	0.047	42.1	12.2	15.33
12:50	74.21	0	0	10 8	15.15	12:50	74.28	0.046	40.6	11.9	15.33
12:51	73.94	0	0	10.7	15.15	12:51	74.04	0.045	40.2	11.8	15.33

12:52	73.96	0	0	10.6	15.17	12:92	74.03	0.045	30.8	11.5	15.33
12:53	73.86	0	0	10.8	15.17	12:53	73.97	0.044	38.0	11.3	15.33
12:54	73.89	0	0	10.8	15.18	12:54	73.94	0.043	38.1	11.2	15.33
12:55	73.84	0	0	10.6	15.18	12:55	73.89	0.043	38	11.1	15.35
12:56	73.83	0	0	10.5	15.18	12:56	73.84	0.043	37.8	11	15.35
12:57	73.68	0	0	10.4	15.18	12:57	73.82	0.042	37.3	10.9	15.35
12:58	73.65	0	0	10.4	15.17	12:58	73.79	0.042	36.8	10.8	15.35
12:59	73.6	0	0	10.5	15.19	12:59	73.53	0.042	37.4	10.7	15.35
13:00	73.48	0	0	10.4	15.2	13:00	73.5	0.042	37.1	10.7	15.34
13:01	73.62	0	0	10.4	15.2	13:01	73.47	0.042	36.8	10.8	15.33
13:02	73.64	0	0	10.4	15.21	13:02	73.73	-0.095	3.3	1.7	17.86
13:03	73.9	0	0	10.5	15.21	13:03	73.44	0.041	36.7	10.3	15.43
13:04	73.43	0	0	10.4	15.21	13:04	73.45	0.041	36	10.4	15.39
13:05	73.54	0	0	10.5	15.21	13:05	73.61	0.04	35.2	10.3	15.39
13:06	73.53	0	0	10.6	15.23	13:06	73.4	0.04	35.2	10.3	15.38
13:07	73.59	0	0	3.8	15.81	13:07	73.5	0.04	35.1	10.2	15.36
13:08	73.5	0	0	10.4	15.18	13:08	73.55	0.04	35.3	10.2	15.36
13:09	73.47	0	0	10.4	15.17	13:09	73.57	0.04	35	10.3	15.34
13:10	73.38	0	0	10.3	15.18	13:10	73.42	0.04	35	10.3	15.34
13:11	73.36	0	0	10.3	15.22	13:11	73.63	0.04	34.6	10.2	15.36
13:12	73.26	0	0	10.3	15.22	13:12	73.33	0.04	35	10.2	15.35
13:13	73.48	0	0	10.3	15.21	13:13	73.54	0.039	34.2	10.1	15.33
13:14	73.56	0	0	10.3	15.22	13:14	73.62	0.04	34.4	10.2	15.35
13:15	73.46	0	0	10.3	15.22	13:15	73.69	0.039	34.3	10.1	15.34
13:16	73.36	0	0	10.2	15.22	13:16	73.48	0.04	34.7	10.1	15.35
13:17	73.38	0	0	10.2	15.21	13:17	73.6	0.038	34.6	10	15.35
13:18	73.45	0	0	10.2	15.21	13:18	73.5	0.039	34.1	10.1	15.35
13:19	73.41	0	0	10.2	15.21	13:19	73.93	0.039	34.2	10	15.36
13:20	73.44	0	0	10.2	15.21	13:20	73.48	0.039	34.4	10	15.36
13:21	73.46	0	0	10.3	15.22	13:21	73.50	0.04	34.8	10.1	15.37
13:22	73.62	0	0	10.2	15.22	13:22	73.66	0.039	34.3	10	15.37
13:23	73.68	0	0	10.2	15.22	13:23	73.66	0.039	33.8	9.8	15.37
13:24	73.63	0	0	10.1	15.21	13:24	73.68	0.038	33.5	9.8	15.38
13:25	73.62	0	0	10.1	15.21	13:25	73.64	0.038	33	9.7	15.38
13:26	73.87	0	0	9.9	15.21	13:26	73.72	0.036	33.1	9.6	15.37
13:27	73.9	0	0	9.9	15.2	13:27	73.92	0.037	32.7	9.5	15.36
13:28	74.03	0	0	9.9	15.19	13:28	74.01	0.037	32.2	9.4	15.35
13:29	74.01	0	0	10	15.2	13:29	73.98	0.037	32.8	9.5	15.35
13:30	74.28	0	0	9.9	15.2	13:30	74.31	0.037	33.1	9.5	15.35
13:31	74.58	0	0	10	15.2	13:31	74.60	0.037	33.1	9.5	15.36
13:32	74.38	0	0	10	15.2	13:32	74.52	-0.121	2	1.8	17.99
13:33	74.57	0	0	9.9	15.2	13:33	74.58	0.036	31.8	9.3	15.39
13:34	74.44	0	0	9.9	15.2	13:34	74.47	0.036	32.2	9.3	15.37
13:35	74.55	0	0	9.8	15.2	13:35	74.66	0.036	32.1	9.3	15.37
13:36	74.42	0	0	9.7	15.19	13:36	74.47	0.036	32.3	9.3	15.36
13:37	74.42	0	0	4.1	10.99	13:37	74.51	0.036	32.6	9.4	15.35
13:38	74.6	0	0	9.7	15.26	13:38	74.63	0.036	32.2	9.3	15.35
13:39	74.43	0	0	9.7	15.24	13:39	74.48	0.036	32.1	9.3	15.35
13:40	74.64	0	0	9.9	15.23	13:40	74.52	0.036	32.1	9.3	15.34
13:41	74.6	0	0	9.9	15.22	13:41	74.60	0.036	32.4	9.4	15.33
13:42	74.5	0	0	10	15.22	13:42	74.57	0.036	32.4	9.4	15.33
13:43	74.39	0	0	9.9	15.19	13:43	74.49	0.036	32.1	9.3	15.31
13:44	74.61	0	0	9.9	15.2	13:44	74.7	0.036	32	9.3	15.31
13:45	74.42	0	0	9.9	15.2	13:45	74.53	0.036	31.7	9.2	15.31
13:46	74.61	0	0	9.9	15.21	13:46	74.68	0.036	31.3	0.2	15.32
13:47	74.5	0	0	9.9	15.21	13:47	74.64	0.036	31.9	9.3	15.32
13:48	74.69	0	0	9.8	15.19	13:48	74.78	0.036	31.9	6.2	15.31
13:49	74.59	0	0	0.7	15.18	13:49	74.75	0.036	31.5	9.2	15.3

13:50	74.53	0	0	9.8	15.18	13:50	74.72	0.035	31.2	9 2	15.31
13:51	74.53	0	0	9 7	15.18	13.51	74.58	0 036	31.9	9.2	15.3
13:52	74.56	0	0	9.7	15 2	13:52	74.6	0.036	31.8	9.3	15.31
13:53	74.65	0	0	9.8	15.18	13:53	74.69	0.035	31.5	9 2	15.29
13 54	74.62	0	0	9.8	15.19	13:54	74.77	0 035	31.1	9.2	15 29
13:55	74.55	0	0	9.8	15.2	13:55	74.89	0 036	31.5	9.3	15.3
13:56	74.57	0	0	9.7	15.2	13:56	74.63	0 036	31.9	9.3	15.3
13:57	74 79	0	0	9.8	15.21	13:57	74.72	0.036	31.7	9.3	15.29
13:58	74.58	0	0	9.8	15.19	13:58	74.69	0.036	32	9.3	15.29
13 59	74 62	0	0	9.8	15.19	13.59	74.81	0 036	31.9	9.4	15.28
14:00	74.87	0	0	9.8	15 18	14:00	74.72	0.036	31.4	9.3	15.27
14:01	74.63	0	0	9.8	15.19	14:01	74.65	0.036	31.7	9.3	15.3
14:02	74.81	0	0	9.9	15.16	14:02	74.88	-0.277	1.2	1.8	16 05
14:03	74.94	0	0	9.9	15.16	14:03	75.16	0.035	30.7	9	15.3
14:04	74.99	0	0	9.9	15.16	14:04	75.1	0 036	31.7	9.2	15 29
14:05	75.01	0	0	9.9	15.17	14:05	75.15	0 036	31.6	9.3	15.29
14:06	75.02	0	0	9.9	15.2	14:06	75.14	0.035	31.4	9.2	15.29
14:07	75.02	0	0	4.2	15.98	14 07	75.08	0.036	31.6	9.2	15.3
14 08	75.19	0	0	9.8	15.18	14:08	75 04	0.036	32	9.3	15.28
14 09	75.1	0	0	9.6	15.2	14:09	75.21	0.035	31.3	9.2	15.27
14 10	75.03	0	0	9 9	15.19	14:10	75.09	0.038	31.8	9 3	15.28
14.11	75.17	0	0	9.9	15.19	14:11	75 18	0.038	31.7	9.3	15.28
14:12	75.06	0	0	9.9	15.2	14:12	75.13	0.036	31.7	9.2	15.28
14:13	75.24	0	0	9.9	15.18	14:13	75.35	0.036	31.8	9.3	15.27
14:14	75.22	0	0	10	15.19	14:14	75.33	0 036	31.9	9.3	15.27
14:15	75.27	0	0	9.9	15.21	14:15	75.25	0.036	31.8	9.2	15 28
14:16	75 42	0	0	10	15.19	14:16	75.53	0.036	31.7	9.3	15 29
14:17	75.44	0	0	10	15.2	14:17	75 42	0 036	32.1	9.3	15.28
14:18	75.48	0	0	10	15.19	14:18	75.5	0 038	31.7	9.3	15.27
14:19	75.43	0	0	10.2	15.18	14:19	75.56	0.038	31.0	9.4	15.27
14:20	75.53	0	0	10	15.18	14:20	75 56	0.036	32	9.4	15.28
14:21	75.52	0	0	10.1	15.16	14:21	75.67	0.036	32	9 4	15.28

Florida Power
CORPORATION

Date:

To: Jeff Koerner

FAX #: (850) 922-6979

Phone #: ( )

From: Scott Osborn

FAX #: (727) 826-4216

Phone #: (727) 826-4258

5 Total number of pages including cover page.

Please notify __________ at (727) 826 - ________ for any problems concerning the receipt of this FAX.

Comments:

Attached is the contract language (see 2nd page), as we discussed. Based on this, we request that you consider either a 10 ppm continuous limit (w/ CEMS) or a lb/hr basis as we originally requested.

Please call me to discuss.

Thanks!

One Power Plaza • 263 - 13th Avenue South • St. Petersburg • Florida 33701-5511
P O Box 14042 • St. Petersburg • Florida 33733-4042 • (727) 820-5151
A Florida Progress Company

3. Performance Data

3.1 Guarantees

3.1.1 Guaranteed Performance on Natural Gas Fuel (At Design Point in Tab 3, Section 3.1.2.1, Base Load [except Nox])

Measurement	Value
Output	84,090 kW
Heat rate	10,490 Btu/kwh
Nox Emissions (60 – 100% Load Range)	9 ppm

3.1.2 Guaranteed Performance on Distillate Fuel (At Design Point in Tab 3, Section 3.1.2.1, Base Load [except Nox])

Measurement	Value
Output (Base, ISO Conditions, Page 3.5)	86,980 kW
Heat rate (Base, ISO Conditions, Page 3.5)	10,940 Btu/kwh
Nox Emissions (50 – 100% Load Range)	42 ppm

3.1.2.1 Design Basis

Measurement	Value
Elevation	74 ft
Compressor inlet temperature	59°F
Relative humidity	60%
Inlet system pressure drop	3.5 in. H_2O
Exhaust system pressure	5.5 in. H_2O
Natural gas fuel heating value (LHV)	20,831 Btu/lb
Distillate fuel heating value (LHV)	18,300 Btu/lb
Diluent injection flow	Water on distillate
Combustion system type	DLN 1.0

The following also apply to performance guarantees:

- Performance is measured at the generator terminals and includes allowances for excitation power and the shaft-driven equipment normally supplied.
- Guarantees are based on new and clean condition of the gas turbine. If more than 150 fired hours have elapsed before a performance test is to be conducted, a GE representative shall have the right to inspect the unit to assure that the power plant is in new and clean condition.
- Guarantees are based on a site test conducted as described in the Reference Documents chapter and per the Terms and Conditions of this offer.
- Guarantees are based on the calculated amount of diluent injection shown on the above Design Basis table. The actual amount of diluent injection as determined during the field compliance test may be different, which will have an effect on the output and heat rate.
- Performance curves for both the turbine and generator are included in the Performance Curves section of this proposal. From these curves it is possible to determine estimated performance at ambient temperatures, percent loads, and barometric conditions differing from those listed in the above design basis table. These curves are used during the site performance test to correct performance readings back to the site conditions at which the performance guarantee was provided.
- Performance testing of the gas turbines will be in accordance with ASME PTC-22 (1997). There will be an allowance for test uncertainty equal to the measurement uncertainty of the test. The measurement uncertainty will be in compliance with ASME PTC-22 (1997). Immediately prior to the test of each unit (within 24 fired hours), the turbine will be subjected to a thorough offline compressor wash followed by a visual inspection of the compressor inlet face to confirm that the unit is indeed clean and ready for the test. If more than 150 fired hours have elapsed prior to the test, a degradation correction will be applied per GE figure 519HA772.

3.1.3 Acoustics Guarantees

3.1.3.1 Far Field Noise Values

The far field sound pressure level (SPL) contribution from the GE supplied equipment is guaranteed not to exceed 68 dBA (ref. 20 micropascals) when measured at a distance of 400 feet (122 meters) from the nearest equipment and operating at rated load in accordance with contract specifications.

3.1.3.2 Near Field Noise Values

The near field sound pressure level (SPL) contribution from the GE supplied equipment is guaranteed not to exceed 85 dBA (ref. 20 micropascals) per single unit when measured 3 feet (1 meter) in the horizontal plane and at an elevation of 5 feet (1.5 meters) above machine base line or personnel platforms with the equipment operating at base load in accordance with contract specifications.

3.1.3.2.1 Basis of Guarantee

The following also apply to the above guarantee:

- Testing methodology shall be based on the latest version of ANSI/ASME PTC 36. The final result shall be the arithmetic average of the SPL's measured around the equipment after background and other corrections have been applied. The equipment shall be in compliance if the final result does not exceed the noise limit(s) specified above.
- Equipment shall be operated in a new and clean condition as intended by the designers when measurements are taken. All access compartments, doors, panels and other temporary openings shall be fully closed; all silencing hardware shall be fully installed; all systems designed to be airtight shall be sealed.
- If the above guaranteed SPL exceeds the measured background noise by 10 dBA, no correction shall be necessary. Otherwise, corrections to the measured SPL shall be made per ANSI/ASME PTC 36 procedures. Background noise is defined as the noise measured with all GE supplied equipment off and all other plant equipment on.
- Intermittent noises such as steam safety blow off valves and filter pulse noise are not included in the above guarantee.
- Measurements shall be taken 3 feet (1 meter) away from the outermost surfaces of equipment, including piping, conduit, framework, barriers and personnel protection devices if provided.
- Measurements shall not be taken in any location where there is an airflow velocity greater than 5 feet per second (1.5 meters per second), including nearby air intakes or exhausts.
- Free field conditions must be prevalent at measurement locations. Testing and for and corrections to a free field shall be per ANSI/ASME PTC 36.
- Testing shall be done according to a test plan agreed to by both the customer and GE. Such a plan shall be submitted to both the customer and GE at least 30 days prior to noise compliance testing. The test results shall

be submitted in the form of a test report that shall be made available to both the customer and GE.

Measurement responsibility shall be stated in the contract. If the customer has responsibility for the compliance measurements, GE reserves the right to audit or parallel these measurements.

11/2/99

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

FLORIDA POWER CORPORATION
(INTERCESSION CITY FACILITY),

Petitioner,

vs. OGC CASE NO. 99-1673

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION,

Respondent.
_______________________________/

ORDER GRANTING REQUEST FOR EXTENSION OF TIME TO FILE PETITION FOR HEARING

This cause has come before the Florida Department of Environmental Protection (Department) on receipt of a request made by Petitioner, Florida Power Corporation (Intercession City Facility), to grant an extension of time to file a petition for an administrative hearing on Application No. 0970014-003-AC. See Exhibit 1.

Respondent, State of Florida Department of Environmental Protection, has no objection to it. Therefore,

IT IS ORDERED:

The request for an extension of time to file a petition for administrative proceeding is granted. Petitioner shall have until December 15, 1999, to file a petition in this matter. Filing shall be complete on receipt by the Office of General Counsel, Mail Station 35, Department of Environmental Protection, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000.

DONE AND ORDERED on this 2nd day of ~~October~~ November, 1999, in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

F. PERRY ODOM
General Counsel

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

CERTIFICATE OF SERVICE

I CERTIFY that a true copy of the foregoing was mailed to:

W. Jeffrey Pardue
Florida Power Corporation
Post Office Box 14042
St. Petersburg, Florida 33733-4042

on this 3rd day of ~~October~~ November, 1999.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

W. DOUGLAS BEASON
Assistant General Counsel
Florida Bar No. 379239

Mail Station 35
3900 Commonwealth Boulevard
Tallahassee, FL 32399-3000
Telephone: (850) 488-9314

Email Memorandum

Date: November 2, 1999

To: Scott Osbourn, Senior Environmental Engineer
Florida Power Corporation

cc: Michael Kennedy, Meteorologist
Florida Power Corporation

Katy Forney, New Source Review
EPA Region 4

From: Jeff Koerner, New Source Review Section
Bureau of Air Regulation - DEP

Re: DEP File No. 097-0014-003-AC (PSD-FL-268)
FPC Intercession City Plant
Response to Comments from FPC and EPA Region 4

I was contacted by our Office of General Counsel concerning the request for an extension of time in which to file for an administrative hearing. It was brought to my attention that the permit processing time clock has stopped with your request. In addition, I am prevented from issuing a final permit until you withdraw your request.

I have reviewed your written comments regarding the Draft Permit, comments and requests made during our meeting on 10/25/99, and comments received from EPA Region 4. For each of your written comments, I have prepared the following responses and have included EPA's comments for similar topics. Any remaining comments made by EPA are discussed at the end of this email.

Page 5

Specific Condition 3. Permitted Capacity: FPC requests that text, similar to that in recent Title V permits, be added to clarify that the heat input values for gas and oil firing are only included for the purposes of determining capacity during testing, and that regular record keeping is not required. FPC also requests a change in the text from "... an inlet air supply cooled to 59° F ..." to "... an inlet air temperature of 59° F ..." **Response**: The Department includes the heat input as a maximum rate based on the fuel heating value, inlet temperature, air pressure, relative humidity, and load. The only record keeping requirement is a monthly recording of the average heat input for each fuel as a check on the permitted capacity. This requirement will be retained. The Department will revise the text regarding inlet air temperature.

Page 6

Specific Condition 6. Hours of Operation: Based on the Department's cost analysis, FPC requests the following revised limits on hours of operation: 5760 hours per year per gas turbine for gas firing and 3000 hours per year per gas turbine for oil firing. EPA Region 4 also comments (#1) that the Department's cost analysis was appropriate, but that hot SCR for continuous operation should not be dismissed based on the estimated cost effectiveness. EPA suggests that these concerns could be addressed if the Draft Permit was revised to limit hours of operation to: 3390 hours per year gas per turbine with no more than 1000 hours per year per turbine. This is consistent with other recent determinations for intermittent, simple cycle combustion turbines in Region 4.

Response: The Department based the limits on hours of operation on the applicant's initial request and planned use of these gas turbines as "peaking units". During our meeting on 10/25/99, I mentioned that your request would result in an increase in emissions, which would require submittal of a modified application and restarting the permit process. In light of EPA's comments, it may be necessary to restrict hours on a "per turbine basis", but it may also be possible to allow for some flexibility above the initial request that was based on an *average* of 3390 hours per year per gas turbine. For example, it may be possible to address EPA's concerns by the following revision, which would not require the submittal of a modified application:

- Retain the aggregate limit of 10,170 hours per year of which no more than 3000 hours per year would be oil firing. (This case would still define "potential emissions", so there would not be an increase in emissions.)
- Limit the hours of operation for each turbine to 5085 hours per year of which no more than 1500 hours per year would be oil firing.

This would require a closer monitoring of the hours by the plant, but allows some flexibility for cases when a unit may be "down". You also indicated the need to maintain the proposed construction schedule. This condition could be revised in many different ways based on your decision. The Department reserves the right to revise the Draft Permit to satisfy EPA's stated concerns.

FPC also requests deletion of the requirement to limit operation below 50% load to less than two hours per unit cycle. **Response**: This requirement is included to limit operation of the gas turbines under conditions that *may* generate excess emissions based on information from General Electric. The excess emissions rule does not properly address this situation because the compliance status for each pollutant is unknown except for NOx, which is continuously monitored. The Department is considering revising this condition to: "Operation below 50% of base load shall be limited to two (2) hours during any calendar day."

Page 7

Specific Condition 11. and 12. Emissions Controls: FPC requests insertion of text similar to "... in accordance with the manufacturer's recommendations ..." after the condition requiring DLN Combustion technology and the condition requiring Water Injection Controls. FPC also requests deletion of the requirement to provide emissions performance versus load diagrams. **Response**: The Department will revise the condition to include the requested text. As discussed during our meeting, the Department will add the following text to the condition requiring load diagrams: "Compliance with this requirement may be demonstrated by compiling data during the initial NSPS tests performed at various load conditions."

FPC also strenuously objects to the requirement of developing a NOx reduction plan if a unit fires more oil than gas during a 12-month period. **Response**: The intent of this requirement was to address the possibility of continued oil firing on a single unit as "normal operations". The Department will revise this requirement to: "If the hours of oil firing for a combustion turbine exceed 1000 hours during any consecutive 12 month period, the permittee shall develop a NOx reduction plan."

Page 8

Specific Condition 15. Emissions Standards: FPC requests that the emissions standards be expressed solely in terms of a mass emissions rate (pounds per hour) using "ppmvd" only as the basis, that the VOC concentration be expressed as ppmvw, and that the CO concentration be expressed as ppmvd. **Response**: The "ppmvd" standards are required to ensure complete utilization of the technical capabilities of the DLN system to minimize NOx emissions. For combustion turbines, units of "ppmvd" are the standard by which environmental agencies compare BACT determinations, have been included in many recent air permits, and are consistent with the federal NSPS Subpart GG. The emissions standards will not be revised. However, the Department will be revise these conditions to express the CO concentration as ppmvd and VOC concentration as ppmvw, consistent with the manufacturer's test data.

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

Specific Condition 16., 17. and 19. Emissions Standards: FPC again requests revision of these conditions to reflect mass-based standards. **Response**: The Department's response is the same as described above.

FPC requests replacing the text "3-hour test averages" for the CO and NOx standards with a reference to the corresponding EPA test method. **Response**: An emissions standard must have an appropriate averaging period in order to be practicably enforceable. The condition will remain unchanged.

FPC requests that the NOx limit when firing oil be revised to a from a 3-hour block average to a 24-hour block average, consistent with gas firing. Because these units are intended to be "peaking units", EPA Region 4 comments (#2) that the 24-hour block averages should be revised to a shorter averaging period, such as a 3-hour block average. **Response**: The Department established the 24-hour block average for gas firing to allow for some fluctuations in emissions resulting from load changes that may require a period of time for the DLN system to completely adjust. The Department required a 3-hour block average for oil firing for two reasons: (1) NOx emissions from oil firing are nearly five times that of gas firing, and (2) the belief that the Speedtronic^{TM} Gas Turbine Automatic Control System is technically capable adjusting the water injection rate to meet this shorter averaging period. So, the averaging period isn't really based on the fuel being fired, but the control methods being used and the corresponding emission rates. In addition, the air quality analysis was based on maximum *hourly* emissions when firing oil. To address EPA's concerns, the Department will include additional text in Specific Condition 21 to clarify the "24-hour block average".

Specific Condition 21. Excess Emissions: In accordance with the original language of Rule 62-210.700, F.A.C., FPC requests that this condition be revised to include the following text " ... unless specifically authorized by the Department for longer duration ... ". FPC also requests that the limit of one hour of excess emissions resulting from startup to simple cycle be removed. EPA Region 4 comments (#4) that automatic exemptions should not be granted for excess emissions. **Response**: The Department notes that Rule 62-210.700(5), F.A.C. also states the following: " ... Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest." Based on FPC's comments and EPA Region 4's comments, the Department is still considering a complete revision of this permit condition.

Page 10

Specific Condition 22. Combustion Turbine Testing Capacity: FPC requests that the text "ambient temperature" be replaced with "inlet temperature". **Response**: The Department agrees and will revise the text.

Page 11

Specific Condition 27(a) and (d). Performance Test Methods: FPC requests clarification of the phrase "annual 3-hour NOx limit". **Response**: The Department will revise this text to "NOx limit based on a 3-hour test average".

Specific Condition 30. Annual Performance Tests: FPC requests removal of the requirement to conduct annual visible emissions tests when firing natural gas. **Response**: The Department established the visible emissions standard as a surrogate BACT standard for regulating particulate matter when firing natural gas. The annual visible emissions test is necessary on at least an annual basis to determine compliance for visible emissions and particulate matter.

FPC requests that annual tests for CO, NOx, and visible emissions when firing oil be required only when oil is fired for more than 400 hours per year per combustion turbine. **Response**: The Department will revise this condition to: "If a combustion turbine operates more than 100 hours on oil firing during any federal fiscal year, the permittee shall schedule and conduct annual tests for CO, NOx, and visible emissions while firing distillate oil. Compliance with the NOx standards may be determined by the continuous monitor data collected during the required CO test."

FPC requests removal of the condition requiring compliance with the visible emissions standard as a surrogate for compliance with the VOC standard. FPC believes that compliance with the CO standard is an adequate surrogate. **Response**: The Department included visible emissions as a surrogate for VOC emissions because compliance may be easily demonstrated on a more frequent basis.

Page 12

Specific Condition 35. Continuous Monitoring Requirements: FPC requests removal of the text that allows substitution of missing data in accordance with Title IV, revising the NOx limits to a mass emissions rate, and changing the NOx limit for oil firing from a 3-hour average to a 24-hour block average. **Response**: The Department has previously responded to the issues regarding a mass emissions standard and averaging period. The Department will remove the text regarding substitution of monitoring data. As a result of this request, the Department is considering a complete revision to Specific Condition No. 21 regarding excess emissions and clarifying the method of calculating the 24-hour block average for NOx emissions.

Page 14

Specific Condition 39. Monthly Operations Summary: FPC requests that this condition be deleted. **Response**: The Department will revise "written log" to "written or electronic log" and add the following text: "Information may be recorded and stored as an electronic file, but must be available for inspection and/or printing at the request of the Compliance Authorities."

Appendix BD

FPC requests revising the BACT Determination consistent with other requested changes. **Response**: This is not necessary because the Department has not agreed to revise the emissions standards.

Remaining EPA Comments

For completeness, I will also discuss the five additional comments made by EPA Region 4, which were not covered above.

#3 EPA comments that an opacity limit for PM/PM_{10} is acceptable, but that the emissions rate should be referenced. To address EPA's comment, the Department will include the PM/PM_{10} emissions rate as the basis for establishing the opacity limit.

#5. EPA comments that there will be an increase in potential VOC emissions from the existing fuel oil tank as a result of this project. The Department agrees, but estimates these emissions to be less than 1 ton per year. Nevertheless, the Department will include a note in the Emissions Unit Description.

#6. EPA notes that the Department's estimated emissions rates for PM/PM_{10} are higher than the initial application and modeling analysis. The Department based these higher rates on information provided by General Electric for the same model gas turbine for another project. The manufacturer reports test data indicating that the back half of the EPA Method 5 train also contains PM_{10} – about the same quantity as the filter portion. In effect, this doubles both the expected PM emissions as well as PM_{10} (assuming all particulate to be PM_{10}). The primary reason for including the higher emissions rate was to establish the basis for future modification and netting determinations. The Department's staff meteorologist concluded that no additional requirements would be triggered as a result of these emissions, which were higher than originally modeled.

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

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

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

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

FAXED TO SCOTT OSBOURNE
AT FPC BY J. KOENER
ON 10/27/99

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

OCT 20 1999

RECEIVED
OCT 25 1999
BUREAU OF AIR REGULATION

4 APT-ARB

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

SUBJ: Preliminary Determination and Draft Permit for Florida Power Corporation (FPC) - Intercession City Plant (PSD-FL-268) located in Osceola County, Florida

Dear Mr. Linero:

Thank you for sending the preliminary determination and draft permit dated September 15, 1999, for the above referenced facility. The preliminary determination is for the proposed construction and operation of three simple cycle combustion turbines (CTs) with a nominal generating capacity of 87 MW each to be located at the existing Intercession City Plant. The combustion turbines proposed for the facility are General Electric (GE), frame 7EA units. The CTs will primarily combust pipeline quality natural gas with No. 2 fuel oil combusted as backup fuel. As proposed, the CTs will be allowed to fire natural gas a total of 10,170 hours per year and No. 2 fuel oil a total of 3000 hours per year for all turbines combined with no restrictions on how these hours are allocated per turbine. Total emissions from the proposed project are above the thresholds requiring Prevention of Significant Deterioration (PSD) review for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}) and sulfuric acid mist (SAM).

Based on our review of the preliminary determination and draft permit, we have the following comments:

1. The applicant proposed a best available control technology (BACT) NO_x emission limit of 9 ppmvd (15% oxygen) for natural gas firing to be achieved by use of dry low-NO_x combustion. The proposed BACT for NO_x emissions when firing No. 2 fuel oil is 42 ppmvd using water injection. In Appendix BD of the draft permit, the NO_x BACT determination is discussed in detail. The applicant performed a cost analysis which considered using selective catalytic reduction (SCR) to control NO_x emissions from the CTs. The applicant's cost analysis assumed an average operating scenario for each CT (firing 2,390 hours per year of natural gas and 1,000 hours per year of fuel oil) and calculated the cost effectiveness of SCR to be $12,890/ton removed of NO_x. The Florida Department of Environmental Protection (FDEP) disagreed with some of the assumptions in the applicant's cost analysis (as we did) and performed their own cost analysis. FDEP's cost analysis calculated the cost effectiveness

of SCR to be \$6,024/ton removed of NO_x, based on a worst-case operating scenario (firing 5,760 hours per year of natural gas and 3,000 hours per year of fuel oil in one turbine). Since condition 6 of the draft permit only limits the total number of operating hours for all three CTs combined and does not set any per unit operating limits, FDEP's cost effectiveness calculation is the appropriate analysis for the current permitted operating scenario. However, FDEP still rejected SCR as BACT based on "unreasonable costs associated with controlling very low NO_x emissions."

Given the results of FDEP's BACT evaluation and given that the draft permit would allow continuous operation of one turbine, Region 4's opinion is that use of SCR can not be dismissed as BACT. Our concerns about the NO_x BACT conclusion will be resolved if FDEP restricts each turbine to a maximum operating schedule of 3,390 hours per consecutive 12 months, of which no more than 1,000 hours can consist of fuel oil firing. Such a restriction is consistent with other recent BACT determinations for intermittent operation, simple cycle combustion turbines elsewhere in Florida (for example, Polk Power) and with other recent determinations for intermittent operation, simple cycle combustion turbines elsewhere in Region 4.

2. In condition 17 of the draft permit, the emission rate for NO_X is set as 32.0 lb/hr (9 ppmvd) on a 24-hr block average as measured by CEMS. Since the proposed CTs will run in simple cycle mode and will seldom operate for 24 consecutive hours, the averaging period for this emission limit should be much shorter, consistent with the 3-hour averaging period proposed for fuel oil combustion.

3. The proposed BACT limit for particulate matter (PM_{10}), found in condition 18 of the draft permit, is 10% opacity for visible emissions. This visible emissions opacity limit is proposed as a surrogate for a BACT particulate matter emissions rate limit. It is acceptable to use the 10% opacity limit as a surrogate for monitoring and recordkeeping; however, the permit conditions also should list the corresponding emission rate for particulate matter.

4. As indicated in condition 20 and 21 of the draft permit, FDEP is proposing to allow excess emissions due to startup, shutdown or malfunction for up to 2 hours in any 24-hour period. Since the Intercession City Plant CTs are designed for intermittent use, it is unclear if the 24 hours refers to consecutive hours or operating hours. Furthermore, it is EPA's policy that BACT applies during all normal operations and that automatic exemptions should not be granted for excess emissions. Startup and shutdown of process equipment are part of the normal operation of a source and should be accounted for in the planning, design, and implementation of operating procedures for the process and control equipment. Accordingly, it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods.

5. The new CTs, which will fire No. 2 fuel oil as backup fuel, have the potential to increase the throughput of the existing fuel oil storage tank. Any increase in VOC emissions from the additional use should be taken into account when calculating the potential to emit (PTE)

VOC emissions. We realize the VOC emissions increase will be small and do not expect it to cause any applicability changes; however, as a matter of completeness, this increase in emissions should be included in all PTE calculations.

6. Emission Changes - The annual emission rates for PM/PM_{10} and SO_2 associated with the planned modification are larger in the Preliminary Determination (PD) than those appearing in the PSD application. Although all modeling results provided in the application used the smaller emission rates, multiplying the very small maximum concentrations reported in Table 7-1 by the ratio of the PD to PSD permit application emission values (i.e., PM_{10} = 73/33 TPY; SO_2 = 95/83.7 TPY) will not cause the maximum impacts to exceed the applicable Significant Impact Levels (SIL). If the short term emission rates are proportional to the annual rates, these emission increases will not change the modeling conclusions presented in the application.

7. EPA agrees with FDEP in limiting the number of operating hours as each new turbine is installed. This condition will prevent the applicant from installing just one combustion turbine and operating it as a baseload turbine instead of intermittently, as proposed in the permit application. Additionally, if the applicant switches from simple cycle to combined cycle operation in the future, this change would be considered a modification potentially subject to PSD review.

8. Modeling Results - The PSD application indicated receptors were located at 100-m resolution about the site boundary and at radial distances of 500 meters; 1.0, 1.5, 2.0, and 2.5 km; and at 5 km intervals from 5 to 50 km. All modeling was performed with all the CT stacks co-located for fuel oil operation only. The following should be noted:

   - From review of Tables 6-1 through 6-8, oil firing does not appear to always produce the maximum emissions for CO, NO_x, and VOC. The SCREEN3 modeling used to determine the CT operational configuration that produces the maximum impact was not complete, so the determination of the worst-case operational configuration could not be confirmed.

   - Review of the ISCST3 modeling revealed the site boundary receptors are not located within 100-m resolution. Also, some of the reported maximum concentrations were located in areas where the maximum resolution is 2 to 5 km.

   - Because of the large receptor grid resolution about the location of reported maximum concentrations, the modeling results may not capture the maximum concentrations from the proposed modification. Modeling about the reported maximum concentrations with more refined receptor grids is needed to ensure maximum concentrations are obtained for comparison to the PSD significant impact levels.

9. Additional Analysis - The section addressing air quality impacts due to emissions associated with industrial, commercial, and residential growth indicated only permanent growth-related

emission sources were considered. Although temporary emissions sources associated with growth should also be addressed, it is believed that inclusion of temporary sources for this facility would not alter the conclusions presented.

Thank you for the opportunity to comment on the FPC-Intercession City facility preliminary determination and draft permit. If you have any questions regarding these comments, please direct them to either Katy Forney at (404) 562-9130 or Jim Little at (404) 562-9118.

Sincerely,

Douglas Neeley

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

cc: J. Koerner, BAR
SWD
NPS

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 22-Oct-1999 01:45pm
From: Patricia Comer TAL
COMER_P
Dept: Office General Counsel
Tel No: 850/488-9730

To: Jeff Koerner TAL (KOERNER_J)

Subject: Re: OGC Case for Project No. 0970014-003-AC

We got a Request for Extension on October 5. Case assigned to Doug Beason.

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 22-Oct-1999 01:41pm
From: Patricia Comer TAL
COMER_P
Dept: Office General Counsel
Tel No: 850/488-9730

To: Jeff Koerner TAL (KOERNER_J)

Subject: Re: OGC Case for Project No. 0970014-003-AC

Heather Chapman would be able to help. She's the chief admin person over here in TT(1-9678)
You can also ask Kathy Carter, your Agency Clerk, who logs in all legal cases...she's in Douglas (8-9736).
Or, if you're really desperate, ask the permitting attorneys...that's Doug Beason for NE, SW and Cen.(8-9624) and Martha Nebelsiek for NW, SE and S (1-9633).
But, today only because it's Friday and all, I'll give you a special deal and check this out myself....I'll get back to you as soon as I find out.

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 22-Oct-1999 01:14pm
From: Jeff Koerner TAL
KOERNER_J
Dept: Air Resources Management
Tel No: 850/414-7268 GIC 069

To: Patricia Comer TAL (COMER_P)

Subject: OGC Case for Project No. 0970014-003-AC

Pat,

I'm working on a project for the FPC Intercession City site. I was trying to update ARMS for the date of publication, but couldn't. Apparently, OGC has locked the ARMS data. I guess there's a petition or a request for an extension in which to file a petition. How can I find out?

Thanks.

Jeff

Florida Power
CORPORATION

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October 19, 1999

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

Dear Mr. Linero:

Re: FPC Intercession City Facility, Notice of Intent to Issue PSD Permit
Draft Permit No. 097-0014-003-AC (PSD-FL-268)

Enclosed please find the notarized proof of publication received from the Osceola News-Gazette for the Florida Department of Environmental Protection *Notice of Intent to Issue PSD Permit* referenced to the above request. The notice was published on September 30, 1999.

If you should have any questions concerning this correspondence, please do not hesitate to contact me at (727) 826-4258.

Sincerely,

Scott H. Osbourn
Senior Environmental Engineer

cc: Len Kozlov, DEP Central District (w/attach)

Attachment

EPA
NPS
J. Koerner, BAR

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PROOF OF PUBLICATION

FROM

Osceola News-Gazette

Kissimmee, Florida
OSCEOLA COUNTY

In the Matter of

Public Notice
Of Intent To Issue
Air Construction
Permit

Filed ..... day of ...., 19 .....
First Publication .. September 30 1999
Last Publication .. September 30 1999

Make Remittance to Osceola News-Gazette
Kissimmee, Florida

PROOF OF PUBLICATION

STATE OF FLORIDA,
COUNTY OF OSCEOLA

Before me, the undersigned authority, personally appeared Dan L. Autrey, who on oath says that he is General Manager of the Osceola News-Gazette, a twice weekly newspaper published at Kissimmee, in Osceola County, Florida; that the attached copy of the advertisement was published weekly in the regular and entire edition of said newspaper in the issues of:

September 30, 1999

Affiant further says that the Osceola News-Gazette is a newspaper published in Kissimmee, in said Osceola County, Florida, and that the said newspaper has heretofore been continuously published in said Osceola County, Florida, each week and has been entered as periodicals postage matter at the post office in Kissimmee, in said Osceola County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Dan L. Autrey

Sworn to and subscribed before me by Dan L. Autrey, who is personally known to me, this 30 day of September 1999

Carol L. Gorrell
Carol L. Gorrell
(N.P. Seal)

Carol L. Gorrell
Notary Public, State of Florida
Commission No. CC 595820
My Commission Exp. 10/24/2000
Bonded Through Fla. Notary Service & Bonding Co.

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft Permit No. 097-0014-003-AC (PSD-FL-268)

FPC Intercession City Plant
Osceola County

Three New Peaking Simple-Cycle Combustion Turbines
New Emissions Units 018, 019, and 020

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to the Florida Power Corporation to increase peaking power at the existing FPC Intercession City Plant. This plant is located approximately 3.5 miles west of Intercession City at 6525 Osceola Polk County Line Road in Osceola County, Florida. The Draft Permit authorizes the installation of three simple cycle, dual-fuel, General Electric Model 7EA combustion turbines with electrical generator sets, each having an hourly capacity of 87 MW. A Best Available Control Technology (BACT) determination was required for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM10), sulfuric acid mist (SAM), and sulfur dioxide (SO2) pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD) of Air Quality. This project is not subject to review under Section 403.506 F.S. (Power Plant Siting Act), because it provides for no expansion in steam generating capacity. The applicant's authorized representative is Mr. W. Jeffrey Pardue, C.E.P., Director of Environmental Services for the Florida Power Corporation. The applicant's mailing address is P.O. Box 14042, MAC BB1A, St. Petersburg, FL 33733.

When firing natural gas, NOx emissions from each gas turbine will be controlled by dry low-NOx combustors capable of achieving emissions of 9 ppmvd corrected to 15% oxygen. When firing low sulfur distillate oil, NOx emissions will be controlled by water injection capable of achieving 42 ppmvd corrected to 15% oxygen. Base load carbon monoxide (CC) limits will be 20 ppmvd corrected to 15% oxygen for gas and oil firing. For the first 12 months of operation, the permit specifies a CO limit of 25 ppmvd corrected to 15% oxygen for gas firing: allow for tuning the gas turbines, dry-low NOx combustors and automated control system. Emissions of volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter will be very low because of the inherently low emissions of the General Electric 7EA gas turbine, the use of pipeline-quality natural gas as the primary fuel, and limited usage of low sulfur distillate oil. Total turbine operating hours for the three combined units are limited to 10,170 hours per year. Of this total, no more than 3000 turbine hours per year may occur when firing low sulfur distillate oil. The permit contains further restrictions if only one or two units are installed.

The following table summarizes the potential project emissions in tons per year and shows the corresponding PSD Significant Emissions Rate.

Pollutant	Project Potential Emissions (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	Subject To BACT?
CO	260	100	Yes	Yes
NOx	365	40	Yes	Yes
PM/PM10	73	15	Yes	Yes
SAM	9	7	Yes	Yes
SO2	95	40	Yes	Yes
VOC	15	40	No	No

After the first 12 months, potential CO emissions will be reduced to 220 tons per year. An air quality impact analysis was conducted. The ambient impact analysis predicted all pollutant emissions to have an insignificant impact on Class I and Class II Areas. Emissions from the facility will not significantly contribute to or cause a violation of any state of federal ambient air quality standard. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and request for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments and request for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known, (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact Al Linero, Administrator of the New Source Review Section, or the Department's reviewing engineer for this project, Jeff Koerner, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

Florida Power
CORPORATION

RECEIVED
OCT 18 1999
BUREAU OF AIR REGULATION

October 15, 1999

Mr. A. A. Linero, P.E.
Administrator, New Source Review Section
Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Re: Florida Power Corporation's Intercession City Facility
New Emissions Units 018, 019 and 020
FDEP File No. 097-0014-003-AC (PSD-FL-268)

Dear Mr. Linero:

The above referenced project was publicly noticed in the Osceola Times on September 30, 1999. The following provides the Department with Florida Power Corporation's (FPC) comments on the various portions of the "Intent to Issue PSD Permit" package, broken down by section.

Technical Evaluation and Preliminary Determination

Project Emissions – Section 3.2 (page TE-3) lists VOC emissions of 15 tons per year (TPY) and a footnote as follows:

> "The initial application indicated that VOC emissions would be greater than 40 TPY, but that estimate was based on 'unburned hydrocarbon' emissions. GE data indicates regulated VOC emissions to be much less. The Draft Permit conditions regulate 'VOC' emissions."

FPC concurs that the application estimates were based on unburned hydrocarbons (UHCs), as UHCs were the basis provided in the GE spec sheets. UHC emissions are also referred to as total hydrocarbon compound (THC) emissions. VOC emissions are a subset of the UHCs (or THCs) that reflect the non-methane/ethane portion. Based on the UHC estimates provided by GE, FPC's application conservatively reflected VOC emissions of 7 ppmvw and 9 lb/hr (at 59°F) for both gas and oil. Assuming operation at 3,390 hr/yr, total VOC emissions were estimated by FPC to be 15.3 TPY per CT, or 45.9 TPY total (just over the 40 TPY PSD significance level). The Department subsequently presents, in Table 5-A (page TE-5), proposed emission limits for VOCs and further states that the proposed "...standards for VOC are not BACT standards, but limits to ensure pollutant emissions remain below the

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corresponding significant emissions rates. FPC is in agreement with the Department that VOC emissions are a subset of the UHC emissions and, therefore, should be lower than the UHC values originally proposed. However, the vendor will not guarantee either the UHC or VOC values. FPC requests that the VOC permit limits be revised to 7 lb/hr (at 59°F) for both gas and oil. This lower value is a compromise that acknowledges that VOCs may be lower than the values reported by GE for UHCs. Further, at a rate of 7 lb/hr, the project VOC emissions would still be below the 40 TPY significant threshold level and exempt from BACT review (35.6 TPY).

Draft Permit

Permitted Capacity - Specific Condition (SC) 3 (page 5 of 14). In accordance with the Department's position on recently issued Title V permits, FPC requests that a permitting note be placed at the end of SC 3 to clarify that the heat input values are only included for purposes of determining capacity during testing, and that regular record keeping is not required. Also, the third sentence of SC 3 should read as follows: "an inlet air temperature of ~~supply cooled to~~ 59°F...".

Hours of Operation - SC 6 (page 6 of 14). FPC requests that the appropriate hour limitations for the units be revisited for the following reasons: 1) FPC had requested 3,390 hr/yr/CT for consistency with past permit requests, but has become aware that other applicants are requesting and receiving operating hour limits in excess of 4,000 hr/yr; 2) FPC conducted all ambient impact modelling, conservatively based on the use of fuel oil at 8,760 hours per year of operation, showing no adverse impacts; and 3) the Department's own BACT analysis was conducted at unlimited operation, assuming 5,760 hr/yr/CT on gas and 3,000 hr/yr/CT on oil. As all of the required analyses conducted by the Department were based on these operating hour assumptions, FPC requests that these hour values (i.e., 5,760 hr/yr/CT, no more than 3,000 hr/yr/CT on oil) be incorporated as limits for each of the CTs.

Also, the permit language in SC 6 states that operation below 50% of base load shall be limited to two hours per unit cycle (breaker open to breaker closed). If the Department is concerned about excess emissions during this period, FPC notes that the Excess Emissions section of the permit (SC 21, page 9 of 14) limits excess emissions due to start-ups, shutdowns and malfunctions to no more than two hours in any 24-hour period. Since combustion turbine peaking units typically operate at close to full load, the units would only be at less than 50% of full load due to initiation of a start-up or shutdown sequence. Therefore, FPC requests that the referenced language in SC 6 be deleted.

Emissions Controls - SC 11 and SC 12 (page 7 of 14). FPC requests that the Department add the phrase "Consistent with best operation and maintenance practices..." to the beginning of each of these conditions. The permit language also requires that "the permittee provide manufacturer's emissions performance versus load diagrams' for the specific system". FPC is reluctant to agree to this language because GE has indicated that they do not typically provide such diagrams. In any event, FPC provided spec sheets in our initial application with emissions data and other stack parameters at different load points. This data was used as the basis for the worst-case ambient impact modelling. The information in these previously submitted spec sheets should be sufficient for the Department's needs and, therefore, FPC requests that the permit language referring to submittal of these diagrams be deleted.

FPC strenuously objects to the language requiring the development of a NOx reduction plan (and an associated lowering of the NOx emission limit), if a unit operates for more hours on oil than gas. The maximum allowable hours of oil and gas firing are appropriately dealt with in this permit proceeding (i.e., the BACT process that determines the best available control technology, as well as the appropriate emission limit, and the ambient impact analysis that reflects all of these assumptions). To require a permittee to revisit these issues simply because more operation on oil than gas occurred in a 12-month period (even though the permittee has operated well below all other applicable limits), is unreasonable. FPC requests that this language be removed.

Emissions Standards - SC 15 (page 8 of 14). FPC requests that this section provide emission limits for VOC, CO and NO_x in terms of "pounds per hour" only, referring to the relevant concentration value (ppm) as the basis for these limits. The VOC basis should be expressed as ppmvw and the CO basis should be expressed as ppmvd. The CO limits on gas (both ppmvd and lb/hr) are lower than the vendor guarantee and, although there is risk involved in agreeing to an emission limit that is lower than the corresponding vendor guarantee, FPC will agree to accept the phased approach proposed in the permit (i.e., 54 lb/hr, based on 25 ppmvd, initially and 43 lb/hr, based on 20 ppmvd, after 12 months). However, FPC requests that the permit language be revised to have the 12-month period commence after initial compliance testing, not first fire in the unit.

Similarly, FPC requests that the language in SC 16 and SC 17 refer to the lb/hr format as the emission limit. Further, instead of referring to 3-hour test averages for CO and NOx compliance, FPC requests that these conditions simply refer to SC 27, which details the appropriate EPA reference test methods. The requested text is provided below.

16. Carbon Monoxide (CO)

Gas Firing: During the first 12 months after initial ~~startup~~ compliance demonstration, CO emissions shall not exceed 54.0 lb/hr (at 59°F) ~~nor~~ based on 25 ~~ppmvd corrected to 15% oxygen~~ based on ~~a 3-hour test average~~ the procedures provided in Condition 27 when firing natural gas in a combustion turbine. Thereafter, CO emissions shall not exceed 43.0 lb/hr (at 59°F) ~~nor~~ based on 20.0 ppmvd corrected to 15% oxygen based on ~~a 3-hour test average~~ the procedures provided in Condition 27 when firing natural gas in a combustion turbine.

Oil Firing: When firing low sulfur distillate oil in a combustion turbine, CO emissions shall not exceed 44.0 lb/hr (at 59°F) ~~nor~~ based on 20 ppmvd ~~corrected to 15% oxygen~~ based on ~~a 3-hour test average~~ the procedures provided in Condition 27.

17. Nitrogen Oxides (NOx)

Gas Firing: When firing natural gas in a combustion turbine, NOx emissions shall not exceed 32.0 lb/hr (at 59°F) ~~nor~~ based on 9 ppmvd corrected to 15% oxygen based on ~~a 3-hour test average~~ the procedures provided in Condition 27. In addition, NOx emissions shall not exceed 32.0 lb/hr (at 59°F) ~~9 ppmvd corrected to 15% oxygen~~ based on a 24-hour block average for data collected from the continuous emissions monitor.

Oil Firing: When firing low sulfur distillate oil in a combustion turbine, NOx emissions shall not exceed 167.0 lb/hr (at 59°F) ~~nor~~ based on 42 ppmvd corrected to 15% oxygen based on ~~a 3-hour test average~~ the procedures provided in Condition 27. In addition, NOx emissions shall not exceed 167.0 lb/hr (at 59°F) ~~9 ppmvd corrected to 15% oxygen~~ based on a ~~3-hour~~ 24-hour block average for data collected from the continuous emissions monitor.

Similarly, FPC requests that the language in SC 19, the limits for VOCs, incorporate the same revisions as discussed above.

Excess Emissions- SC 21 provides the standard language that "...excess emissions during startup, shutdown and malfunction not exceed 2 hours in any 24-hour period", however, the phrase "unless specifically authorized by the DEP for longer duration" needs to be added to the text. Also, this condition includes the following language: "Excess emissions resulting from startup to simple cycle mode shall not exceed one hour." FPC requests that this language be removed, as it is unnecessarily restrictive and has not been observed in other recently issued permits.

Emissions Performance Testing- In the text of SC 22, when referring to the combustion turbine testing capacity, the phrase heat input vs. ambient temperature is used. In cases where inlet cooling is utilized, it's more technically correct to use the phrase heat input vs. inlet temperature. In the discussion on performance test methods (SC 27), EPA Methods 7E and 20 refer to an "annual 3-hour NOx limit". FPC requests that this language be removed, as it is confusing and serves no purpose. Regarding the annual performance testing requirements listed in SC 30, FPC does not believe that it's necessary to conduct annual VE tests while firing natural gas fuel. Also, annual testing for CO, NOx and VEs should only be required for oil firing if oil is fired for more than 400 hours per CT in a federal fiscal year. Finally, the condition provides that an annual test for VOCs is not required as long as the unit remains in compliance with the CO and visible emissions limits specified in the permit. FPC believes that CO emissions are a good surrogate for the VOC compliance status and the Department has traditionally used the VOC/CO representation in permit language. However, the inclusion of VE as an additional surrogate for VOC compliance is new language and unnecessary. FPC requests that the language relating visible emissions compliance to VOC compliance be removed.

Continuous Monitoring Requirements- The requirement in SC 35 (page 12 of 14) to substitute missing data per Title IV (40 CFR 75) is overly punitive when applied to averaging periods shorter than what is contained in Title IV (calendar year annual average). Missing data periods, as well as startup/shutdown (less than fifty percent load) and malfunction periods, should be excluded from the calculation of short-term averages. Further, the NO$_x$ limits in this condition should be stated in terms of "pounds per hour" only, using the concentration in ppm as the basis. The averaging period while firing fuel oil should be changed from "3 hr average" to "24 hour block average" similar to the requirement for gas firing. The averaging times requested by FPC should be pollutant-specific, not fuel-specific. FPC does not understand the rationale for requiring a shorter averaging time for a NOx standard on oil vs. a NOx standard based on gas-firing.

Compliance Demonstrations- SC 39 refers to the requirement for a monthly operations summary. This summary is described as a written log, updated each month, to include hours of firing on each fuel, the quantity of fuel fired, the average heat input of each fuel fired, the average sulfur content, etc. FPC intends to record and maintain all records and data onsite that are necessary for compliance with this permit. The requirement for a separate written monthly summary is unnecessary and FPC requests that SC 39 be deleted.

Appendix BD

The BACT determination should be modified to reflect the changes referenced above, such as stating the proposed limits in terms of "pounds per hour", inclusion of appropriate averaging times and references to EPA reference test methods.

FPC appreciates the opportunity to provide these comments and, at your convenience, would like to arrange for a meeting to discuss these issues. In the meantime, if you have any questions, please feel free to contact me at (727) 826-4258.

Sincerely,

Scott H. Osbourn
Senior Environmental Engineer

cc: Jeff Koerner, DEP BAR
Robert Manning, HGS&S

cc: L. Kozlov, Central District
EPA
NPS

Florida
Power
CORPORATION

RECEIVED
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DEPT OF ENVIRONMENTAL PROTECTION
OFFICE OF GENERAL COUNSEL

September 30, 1999

Ms. Kathy Carter, Clerk
Office of General Counsel
Florida Department of Environmental Protection
Room 638
3900 Commonwealth Blvd.
Tallahassee, FL 32399-3000

Dear Ms. Carter:

RE: Florida Power Corporation, Intercession City Facility
REQUEST FOR EXTENSION OF TIME on the *Intent to Issue Air Construction Permit*
Draft Permit No. 097-0014-003-AC (PSD-FL-268)

On September 20, 1999, Florida Power Corporation (FPC) received the above-referenced *Intent to Issue Air Construction Permit*. A review of the permit conditions has revealed that several issues remain to be resolved. Accordingly, FPC requests an extension of time, pursuant to Florida Administrative Code Rule 62-110.106(4), to and including November 30, 1999, in which to file a Petition for Administrative Proceedings in the above-styled matter. Granting of this request will not prejudice either party, but will further both parties' mutual interest by hopefully avoiding the need to actually file a Petition for Administrative Proceeding in this matter. If the Department denies this request, FPC requests the opportunity to file a Petition for Administrative Proceeding within 10 days of such denial.

If you should have any questions, please contact Mr. Scott Osbourn of FPC at (727) 826-4258.

Sincerely,

for

W. Jeffrey Pardue, C.E.P.
Director, Environmental Services Department
Title V Responsible Official

Angela R. Morrison for

Robert A. Manning, Esq.
Hopping Green Sams & Smith

cc: Scott Sheplak, DEP
Jeffrey Brown, DEP OGC

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EXHIBIT 1

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 15, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: PSD Review and Custom Fuel Monitoring Schedule
FPC Intercession City Plant
Air Permit No. PSD-FL-268

Dear Mr. Neeley:

Enclosed is a copy of the Department's draft permit to construct three 87 MW simple cycle, peaking combustion turbines for the FPC Intercession City Plant in Osceola County, Florida. The Department's Intent to Issue package was already mailed to Mr. Gregg Worley of Region 4. This project authorizes the installation of three simple cycle, dual-fuel, General Electric Model 7EA combustion turbines with electrical generator sets, each having a maximum hourly capacity of 87 MW. The new units will use the existing infrastructure including oil storage and support equipment. Total turbine operating hours for the three combined units are limited to 10,170 hours per year. Of this total, no more than 3000 turbine hours per year may occur when firing low sulfur distillate oil. The permit contains further restrictions if only one or two units are installed.

When firing natural gas, NOx emissions from each gas turbine will be controlled by dry low-NOx combustors capable of achieving emissions of 9 ppmvd corrected to 15% oxygen. When firing low sulfur distillate oil, NOx emissions will be controlled by water injection capable of achieving 42 ppmvd corrected to 15% oxygen. Base load carbon monoxide (CO) limits will be 20 ppmvd corrected to 15% oxygen for gas and oil firing. For the first 12 months of operation, the permit specifies a CO limit of 25 ppmvd corrected to 15% oxygen for gas firing to allow for tuning the combustion turbines, dry-low NOx combustors and automated control system. Emissions of volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter will be very low because of the inherently low emissions of the General Electric 7EA gas turbine, the use of pipeline-quality natural gas as the primary fuel, and limited usage of low sulfur distillate oil.

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

37. Fuel Records

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

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

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

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

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

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

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

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

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

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

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

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

[40 CFR 60, Subpart GG, Applicant Request]

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

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

Sincerely,

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

AAL/jfk

Enclosures

Z 333 618 141

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.
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Street & Number EPA	
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Postmark or Date 9-15-99 PSO-FI-268 0970014-003-AC	

PS Form **3800**, April 1995

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- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
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1. ☐ Addressee's Address
2. ☐ Restricted Delivery

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3. Article Addressed to:

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

4a. Article Number Z 333 618 141

4b. Service Type

☐ Registered ☒ Certified
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7. Date of Delivery

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6. Signature: *(Addressee or Agent)*
X SEP 17 1999

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

FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 15, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: DEP File No. 097-0014-003-AC (PSD-FL-268)
FPC Intercession City Plant
New Emissions Units 018, 019, and 020

Dear Mr. Pardue:

Enclosed is one copy of the draft air construction permit to install three new simple-cycle peaking combustion turbines at the existing FPC Intercession City Plant. This plant is located approximately 3.5 miles west of Intercession City at 6525 Osceola Polk County Line Road in Osceola County, Florida. The Technical Evaluation and Preliminary Determination, the Department's Intent to Issue Air Construction Permit and the Public Notice of Intent to Issue Air Construction Permit are also included.

The Public Notice of Intent to Issue Air Construction Permit must be published one time only, as soon as possible, in the legal advertisement section of a newspaper of general circulation in the area affected, pursuant to the requirements Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any other questions, please contact Jeff Koerner at 850/414-7268.

Sincerely,

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

CHF/jfk

Enclosures

In the Matter of an
Application for Permit by:

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

Permit No. 097-0014-003-AC
PSD-FL-268
FPC Intercession City Plant
New Emissions Units 018, 019, and 020
Osceola County

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of Draft permit attached) for the proposed project, detailed in the application specified above and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, Mr. W. Jeffrey Pardue, C.E.P., Director, Environmental Services of Florida Power Corporation, applied on May 25, 1999 to the Department for an air construction permit to increase peaking power at the existing FPC Intercession City Plant. This plant is located approximately 3.5 miles west of Intercession City at 6525 Osceola Polk County Line Road in Osceola County, Florida. The Draft Permit authorizes the installation of three simple cycle, dual-fuel, General Electric Model 7EA combustion turbines with electrical generator sets, each having an hourly capacity of 87 MW.The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit is required to perform proposed work.

The Department intends to issue this air construction permit based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of Public Notice of Intent to Issue Air Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

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

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

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit (including the Public Notice of Intent to Issue Air Construction Permit, Technical Evaluation and Preliminary Determination, and the Draft permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 9-15-99 to the person(s) listed:

Mr. W. Jeffrey Pardue, FPC*
Mr. Scott Osborne, FPC
Mr. J. Michael Kennedy, FPC
Mr. Len Kozlov, DEP - Central District Office
Mr. Gregg Worley, EPA
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 9-15-99
(Clerk) (Date)

Z 333 618 142

US Postal Service

Receipt for Certified Mail

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

Sent to Jeffrey Pardue
Street & Number FPC
Post Office, State, & ZIP Code St. Pete Fl

Postage	$
Certified Fee	
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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 9-15-99
0970014-003-AC
PSO-F1-268

PS Form **3800**, April 1995

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reverse side?

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

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

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

Consult postmaster for fee.

3. Article Addressed to:
Jeffrey Pardue, CEP
Fla. Power Corp
O Box 14042, MAC BB1A
St. Petersburg, Fl
33733

4a. Article Number
Z 333 618 142

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

7. Date of Delivery
SEP 17 1999

5. Received By: *(Print Name)*

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

nature: *(Addressee or Agent)*

m **3811,** December 1994

102595-98-B-0229 Domestic Return Receipt

Thank you for using Return Receipt Service.

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft Permit No. 097-0014-003-AC (PSD-FL-268)

FPC Intercession City Plant
Osceola County

Three New Peaking Simple-Cycle Combustion Turbines
New Emissions Units 018, 019, and 020

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to the Florida Power Corporation to increase peaking power at the existing FPC Intercession City Plant. This plant is located approximately 3.5 miles west of Intercession City at 6525 Osceola Polk County Line Road in Osceola County, Florida. The Draft Permit authorizes the installation of three simple cycle, dual-fuel, General Electric Model 7EA combustion turbines with electrical generator sets, each having an hourly capacity of 87 MW. A Best Available Control Technology (BACT) determination was required for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2) pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD) of Air Quality. This project is not subject to review under Section 403.506 F.S. (Power Plant Siting Act), because it provides for no expansion in steam generating capacity. The applicant's authorized representative is Mr. W. Jeffrey Pardue, C.E.P., Director of Environmental Services for the Florida Power Corporation. The applicant's mailing address is P.O. Box 14042, MAC BB1A, St. Petersburg, FL 33733.

When firing natural gas, NOx emissions from each gas turbine will be controlled by dry low-NOx combustors capable of achieving emissions of 9 ppmvd corrected to 15% oxygen. When firing low sulfur distillate oil, NOx emissions will be controlled by water injection capable of achieving 42 ppmvd corrected to 15% oxygen. Base load carbon monoxide (CO) limits will be 20 ppmvd corrected to 15% oxygen for gas and oil firing. For the first 12 months of operation, the permit specifies a CO limit of 25 ppmvd corrected to 15% oxygen for gas firing to allow for tuning the gas turbines, dry-low NOx combustors and automated control system. Emissions of volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter will be very low because of the inherently low emissions of the General Electric 7EA gas turbine, the use of pipeline-quality natural gas as the primary fuel, and limited usage of low sulfur distillate oil. Total turbine operating hours for the three combined units are limited to 10,170 hours per year. Of this total, no more than 3000 turbine hours per year may occur when firing low sulfur distillate oil. The permit contains further restrictions if only one or two units are installed.

The following table summarizes the potential project emissions in tons per year and shows the corresponding PSD Significant Emissions Rate.

Pollutant	Project Potential Emissions (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	Subject To BACT?
CO	260	100	Yes	Yes
NOx	365	40	Yes	Yes
PM/PM_{10}	73	15	Yes	Yes
SAM	9	7	Yes	Yes
SO_2	95	40	Yes	Yes
VOC	15	40	No	No

After the first 12 months, potential CO emissions will be reduced to 220 tons per year. An air quality impact analysis was conducted. The ambient impact analysis predicted all pollutant emissions to have an insignificant impact on Class I

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

and Class II Areas. Emissions from the facility will not significantly contribute to or cause a violation of any state or federal ambient air quality standard. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by rule 28-106.301

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact Al Linero, Administrator of the New Source Review Section, or the Department's reviewing engineer for this project, Jeff Koerner, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

FPC Intercession City Plant

Three New Peaking Simple-Cycle Combustion Turbines
New Emissions Units 018, 019, and 020

Osceola County

Facility I.D. No. 097-0014

Draft Permit No. 097-0014-003-AC (PSD-FL-268)

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
New Source Review Section

September 9, 1999

1.0 APPLICATION INFORMATION

1.1 Applicant Name and Address

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

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

1.2 Reviewing and Processing Schedule

05/25/99	Received the PSD air pollution construction permit application
06/06/99	Received comments from the National Park Service
06/22/99	Department requested additional information
08/02/99	Department received additional information from the applicant; application complete

2.0 EXISTING FACILITY INFORMATION

2.1 Existing Facility Description

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

2.2 Facility Location

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

2.3 Standard Industrial Classification Codes (SIC)

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

2.4 Regulatory Categories

Power Plant Siting: The project is not subject to requirements of Chapter 403, Part II, F.S. or Chapter 62-17, F.A.C., Electric Power Plant and Transmission Line Siting because the it will not result in an increase in steam produced electrical power.

Title III – HAP: The facility is not believed to be a major source of hazardous air pollutants.

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

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

PSD Major Source: The facility is a "major facility" with respect to the Prevention of Significant Deterioration (PSD) of Air Quality program because emissions of at least one criteria pollutant are greater than 250 tons per year. Pursuant to Rule 62-212.400, F.A.C., each modification to a PSD major source requires a PSD review and determination of the Best Available Control Technology (BACT) if the resulting emissions increases are greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C.

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

3.0 PROPOSED PROJECT

3.1 Project Description

The applicant, Florida Power Corporation (FPC), proposes to add three new General Electric Model No. PG7121 7EA dual-fuel simple cycle combustion turbines with electrical generator sets having a nominal power production of 87 MW (Emissions Units 018, 109, and 020). The new units will employ evaporative cooling and use the existing infrastructure including oil storage and support equipment. Dry low-NOx (DLN) combustion technology will be used to control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will be used to control nitrogen oxide emissions when firing low sulfur distillate oil. The applicant requested the operational flexibility of limiting total turbine operating hours for the three combined units to 10,170 hours per year. Of this total, no more than 3000 turbine hours per year would occur when firing low sulfur distillate oil. Combustion design and clean fuels will be used to minimize emissions of carbon monoxide, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. Emissions will exit the combustion turbine at through a 56 feet high stack.

3.2 Project Emissions

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

Pollutant	Project Potential Emissions (Tons Per Year)[c]	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	Subject To BACT?
CO	260 / 220[a]	100	Yes	Yes
NOx	365[b]	40	Yes	Yes
PM/PM10	73[b]	15	Yes	Yes
SAM	9[b]	7	Yes	Yes
SO2	95[b]	40	Yes	Yes
VOC[d]	15[b]	40	No	No

[a] - "260" is based on 25 ppmvd for gas firing the first year of operation. "220" is based on 20 ppmvd for gas firing thereafter. Both calculations include 3000 total turbine hours of firing distillate oil based on 20 ppmvd.

[b] - Based on worst case of 7170 total turbine hours per year of gas firing and 3000 total turbine hours per year of oil firing and GE data. Assumes all particulate matter is PM10.

[c] - The project is not believed to be a major source of hazardous air pollutants (HAPs) or subject to any NESHAP or MACT control requirements pursuant to Section 112 of the Clean Air Act.

[d] - The initial application indicated that VOC emissions would be greater than 40 tons per year, but that estimate was based on "unburned hydrocarbon" emissions. GE data indicates regulated VOC emissions to be much less. The Draft Permit conditions regulate "VOC" emissions.

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

4.0 RULE APPLICABILITY

4.1 PSD Review

As previously discussed, the existing facility is considered a PSD major source and is 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). In addition, the proposed project will emit pollutants exceeding the Significant Emission Rates defined in Table 212.400-1, F.A.C. Therefore, the project is subject to a review for the Prevention of Significant Deterioration of Air Quality accordance with Rule 62-212.400, F.A.C.

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

4.2 State Regulations

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

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

4.3 Federal Regulations

This project is also subject to the applicable federal provisions regarding air quality as established by the EPA in the Code of Federal Regulations (CFR) and summarized below.

40 CFR 52.21	Prevention of Significant Deterioration

40 CFR 52.166	Prevention of Significant Deterioration
40 CFR 60	NSPS Subpart GG – Stationary Gas Turbines
40 CFR 60	Subpart A, General Provisions for NSPS Sources
40 CFR 72	Acid Rain Permits
40 CFR 73	Allowances
40 CFR 75	Monitoring
40 CFR 77	Acid Rain Program - Excess Emissions

5.0 SUMMARY OF BACT DETERMINATION

The Department has determined that a combination of control technologies for the firing of different fuels represents BACT for this project. Dry low-NOx (DLN) combustion technology will be used to control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will be used to control nitrogen oxide emissions when firing low sulfur distillate oil as a backup fuel. As requested by the applicant for operational flexibility, total turbine operating hours for the three combined units are limited to 10,170 hours per year. Of this total, no more than 3000 turbine hours per year may occur when firing low sulfur distillate oil. The permit contains further restrictions if only one or two units are installed. Combustion design and clean fuels will be used to minimize emissions of carbon monoxide, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. A detailed analysis of the BACT Determination is presented in Appendix BD of the Draft Permit included with the Department's Intent to Issue Permit. The following table summarizes the resulting emissions standards.

Table 5-A. Summary of Emissions Standards

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

EU-018, 019, and 020: GE Model 7EA Combustion Turbines

Pollutant	**Controls**[a]	**Emission Standards**[b]
CO	Gas Firing W/DLN, First 12 Months After Initial Startup	25.0 ppmvd @ 15% oxygen 54.0 pounds per hour
	Gas Firing W/DLN, After First 12 Months After Initial Startup	20.0 ppmvd @ 15% oxygen 43.0 pounds per hour
	Oil Firing W/Wet Injection	20.0 ppmvd @ 15% oxygen 44.0 pounds per hour
NOx	Gas Firing W/DLN	9.0 ppmvd @ 15% oxygen 32.0 pounds per hour
	Oil Firing W/Wet Injection	42.0 ppmvd @ 15% oxygen 167.0 pounds per hour
PM/PM10	Fuel Sulfur Specifications and Combustion Design	Visible emissions ≤ 10% opacity (PM estimated at 0.002 grains/dscf)
SAM/SO2	Natural Gas Sulfur Specification	1 grain per 100 SCF of gas
	Low Sulfur Distillate Oil Sulfur Specification	0.05% sulfur by weight
VOC	Gas Firing W/Combustion Design	2.0 ppmvd as methane 2.0 pounds per hour
	Oil Firing W/Combustion Design	4.0 ppmvd as methane 5.0 pounds per hour

6.0 AIR QUALITY ANALYSIS

6.1 Introduction

The proposed project will increase emissions of six pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, CO, NO_X, SO_2, SAM and VOC. PM_{10}, SO_2 and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO is a criteria pollutant and has only AAQS and significant impact levels defined for it. There are no applicable PSD increments or AAQS for SAM.

Potential emissions for VOC are above the 40 TPY significance threshold for the pollutant ozone. The applicant presented the potential increases to the Department and the U.S. EPA, and discussed options available to predict potential impacts associated with the emissions and formation of ozone. Based on the available information, the Department has determined that the use of regional models which incorporate the complex chemical mechanisms for predicting ozone formation are not feasible for this project. *(In addition, the applicant's VOC emission estimate was based on "unburned hydrocarbons". The Department reviewed additional information from General Electric indicating that regulated "VOC" emissions were well below the "unburned hydrocarbon" emissions rate. The Draft Permit regulates "VOC" emissions well below the PSD Significant Emissions Rate for VOC.)*

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

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

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

6.2 Models and Meteorological Data Used in the Significant Impact Analysis

The EPA-approved SCREEN3 (screening model) and Industrial Source Complex Short-Term (ISCST3) dispersion models were used to evaluate the pollutant emissions from the proposed project. These models determine ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. They incorporate elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfy the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at Orlando, Florida (surface data) and Ruskin, Florida (upper air data). The 5-year period of meteorological data was from 1987 through 1991. These NWS stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

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

6.3 Significant Impact Analysis

Initially, the applicant conducts modeling using only the proposed project's emissions at worst load conditions. In order to determine worst-case load conditions the SCREEN3 model was used to evaluate dispersion of emissions from the combined cycle facility for four loads (25%, 50%, 75% and 100%) and three seasonal operating conditions (summer, winter, and average). Once the worst-case loads are identified, the applicant utilizes the ISCST3 model to evaluate impacts at these loads, and compares the results to the significant impact levels. If the modeling at worst-case load conditions shows significant impacts, additional multi-source modeling is required to determine the project's impacts on existing air quality and any applicable AAQS and PSD increments.

Receptors were placed along the fence line of the facility, which is located in a PSD Class II area. Receptors were also placed in the Chassahowitzka National Wilderness Area (CNWA), which is the closest PSD Class I area. CNWA is located approximately 113 km northwest of the project. The receptor grid for predicting maximum concentrations in the vicinity of the project was a polar receptor grid that contained 15 rings and 10° spacing radials with dimensions centered on the simple-cycle facility stacks. The inner portion of the grid had rings at 500 m spacing out to 2,500 m. A 2,500-m spacing was used out to 5,000 m; and a 5,000-m spacing was used out to 50,000 m. For predicting impacts at the CNWA, thirteen discrete receptors along the border of the PSD Class I area were used. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project are predicted in the vicinity of the facility or in the CNWA.

Initially, ISCST3 modeling predicted an exceedance of the 24-hour Class I SO_2 significant impact level in the CNWA. The NPS and the Department directed the applicant to further evaluate the SO_2 impacts on the Class I area by using the long-range transport model, CALPUFF, which is a more applicable model for distances greater than 100 km. The results of this model showed that the impact of increased SO_2 emissions from the project is less than the EPA proposed significant impact level of 0.2 ug/m^3. The tables below show the results of the significant impact modeling.

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

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.01	1	NO
	24-hour	0.16	5	NO
CO	8-hour	17.2	500	NO
	1-hour	73.6	2000	NO
NO_2	Annual	0.13	1	NO
SO_2	Annual	0.04	1	NO
	24-hour	0.50	5	NO
	3-hour	2.44	25	NO

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

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Proposed EPA Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.002	0.2	NO
	24-hour	0.04	0.3	NO
NO_2	Annual	0.03	0.1	NO
SO_2	Annual	0.01	0.1	NO
	24-hour	0.13	0.2	NO
	3-hour	0.91	1	NO

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

6.4 Impacts Analysis

Impacts On Soils, Vegetation, And Wildlife

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

Impact On Visibility

Natural gas and low ash distillate fuel oil are clean fuels and produce little ash. This will minimize smoke formation. The low NO_X and SO_2 emissions will also minimize plume opacity. Because no add-on control equipment and no reagents are required, there will be no steam plume or tendency to form ammoniated particulate species. Due to the distance of the source from the CNWA, plus the type and amount of emissions from the source, the NPS believes that there is a low potential for visibility impacts. Therefore, no regional haze analysis was required for this project.

Growth-Related Air Quality Impacts

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

7.0 CONCLUSION

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

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

DRAFT PERMIT

PERMITTEE:

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

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

ARMS Permit No.	097-0014-003-AC
PSD Permit No.	PSD-FL-268
Facility ID No.	097-0014
SIC No.	4911
Expires:	(DRAFT)

PROJECT

This permit is issued pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit). This existing facility is an electric power generating plant with a nominal hourly capacity of 897 megawatts (MW). The proposed project will add three simple cycle, dual-fuel, General Electric Model 7EA combustion turbines with electrical generator sets each having a maximum hourly capacity of 87 MW.

LOCATION

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

STATEMENT OF BASIS

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

APPENDICES

The following Appendices are attached as part of this permit.

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

(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources Management

FACILITY DESCRIPTION

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

NEW EMISSIONS UNIT

The proposed project will add the following new emissions units.

ARMS ID No.	EMISSION UNIT DESCRIPTION
018 019 020	**Peaking Units P12, P13, and P14**: Each peaking unit consists of a General Electric Model No. PG7121 7EA dual-fuel simple cycle combustion turbine with electrical generator set having a nominal hourly power production output of 87 MW. The units may employ an evaporative cooling system. Dry low-NOx (DLN) combustion technology will be used to control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will be used to control nitrogen oxide emissions when firing the backup fuel of low sulfur distillate oil.

REGULATORY CLASSIFICATION

The facility is a "major facility" with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD) of Air Quality because emissions of at least one pollutant exceed 250 tons per year. Therefore, each modification to this facility resulting in emissions increases greater than the Significant Emissions Rates specified in Table 62-212.400-2 also requires a PSD review and Best Available Control Technology (BACT) determination. For this project, emissions of CO, NOx, PM/PM_{10}, and SAM/SO_2 are significant and this permit establishes the Best Available Control Technology (BACT) for each pollutant.

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

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

RELEVANT DOCUMENTS

- Permit application (05/25/99) and all related correspondence.
- Technical information on DLN-1 combustor technology by General Electric.
- Technical information on inlet air fogging by Caldwell Energy and Environmental, Inc.
- Calpuff modeling analysis performed by Golder Associates, Inc. (08/02/99).

GENERAL AND ADMINISTRATIVE REQUIREMENTS

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

2. Compliance Authority: All documents related compliance activities such as reports, tests, and notifications should be submitted to the Central District Office, Florida Department of Environmental Protection, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767. The phone number is 407/894-7555 and the fax number is 407/897-2966.

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

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

5. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

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

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

8. BACT Determination: In conjunction with extension of the 18 month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 52.166(j)(4)]

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

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

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

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

This permit addresses the following new emissions units.

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

APPLICABLE STANDARDS AND REGULATIONS

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

2. NSPS Requirements: The combustion turbine (EU-004) shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

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

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

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

PERFORMANCE RESTRICTIONS

3. Permitted Capacity: Each combustion turbine shall operate only in simple-cycle mode and generate a nominal 87 MW per hour of electrical power. Operation of each unit shall not exceed 885 mmBTU per hour of heat input from firing natural gas or 954 mmBTU per hour of heat input from firing low sulfur distillate oil. The maximum heat inputs are based on the lower heating value (LHV) of each fuel, an inlet air supply cooled to 59°F, a relative humidity of 60%, an ambient air pressure of 14.7 psi, and 100% of base load. Therefore, maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's performance curves, corrected for site conditions or equations for correction to other ambient conditions, shall be provided to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definition – Potential Emissions)]

4. Simple Cycle Operation Only: The combustion turbines shall operate only in simple cycle mode. This requirement is based on the permittee's request which formed the basis of the NOx BACT

determination and resulted in the emission standards specified in this permit. Specifically, the NOx BACT determination eliminated several control alternatives based on technical considerations and costs due to the elevated temperatures of the exhaust gas. Any request to convert these units to combined cycle operation by installing a new heat recovery steam generator or connecting to an existing heat recovery steam generator shall require the permittee to perform a new, current NOx BACT analysis and the approval of the Department through a permit modification. The results of this analysis may validate the initial BACT determination or result in the submittal of a full PSD permit application, new control equipment, and new emissions standards. [Rule 62-212.400(6)(b), F.A.C.]

5. Allowable Fuels: Each combustion turbine shall be fired by pipeline natural gas containing no more than 1 grain of sulfur per 100 dry standard cubic feet of gas. As a backup fuel, each combustion turbine may be fired with No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Each unit shall be capable of accommodating either fuel. Compliance with limits on fuel sulfur content shall be demonstrated by the record keeping requirements and/or the conditions of the Alternate Monitoring Plan specified in this permit. It is noted that these limitations are much more stringent than the NSPS sulfur dioxide limitation and assure compliance with 40 CFR 60.333 and 60.334. [Applicant Request, Rule 62-210.200, F.A.C. (Definition - Potential Emissions)]

6. Hours of Operation: The following limits apply to this group of three combustion turbines.

   (a) **Installation of One Gas Turbine**: When one gas turbine is installed, the total turbine operating hours shall not exceed 3390 hours per consecutive 12 months. Of this total, low sulfur distillate oil shall not be fired for more than 1000 turbine operating hours per consecutive 12 months.

   (b) **Installation of Two Gas Turbines**: When two gas turbines are installed, the total turbine operating hours shall not exceed 6780 hours per consecutive 12 months. Of this total, low sulfur distillate oil shall not be fired for more than 2000 turbine operating hours per consecutive 12 months.

   (c) **Installation of Three Gas Turbines**: When all three gas turbines are installed, the total turbine operating hours shall not exceed 10,170 hours per consecutive 12 months. Of this total, low sulfur distillate oil shall not be fired for more than 3000 turbine operating hours per consecutive 12 months.

   In addition, operation below 50% of base load operation shall be limited to two (2) hours per unit cycle (breaker open to breaker closed). The permittee shall install, calibrate, operate and maintain fuel flow meters to measure and accumulate the amount of each fuel fired in each combustion turbine. [Applicant Request; Rule 62-212.400, F.A.C. (BACT); Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

7. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbines and pollution control devices in accordance with the guidelines and procedures established by each equipment manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

8. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the Compliance Authority as soon as possible, but at least within one (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where

applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

EMISSIONS CONTROLS

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

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

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

12. Water Injection: To control NOx emissions when firing low sulfur distillate oil, the permittee shall install, calibrate and operate an automated water injection system for each unit. This system shall be maintained and adjusted to provide the minimum NOx emissions possible by water injection. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific water injection system prior to commencement of operation.

    When the hours of oil firing exceed the hours of gas firing during any consecutive 12-month period for any unit, the permittee shall develop a NOx reduction plan. This plan shall include a testing protocol designed to establish the maximum water injection rate and the lowest NOx emissions possible without affecting the actual performance of the gas turbine. The testing protocol shall set a range of water injection rates and attempt to quantify the corresponding NOx emissions for each rate and noting any problems with performance. Based on the test results, the plan shall recommend a new NOx emissions limiting standard and shall be submitted to the Department's Bureau of Air Regulation and Compliance Authority for review. If the Department determines that a lower NOx emissions standard is warranted for oil firing, this permit shall be revised.

    [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

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

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

EMISSIONS STANDARDS

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

EU-018, 019, and 020: GE Model 7EA Combustion Turbines

Pollutant	Controls[a]	Emission Standards[b]
CO	Gas Firing W/DLN, First 12 Months After Initial Startup	25.0 ppmvd @ 15% oxygen 54.0 pounds per hour
	Gas Firing W/DLN, After First 12 Months After Initial Startup	20.0 ppmvd @ 15% oxygen 43.0 pounds per hour
	Oil Firing W/Wet Injection	20.0 ppmvd @ 15% oxygen 44.0 pounds per hour
NOx	Gas Firing W/DLN	9.0 ppmvd @ 15% oxygen 32.0 pounds per hour
	Oil Firing W/Wet Injection	42.0 ppmvd @ 15% oxygen 167.0 pounds per hour
PM/PM10	Fuel Sulfur Specifications and Combustion Design	Visible emissions ≤ 10% opacity (PM estimated at 0.002 grains/dscf)
SAM/SO2	Natural Gas Sulfur Specification	1 grain per 100 SCF of gas
	Low Sulfur Distillate Oil Sulfur Specification	0.05% sulfur by weight
VOC	Gas Firing W/Combustion Design	2.0 ppmvd as methane 2.0 pounds per hour
	Oil Firing W/Combustion Design	4.0 ppmvd as methane 5.0 pounds per hour

[a] DLN means dry low-NOx controls. Oil firing is limited to an average of 1000 hours per year per gas turbine.

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

16. Carbon Monoxide (CO)

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

(b) **Oil Firing**: When firing low sulfur distillate oil in a combustion turbine, CO emissions shall not exceed 44.0 pounds per hour nor 20.0 ppmvd based on a 3-hour test average.

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

17. Nitrogen Oxides (NOx)

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

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

oxygen based on a 3-hour block average for data collected from the continuous emissions monitor.

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

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

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

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

19. Volatile Organic Compounds (VOC)

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

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

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

EXCESS EMISSIONS

20. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. These emissions shall be included in the calculation of the 24-hour NOx averages for compliance determinations. [Rule 62-210.700, F.A.C.]

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

EMISSIONS PERFORMANCE TESTING

22. Combustion Turbine Testing Capacity: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C. [Rule 62-297.310(2), F.A.C.]

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

24. Applicable Test Procedures

    (a) **Required Sampling Time.**

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

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

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

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

25. Determination of Process Variables

    (a) **Required Equipment.** The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. [Rule 62-297.310(5)(a), F.A.C.]

    (b) **Accuracy of Equipment.** Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value. [Rule 62-297.310(5)(b), F.A.C.]

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

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

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

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

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

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

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

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

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

29. Initial Tests Required: Initial compliance with the allowable emission standards specified in this permit shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days after initial operation of the emissions unit. Initial tests for emissions from the combustion turbine shall be conducted for CO, NOx, VOC, and visible emissions individually for the firing of natural gas and low sulfur distillate oil. Initial NOx performance test data shall also be converted into the units of the corresponding NSPS Subpart GG emissions standards to demonstrate compliance (see Appendix GG). [Rule 62-297.310(7)(a)1., F.A.C.]

30. Annual Performance Tests: Annual performance tests for CO, NOx, and visible emissions from the combustion turbine shall be conducted individually for the firing of natural gas and low sulfur distillate oil. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). An annual test for VOC emissions is not required as long as the unit remains in compliance with the CO and visible emissions limits specified by this permit. When conducted at permitted capacity, the annual NOx continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the annual compliance stack test. [Rule 62-297.310(7)(a)4., F.A.C.]

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

32. Tests After Substantial Modifications: All performance tests required for initial startup shall also be conducted after any substantial modification and appropriate shake-down period of air pollution control

equipment including the replacement of dry low-NOx combustors. Shakedown periods shall not exceed 100 days after re-starting the combustion turbine. [Rule 62-297.310(7)(a)4., F.A.C.]

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

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

CONTINUOUS MONITORING REQUIREMENTS

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

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

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

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

COMPLIANCE DEMONSTRATIONS

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

37. Fuel Records

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

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

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

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

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

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

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

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

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

        (2) The permittee shall submit a monitoring plan, certified by signature of the Authorized Representative, that commits to using a primary fuel of pipeline supplied natural gas

containing no more than 1 grain of sulfur per 100 SCF of gas pursuant to 40 CFR 75.11(d)(2);

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

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

[40 CFR 60, Subpart GG, Applicant Request]

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

REPORTS

40. Emissions Performance Test Reports: A report indicating the results of the required emissions performance tests shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.].

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

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

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
DB - Duct Burner
HRSG - Heat Recovery Steam Generator
DLN - Dry Low-NOx Combustion Technology
SCR - Selective Catalytic Reduction
OC - Oxidation Catalyst Technology for CO Control

RULE CITATIONS

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

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

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

Facility Identification (ID) Number:

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

New Permit Numbers:

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

Old Permit Numbers:

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

APPENDIX GC - CONSTRUCTION PERMIT GENERAL CONDITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

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

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

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

G.14 The permittee shall comply with the following:

(a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

(b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

(c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

Florida Power Corporation
FPC Intercession City Plant
Osceola County

Draft Permit No. 097-0014-003-AC (PSD-FL-268)
Three New Peaking Simple-Cycle Combustion Turbines
New Emissions Units 018, 019, and 020

1.0 EXISTING FACILITY

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

Because emissions of at least one criteria pollutant are greater than 250 TPY, the existing facility is considered a "major facility" with respect to Rule 62-212.400, F.A.C. - Prevention of Significant Deterioration (PSD) of Air Quality. Therefore, a PSD review and a Best Available Control Technology (BACT) determination is required for each pollutant that will experience an emissions increase greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C.

2.0 PROJECT DESCRIPTION

The applicant, Florida Power Corporation (FPC), proposes to add three new General Electric Model No. PG7121 7EA dual-fuel simple cycle combustion turbines with electrical generator sets having a nominal power production of 87 MW. The new units may employ an evaporative cooling system and will use the existing infrastructure including oil storage and support equipment. Dry low-NOx (DLN) combustion technology will be used to control nitrogen oxide emissions when firing the primary fuel of pipeline natural gas. Water injection will be used to control nitrogen oxide emissions when firing low sulfur distillate oil. The applicant requested the operational flexibility of limiting total turbine operating hours for the three combined units to 10,170 hours per year. Of this total, no more than 3000 turbine hours per year would occur when firing low sulfur distillate oil. Combustion design and clean fuels will be used to minimize emissions of carbon monoxide, particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. Emissions will exit the combustion turbine at through a 56 feet high stack.

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

3.0 APPLICATION PROCESSING SCHEDULE

05/25/99	The Department received a PSD air construction permit application.
06/22/99	The Department requested additional information.
08/02/99	The Department received additional information from the applicant; application complete.

4.0 PSD APPLICABILITY REVIEW

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

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

The existing facility is considered a PSD major source of air pollution because current potential emissions of at least one criteria pollutant are greater than 250 tons per year. Once a facility is classified as a PSD major source, new projects are reviewed for PSD applicability based on lower thresholds known as the Significant Emission Rates listed in Table 212.400-2, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each significant pollutant in accordance with Rule 62-212.400, F.A.C. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to implement BACT for several "significant" regulated pollutants.

This project will be located in Osceola County, an area that is currently in attainment, or designated as unclassifiable, for all air pollutants subject to a National Ambient Air Quality Standard (AAQS). The following table summarizes the potential emissions increases and PSD applicability for this new project.

Pollutant	Project Potential Emissions (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	Subject To BACT?
CO	260 / 220[a]	100	Yes	Yes
NOx	365[b]	40	Yes	Yes
PM/PM10	73[b]	15	Yes	Yes
SAM	9[b]	7	Yes	Yes
SO2	95[b]	40	Yes	Yes
VOC	15[b]	40	No	No

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

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

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

5.0 BACT DETERMINATION PROCEDURE

For projects subject to PSD review, it is the Department's responsibility to determine the Best Available Control Technology (BACT) for each regulated pollutant emitted in excess of a Significant Emission Rate. The BACT determination must be based on the maximum degree of emissions reduction that the Department determines is achievable through application of production processes and available methods, systems, and techniques for control of each such pollutant. The Department's determination is made on a case-by-case basis for each proposed project, taking into account energy, environmental and economic impacts. In addition to the information submitted by the applicant, the Department may rely upon other available information in making its BACT determination and shall also give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently directs that BACT should be determined using the "top-down" approach. In this approach, available control technologies are ranked in order of control effectiveness for the emissions unit under review. The most stringent control option is evaluated first and selected as BACT unless it is technically infeasible for the proposed project or rejected due to adverse energy, environmental or economic impacts. If the control option is eliminated, the next most stringent alternative is considered. This top-down approach continues until BACT is determined.

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

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

6.0 PROJECT ANALYSIS AND BACT DETERMINATIONS

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

- Comments from the National Park Service dated June 6, 1999;
- No comments were received from EPA Region 4;
- DOE web site information on Advanced Turbine Systems Project;
- Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines;
- General Electric technical product literature regarding the DLN-1 combustor design, CO/NOx performance curves vs. load, and the Speedtronic^{TM} Mark V Gas Turbine Control System.
- Emissions stack test results (September/October 1996) for a similar GE Model 7EA combustion gas turbine located at the Panda-Brandywine Cogeneration Facility in Brandywine, Maryland.

- Goal Line Environmental Technology Website: http://www.glet.com;
- TEC Website – www.teco-energy.com;
- Catalytica Website – www.catalytica-inc.com
- ARMS compliance data for similar General Electric 7EA units located at Gainesville Regional Utilities' Deerhaven Station and Kissimmee Utilities Authority's Cane Island Plant.

6.1 NITROGEN OXIDES (NOX)

6.1.1 Discussion of NOx Emissions

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

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

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

6.1.2 Applicant's Proposed NOx Controls

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

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

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

Conventional Selective Catalytic Reduction (SCR): This is an add-on control technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst bed to combine with NOx in a reduction reaction forming nitrogen and water. For this reaction to proceed satisfactorily, the exhaust gas temperature must be maintained between 450° F and 850°F. SCR is a commercially available, demonstrated control technology currently employed on several combined cycle combustion turbine projects capable of very low NOx emissions (< 3.5 ppmvd). However, conventional SCR is not technically feasible because the combustion turbine exhaust temperature of 1100°F is too high for standard catalysts and the oxidation reaction would not occur.

"Hot" Selective Catalytic Reduction (SCR): Due to the temperature limitation of conventional SCR catalysts, manufacturers have developed specially formulated zeolite catalysts designed to further the reduction reaction at temperatures up to 1025°F which is within the range of the exhaust gas temperature (1000°F) of this project. Typical NOx removal efficiencies for a hot SCR system would be 70% to 90% removal. Hot SCR is technically feasible for this project.

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

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

SCONOx™: SCONOx™ is a NOx and CO control system exclusively offered by Goal Line Environmental Technologies. Specialized potassium carbonate catalyst beds reduce CO and NOx emissions using an oxidation/absorption/regeneration cycle. The required operating temperature range is between 300°F and 700°F which requires a HRSG for use with a gas turbine. SCONOx™ is not technically feasible because the combustion turbine exhaust temperature of 1100°F is too high.

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

Of the control alternatives discussed, only DLN combustor technology, wet injection, and hot SCR remain as viable control options. For evaluation purposes, DLN for gas firing and wet injection for oil firing were combined to form a single control alternative. For this project, hot selective catalytic reduction (SCR) with ammonia injection is recognized as the top control option followed by dry low-NOx (DLN) combustor technology for gas firing combined with water injection for oil firing. The applicant reviewed hot SCR for the following additional adverse impacts.

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

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

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

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

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

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

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

6.1.3 Department's NOx BACT Determination

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

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

Environmental Impacts: The Department gives no consideration to the applicant's comment that NOx levels are already below the PSD significant impact levels and AAQS. This is considered only in the air quality analysis and not in making a BACT determination. However, hot SCR requires the injection of ammonia at slightly above the stoichiometric rate which inevitably results in ammonia "slip" or emissions of unreacted ammonia perhaps as much as 25 tons per year could slip by the hot SCR system. Ammonia may react with sulfur to generate up to additional 50% more PM$_{10}$ emissions in the form of ammonium sulfates and bisulfates. Ammonia has been designated as an Extremely Hazardous Substance under federal SARA Title III regulations. Finally, the spent catalyst could be considered hazardous requiring handling and disposal subject to RCRA regulations.

Economic Impacts: The Department disagrees with the applicant's cost analysis. First, the applicant multiplied the costs from another project nearly twice the size of the proposed combustion turbine by 50% to estimate costs for hot SCR. Second, the applicant estimated NOx emission reductions were based on 2390 hours of gas firing and 1000 hours of oil firing. However, the applicant also requested a limit of 10,170 total turbine hours for the three combined units with up to 3000 hours of total oil firing to provide operational flexibility. So, hours of operation for any one turbine could be much higher because of the requested flexible limits. Therefore, the Department performed a cost analysis using a vendor quote from an ongoing project that also involves hot SCR applied to a General Electric Model 7EA combustion turbine. In addition, the Department believes it is conservative to consider 5760 hours of gas firing and 3000 hours of oil firing to estimate potential emission reductions. The following table summarizes the Department's analysis. The applicant reviewed SCR for the following additional adverse impacts.

Control Option	Fuel	Emissions Ton Per Year	Control Efficiency	Reduction TPY	Totals TPY	Cost per Ton of NOx Removed
Hot SCR	Gas	37	60%[a]	55	206	$6024/ton NOx[b]
	Oil	100	60%	151		
DLN	Gas	92	Baseline	Baseline	Baseline	Baseline
Wet Injection	Oil	251	Baseline	Baseline		

Table Notes:

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

[b] Based on estimated installed capital cost of $4,644,270 and a total annualized cost of $1,240,955 per year from the application and a vendor quote for a similar unit (Hardee Power Station, PSD-FL-140a).

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

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

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

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

6.2 CARBON MONOXIDE (CO)

6.2.1 Discussion of CO Emissions

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

6.2.2 Applicant's Proposed CO BACT

The applicant identifies two control options that are technically feasible and commercially available for combustion turbines: an oxidation catalyst and combustion process design. Noble metal oxidation catalysts may be incorporated into the combustion turbine exhaust. These catalysts promote the oxidation of CO to carbon dioxide (CO_2) at much lower temperatures (650°F to 1150°F) than possible for oxidation without the catalyst. For this project, the exhaust gas temperature of 1100°F is in the proper design range and at this temperature, the control efficiency is primarily a function of gas residence time. An oxidation catalyst is recognized as the top control option and the applicant reviewed this option for the following additional adverse impacts.

Energy Impacts: Installation of an oxidation catalyst would result in an energy penalty due to the pressure drop across the catalyst bed of about 2 inches of water. This equates to about 12.5 million kWh per year of potential lost power generation or nearly1000 residential customers per year.

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

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

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

Table Notes:

[a] Based on emissions from DLN-controlled level to oxidation catalyst-controlled level. Assumes similar level of control for gas or oil firing. Assumes 2390 hours of gas firing and 1000 hours of oil firing.

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

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

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

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

6.2.3 Department's CO BACT Determination

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

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

Environmental Impacts: The Department rejects the applicant's argument that the further reduction of CO emissions would have negligible ambient impacts. Ambient impacts are evaluated in the modeling analysis and are not considered in the BACT determination.

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

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

Table Notes:

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

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

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

- The Department is aware of two similar GE 7EA units permitted in Florida. The Gainesville Regional Utilities' Deerhaven Station operates a simple cycle peaking unit with a NOx limit of 15 ppmvd and a CO limit to remain under 100 tons per year. Stack tests indicate CO emissions of 7.1 ppmvd with NOx emissions at 7.9 ppmvd. Kissimmee Utilities Authority's Cane Island Plant operates a combined cycle unit with a CO limit of 20 ppmvd and a NOx emissions limit of 25 ppmvd. However, this unit has tested at a rate of 9.7 ppmvd for CO and 10.5 ppmvd for NOx.
- Stack test information submitted by the applicant for an identical unit in Brandywine, Maryland indicates actual tested CO emissions levels of less than 10 ppmvd for firing natural gas and less than 5 ppmvd for firing distillate oil.
- The Department is aware that General Electric guarantees CO/NOx limits for the DLN-1 combustor dependent on the tuning for NOx. In other words, GE is able to tune the DLN-1 combustor for very

low NOx emissions at the expense (or possibility) of increasing CO emissions. However, based on the available stack test information, these guarantees appear very conservative.

- The RACT/BACT/LAER Clearinghouse database identifies only a few projects where an oxidation catalyst was required as BACT. In each of these projects, the units were either much larger or much smaller than the General Electric Model 7EA.

The Department contacted the applicant with the above information. The applicant indicated that General Electric is unwilling to guarantee a lower CO limit due to some site-specific problems with other installations. However, GE was able to make specific modifications to the combustor to lower the CO emissions for these sites. The Department discussed that an oxidation catalyst appeared cost effective assuming the proposed baseline emission rate of 25 ppmvd for gas firing. However, from the data reviewed, it seemed reasonable to expect much lower CO emissions. Reducing the baseline DLN CO limit from 25 ppmvd to 20 ppmvd (same as for oil firing) results in the following analysis.

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

Table Notes:

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

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

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

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

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

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

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

6.3 PARTICULATE MATTER (PM/PM10), SULFURIC ACID MIST (SAM) AND SULFUR DIOXIDE (SO2)

6.3.1 Discussion of PM/PM10, SAM, and SO2 Emissions

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

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

6.3.2 Applicant's Proposed PM/PM10, SAM, and SO2 BACT

Several available control technologies for particulate matter removal including centrifugal collectors, electrostatic precipitators, fabric filters, and wet scrubbers were identified. General Electric, the combustion turbine manufacturer, guarantees PM_{10} emissions for the Model 7EA unit of no more than 10 pounds per hour for natural gas firing and 25 pounds per hour for low sulfur distillate oil firing, including filterable and condensable fractions of the sampling train. Based on the design flow rate, this equates to approximately 0.002 grains per dry standard cubic feet of exhaust gas or roughly the emissions concentrations to be expected *after* control by a fabric filter. This level of emissions would be difficult to control with add-on equipment as well as measure during a performance test.

Wet or dry flue gas desulfurization and fuel treatment could be applied to this project to remove sulfur compounds. Although no cases of flue gas desulfurization applied to combustion turbines were identified, this option is technically feasible. Fuel treatment involves the desulfurization of natural gas and distillate oil by the fuel vendor prior to delivery to the user. For this project, the applicant has requested the use of pipeline quality natural gas containing less than 1 grain of sulfur per 100 SCF and distillate oil containing no more than 0.05% sulfur by weight. Limiting the sulfur content of the fuels also establishes the maximum potential SAM and SO_2 emissions. At these already very low levels, the control efficiency of an add-on technology would be unreasonably low and cost prohibitive.

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

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

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

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

6.3.3 Department's PM/PM10, SAM, and SO2 BACT Determination

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

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

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

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

(a) **Installation of One Gas Turbine**: When one gas turbine is installed, the total turbine operating hours shall not exceed 3390 hours per consecutive 12 months. Of this total, low sulfur distillate oil shall not be fired for more than 1000 turbine operating hours per consecutive 12 months.

(b) **Installation of Two Gas Turbines**: When two gas turbines are installed, the total turbine operating hours shall not exceed 6780 hours per consecutive 12 months. Of this total, low sulfur distillate oil shall not be fired for more than 2000 turbine operating hours per consecutive 12 months.

(c) **Installation of Three Gas Turbines**: When all three gas turbines are installed, the total turbine operating hours shall not exceed 10,170 hours per consecutive 12 months. Of this total, low sulfur distillate oil shall not be fired for more than 3000 turbine operating hours per consecutive 12 months.

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

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

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

6.4 VOLATILE ORGANIC COMPOUNDS

Originally, the applicant indicated VOC emissions above the significant emissions rate of 40 tons per year. However, this was based on the manufacturer's estimated maximum *unburned hydrocarbon* emissions rates. For an identical combustion turbine, General Electric guarantees VOC emissions of less than 2 lb/hour for gas firing and 5 lb/hr for oil firing. This would result in potential project VOC emissions of only 15 tons per year, which is well below the Significant Emissions Rate. Therefore, no BACT determination is required for this pollutant. However, the Department determines the following VOC emissions standards are necessary to ensure emissions levels are actually minor for purposes of this PSD review.

Gas Firing: 2.0 ppmvd measured as methane (2.0 lb/hr), 3-hour test average

Oil Firing: 4.0 ppmvd measured as methane (5.0 lb/hr), 3-hour test average

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

7.0 SUMMARY OF DEPARTMENT'S BACT DETERMINATION

7.1 BACT EMISSION LIMITS

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

EU-018, 019, and 020: GE Model 7EA Combustion Turbines

Pollutant	Controls[b]	Emission Standard
CO	Gas Firing W/DLN, First 12 Months After Initial Startup	25.0 ppmvd @ 15% oxygen 54.0 pounds per hour
	Gas Firing W/DLN, After First 12 Months After Initial Startup	20.0 ppmvd @ 15% oxygen 43.0 pounds per hour
	Oil Firing W/Wet Injection	20.0 ppmvd @ 15% oxygen 44.0 pounds per hour
NOx	Gas Firing W/DLN	9.0 ppmvd @ 15% oxygen 32.0 pounds per hour
	Oil Firing W/Wet Injection	42.0 ppmvd @ 15% oxygen 167.0 pounds per hour
PM/PM10	Fuel Sulfur Specifications and Combustion Design	Visible emissions ≤ 10% opacity
SAM[a]/SO2	Natural Gas Sulfur Specification	1 grain per 100 SCF of gas
	Low Sulfur Distillate Oil Sulfur Specification	0.05% sulfur by weight
VOC[a]	Gas Firing W/Combustion Design	2.0 ppmvd as methane 2.0 pounds per hour
	Oil Firing W/Combustion Design	4.0 ppmvd as methane 5.0 pounds per hour

[a] The VOC standards are synthetic (PSD) minor limits - not BACT limits.
[b] DLN means dry low-NOx controls.

7.2 BACT COMPLIANCE DEMONSTRATION

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

Pollutant	Compliance Methods*
CO	EPA Method 10 for initial and annual tests concurrent with NOx.
NOx	EPA Method 20 for initial and annual tests concurrent with CO; continuous compliance shall be demonstrated with data from the certified continuous emissions monitor; annual RATA results may be substituted for annual tests if all capacity, notification, and reporting requirements are met.
PM/PM10	EPA Method 9 for initial and annual visible emissions tests as a surrogate standard for PM/PM10.
SO2/SAM	Record keeping for the sulfur content of fuels delivered to the site.
VOC	Method 18, 25, or 25A for initial tests and prior to renewal of the operation permit, thereafter compliance is assumed IF compliance is maintained with the CO and VE standards.

* Compliance shall be demonstrated for each fuel type.

7.3 BACT EXCESS EMISSIONS ALLOWED

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

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

Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. These emissions shall be included in the calculation of the 24-hour NOx averages for compliance determinations. [Rule 62-210.700(4), F.A.C.]

8.0 COMMENTS FROM NPS AND EPA REGION 4

8.1 NPS COMMENTS

The National Park Service stated that they had no comments on this project.

8.2 EPA REGION 4 COMMENTS

EPA Region 4 did not comment on this project.

9.0 RECOMMENDATION AND APPROVAL

The permit project engineer and reviewing Professional Engineer is Jeff Koerner, P.E. The New Source Review Section recommends the above BACT determinations for this project. Additional details of this analysis may be obtained by contacting the project engineer at 850/414-7268 or the following address:

Department of Environmental Protection
Bureau of Air Regulation
New Source Review Section
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:	*Approved By:*
(DRAFT)	(DRAFT)
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Howard L. Rhodes, Director Division of Air Resources Management
Date: ______________	Date: ______________

APPENDIX GG - FEDERAL NEW SOURCE PERFORMANCE STANDARDS (NSPS)

40 CFR 60, SUBPART A - NSPS GENERAL PROVISIONS

This emissions unit is subject to the applicable portions of 40 CFR 60, Subpart A, General Provisions, including:

- 40 CFR 60.7, Notification and Record Keeping
- 40 CFR 60.8, Performance Tests
- 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
- 40 CFR 60.12, Circumvention
- 40 CFR 60.13, Monitoring Requirements
- 40 CFR 60.19, General Notification and Reporting Requirements

For copies of these requirements, please contact the Department's New Source Review Section.

40 CFR 60, SUBPART GG - STATIONARY GAS TURBINES

This emissions unit is subject to 40 CFGR 60, Subpart GG for stationary gas turbines adopted by reference in Rule 62-204.800(7)(b), F.A.C. The following conditions follow the original NSPS rule language and numbering scheme. Regulations that are not applicable were omitted for clarity. Because this emissions units is subject to an NSPS, it is also subject to the following federal provisions: 40 CFR 60, Subpart A, General Provisions for sources subject to an NSPS, adopted by reference in Rule 62-204.800(7)(d), F.A.C.; 40 CFR 60, Appendix A - Test Methods, Appendix B - Performance Specifications, Appendix C - Determination of Emission Rate Change, Appendix D - Required Emissions Inventory Information, Appendix F - Quality Assurance Procedures, adopted by reference in Rule 62-204.800(7)(e).

40 CFR 60.330 APPLICABILITY AND DESIGNATION OF AFFECTED FACILITY.

(a) The provisions of this subpart are applicable to all stationary gas turbines with a heat input at peak load equal to or greater than 10 million BTU per hour, based on the lower heating value of the fuel fired.

40 CFR 60.331 DEFINITIONS.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) 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:

$$NOx = (NOxo)\,(P_r/P_o)^{0.5}\,(e^{19\,(H_o - 0.00633)})\,(288°K/T_a)^{1.53}$$

Where

NOx = emission rate of NOx at 15 percent oxygen and ISO standard ambient conditions, volume percent.

NOxo = observed NOx concentration, ppm by volume.

P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.

P_o = observed combustor inlet absolute pressure at test, mm Hg.

H_o = observed humidity of ambient air, g H_2O/g air.

E = transcendental constant, 2.718.

T_a = ambient temperature, °K.

(2) The monitoring device of Sec. 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with Sec. 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

(d) The owner or operator shall determine compliance with the sulfur content standard in Sec. 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference--see Sec. 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some

fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

(e) To meet the requirements of Sec. 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

APPENDIX XS - CEMS EXCESS EMISSIONS REPORT

FIGURE 1--SUMMARY REPORT--GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant *(Circle One)*: SO_2 NOx TRS H_2S CO Opacity

Reporting period dates: From ____________________ to ____________________

Company: ____________________

Emission Limitation: ____________________

Address: ____________________

Monitor Manufacturer and Model No.: ____________________

Date of Latest CMS Certification or Audit: ____________________

Process Unit(s) Description: ____________________

Total source operating time in reporting period [1]: ____________________

Emission data summary [1]	**CMS performance summary** [1]
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:
a. Startup/shutdown .... ____	a. Monitor equipment malfunctions .... ____
b. Control equipment problems .... ____	b. Non-Monitor equipment malfunctions .. ____
c. Process problems .... ____	c. Quality assurance calibration .... ____
d. Other known causes .... ____	d. Other known causes .... ____
e. Unknown causes .... ____	e. Unknown causes .... ____
2. Total duration of excess emissions .... ____	2. Total CMS Downtime .... ____
3. [Total duration of excess emissions] x (100) / [Total source operating time] .... ____% [2]	3. [Total CMS Downtime] x (100) / [Total source operating time] .... ____ % [2]

[1] For opacity, record all times in minutes. For gases, record all times in hours.

[2] For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

<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: ____________________

Signature: ____________________

Title: ____________________

Date: ____________________

Memorandum

Florida Department of
Environmental Protection

TO: Clair Fancy, Chief, BAR

FROM: Jeff Koerner, New Source Review Section, BAR

DATE: September 15, 1999

SUBJECT: FPC Intercession City Plant
Three 87 MW Simple Cycle Peaking Combustion Turbines (PSD-FL-268)

Attached is the public notice package for the installation of three simple cycle, dual-fuel, General Electric Model 7EA combustion turbines with electrical generator sets each having a maximum hourly capacity of 87 MW. These new units will be added to the existing FPC Intercession City Plant that currently consists of eleven combustion turbine peaking units. The new units will use the existing infrastructure including oil storage and support equipment. As requested by the applicant for operational flexibility, total turbine operating hours for the three combined units are limited to 10,170 hours per year. Of this total, no more than 3000 turbine hours per year may occur when firing low sulfur distillate oil. The permit contains further restrictions if only one or two units are installed.

When firing natural gas, NOx emissions from each gas turbine will be controlled by dry low-NOx combustors capable of achieving emissions of 9 ppmvd corrected to 15% oxygen. When firing low sulfur distillate oil, NOx emissions will be controlled by water injection capable of achieving 42 ppmvd corrected to 15% oxygen. Base load CO limits will be 20 ppmvd corrected to 15% oxygen for gas and oil firing. However, for the first 12 months of operation, the permit specifies a CO limit of 25 ppmvd corrected to 15% oxygen for gas firing to allow for tuning the gas turbines, dry-low NOx combustors and automated control systems. Emissions of volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter will be very low because of the inherently low emissions of the General Electric 7EA gas turbine, the use of pipeline-quality natural gas as the primary fuel, and limited usage of low sulfur distillate oil.

Day #74 is 10/14/99. I recommend your approval of the attached Intent to Issue package for this project.

JFK

Attachments

FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

P.E. CERTIFICATION STATEMENT

PERMITTEE

Florida Power Corporation
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733

ARMS Permit No.	097-0014-003-AC
PSD Permit No.	PSD-FL-268
Facility ID No.	097-0014
SIC No.	4911

PROJECT DESCRIPTION

This project authorizes the installation of three simple cycle, dual-fuel, General Electric Model 7EA combustion turbines with electrical generator sets each having a maximum hourly capacity of 87 MW. These new units will be added to the existing FPC Intercession City Plant that currently consists of eleven combustion turbine peaking units. The new units will use the existing infrastructure including oil storage and support equipment. As requested by the applicant for operational flexibility, total turbine operating hours for the three combined units are limited to 10,170 hours per year. Of this total, no more than 3000 turbine hours per year may occur when firing low sulfur distillate oil. The permit contains further restrictions if only one or two units are installed.

When firing natural gas, NOx emissions from each gas turbine will be controlled by dry low-NOx combustors capable of achieving emissions of 9 ppmvd corrected to 15% oxygen. When firing low sulfur distillate oil, NOx emissions will be controlled by water injection capable of achieving 42 ppmvd corrected to 15% oxygen. Base load carbon monoxide (CO) limits will be 20 ppmvd corrected to 15% oxygen for gas and oil firing. For the first 12 months of operation, the permit specifies a CO limit of 25 ppmvd corrected to 15% oxygen for gas firing to allow for tuning the gas turbines, dry-low NOx combustors and automated control system. Emissions of volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter will be very low because of the inherently low emissions of the General Electric 7EA gas turbine, the use of pipeline-quality natural gas as the primary fuel, and limited usage of low sulfur distillate oil.

Impacts due to the proposed project emissions are all less than the applicable significant impact limits corresponding to the nearest PSD Class I Area (Everglades National Park) and Class II areas.

I HEREBY CERTIFY *that the engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).*

Jeffery J. Koerner

Jeffery F. Koerner, P.E.
Registration Number: 49441

9-2-99
Date

Department of Environmental Protection
Bureau of Air Regulation, New Source Review Section
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Phone (850) 414-7268

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 24-Aug-1999 04:18pm
From: Jeff Koerner TAL
KOERNER_J
Dept: Air Resources Management
Tel No: 850/414-7268 GIC 069

To: Kristine Roselius TAL (ROSELIUS_K @ EPIC5A1 @ DER)
To: Howard Rhodes TAL (RHODES_H)
To: Clair Fancy TAL (FANCY_C)
To: Alvaro Linero TAL (LINERO_A)

Subject: Phone Call From Gainesville Sun Reporter

Here's the Media Contact Sheet for a phone call I received at about 3:30 pm this afternoon.

DEP MEDIA HOT SHEET

EMAIL TO:

TO: Kristine Roselius, Office of Communications
Howard L. Rhodes, Director, DARM
Clair Fancy, Chief, BAR

FAX: 850/921-6227 or SC 291-6227 (Communication Office)

TOPIC: Routine Checking of Owner's Compliance History for All Air Permit Projects

DATE: August 24, 1999 REPORTERS NAME: Ron Maidus(sp?)

FROM: Gainesville Sun TELEPHONE: Unknown
(Newspaper, TV Station, Radio, etc.)

PERSON INTERVIEWED: Jeff Koerner TELEPHONE: 850/414-7268

DIVISION/BUREAU/OFFICE: DARM/BAR, New Source Review Section

DATE OF INTERVIEW: August 24, 1999 (3:30 pm) ACTION TIME NEEDED: None

FOLLOW-UP NEEDED? No

DEADLINE: None

SUMMARY OF CONVERSATION (Use additional pages if necessary)

The reporter asked specifically about a current air permitting project for Florida Power Corporation (FPC) in Intercession City (PSD-FL-268). He was aware of a project to add several new combustion turbine peaking units to the existing facility. We discussed the existing plant capacities and the proposed additional capacities in terms of electrical power production. I briefly described the process of requesting and receiving additional information for this project and that the application appeared to be complete. He asked me when I expected to make a preliminary determination and I replied probably within the next three weeks.

Next, he asked how I intended to determine the compliance history for this particular corporation. I responded that DEP's District office was responsible for determining compliance for the existing facility. In addition, copies of the permit application are available to each District office. No negative comments regarding the compliance history had been received from the District office.

He revised his question to include not just the compliance history for the existing facility, but for FPC in general, the owner of several power plants in Florida. I responded that I was unaware of any ongoing enforcement actions against FPC. He followed this up by asking me to define the normal steps the Department uses to determine whether or not a permit applicant's violation of Department rules is great enough to warrant a denial. He specifically mentioned the Suwanee American cement plant denial. I mentioned that, for some projects, I have used our state database (ARMS) to view the history of enforcement actions for a given applicant. Again, I stated that I was not aware of any ongoing enforcement actions against FPC, but could ask our Compliance/Enforcement staff if he had specific information. He responded that no, that really wasn't what he wanted. He was just trying to better understand the steps that the Department normally takes to ensure a “satisfactory” compliance history before issuing a permit.

We briefly discussed general permits, minor source permits, and major source permits. He asked for the correct spelling of my name, thanked me for my time and hung up.

INTEROFFICE MEMORANDUM

Date: 12-Aug-1999 07:49pm
From: Dee_Morse
Dee_Morse@nps.gov
Dept:
Tel No:

To: Jeff Koerner TAL 850/414-7268 GIC 0 (Jeff.Koerner@dep.state.fl.us)

Subject: Re[2]: US Sugar PSD Application

Further update on Intercession City. Ellen Porter is the lead for sources locating near US Fish and Wildlife Service Class I areas. I found out that Intercession City is a source close to Chassahowitzka NWR, Ellen informed Florida DEP that given the long distance from Intercession City to Chassahowitzka NWR and low emissions, the FWS did not think there would be any significant impacts on resources at the NWR from this source, therefore they informed Florida DEP on 6/9/1999 that they had no comments on this application.

______________________Reply Separator______________________
Subject: Re: US Sugar PSD Application
Author: Jeff Koerner TAL 850/414-7268 GIC 069 <Jeff.Koerner@dep.state.fl.us>
Date: 08/12/1999 1:55 PM

Dee,

Thanks for sending Don's comments early on the US Sugar project. I'll look for modeling comments next week.

I have another project, Florida Power Corp. - Intercession City, that I haven't seen any comments on BACT or modeling yet. It's listed as PSD-FL-268. Of course, it involves three simple cycle conbustion turbines (GE 7EA's). The application was received on May 25, 1999, I requested additional information on June 22, 1999, and I received their information on August 2, 1999. You should have copies of everything. Please let me know if NPS have any comments on this project (or no comments).

Thanks!

Jeff

```
Received: from epic5.dep.state.fl.us (199.73.143.30) by ccmail.itd.nps.gov with
SMTP
  (IMA Internet Exchange 2.12 Enterprise) id 00330D0C; Thu, 12 Aug 99 16:12:00
-0400
Received: from epic1.dep.state.fl.us ([199.73.238.11])
 by mail.epic5.dep.state.fl.us (PMDF V5.2-32 #31508)
 with ESMTP id <01JEOKW8Y37C0020PO@mail.epic5.dep.state.fl.us> for
 Dee_Morse@nps.gov; Thu, 12 Aug 1999 14:01:26 EDT
Received: from a1.epic1.dep.state.fl.us by mail.epic1.dep.state.fl.us
 (PMDF V5.2-32 #37976) id <01JEOKOKFLBE0000FE@mail.epic1.dep.state.fl.us> for
 Dee_Morse@nps.gov; Thu, 12 Aug 1999 13:55:15 -0400 (EDT)
Alternate-recipient: prohibited
Date: Thu, 12 Aug 1999 13:55:11 -0400 (EDT)
From: Jeff Koerner TAL 850/414-7268 GIC 069 <Jeff.Koerner@dep.state.fl.us>
```

INTEROFFICE MEMORANDUM

Date: 12-Aug-1999 07:19pm
From: Dee_Morse
Dee_Morse@nps.gov
Dept:
Tel No:

To: Jeff Koerner TAL 850/414-7268 GIC 0 (Jeff.Koerner@dep.state.fl.us)

Subject: Re[2]: US Sugar PSD Application

I have not seen the Intercession City PSD application. Where is it locate with regard to Everglades NP?

____________________Reply Separator____________________
Subject: Re: US Sugar PSD Application
Author: Jeff Koerner TAL 850/414-7268 GIC 069 <Jeff.Koerner@dep.state.fl.us>
Date: 08/12/1999 1:55 PM

Dee,

Thanks for sending Don's comments early on the US Sugar project. I'll look for modeling comments next week.

I have another project, Florida Power Corp. - Intercession City, that I haven't seen any comments on BACT or modeling yet. It's listed as PSD-FL-268. Of course, it involves three simple cycle conbustion turbines (GE 7EA's). The application was received on May 25, 1999, I requested additional information on June 22, 1999, and I received their information on August 2, 1999. You should have copies of everything. Please let me know if NPS have any comments on this project (or no comments).

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Jeff

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Received: from epic5.dep.state.fl.us (199.73.143.30) by ccmail.itd.nps.gov with
SMTP
  (IMA Internet Exchange 2.12 Enterprise) id 00330D0C; Thu, 12 Aug 99 16:12:00
-0400
Received: from epic1.dep.state.fl.us ([199.73.238.11])
 by mail.epic5.dep.state.fl.us (PMDF V5.2-32 #31508)
 with ESMTP id <01JEOKW8Y37C0020PO@mail.epic5.dep.state.fl.us> for
 Dee_Morse@nps.gov; Thu, 12 Aug 1999 14:01:26 EDT
Received: from a1.epic1.dep.state.fl.us by mail.epic1.dep.state.fl.us
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 Dee_Morse@nps.gov; Thu, 12 Aug 1999 13:55:15 -0400 (EDT)
Alternate-recipient: prohibited
Date: Thu, 12 Aug 1999 13:55:11 -0400 (EDT)
From: Jeff Koerner TAL 850/414-7268 GIC 069 <Jeff.Koerner@dep.state.fl.us>
Subject: Re: US Sugar PSD Application
To: Dee_Morse <Dee_Morse@nps.gov>
Message-id: <C2135IBA2ZY5E*/R=A1/R=EPIC1/U=KOERNER_J/@MHS>
MIME-version: 1.0
Content-type: TEXT/PLAIN; CHARSET=US-ASCII
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Florida Power
CORPORATION

RECEIVED

AUG 02 1999

BUREAU OF AIR REGULATION

July 30, 1999

Mr. Al Linero, P.E.
Administrator, New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Dear Mr. Linero:

Re: Florida Power Corporation's Intercession City Facility
Addition of Three New Combustion Turbine Peaking Units
Draft Permit No. 097-0014-003-AC (PSD-FL-268)

Florida Power Corporation (FPC) is in receipt of the Department's letter, dated June 22, 1999, indicating that the application for the above-referenced project has been received and reviewed. The Department has determined that additional information is necessary to continue with the processing of the application. This letter serves to provide responses to the Department's requests in the order they were listed.

Summary of Project- The Department's summary of the proposed project is correct. The only aspect that is not an accurate statement relates to the start-up of the combustion turbines (CTs). FPC had supplied information in the application indicating that the CTs "light off" on oil. This was accurate for the last phase of CTs that were installed at the site and was inadvertently left in the application for the three proposed units. However, with natural gas capability at the site and the dual-fuel capability of the proposed CTs, it is not necessary to start-up or light off the CTs on oil prior to firing natural gas.

Further, the Department has requested that FPC provide a description of the proposed inlet air cooling system and equipment. The system is typically referred to as inlet air "fogging". FPC recently added inlet fogging to the existing four GE 7EA units at the Intercession City. This information is attached as Appendix A.

NO_x BACT Determination- Only one dry low NO_x (DLN) combustor system is available for GE 7EA units. GE refers to the 7EA system as its DLN 1.0. This particular combustor has a proven design that inhibits the formation of NO_x. As requested, FPC is enclosing the manufacturer's description of the combustor design that includes its effects on NO_x formation (Appendix B). The Department also requested documentation concerning the vendor's guarantee to meet the proposed NO_x emission limits of 9 and 42 ppmvd at 15 percent O_2 while firing gas and oil, respectively. FPC has attached the vendor specification sheet for each fuel (Appendix C) containing emissions data with the appropriate guarantees noted.

CO BACT Determination- The Department notes that FPC's application proposes CO emission limits of 25 and 20 ppmvd at 15 percent O_2 for gas and oil firing, respectively. The Department asks FPC to verify that this is the case when, in general, available information for a variety of manufacturers and models of CTs seems to indicate higher CO emissions when firing oil than when firing gas (the opposite of the proposed limits). In response to the Department's comment, FPC again approached the vendor to confirm the CO emissions data. Upon further review, GE has confirmed that the information supplied in FPC's original application is indeed correct, only ***not*** corrected to 15 percent O_2.

Air Quality Impact Analysis- As noted in the Department's letter, the emission rates used in the SCREEN modeling were for a single unit. This was to assess the worst-case conditions for each unit, and one unit was representative since the three units are identical to each other. For purposes of the refined ISCST3 modeling, the simultaneous operation of all three proposed turbines was used as input.

As reflected in the Department's letter, the ISCST3 analysis predicted one exceedance of the 24-hour PSD Class I significance level for SO_2. Following discussions with Mr. Cleve Holladay, it was determined that an additional analysis of the Class I receptor impact would be performed using the CALPUFF model. Golder Associates performed this analysis, and the results show that expected maximum SO_2 impacts from the proposed sources will be well below the Class I significance levels. An analysis report is attached as Appendix D.

Maximum SO2 Emissions Rate- The maximum SO_2 emission rate of 55 lb/hour used in the ISCST3 analysis was provided by the combustion turbine manufacturer (GE). The slightly higher rate of 56.4 lb/hour was inadvertently not included in the subsequent CALPUFF analysis. This small difference will not have a substantive effect on the predicted ambient concentrations. All impacts will remain less than significance levels.

Additional Impacts Analysis- Through discussions with Mr. Cleve Holladay, it was determined that neither the DEP nor the National Parks Service will require a regional haze or visibility analysis for this proposed installation.

NPS Comments- To date, the NPS has not provided any additional comments or questions regarding this application.

Please contact Mike Kennedy at (727) 826-4334 or me at (727) 826-4258 if you have any questions regarding this submittal.

Sincerely,

Scott H. Osboum
Senior Environmental Engineer

CC: EPA
NPS

Enclosures

cc: Jeffery F. Koerner, P.E., DEP Tallahassee
Chris Carlson, DEP Tallahassee
Len Kozlov, DEP Central District
Robert C. McCann, Jr., Golder Associates

APPENDIX A

INLET FOGGING

CALDWELL ENERGY &
ENVIRONMENTAL, INC.

POWERFog™

Performance Engineered Combustion Turbine Inlet Air Cooling

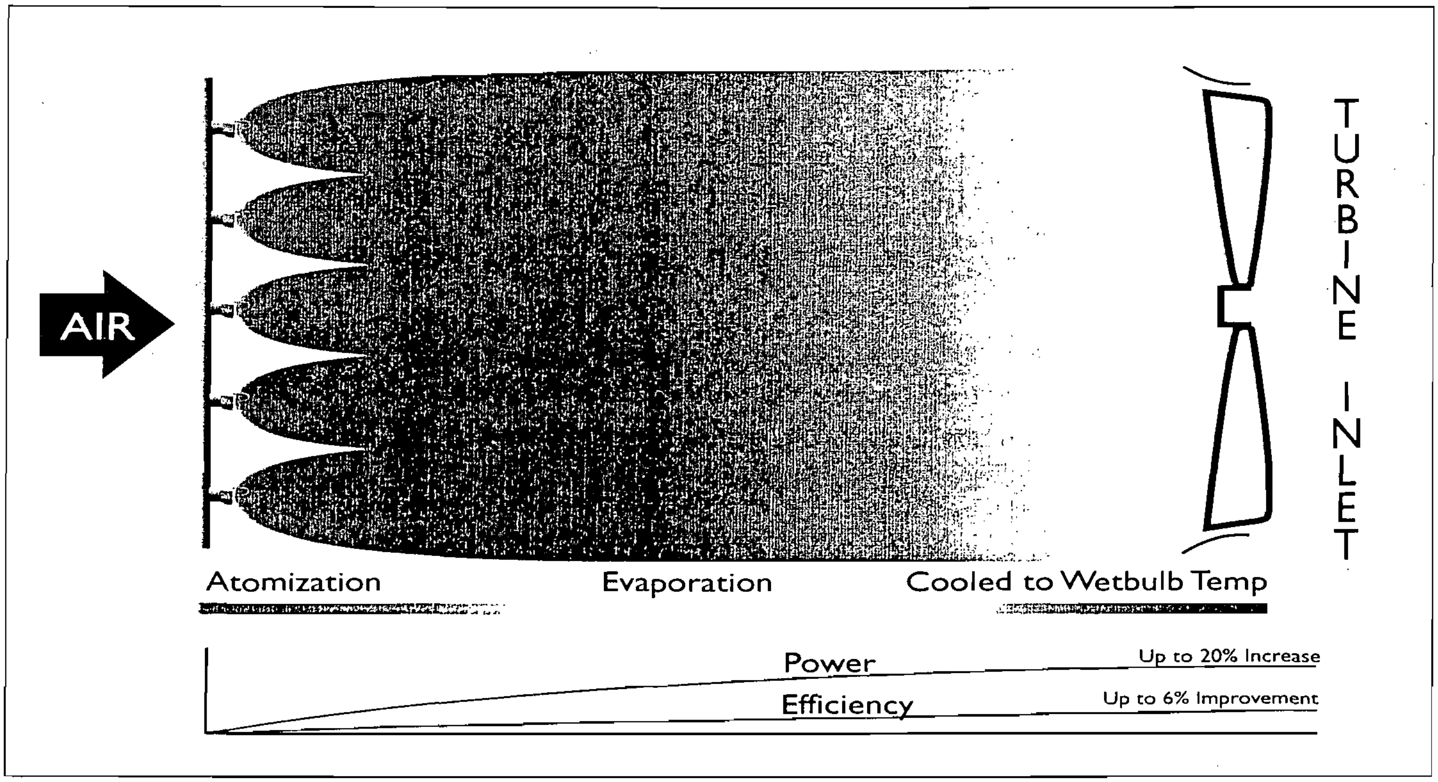

Figure 1

One of the most cost-effective ways to increase combustion turbine power output in high temperature ambient conditions is to reduce the air temperature by evaporating water into the turbine's inlet air. This denser air increases the mass flow to the turbine and since combustion turbines rely on this mass flow for power, output of the combustion turbine is significantly increased. On a 90° F day, with 20% relative humidity, inlet air temperature can be reduced to 63° F simply by evaporating water into the turbine's air stream. For the majority of combustion turbine types, this means a 9% increase in power output. The illustration above shows how a POWERFog™ system can improve your Combustion Turbine(s) performance.

Traditional methods of evaporating water into the inlet air use media blocks and de-misters that increase the pressure drop, and therefore reduce the power output capability of combustion turbines. These systems also require a significant amount of annual maintenance.

A more efficient way to evaporate water into the inlet air stream is to use a device that creates a "fog" of micron sized droplets of water. These droplets can be made so small that they can achieve more evaporative efficiency than traditional evaporative coolers. Inlet pressure drop across the system typically cannot even be measured by plant instrumentation. Caldwell Energy will engineer and guarantee the superior performance of a POWERFog™ system over media type evaporative coolers.

Caldwell Energy & Environmental, Inc. 4020 Tower Road, Louisville, KY 40219 Phone(502)964-6450 Fax(502)964-7444

Caldwell Energy engineered the POWERfog HP system specifically for combustion turbine applications. This Combustion Turbine Inlet Air Cooling (CTIAC) system uses Caldwell Energy's proprietary high pressure nozzle design which maximizes evaporative efficiency and hence the power output of the combustion turbine. Custom engineered advanced control system logic, combined with multiple nozzle arrays, are all designed to optimize the system's performance. Special features provide for safe system operation.

The POWERfog HP nozzle creates a fog by spraying a high pressure water jet at an impaction pin directly in front of the ejected water stream. Water pressure can vary, typically between 1,000 and 3,500 pounds per square inch depending on the required droplet size. A drawing of the POWERfog HP nozzle is illustrated in Figure 2. Increased pressure reduces the size of the droplets. The key to determining the system design is the residence time of the water droplets in the inlet air, prior to the cooled air entering the compressor of the combustion turbine. This defines the required droplet size.

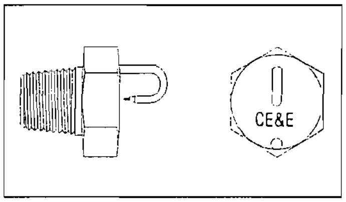

Figure 2

Fogging systems cool inlet air down to the wet bulb temperature of the ambient. This makes it highly effective in dry climates but also effective in more humid ones. Fogging systems in humid climates are still economical since the hottest periods of a day coincide with the periods of lowest relative humidity. Figure 3 illustrates the temperature and humidity distribution for a hot, sunny, and humid day. Note that the wet bulb temperature remains relatively constant.

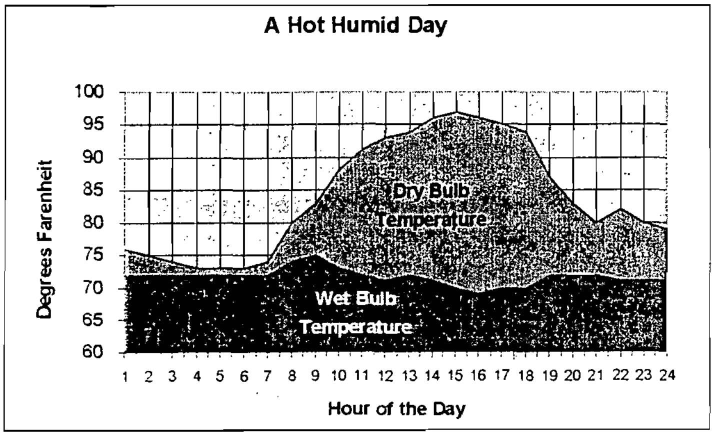

Figure 3

In the case where the residence time of the fog prior to entry into compressor section of the combustion turbine is short, high pressure systems may not ensure complete evaporation. To address this condition, Caldwell Energy developed the POWERfog US system. This system produces smaller droplets, a fraction of the diameter of high pressure systems. These smaller droplets allow for faster evaporation.

Internally mounted POWERfog systems can be installed during a 2-4 day outage while you are doing your turbine inspection. Externally mounted POWERfog systems can normally be installed while the combustion turbine is running.

Caldwell Energy engineers, designs, manufactures, and installs all types of combustion turbine Inlet Air Cooling (CTIAC) systems, including fogging, chilling, refrigeration, and thermal energy storage systems. Let us give you the complete cooling picture today.

Contact:
Caldwell Energy & Environmental, Inc.
4020 Tower Road, Louisville, KY 40219
Phone(502)964-6450 Fax(502)964-7444
Email: mail@caldwellenergy.com
Or visit our Website at www.caldwellenergy.com

APPENDIX B

VENDOR DESIGN INFORMATION

DRY LOW NO$_x$ COMBUSTION SYSTEMS FOR GE HEAVY-DUTY GAS TURBINES

L.B. Davis
GE Power Systems
Schenectady, NY

ABSTRACT

State-of-the-art emissions control technology for heavy-duty gas turbines is reviewed with emphasis on the operating characteristics and field experience of Dry Low NO$_x$(DLN) combustors for E- and F- technology machines. The lean premixed DLN systems for gas fuel have demonstrated their ability to meet the ever-lower emission levels required today. Lean premixed technology has also been demonstrated on oil fuel and is also discussed.

INTRODUCTION

The regulatory requirements for low emissions from gas turbine power plants have increased during the past 10 years. Environmental agencies throughout the world are now requiring even lower rates of emissions of NO$_x$ and other pullutants from both new and existing gas turbines. Traditional methods of reducing NO$_x$ emissions from combustion turbines (water and steam injection)are limited in their ability to reach the extremely low levels required in many localities. GE's involvement in the development of both the traditional methods (References 1 through6) and the newer Dry Low NO$_x$(DLN) technology (References 7 and 8) has been well-documented. This paper focuses on DLN.

Since the commercial introduction of GE's DLN combustion systems for natural-gas-fired heavy-duty gas turbines in 1991, systems have been installed in more than 145 machines, from the most modern F technology (firing temperature class of 2400 F/1316 C) to field retrofits of older machines. As of August 1996, these machines have operated more than one million hours with DLN; more than 290,000 hours have been in the F technology. To meet marketplace demands, GE has developed DLN products broadly classified as either DLN-1, which was developed for E-technology (2000 F/1093C firing temperature class) machines, or DLN-2, which was developed specifically for the F technology machines and is also being applied to the EC, G and H machines.

Development of these products has required an intensive engineering effort involving both GE Power Systems and GE Corporate Research and Development. This collaboration will continue as DLN is applied to the G and H machines and combustor development for Dry Low NO$_x$ on oil ("dry oil") continues.

This paper presents the current status of DLN-1 technology and experience, including dry oil, and of DLN-2 technology and experience. Background information about gas turbine emissions and emissions control is contained in the Appendix.

DRY LOW NO$_X$ SYSTEMS

Dry Low NO$_X$ Product Plan

Figure 1 shows GE's Dry Low NO$_x$ product offerings for its new and existing machines in three major groupings. The first group includes the MS3000, MS5000 and MS6001B products. The 6B DLN-1 is the technology flagship product for this group and, as can be noted, is available to meet 9 ppm NO$_x$ requirements. Such low NO$_x$ emissions are generally not attainable on lower firing temperature machines such as the MS3000s and MS5000s because carbon monoxide (CO) would be excessive.

The second major group includes the MS7000B/E, MS7001EA and MS9001E machines with the 9 ppm 7EA DLN-1 as the flagship product. The dry oil program focuses initially on this group.

The third group combines all of the DLN-2 products and includes the FA, EC, G and H machines, with the 7FA product as the flagship.

As shown in Figures 2 and 3, most of these products are capable of power augmentation and of peak firing with increased NO$_x$ emissions. With gas fuel, power augmentation with steam is in the premixed mode for both DLN-1 and DLN-2 systems. Power augmentation with water is in the lean-lean mode for DLN-1 and in the premixed mode for DLN-2.

The GE DLN systems integrate a staged premixed combustor, the gas turbine's SPEEDTRONICTM controls and the fuel and associated systems. There

	Gas			Distillate		
Turbine Model	NO_x (ppmvd)	CO (ppmvd)	Diluent	NO_x (ppmvd)	CO (ppmvd)	Diluent
MS3002 (J) - RC	33	25	Dry	Not Available		
MS3002 (J) - SC	42	50	Dry			
MS5001P	42	50	Dry	65	20	Water
MS5001R	42	50	Dry	65	20	Water
MS5002C	42	50	Dry	65	20	Water
MS6001B	25	15	Dry	42	20	Water
	9	25	Dry	42	30	Water/Steam
MS7001B/E Conv.	25	25	Dry	42	30	Water
MS7001EA	25	15	Dry	42	20	Water
	15	25	Dry	42	30	Water/Steam
	9	25	Dry	42	30	Water/Steam
MS9001E	35	15	Dry	42	20	Water
	25	25	Dry	42	20	Water
	25	25	Dry	90	20	Dry
MS6001FA	25	15	Dry	42/65	20	Water/Steam
MS7001FA	25	15	Dry	42/65	20	Water/Steam
	9	9	Dry	42/65	30	Water/Steam
MS7001H	25	15	Dry	42/65	20	Water/Steam
	9	9	Dry	42/65	30	Water/Steam
MS9001EC	25	15	Dry	42/65	20	Water/Steam
MS9001FA	25	15	Dry	42/65	20	Water/Steam
MS9001H	25	15	Dry	42/65	20	Water/Steam

Notes: 1. No_x levels are at 15% oxygen. Ambient range 30 F/-1 C to 100 F/30 C

GT24717E

Figure 1. Dry Low No_x product plan

are two principal measures of performance. The first is meeting the emission levels required at base load on both gas and oil fuel and controlling the variation of these levels across the load range of the gas turbine.

The second measure is system operability, with

Turbine Model	NO_x @15% O_2 (ppmvd)	Operating Mode	Diluent	Maximum Diluent/Fuel	NO_x at Max D/F (ppmvd)	CO Max D/F (ppmvd)
MS6001(B)	9	Premix	Steam	2.5/1	9	25
		Lean-Lean	Steam	2.5/1	25	15
	25	Premix	Steam	2.5/1	25	15
		Lean-Lean	Water	1.5/1	25	15
		Lean-Lean	Steam	2.5/1	25	15
MS7001(EA)	9	Premix	Steam	2.5/1	9	25
		Lean-Lean	Water	1.5/1	25	15
		Lean-Lean	Steam	2.5/1	25	15
	25	Premix	Steam	2.5/1	25	15
		Lean-Lean	Water	1.5/1	25	15
		Lean-Lean	Steam	2.5/1	25	15
MS7001(FA)	25	Premix	Steam	2.1/1	25	15

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Figure 2. DLN power augmentation summary - gas fuel

	NO_x-Base (ppmvd)	NO_x-Peak (ppmvd)	CO-Base (ppmvd)	CO-Peak (ppmvd)
MS6001(B)	9 25	18 50	25 15	6 4
MS7001(EA)	9 25	18 50	25 15	6 4
MS7001(FA)	25	35	15	6
MS9001(E)	25	40	15	6

GT24557A .ppt

Figure 3. DLN peak firing summary - gas fuel

emphasis placed on the smoothness and reliability of combustor mode changes, ability to load and unload the machine without restriction, capability to switch from one fuel to another and back again, and system response to rapid transients (e.g., generator breaker open events or rapid swings in load). GE's design goal is to make the DLN system operate so the gas turbine operator does not know whether a DLN or conventional combustion system is installed (i.e., its operation is "transparent to the user"). As of August 1996, a significant portion of the DLN design and development effort has focused on system operability.

Design of a successful DLN combustor for a heavy-duty gas turbine also requires the designer to develop hardware features and operational methods that simultaneously allow the equivalence ratio and residence time in the flame zone to be low enough to achieve low NO_x, but with acceptable levels of combustion noise (dynamics), stability at part load operation and sufficient residence time for CO burn-out, hence the designation of DLN combustion design as "four-sided box" (Figure 4).

A scientific and engineering development program by GE's Corporate Research and Development Center, Power Systems business and Aircraft Engine business has focused on understanding and controlling dynamics in lean premixed flows. The objectives have been to:

- Gather and analyze machine and laboratory data to create a comprehensive dynamics data base
- Create analytical models of gas turbine combustion systems that can be used to understand dynamics behavior
- Use the analytical models and experimental methods to develop methods to control dynamics

As of August 1996, these efforts have resulted in a large number of hardware and control features that limit dynamics, plus analytical tools that are used to predict system behavior. The latter are particularly useful in correlating laboratory test data from full scale combustors with actual gas turbine data.

DLN-1 System

DLN-1 development began in the 1970s with the goal of producing a dry oil system to meet the United States Environmental Protection Agency's New Source Performance Standards of 75 ppmvd NO_x at 15% O_2. As noted in Reference 7, this system was tested on both oil and gas fuel at Houston Lighting & Power in 1980 and met its emission goals. Subsequent to this, DLN program goals changed in response to stricter environmental regulations and the pace of the program accelerated in the late 1980s.

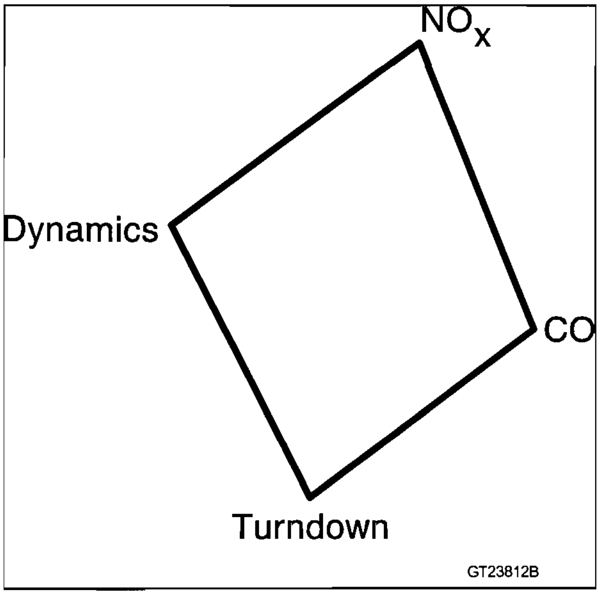

Figure 4. DLN technology - a four-sided box

DLN-1 Combustor

The GE DLN-1 combustor (shown in cross section in Figure 5 and described in Reference 8) is a two-stage premixed combustor designed for use with natural gas fuel and capable of operation on liquid fuel. As shown, the combustion system includes four major components: fuel injection system, liner, venturi and cap/centerbody assembly.

These components form two stages in the combustor. In the premixed mode, the first stage thoroughly mixes the fuel and air and delivers a uniform, lean, unburned fuel-air mixture to the second stage.

The GE DLN-1 combustion system operates in four distinct modes, illustrated in Figure 6, during pre-mixed natural gas or oil fuel operation:

Mode	Operating Range
Primary	Fuel only to the primary nozzles. Flame is in the primary stage only. This mode of operation is used to ignite, accelerate and operate the machine over low- to mid-loads, up to a preselected combustion reference temperature.
Lean-Lean	Fuel to both the primary and secondary nozzles. Flame is in both the primary and secondary stages. This mode of operation is used for intermediate loads between two preselected combustion reference temperatures.
Secondary	Fuel to the secondary nozzle only. Flame is in the secondary zone only. This mode is a transition state between lean-lean and premix modes. This mode is necessary to extinguish the flame in the primary zone, before fuel is reintroduced into what becomes the primary premixing zone.
Premix	Fuel to both primary and secondary nozzles. Flame is in the secondary stage only. This mode of operation is achieved at and near the combustion reference temperature design point. Optimum emissions are generated in premix mode.

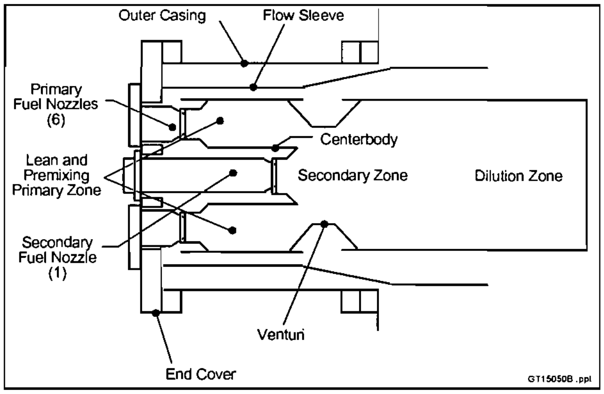

Figure 5. DLN-1 combustor schematic

The load range associated with these modes varies with the degree of inlet guide vane modulation and, to a smaller extent, with the ambient temperature. At ISO ambient, the premix operating range is 50% to 100% load with IGV modulation down to 42 Degrees, and 75% to 100% load with IGV modulation down to 57 Degrees. The 42 Degrees IGV minimum requires an inlet bleed heat system.

If required, both the primary and secondary fuel nozzles can be dual-fuel nozzles, thus allowing automatic transfer from gas to oil throughout the load range. When burning either natural gas or distillate oil, the system can operate to full load in the lean-lean mode (Figure 6) and in the pre-mixed. Power augmentation with water is the most common reason.

The spark plug and flame detector arrangements in a DLN-1 combustor are different from those used in a conventional combustor. Since the first stage must be re-ignited at high load in order to transfer from the

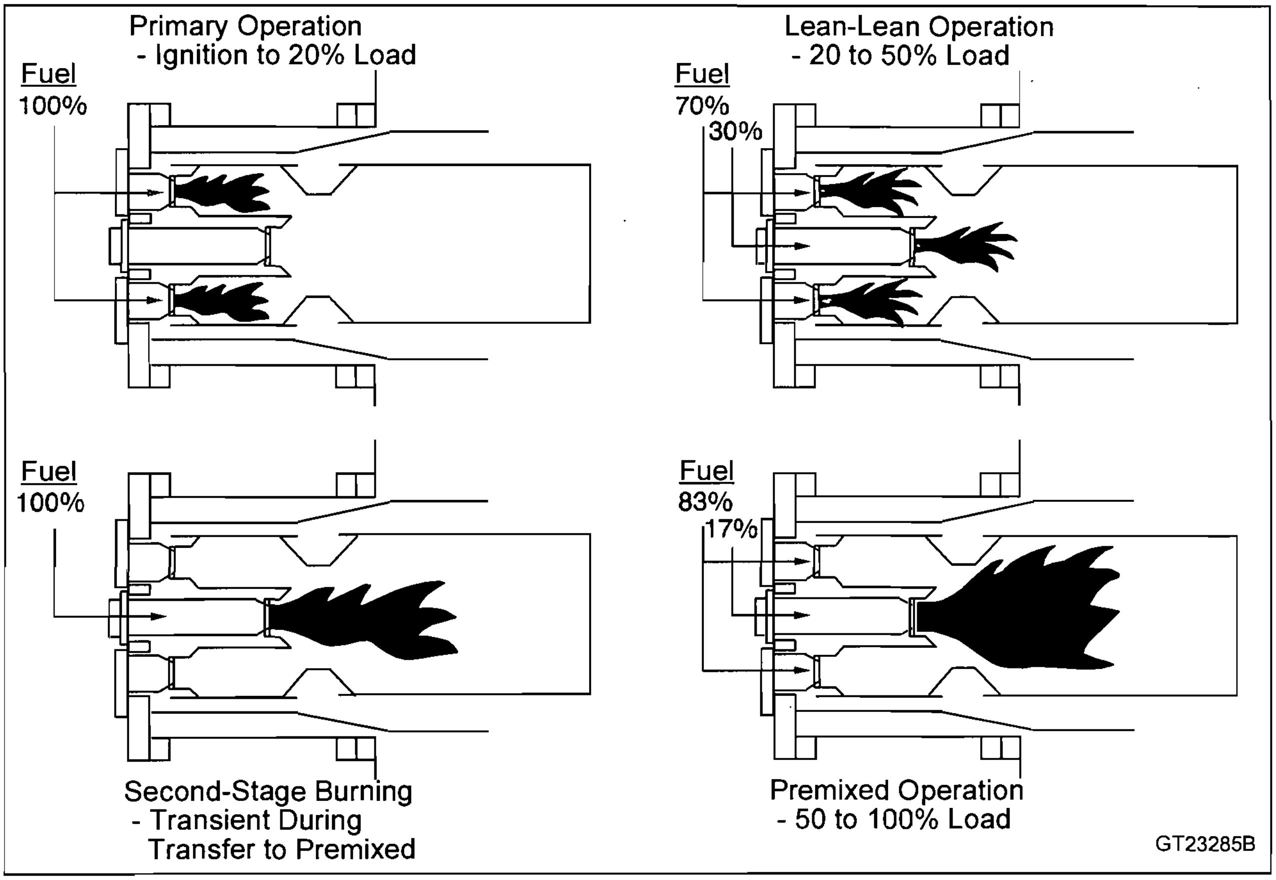

Figure 6. Fuel-staged Dry Low NOx operating modes

premixed mode back to lean-lean operation, the spark plugs do not retract. One plug is mounted in a primary zone cup in each of two combustors. The system uses flame detectors to view the primary stage of selected chambers (similar to conventional systems), and secondary flame detectors that look through the centerbody and into the second stage.

The primary fuel injection system is used during ignition and part load operation. The system also injects most of the fuel during premixed operation and must be capable of stabilizing the flame. For this reason, the DLN-1 primary fuel nozzle is similar to GE's MS7001EA multi-nozzle combustor with multiple swirl-stabilized fuel injectors. The GE DLN-1 system uses five primary fuel nozzles for the MS6001B and smaller machines and six primary fuel nozzles for the larger machines. This design is capable of providing a well-stabilized diffusion flame that burns efficiently at ignition and during part load operation.

In addition, the multi-nozzle fuel injection system provides a satisfactory spatial distribution of fuel flow entering the first-stage mixer. The primary fuel-air mixing section is bound by the combustor first-stage wall, the cap/centerbody and the forward cone of the venturi. This volume serves as a combustion zone when the combustor operates in the primary and lean-lean modes. Since ignition occurs in this stage, crossfire tubes are installed to propagate flame and to balance pressures between adjacent chambers. Film slots on the liner walls provide cooling, as they do in a standard combustor.

In order to achieve good emissions performance in premixed operation, the fuel-air equivalence ratio of the mixture exiting the first-stage mixer must be very lean. Efficient and stable burning in the second stage is achieved by providing continuous ignition sources at both the inner and outer surfaces of this flow. The three elements of this stage comprise a piloting flame, an associated aerodynamic device to force interaction between the pilot flame and the inner surface of the main stage flow, and an aerodynamic device to create a stable flame zone on the outer surface of the main stage flow exiting the first stage.

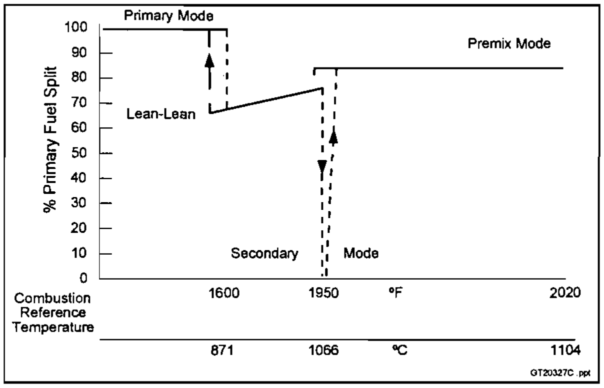

Figure 7. Typical Dry Low Nox fuel gas split schedule

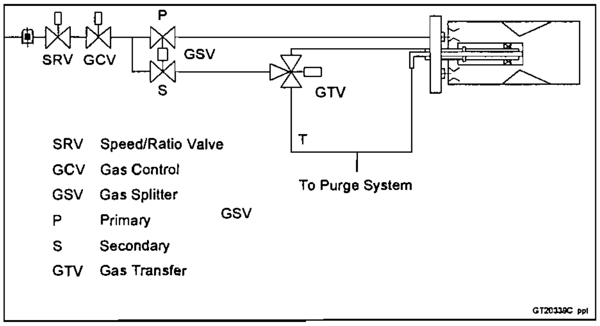

Figure 8. DLN-1 gas fuel system

The piloting flame is generated by the secondary fuel nozzle, which premixes a portion of the natural gas fuel and air (nominally, 17% at full-load operation) and injects the mixture through a swirler into a cup where it is burned. This flame is stabilized by burning an even smaller amount of fuel (less than 2% of the total fuel flow) as a diffusion flame in the cup. The secondary nozzle, which is mounted in the cap centerbody, is simple and highly effective for creating a stable flame.

A swirler mounted on the downstream end of the cap/centerbody surrounds the secondary nozzle. This creates a swirling flow that stirs the interface region between the piloting flame and the main-stage flow and ensures that the flame is continuously propagated from the pilot to the inner surface of the fuel-air mixture exiting the first stage. Operation on oil fuel is similar except that all of the secondary oil is burned in a diffusion flame in the current dry oil design.

The sudden expansion at the throat of the venturi creates a toroidal recirculation zone over the downstream conical surface of the venturi. This zone, which entrains a portion of the venturi cooling air, is a stable burning zone that acts as an ignition source for the main stage fuel-air mixture. The cone angle and axial location of the venturi cooling air dump have significant effects on the efficacy of this ignition source. Finally, the dilution zone (the region of the combustor immediately downstream from the flame zone in the secondary) provides a region for CO burnout and for shaping the gas temperature profile exiting the combustion system.

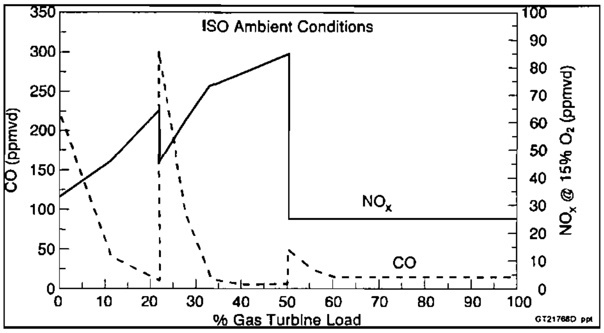

Figure 9. MS7001EA/MS9001E DLN-1 combustion system performance on natural gas fuel

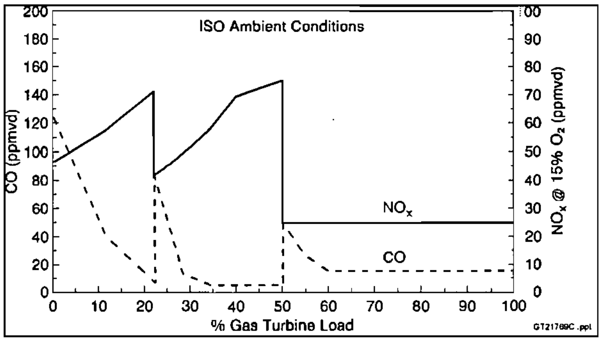

Figure 10. MS6001B DLN-1 emissions performance on natural gas fuel

DLN-1 Controls and Accessories

The gas turbine accessories and control systems are configured so that operation on a DLN-equipped turbine is essentially identical to that of a turbine equipped with a conventional combustor. This is accomplished by controlling the turbines in identical fashions, with the exhaust temperature, speed and compressor discharge pressure establishing the fuel flow and compressor inlet guide vane position.

A turbine with a conventional diffusion combustor that uses diluent injection for NO_x control will use an underlying algorithm to control steam or water injection. This algorithm will use top level control variables (exhaust temperature, speed, etc.) to establish a steam-to-fuel or water-to-fuel ratio to control NO_x.

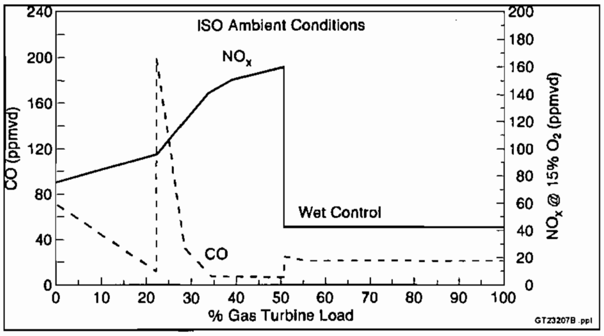

Figure 11. MS7001EA/MS9001E DLN-1 combustion system performance on distillate oil

In a similar fashion, the same variables are used to divide the total turbine fuel flow between the primary and secondary stages of a DLN combustor. The fuel division is accomplished by commanding a calibrated splitter valve to move to a set position based on the calculated combustion reference temperature (Figure 7). Figure 8 shows aschematic of the gas fuel system for a DLN-equipped turbine.

The only special control sequences required are concerned protection of the turbine during a generator breaker-open trip, or flashback, from the second stage to the first stage during premixed operation. When either the breaker opens at load or flashback is sensed by ultraviolet flame detectors looking into the first stage, the splitter valve is commanded to move to a pre-determined position. In the case of a flashback, the control system can execute an automatic sequence to return to premixed, full-load operation.

DLN-1 Emissions

The emissions performance of the GE DLN system can be illustrated as a function of load for a given ambient temperature and turbine configuration. Figures 9 and 10 show the NO$_x$ and CO emissions from typical MS7001EA and MS6001B DLN systems designed for 9 ppmvd NO$_x$ and 25 ppm CO when operated on natural gas fuel. Note that in premixed operation, NO$_x$ is generally highest at higher loads and CO only approaches 25 ppm at lower premixed loads.

Figures 11 and 12 show NO$_x$ and CO emissions for the same systems operated on oil fuel with water injection for NO$_x$ control, rather than premixed oil. These figures are for units equipped with inlet bleed heat and extended IGV modulation. NO$_x$ and CO emissions from the DLN combustor at loads less than 20% of base load are similar to those from standard combustion systems. This result is expected because both systems are operating as diffusion flame combustors in this range. Between 20% and 50% load, the DLN system is operated in the lean-lean mode, and the flow split between the primary fuel nozzles and secondary nozzle is varied to give the decreasing NO$_x$ characteristic shown.

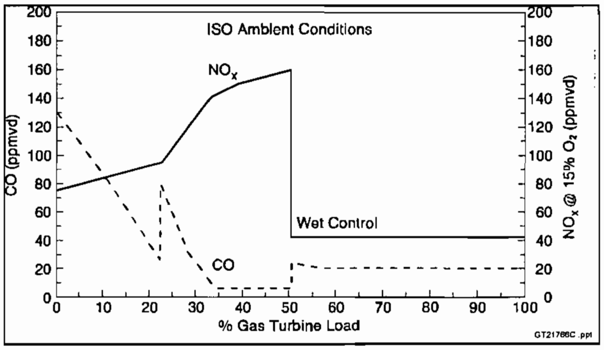

Figure 12. MS6001B DLN-1 emissions performance on distillate oil fuel

From 50%to 100%load, the DLNsystem operates as a lean premixed combustor. As shown in Figures 9 through 12, NO$_x$ emissions are significantly reduced, while CO emissions are comparable to those from the standard system.

DLN-1 Experience

GE's first DLN-1 system was tested at Houston Lighting & Power in 1980 (Reference 7). A prototype DLN system using the combustor design discussed above was tested on an MS9001E at the Electricity Supply Board's (ESB) Northwall Station in Dublin, Ireland, between October 1989 and July 1990. A comprehensive engineering test of the prototype DLN combustor, controls and associated systems was conducted with NO$_x$ levels of 32 ppmvd (at 15% O$_2$) obtained at base load. The results were incorporated into the design of prototype systems for the MS7001E and MS6001B.

The 7E DLN-1 prototype was tested at Anchorage Municipal Light and Power (AMLP) in early 1991 and entered commercial service shortly afterward. Since then, development of advanced combustor configurations have been carried out at AMLP. These results have been incorporated into production hardware.

The MS6001B prototype system was first operated at Jersey Central Power & Light's Forked River Station in early 1991. A series of additional tests culminated in the demonstration of a 9 ppm combustor at Jersey Central in November 1993.

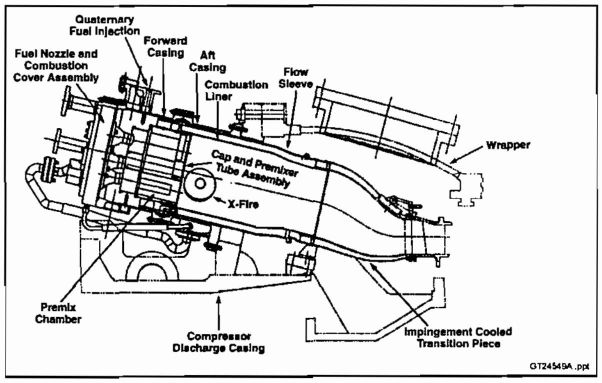

Figure 13. DLN-2 combustion system

As of August 1996, 28 MS6001B machines are equipped with DLN-1 systems. In total, they have accumulated more than 370,000 hours of operation. There are, in addition, four MS7001E, eight MS7001B-E, 26 MS7001EA, 18 MS9001E, one MS5001P and three MS3002J DLN-1 machines that have collectively operated for more than 350,000 hours. Excellent emission results have been obtained in all cases, with single-digit NO_x and COachieved on several MS7001EAs. Several MS7001E/EA machines have the capability to power augment with either massive water or steam injection.

Starting in early 1992, eight MS7001F machines equipped with GE DLN systems were placed in service at Korea Electric Power Company's Seoinchon site. These F technology machines have achieved better than 55% (gross) efficiency in combined-cycle operation, and the DLN systems are currently operating between 30 and 40 ppmvd NO_x on gas fuel (the guarantee level is 50 ppmvd). These units have operated for more than 150,000 hours. Four additional F technology DLN-1 systems have been commissioned at Scottish Hydro's Keadby site and at National Power's Little Barford site. These 9F machines have operated more than 20,000 hours at less than 60 ppm NO_x.

The combustion laboratory testing and field operation have shown that the DLN-1 system can achieve single digit NO_x and CO levels on E technology machines operating on gas fuel. Current DLN-1 development activity focuses on four goals:

- Application of single-digit technology to the MS6001B, MS7001EA and MS9001E
- Application of DLN-1 technology for retrofitting existing field machines (including MS3002s and MS5000s, some of which will require upgrade before DLN retrofit)

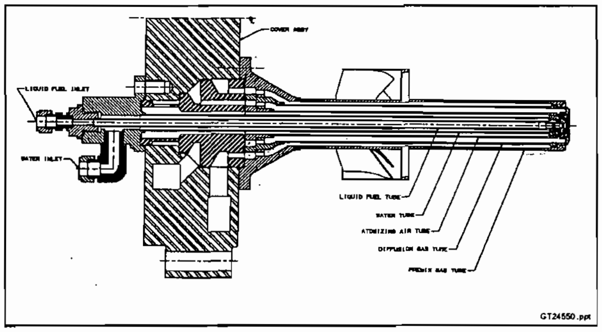

Figure 14. Cross-section of a DLN-2 fuel nozzle

- Completing the development of steam and water power augmentation as needed by the market
- Completing the development of dry oil DLN-1 products.

DLN-2 SYSTEM

As F-technology gas turbines became available in the late 1980s, studies were conducted to establish what type of DLN combustor would be needed for these new higher firing temperature machines. Studies concluded that that air usage in the combustor (e.g., for cooling) other than for mixing with fuel would have to be strictly limited. A team of engineers from GE Power Generation, GE Corporate Research and Development and GE Aircraft Engine proposed a design that repackaged DLN-1 premixing technology but eliminated the venturi and centerbody assemblies that require cooling air.

The resulting combustor is called DLN-2, which is the standard system for the 6FA, 7FA, 9FA, 9EC, 7G, 7H, 9G and 9H machines. Fourteen combustors are installed in the 7FA and 9EC, 18 in the 9FA, and six in the 6FA. These combustors, for all but the 7FA, are not scaled, but are full-size 9FA combustors; the 7FA is slightly smaller.

DLN-2 Combustion System

The DLN-2 combustion system shown in Figure 13 is a single-stage dual-mode combustor that can operate on both gaseous and liquid fuel. On gas, the combustor operates in a diffusion mode at low loads (< 50% load), and a premixed mode at high loads (> 50% load). While the combustor can operate in the diffusion mode across the load range, diluent injection would be required for NO_x abatement. Oil operation on this combustor is in the diffusion mode

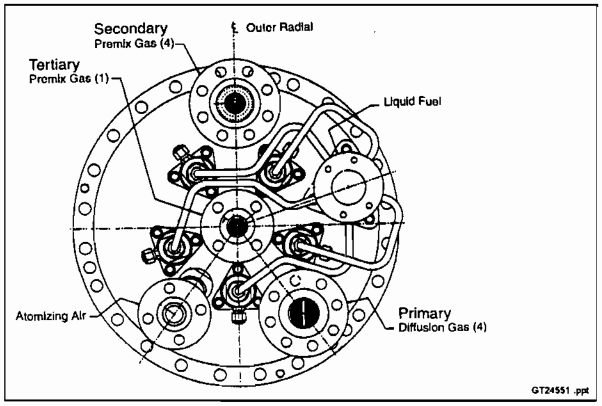

Figure 15. External view of DLN-2 fuel nozzles mounted

across the entire load range, with diluent injection used for NO_X control.

Each DLN-2 combustor system has a single burning zone formed by the combustor liner and the face of the cap. In low emissions operation, 90% of the gas fuel is injected through radial gas injection spokes in the premixer, and combustion air is mixed with the fuel in tubes surrounding each of the five fuel nozzles. The premixer tubes are part of the cap assembly. The fuel and air are thoroughly mixed, flow out of the five tubes at high velocity and enter the burning zone where lean, low- NO_x combustion occurs. The vortex breakdown from the swirling flow exiting the premixers, along with the sudden expansion in the liner, are mechanisms for flame stabilization. The DLN-2 fuel nozzle/premixer tube arrangement is similar in design and technology to the secondary nozzle/centerbody of a DLN-1. Five nozzle/premixer tube assemblies are located on the head end of the combustor. A quaternary fuel manifold is located on the circumference of the combustion casing to bring the remaining fuel flow to casing injection pegs located radially around the casing.

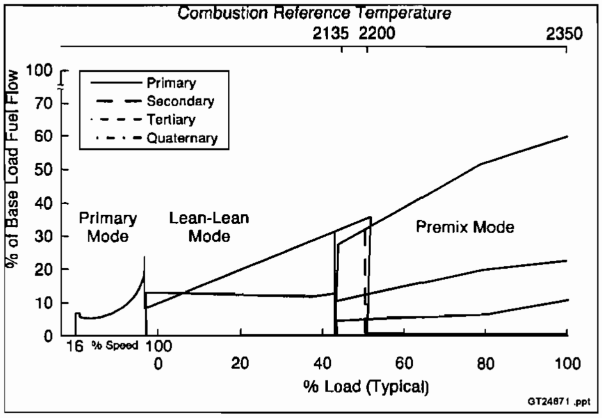

Figure 16. Fuel flow scheduling associated with DLN-2 operation

Figure 14 shows a cross-section of a DLN-2 fuel nozzle. As noted, the nozzle has passages for diffusion gas, premixed gas, oil and water. When mounted on the end cover, as shown in Figure 15, the diffusion passages of four of the fuel nozzles is fed from a common manifold, called the primary, that is built into the end cover. The premixed passage of the same four nozzles are fed from another internal manifold called the secondary. The premixed passages of the remaining nozzle are supplied by the tertiary fuel system; the diffusion passage of that nozzle is always purged with compressor discharge air and passes no fuel.

Figure 15 shows the fuel nozzles installed on the combustion chamber end cover and the connections for the primary, secondary and tertiary fuel systems. DLN-2 fuel streams are:

- Primary fuel – fuel gas entering through the diffusion gas holes in the swirler assembly of each of the outboard four fuel nozzles
- Secondary fuel – premix fuel gas entering through the gas metering holes in the fuel gas injector spokes of each of the outboard four fuel nozzles
- Tertiary fuel – premix fuel gas delivered by the metering holes in the fuel gas injector spokes of the inboard fuel nozzle
- The quaternary system – injects a small amount of fuel into the airstream just upstream from the fuel nozzle swirlers

The DLN-2 combustion system can operate in several different modes.

Primary

Fuel only to the primary side of the four fuel nozzles; diffusion flame. Primary mode is used from ignition to 81% corrected speed.

Lean-Lean

Fuel to the primary (diffusion) fuel nozzles and single tertiary (premixing) fuel nozzle. This mode is used from 81% corrected speed to a preselected combustion reference temperature. The percentage of primary fuel flow is modulated throughout the range of operation as a function of combustion reference temperature. If necessary, lean-lean mode can be operated throughout the entire load range of the turbine. Selecting "lean-lean base on" locks out premix operation and enables the machine to be taken to base load in lean-lean.

Premix Transfer

Transition state between lean-lean and premix modes. Throughout this mode, the primary and secondary gas control valves modulate to their final position for the next mode. The premix splitter valve is also modulated to hold a constant tertiary flow split.

Piloted Premix

Fuel is directed to the primary, secondary and tertiary fuel nozzles. This mode exists while operating with temperature control off as an intermediate mode between lean-lean and premix mode. This mode also exists as a default mode out of premix mode and, in the event that premix operating is not desired, piloted premix can be selected and operated to base load. Primary, secondary and tertiary fuel split are constant during this mode of operation.

Premix

Fuel is directed to the secondary, tertiary and quaternary fuel passages and premixed flame exists in the combustor. The minimum load for premixed operation is set by the combustion reference temperature and IGV position. It typically ranges from 50% with inlet bleed heat on to 65% with inlet bleed heat off. Mode transition from premix to piloted premix or piloted premix to premix, can occur whenever the combustion reference temperature is greater than 2200 F/1204 C. Optimum emissions are generated in premix mode.

Tertiary Full Speed No Load (FSNL)

Initiated upon a breaker open event from any load greater than 12.5%. Fuel is directed to the tertiary nozzle only and the unit operates in secondary FSNL mode for a minimum of 20 seconds, then transfers to lean-lean mode.

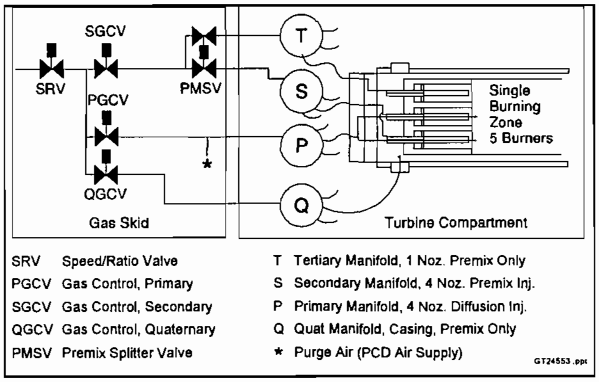

Figure 17. DLN-2 gas fuel system

Figure 16 illustrates the fuel flow scheduling associated with DLN-2 operation. Fuel staging depends on combustion reference temperature and IGV temperature control operation mode.

DLN-2 Controls and Accessories

The DLN-2 control system regulates the fuel distribution to the primary, secondary, tertiary and quaternary fuel system. The fuel flow distribution to each combustion fuel system is a function of combustion reference temperature and IGV temperature control mode. Diffusion, piloted premix and premix flame are established by changing the distribution of fuel flow in the combustor. The gas fuel system (Figure 17) consists of the gas fuel stop/ratio valve, primary gas control valve, secondary gas control valve premix splitter valve and quaternary gas control valve. The stop/ratio valve is designed to maintain a predetermined pressure at the control valve inlet.

The primary, secondary and quaternary gas control valves regulate the desired gas fuel flow delivered to the turbine in response to the fuel command from the SPEEDTRONICTM controls.

The premix splitter valve controls the fuel flow split between the secondary and tertiary fuel system.

DLN-2 Emissions Performance

Figures 18 and 19 show the emissions performance for a DLN-2 equipped 7FA/9FA for gas fuel and for oil fuel with water injection.

DLN-2 Experience

The first DLN-2 systems were placed in service at Florida Power and Light's Martin Station with com-

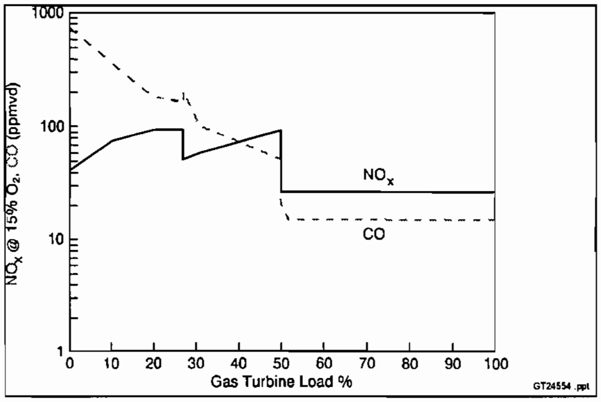

Figure 18. Emissions performance for DLN-2-equipped 7FA/9FA for gas fuel

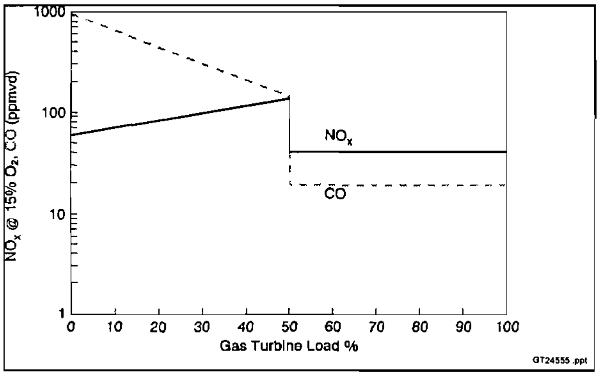

Figure 19. Emissions performance for DLN-2-equipped 7FA/9FA for oil fuel with water injection

missioning beginning in September 1993, and the first two (of four) 7FA units entering commercial service in February 1994. During commissioning, quaternary fuel was added and other combustor modifications were made to control dynamic pressure oscillations in the combustor.

As of August 1996, 23 DLN-2 7FA and 17 9FA units are in commercial service. They have accumulated more than 150,000 hours of operation. Of these units, 11 are dual-fuel units, and the remainder are gas-only.

CONCLUSION

GE's Dry Low NO_x Program continues to focus on the development of systems capable of the extremely low NO_x levels required to meet today's regulations and to prepare for more stringent requirements in the future. New unit production needs and the requirements of existing machines, are being addressed. GE DLN systems are operating on more than 145 machines and have accumulated more than one million service hours. More than 200 DLN systems have been either put into service, shipped or placed on order. GE is the only manufacturer with F technology machines operating below 25 ppmvd.

APPENDIX

Gas Turbine Combustion Systems

A gas turbine combustor mixes large quantities of fuel and air and burns the resulting mixture. In concept the combustor is comprised of a fuel injector and a wall to contain the flame. There are three fundamental factors and practical concerns that complicate the design of the combustor: equivalence ratio, flame stability, and ability to operate from ignition through full load.

Equivalence ratio

A flame burns best when there is just enough fuel to react with the available oxygen. With this stoichiometric mixture (equivalence ratio of 1.0) the flame temperature is the highest and the chemical reactions are the fastest, compared to cases where there is either more oxygen ("fuel lean," < 1.0) or less oxygen ("fuel rich," > 1.0) for the amount of fuel present.

In a gas turbine, the maximum temperature of the hot gases exiting the combustor is limited by the tolerance of the turbine nozzles and buckets. This temperature corresponds to an equivalence ratio of 0.4 to 0.5 (40 to 50% of the stoichiometric fuel flow). In the combustors used on modern gas turbines, this fuel-air mixture would be too lean for stable and efficient burning. Therefore, only a portion of the compressor discharge air is introduced directly into the combustor reaction zone (flame zone) to be mixed with the fuel and burned. The balance of the airflow either quenches the flame prior to the combustor discharge entering the turbine or to cool the wall of the combustor.

Flame Stability

Even with only part of the air being introduced into the reaction zone, flow velocities in the zone are higher than the turbulent flame speed at which a flame propagates through the fuel-air mixture. Special mechanical or aerodynamic devices must be used to stabilize the flame by providing a low velocity region. Modern combustors employ a combination of swirlers and jets to achieve a good mix and to stabilize the flame.

Operational Stability

The combustor must be able to ignite and to support acceleration and operation of the gas turbine over the entire load range of the machine. For a single-shaft generator-drive machine, speed is constant under load and, therefore, so is the airflow for a fixed ambient temperature. There will be a five- or six-to-one turndown in fuel flow over the load range, and a combustor whose reaction zone equivalence ratio is optimized for full load operation will be very lean at the lower loads. Nevertheless, the flame must be sta-

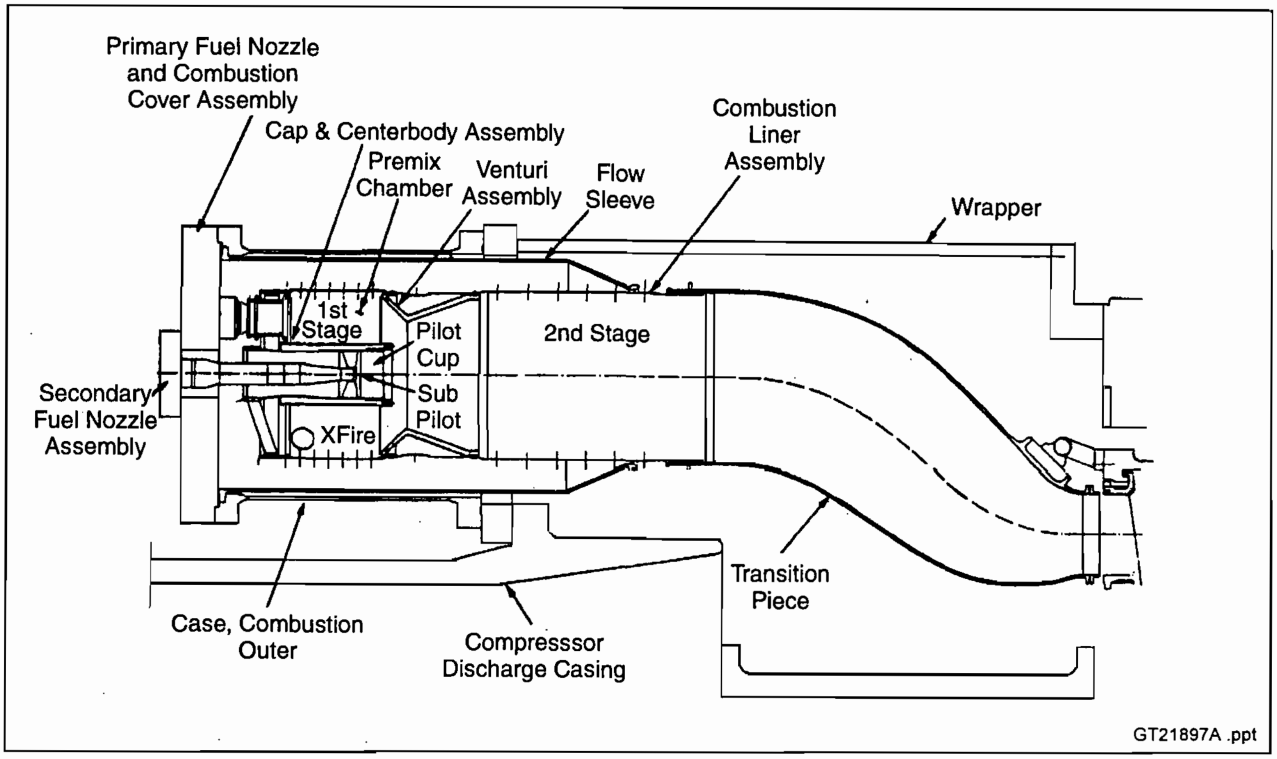

Figure A1. MS7001EA Dry Low Nox combustion chamber

ble and the combustion process must be efficient at all loads.

GE uses multiple-combustion chamber assemblies in its heavy-duty gas turbines to achieve reliable and efficient turbine operation. As shown in Figure A-1, each combustion chamber assembly comprises a cylindrical combustor, a fuel injection system and a transition piece that guides the flow of the hot gas from the combustor to the inlet of the turbine. Figure A-2 illustrates the multiple-combustor concept.

There are several reasons for using the multiple-chamber arrangement instead of large silo-type combustors:

- The configuration permits the entire turbine to be factory assembled, tested and shipped without interim disassembly
- The turbine inlet temperature can be better controlled, thus providing for longer turbine life with reduced turbine cooling air requirements
- Smaller parts can be handled more easily during routine maintenance
- Smaller transition pieces are less susceptible to damage from dynamic forces generated in the combustor; furthermore, the shorter combustion system length ensures that acoustic natural frequencies are higher and less likely to couple with the pressure oscillations in the flame
- Smaller combustors generate less NO_x because of much better mixing and shorter residence time
- As turbine inlet temperatures have increased to improve efficiency, the size of the combustors has decreased to minimize cooling requirements, as in aircraft gas turbine combustors
- Small can-type combustors can be completely developed in the laboratory through a combination of both atmospheric and full-pressure, full-flow tests. Therefore, there is a higher degree of confidence that a combustor will perform as designed across all load ranges before it is installed and tested in a machine.

Gas Turbine Emissions

The significant products of combustion in gas turbine emissions are:

- Oxides of nitrogen (NO and NO_2, collectively called NO_x)
- Carbon monoxide (CO)
- Unburned hydrocarbons or UHCs (usually expressed as equivalent methane (CH_4) particles and arise from incomplete combustion)

- Oxides of sulfur (SO_2 and SO_3) particulates.

Unburned hydrocarbons include both volatile organic compounds (VOCs), which contribute to the formation of atmospheric ozone, and compounds, such as methane, that do not.

There are two sources of NO_x emissions in the exhaust of a gas turbine. Most of the NO_x is generated by the fixation of atmospheric nitrogen in the flame, which is called thermal NO_x. Nitrogen oxides are also generated by the conversion of a fraction of any nitrogen chemically bound in the fuel (called fuel-bound nitrogen or FBN). Lower-quality distillates and low-Btu coal gases from gasifiers with hot gas cleanup carry various amounts of fuel-bound nitrogen that must be taken into account when emissions calculations are made. The methods described below to control thermal NO_x emissions are ineffective in controlling the conversion of FBN to NO_x.

Thermal NO_x is generated by a chemical reaction sequence called the Zeldovich Mechanism (Reference 6). This set of well-verified chemical reactions postulates that the rate of generation of thermal NO_x is an exponential function of the temperature of the flame. The amount of NO_x generated is a function of the flame temperature and of the time the hot gas mixture is at flame temperature. This turns out to be a linear function of time. Thus, temperature and residence time determine thermal NO_x emissions levels and are the principal variables that a gas turbine designer can adjust to control emission levels.

For a given fuel, since the flame temperature is a unique function of the equivalence ratio, the rate of NO_x generation can be cast as a function of the equivalence ratio. Figure A-3, shows that the highest rate of NO_x production occurs at an equivalence ratio of 1.0, when the temperature is equal to the stoichiometric, adiabatic flame temperature.

To the left of the maximum temperature point (Figure A-3), more oxygen is available (the equivalence ratio is less than 1.0) and the resulting flame temperature is lower. This is a fuel-lean operation. Since the rate of NO_x formation is a function of temperature and time, it follows that some difference in NO_x emissions can be expected when different fuels are burned in a given combustion system. Since distillate oil and natural gas have approximately a 100F/38 C flame temperature difference, a significant difference in NO_x emissions can be expected if reaction zone equivalence ratio, water injection rate, etc. are equal.

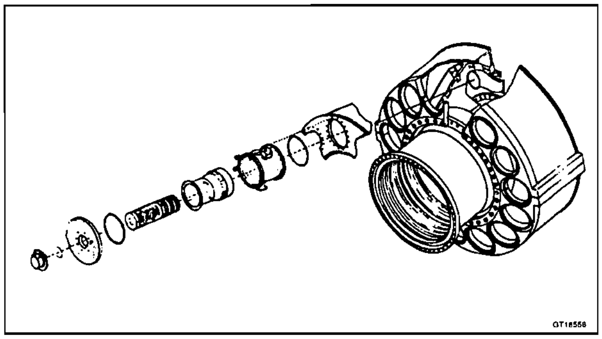

Figure A2. Exploded view of combustion chamber

As shown in Figure A-3, the rate of NO_x production dramatically decreases as flame temperature decreases (i.e., the flame becomes fuel lean). This is because of the exponential effect of temperature in the Zeldovich Mechanism and is the reason why diluent injection (usually water or steam) into a gas turbine combustor flame zone reduces NO_x emissions. For the same reason, very lean dry combustors can be used to control emissions. This is desirable for reaching the lower NO_x levels now required in many applications.

There are two design challenges associated with very lean combustors. First, care must be taken to ensure that the flame is stable at the design operating point. Secondly, a turndown capability is necessary since a gas turbine must ignite, accelerate, and operate over the load range. At lower loads, as fuel flow to the combustors decreases, the flame will be very lean and will not burn well, or it can become unstable and blow out.

In response to these challenges, combustion system designers use staged combustors so a portion of the flame zone air can mix with the fuel at lower loads or during startup. The two types of staged combustors are fuel-staged and air-staged (Figure A-4). In its simplest and most common configuration, a fuel-staged combustor has two flame zones; each receives a constant fraction of the combustor airflow. Fuel flow is divided between the two zones so that at each machine operating condition, the amount of fuel fed to a stage matches the amount of air available.

An air-staged combustor uses a mechanism for diverting a fraction of the airflow from the flame zone to the dilution zone at low load to increase turndown. These methods can be combined.

Emissions Control Methods

There are three principal methods for controlling gas turbine emissions:

- Injection of a diluent such as water or steam into the burning zone of a conventional (diffusion flame) combustor
- Catalytic clean-up of NO_x and CO from the gas turbine exhaust (usually used in conjunction with the other two methods)
- Design of the combustor to limit the formation of pollutants in the burning zone by utilizing "lean-premixed" combustion technology.

The last method includes both DLN combustors and catalytic combustors. GE has considerable experience with each of these three methods.

Since September 1979, when regulations required that NO_x emissions be limited to 75 ppmvd (parts per million by volume, dry), more than 300 GE heavy-duty gas turbines have accumulated more than 2.5 million operating hours using either steam or water-injection to meet or exceed these required NO_x emissions levels. The amount of water required to accomplish this is approximately one-half of the fuel flow. However, there is a 1.8% heat-rate penalty associated with using water to control NO_x emissions for oil-fired simple-cycle gas turbines. Output, increases by approximately 3%, making water (or steam) injection for power augmentation economically attractive in some circumstances (such as peaking applications).

Single-nozzle combustors that use water or steam injection are limited in their ability to reduce NO_x levels below 42 ppmvd on gas fuel and 65 ppmvd on oil fuel. GE developed multi-nozzle quiet combustors (MNQC) for the MS7001EA and MS7001FA capable of achieving 25 ppmvd on gas fuel and 42 ppmvd on oil, using either water or steam injection. Since October 1987, more than 26 MNQC-equipped MS7001s that use water or steam injection have been placed in service. One unit that uses steam injection has operated nearly 50,000 hours at 25 ppmvd NO_x(at 15% O_2).

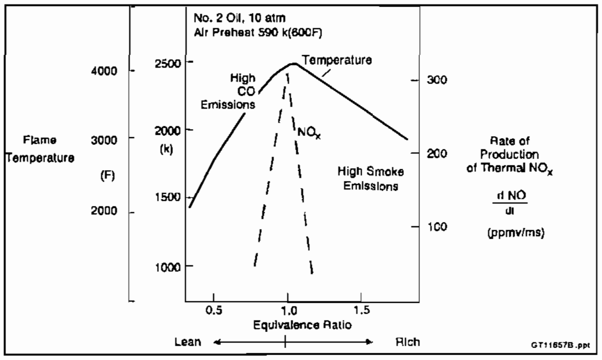

Figure A3. Rate of thermal Nox production

Frequent combustion inspections and decreased hardware life are undesirable side effects that can result from the use of diluent injection to reduce NO_x emissions from combustion turbines. For applications that require NO_x emissions below 42 ppmvd (or 25 ppmvd in the case of the MS7001EA or MS7001FA MNQC), or to avoid the significant cycle efficiency penalties incurred when water or steam injection is used for NO_x control, one of the other two principal methods of NO_x control mentioned above must be used.

Selective catalytic reduction (SCR) converts NO and NO_2 in the gas turbine exhaust stream to molecular nitrogen and oxygen by reacting the NO_x with ammonia in the presence of a catalyst. Conventional SCR technology requires that the temperature of the exhaust stream remain in a narrow range (550 F to 750 F or 288 C to 399 C) and is restricted to applications with a heat recovery system installed in the exhaust. The SCR is installed at a location in the boiler where the exhaust gas temperature has decreased to the above temperature range. New high-temperature SCR technology is being developed that may allow SCRs to be used for applications without heat recovery boilers.

For an MS7001EA gas turbine, an SCR designed to remove 90% of the NO_x from the gas turbine exhaust stream has a volume of approximately 175 cubic meters and weighs 111 tons. It is comprised of

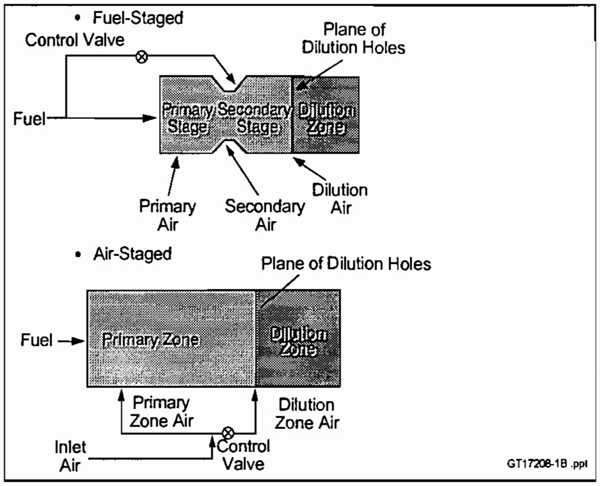

Figure A4. Staged combustors

segments stacked in the exhaust duct. Each segment has a honeycomb pattern with passages that are aligned in the direction of the exhaust gas flow. A catalyst, such as vanadium pentoxide, is deposited on the surface of the honeycomb.

SCR systems are sensitive to fuels containing more than 1,000 ppm of sulfur (light distillate oils may have up to 0.8% sulfur). There are two reasons for this sensitivity: first, sulfur poisons the catalyst being used in SCRs.

Secondly, the ammonia will react with sulfur in the presence of the catalyst to form ammonium bisulfate, which is extremely corrosive, particularly near the discharge of a heat recovery boiler. Special catalyst materials that are less sensitive to sulfur have been identified, and there are some theories as to how to inhibit the formation of ammonium bisulfate. This, however, remains an open issue with SCRs.

More than 100 GE units have accumulated more than 100,000 operating hours with SCRs installed. Twenty of the units are in Japan; others are located in California, New Jersey, New York and several other eastern U.S. states. Units operating with SCRs include MS9000s, MS7000s, MS6000s, LM2500s and LM5000s.

Lean premixed combustion is the basis for achieving low emissions from Dry Low NO_x and catalytic combustors. GE has participated in the development of catalytic combustors for many years. These systems use a catalytic reactor bed mounted within the combustor to burn a very lean fuel-air mixture. They have the potential to achieve extremely low emissions levels without resorting to exhaust gas cleanup. Technical challenges in the combustor and in the catalyst and reactor bed materials must be overcome in order to develop an operational catalytic combustor. GE has development programs in place with both ceramic and catalyst manufacturers to address these challenges. GE does not believe commercial systems employing this technology will be available in the near term.

REFERENCES

1. Washam, R. M., “Dry Low NO_x Combustion System for Utility Gas Turbine,” ASME Paper 83-JPGC-GT-13, Sept. 1983.
2. Davis, L. B. and Washam, R. M., “Development of a Dry Low NO_x Combustor,” ASME Paper No. 89-GT-255, June 1989.
3. Dibelius, N.R., Hilt, M.B., and Johnson, R.H., “Reduction of Nitrogen Oxides from Gas Turbines by Steam Injection,” ASME Paper No. 71-GT-58, Dec. 1970
4. Miller, H. E., “Development of the Quiet Combustor and Other Design Changes to Benefit Air Quality,” American Cogeneration Association, San Francisco, March 1988.
5. Cutrone, M. B., Hilt, M. B., Goyal, A., Ekstedt, E. E., and Notardonato, J., “Evaluation of Advanced Combustor for Dry NO_x Suppression with Nitrogen Bearing Fuels in Utility and Industrial Gas Turbines,” ASME Paper 81-GT-125, March 1981.
6. Zeldovich, J., “The Oxidation of Nitrogen in Combustion and Explosions,” Acta Physicochimica USSR, Vol. 21, No. 4, 1946, pp. 577-628.
7. Washam, R. M., “Dry Low NO_x Combustion System for Utility Gas Turbine,” ASME Paper 83-JPGC-GT-13, Sept. 1983.
8. Davis, L. B., and Washam, R. M., “Development of a Dry Low NO_x Combustor,” ASME Paper No. 89-GT-255, June 1989.

LIST OF FIGURES

APPENDIX C

VENDOR SPEC SHEET

Florida Power Corp - Intercession City

ESTIMATED PERFORMANCE PG7121(EA)

Load Condition		BASE	
Ambient Temp.	Deg F.	59.	
Output	kW	84,090.	*
Heat Rate (LHV)	Btu/kWh	10,490.	*
Heat Cons. (LHV) X 10^6	Btu/h	882.1	
Exhaust Flow X 10^3	lb/h	2356.	
Exhaust Temp.	Deg F.	998. +/- 10 F	*
Exhaust Heat (LHV) X 10^6	Btu/h	561.6	

EMISSIONS

NOx	ppmvd @ 15% O2	9.	*
NOx AS NO2	lb/h	32.	
CO	ppmvd	25.	*
CO	lb/h	54.	
UHC	ppmvw	7.	
UHC	lb/h	9.	
Particulates (TSP)	lb/h	5.0	
Opacity		10%	*

EXHAUST ANALYSIS % VOL.

Argon	0.90
Nitrogen	74.92
Oxygen	13.86
Carbon Dioxide	3.22
Water	7.10

SITE CONDITIONS

Elevation	ft.	74.0
Site Pressure	psia	14.66
Inlet Loss	in Water	3.5
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20831 @ 60 °F
Application		7A6 Air-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

* Guarantee Parameter

IPS- 80883 version code- 1 . 5 . 1 Opt: N 71210696
ALMSTEJO 6/16/99 13:08 Base Guar 59F Gas IBH.dat

Florida Power Corp - Intercession City
ESTIMATED PERFORMANCE PG7121(EA)

Load Condition		BASE	
Ambient Temp.	Deg F.	59.	
Output	kW	86,980.	*
Heat Rate (LHV)	Btu/kWh	10,940.	*
Heat Cons. (LHV) X 10^6	Btu/h	951.6	
Exhaust Flow X 10^3	lb/h	2407.	
Exhaust Temp.	Deg F.	993. +/- 10 F	*
Exhaust Heat (LHV) X 10^6	Btu/h	574.7	
Water Flow	lb/h	(* Guarantee not to exceed 51,500 lb/hr at this operating condition & fuel definition)	

EMISSIONS

NOx	ppmvd @ 15% O2	42.	*
NOx AS NO2	lb/h	167.	
CO	ppmvd	20.	*
CO	lb/h	43.	
UHC	ppmvw	7.	
UHC	lb/h	9.	
Particulates (TSP)	lb/h	10.0	
Opacity		10%	*

EXHAUST ANALYSIS % VOL.

Argon	0.88
Nitrogen	73.53
Oxygen	13.21
Carbon Dioxide	4.52
Water	7.86

SITE CONDITIONS

Elevation	ft.	74.0
Site Pressure	psia	14.66
Inlet Loss	in Water	3.5
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Distillate, H/C Ratio of 1.8
Fuel LHV	Btu/lb	18300 @ 60 °F
Application		7A6 Air-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.

* Guarantee Parameter
IPS- 80883 version code- 1 . 5 . 1 Opt: N 71210696
ALMSTEJO 6/16/99 13:02 Base Guar 59F Dist IBH.dat

APPENDIX D

CALPUFF ANALYSIS

CALPUFF CLASS I AREA ANALYSIS

INTRODUCTION

Florida Power Corporation (FPC) is proposing to construct three nominal 100-Mw combustion turbines (CT) at the existing Intercession City power plant located in Osceola County. The CTs will be fired with natural gas and distillate fuel oil with a maximum sulfur content of 0.05 percent. Based on the proposed maximum pollutant emission levels, the project is subject to the requirements under the Prevention of Significant Deterioration (PSD) regulations as part of new source review. The preliminary air modeling analysis performed by FPC using the Industrial Source Complex Short-Term (ISCST3) model (Version 98356) has indicated that the proposed project's maximum 24-hour average sulfur dioxide (SO_2) concentration was predicted to be slightly greater than the corresponding PSD Class I significant impact level (SIL), proposed by the Environmental Protection Agency's (EPA), at the Chassahowitzka National Wildlife Refuge (CNWR), a PSD Class I area. However, this value was predicted to occur only at one receptor for <u>one</u> 24-hour averaging period during the five years considered in the modeling analysis. Thus, the probability that the maximum project's concentrations would be greater than the significant impact levels is very low:

- one occurrence from a potential <u>1,826</u> 24-hour average concentrations predicted at that receptor and
- one occurrence in about <u>23,700</u> 24-hour average concentrations predicted for the entire receptor grid at the Chassahowitzka NWR;

For all other receptors for that year and at all receptors for other years, the maximum 24-hour SO_2 concentrations were predicted to be 15 percent or more lower than the significant impact level of 0.2 ug/m^3.

The CNWR is located approximately 113 kilometers (km) to the west, northwest of the project site. At distances beyond 50 km, the ISCST3 model is considered to overpredict air quality impacts because it is a steady-state model. To provide a more realistic assessment of the project's air quality impacts at the CNWR, Golder Associates Inc. (Golder) was contracted to perform a significant impact analysis at the PSD Class I area using the long-range transport model, California Puff model (CALPUFF, Version 5.0).

Currently, CALPUFF is not a recommended model in EPA's Guideline on Air Quality Models (40 CFR Part 51, Appendix W). As such, the model must be approved by EPA on a case-by-case basis. EPA is planning to formally propose incorporating CALPUFF into Appendix W at the 7th Conference on Air Quality Modeling currently planned for the fall of 1999. However, in the interim, the Federal Land Managers (FLM) and the Interagency Workgroup on Air Quality Modeling (IWAQM) are recommending the use of CALPUFF for all long-range transport assessments at PSD Class I areas.

A discussion of the CALPUFF model and modeling methodology used for this analysis and the air modeling results is presented in the following sections.

MODEL SELECTION

CALPUFF is a non-steady-state Lagrangian, Gaussian puff model appropriate for simulating air quality impacts over large distances. The model features include algorithms for simulating plume behavior over complex (i.e., terrain above stack plume height) terrain, plume transport over water bodies, coastal (i.e., land-sea air) interaction, chemical transformation, and wet and dry deposition and removal. CALPUFF can also incorporate the same building downwash effects currently used within the ISCST3 model. The model can be used in a screening mode by processing an "enhanced" ISCST3 meteorological data set, or in a refined mode by inputting a three-dimensional meteorological parameter data set generated by the meteorological preprocessor program CALMET. The "enhanced" meteorological data refers to the additional parameters used by the model. These parameters include relative humidity, precipitation, and solar radiation. CALMET produces this data set by inputting various surface, upper air, precipitation, land use, and terrain data over a region and processes this data for a predetermined modeling domain. A postprocessor program called CALPOST processes the CALPUFF-generated concentration or deposition data and produces output of pollutant species concentrations and depositions for various averaging times.

For this analysis, CALPUFF was used in a screening analysis mode, as recommended by the IWAQM Phase 2 Summary Report (12/98). The CALPUFF screening analysis is also referred to as the IWAQM Level II screening analysis or a CALPUFF "light" analysis. The following modeling procedures were used for the Phase II screening analysis.

- Five years of ISCST preprocessed meteorological data. The data set includes the standard ISCST model parameters of wind direction, wind speed, temperature, mixing height and atmospheric stability class, and additional parameters used for dry and wet deposition. These additional parameters include relative humidity, precipitation, and solar radiation.
- Location of receptors in a circle at radials separated by 2-degree intervals. The receptors are located on each radial at a distance that passes through the PSD Class I area. For this analysis, a radius of 113 km was used, which is the closest distance from the FPC project site to the CNWR.
- For SO2, use two pollutant species of SO_2 and SO_4.
- MESOPUFF II scheme for chemical transformation with CALPUFF default background concentrations of 80 and 10 ppb for ozone and ammonia, respectively
- Both dry and wet deposition and plume depletion
- Modeling domain extends 80 km beyond receptor grid.
- Agricultural, unirrigated land use; minimum mixing height of 50 m
- Transitional plume rise, stack-tip downwash, and partial plume penetration
- Puff plume element dispersion (Pasquill-Gifford), rural mode, and ISC building downwash scheme
- Partial plume path adjustment terrain effects
- Highest concentrations predicted in 5 years compared to allowable PSD increments.

BUILDING WAKE EFFECTS

The air modeling analysis included the proposed project's building dimensions to account for the effects of building-induced downwash on the emission sources. The building's dimensions were processed using the Building Profile Input Program (BPIP), Version 95086 and were included in the preliminary ISCST3 modeling analysis.

RECEPTOR LOCATIONS

Receptors were located along a circle that was centered over the FPC project site with a radius equal to the minimum distance to the CNWR (i.e., 113.2 km). The circle contained 180 receptors, equally spaced at 2-degree intervals. A second modeling analysis was performed with 13 receptors located only at the CNWR. Results for both sets of receptors are presented.

METEOROLOGICAL DATA

A 5-year data record was used that consisted of hourly surface observations taken from the National Weather Service (NWS) station at the Orlando International Airport (OIA), coupled with twice-daily mixing height data from the NWS station in Ruskin. The data record was for the years 1987 to 1991. Because certain required parameters of the enhanced data set were not available from the NWS at the OIA for the entire period of record (see discussion below), data from the NWS station at Tampa International Airport (TPA) was used as a substitute for those parameters during those years.

The surface and upper data were preprocessed into an ASCII modeling format by EPA's PCRAMMET meteorological preprocessing program. An anemometer height of 33 ft was used for the modeling analysis.

Additional meteorological parameters were added to the meteorological data records for use with the CALPUFF model. The addition parameters include:

1. Friction velocity,
2. Monin-Obukhov length,
3. Surface roughness used for calculating dry deposition,

4. Precipitation type code and precipitation rate used for calculating wet deposition,
5. Short-wave solar radiation, and
6. Relative humidity used for calculating chemical transformation rates.

The dry deposition parameters were added to the meteorological data records using the PCRAMMET model in dry deposition mode. Using the guidance provided in Section 3.1 of the PCRAMMET User's Manual (8/98), the following input values were selected:

1. Surface roughness at both application and measurement sites: 0.15 m,
2. Noontime Albedo: 0.2,
3. Bowen Ratio: 1.0,
4. Anthropogenic Heat flux: 0,
5. Minimum Monin-Obukhov Length: 2 m, and
6. Fraction of Net Radiation Absorbed by Ground: 0.15.

Hourly precipitation data were obtained from the NWS stations at OIA (1990 to 1991) and TPA (1987 to 1989). A precipitation code value was determined for each hour, based on the precipitation classification scheme provided in Table 2-11 of the CALPUFF Users' Manual (7/95). An hour during which no precipitation occurred received a precipitation code value of zero. Hours with precipitation amounts of 0.01 to 0.1, inches, greater than 0.1 to 0.3 inches and greater than 0.3 inches, received precipitation codes of 1, 2, or 3, respectively. These codes are indicative of slight, moderate and heavy rain, respectively. Hourly relative humidity and short-wave radiation data were added to the meteorological data record for each of the 5 years. The relative humidity data were obtained from the NWS station at OIA (1990 to 1991) and from the NWS station at TPA (1987 to 1989), while the radiation data were obtained from the NWS station at TPA for all years. The addition parameters were obtained from the National Climatic Data Center's Solar and Meteorological Surface Observation Network (SAMSON) and Hourly United States Weather Observations (HUSWO) CDs.

EMISSION INVENTORY

Source parameter and emission rate data used for the CALPUFF modeling analysis are identical to that used by FPC for their ISCST3 air modeling analysis.

RESULTS

CIRCLE OF 180 RECEPTORS

The results of the Level II screening analysis are summarized in Table 1. The highest and second-highest 24-hour predicted concentrations are 0.13 and 0.11 ug/m^3. These concentrations are below the proposed EPA Class I significant impact level of 0.2 ug/m^3.

RECEPTORS AT CHASSAHOWITZKA NWA

The results of the Level II screening analysis are summarized in Table 1. The highest and second-highest 24-hour predicted concentrations are 0.094 and 0.072 ug/m^3. These concentrations are well below the proposed EPA Class I significant impact level of 0.2 ug/m^3.

Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

June 22, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. W. Jeffrey Pardue, C.E.P
Director, Environmental Services
Florida Power Corporation
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733

Re: DRAFT Permit No. 097-0014-003-AC (PSD-FL-268)
FPC Intercession City Plant
Propose Peaking Gas Turbines

Dear Mr. Pardue:

On May 25, 1999, the Department received your application to install three new GE Frame 7EA combustion turbines to provide additional peaking power at FPC's Intercession City plant. After review of the application, the Department has determined that the additional information listed below is necessary to process this request.

1. Summary of Project: The project consists of three identical Model PG 7121EA combustion turbines manufactured by General Electric, each capable of generating 87.3 MW of electrical power. The primary fuel will be pipeline natural gas with low sulfur distillate oil as a backup. NOX will be controlled by DLN combustion technology when firing gas and water injection when firing oil. A cooling system will reduce the temperature of the inlet air to the turbine to a nominal 59°F. The applicant requests the flexibility to be able to operate any combination of the three combustion turbines up to a maximum of 10,170 turbine hours per year of which 3000 turbine hours may be on low sulfur oil. This equates to 3390 hours of operation per year per turbine with maximum oil firing of 1000 hours per year per turbine. Startup of the combustion turbines is on oil. Is this information correct? Please provide a description of the inlet air cooling system and equipment. What is the purpose of "lighting off" the units on oil?

2. NOx BACT Determination: The application references the "quiet" combustor and the "9/42" combustor. Please specify the dry low-NOx combustor to be used (i.e., DLN 1.0, 2.0. 2.6, etc.) and provide the manufacturer's description of how this design inhibits the formation of NOx. Also, please provide the manufacturer's guarantee to meet the proposed NOx emission limits of 9.0/42 ppmvd @ 15% oxygen for gas/oil firing.

3. <u>CO BACT Determination</u>: The application proposes CO emission limits of 25/20 ppmvd @ 15% oxygen for gas/oil firing. In general, available information for a variety of manufacturers and models of combustion turbines seems to indicate higher CO emissions when firing oil than when firing gas (the opposite of the proposed limits). Please verify the CO limits for gas/oil firing and provide the manufacturer's guarantee.

4. <u>Air Quality Impact Analysis</u>: The Department received the ISCST3 model output files on June 17th. Based on review of this new information, we may have additional modeling questions.

   The application indicates that the SCREEN3 model results were used as inputs to the ISCST3 model. The emission rates used in the SCREEN3 modeling were for a single combustion turbine. Did the ISCST3 modeling consider simultaneous operation of all three proposed turbines?

   The modeling analysis summary indicates an exceedance of the 24-hour PSD Class I significance level for SO_2. Please provide a modeling analysis including other major sources from the area using ISCST3.

5. <u>Maximum SO_2 Emissions Rate</u>: What was the basis for the SO_2 emissions rate when burning distillate oil? I calculate 56.43 pounds per hour based on a maximum firing rate of 8038 gallons per hour and oil containing 0.05% sulfur by weight with a density of 7.02 pounds per gallon. Although this is a very small difference, please use the higher emissions rate for any additional SO_2 modeling.

6. <u>Additional Impacts Analysis</u>: Please model regional haze and visibility impacts with CALPUFF for this project.

7. <u>NPS Comments</u>: Conversations with the National Parks Services (NPS) indicate they will have questions and comments regarding this project. When available, the Department will forward these comments for your response.

The Department will resume processing this application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to Department requests for additional information of an engineering nature. Permit applicants are advised that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for additional information within 90 days. If there are any questions, please call me at 850/414-7268. Matters regarding modeling issues should be directed to Chris Carlson (Department meteorologist) at (850) 921-9537.

Sincerely,

Jeffery F. Koerner, P.E.
New Source Review Section

JFK/jfk

cc: Jennifer L. Tillman, P.E., FPC
J. Michael Kennedy, Q.E.P., FPC
Mr. Greg Worley, EPA
Mr. John Bunyak, NPS
Len Kozlov, DEP Central District

Z 333 618 164

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PS Form **3800**, April 1995

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- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

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FPC
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St. Pete, Fl
33733

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JUN 24 1999

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6. Signature: *(Addressee or Agent)*

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Florida
Power
CORPORATION

RECEIVED
JUN 16 1999
BUREAU OF
AIR REGULATION

June 16, 1999

Mr. Cleve Holladay
New Source Review Section
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Florida 32399

Dear Mr. Holladay:

Re: Modeling Files for Intercession City PSD - FL - 268

The purpose of this letter is to transmit the air quality dispersion modeling files for Florida Power Corporation's (FPC) proposed Intercession City Units P12 - P14 permit application. Due to the volume of information contained in these files, they were not included as part of the application document. The ISCST3 input and output files from the refined modeling analysis are contained on the two diskettes included with this letter. In order to identify the files, the following describes the file naming system:

Filename: icxxx.zii

ic - refers to Intercession City
xxx - pollutant designation (SO_2, NO_2, PM, CO)
z - denotes input (I) or output (o) file
ii - denotes year of meteorological data (87 through 91)

Please feel free to review these files in conjunction with the PSD permit application review. Please contact me at (727) 826-4334 if you have any questions.

Sincerely,

J. Michael Kennedy, Q.E.P.
Manager, Air Programs

ONE POWER PLAZA, 263 - 13th Avenue South, BB1A, St. Petersburg, FL 33701-5511 •
P.O. Box 14042, BB1A • St. Petersburg • Florida 33733-4042 • (727) 866-5151
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Florida Power
CORPORATION

RECEIVED

JUN 10 1999

BUREAU OF
AIR REGULATION

June 3, 1999

Mr. Jeff Koerner, P.E.
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

Dear Mr. Koerner:

Re: Intercession City PSD Application Sections 7 and 8

I have enclosed a clean copy of Sections 7 and 8 of the PSD permit application for proposed Units P12 - P14 at Florida Power Corporation's (FPC) Intercession City facility. Several pages were missing from the copies that were distributed.

I apologize for the error and hope that it has not inconvenienced you. Please contact Scott Osbourn at (727) 826-4258 or me at (727) 826-4334 if you have any questions.

Sincerely,

J. Michael Kennedy, Q.E.P.
Manager, Air Programs

EPA
NPS
Central District

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7.0 AIR QUALITY IMPACT ANALYSIS RESULTS

This section summarizes the results of the modelling analyses conducted as described in Section 6.0.

7.1 Intercession City Units P12 - P14

7.1.1 Worst-case Operation Analysis

As indicated in Section 6.4.1, the proposed facility was evaluated for both the primary fuel (natural gas) and the back-up fuel (fuel oil) to determine the worst-case impacts. Since the emissions on fuel oil are higher for the criteria pollutants than for natural gas, the analysis of short-term impacts focused on the fuel oil case. Based on the results of the SCREEN3 analysis, it was determined that 100% load would produce the maximum ground-level impacts for NOx and SO_2. For PM, the worst-case impacts occur at 25% load, and for CO emissions the worst case occurred at 50% load.

For conservatism, all model analyses, including those for annual average concentrations, were run using the worst-case oil-firing emissions described above for year-round operation. In reality, oil-firing will occur a maximum equivalent of 1,000 hours per year per unit.

7.1.2 Significant Impact Analysis

Once the worst-case operating scenario was determined, the next step in the analysis was to determine whether the ambient air quality impact from the proposed units is considered significant under the PSD rules. The worst-case emissions scenario for each pollutant was modeled at the receptor locations described in Section 6.5.1.

The results of the significant impact analysis are presented in Table 7-1. As indicated in Table 7-1, there were no predicted impacts greater than the PSD significance thresholds. Thus, no further analysis is required for purposes of PSD increment consumption and AAQS compliance analysis. A complete set of the ISCST3 model output files have been submitted to the FDEP under separate cover.

7.2 PSD INCREMENT ANALYSIS

7.2.1 Class II Area

Because the maximum predicted ambient air quality impacts are less than the PSD significance levels, no additional PSD Class II increment analysis is required.

7.2.2 Class I Area

Although the proposed project will be located approximately 113 km from the nearest boundary of the nearest Class I PSD area, which is the Chassahowitzka National Wilderness Area (NWA), the impacts of the proposed project were modelled. In its proposed New Source Review reform package, EPA has proposed PSD significance levels for Class I areas. FDEP has approved the use of these proposed values for purposes of assessing significant impacts at Class I areas in. These values are listed in Table 7-2.

A summary of the project's maximum predicted impact on the Class I area is presented in Table 7-2. As indicated, the predicted maximum impacts are below the EPA significance values for particulate matter (PM), SO_2, and NO_2, with the exception of one 24-hour SO_2 average. This single value occurred on February 19, 1991, showing a predicted value of 0.23 ug/m^3. Examination of the meteorological data for this day reveals that 8 calm hours occurred during the day. The model conservatively assumes that, during calm periods, the wind direction remains constant when in fact the wind is not moving in any direction. It is unlikely that the plume from the Intercession City units could travel the 113-km distance to the NWA under such conditions. In addition, the model analysis assumes that all three units operated on oil at maximum load for the entire 24-hour period. Since these are peaking units, this scenario would not actually occur, so the analysis is quite conservative. All other modelled periods resulted in predicted concentrations well below the Class I significance levels. Therefore, the expected impact on the NWA is less than significant.

7.3 Air Toxics Analysis

Concentrations of sulfuric acid mist were modelled with ISCST3 in the same way that SO_2 was modelled. As with SO_2, highest emissions of this pollutant occur while using fuel oil. The predicted maximum 24-hour average concentration of sulfuric acid mist is 0.05 ug/m^3. This is well below the former FDEP ambient reference concentration (ARC) of 2.4 ug/m^3. Therefore, no adverse impacts will occur from emissions of sulfuric acid mist.

TABLE 7-1

SUMMARY OF SIGNIFICANT IMPACT ANALYSIS CONCENTRATIONS

PSD CLASS II AREAS

Pollutant	Averaging Period	Maximum (1) Predicted Concentration (ug/m^3)	Location (2)		Year	Significance Level (ug/m^3)	Distance to Significance (km)	Significant Impact (Yes/No)
			East (km)	North (km)				
Carbon Monoxide	1-Hour	73.6	447.45	3125.0	1988	2,000	None	No
	8-Hour	17.2	433.31	3133.5	1991	500	None	No
Nitrogen Dioxide	Annual	0.13	437.64	3121.0	1990	1	None	No
Sulfur Dioxide	3-Hour	2.44	427.51	3119.2	1988	25	None	No
	24-Hour	0.50	433.31	3133.5	1991	5	None	No
	Annual	0.04	437.64	3121.0	1990	1	None	No
Particulate Matter (PM_{10}) (3)	24-Hour	0.16	433.31	3133.5	1991	5	None	No
	Annual	0.01	446.30	3131.0	1991	1	None	No
Sulfuric Acid Mist	24-Hour	0.05	433.31	3133.5	1991	N/A	N/A	N/A

(1) Short-term values are highest values for this analysis.

(2) With respect to zero point of 446.30 km E; 3,126.0 km N.

(3) As a conservative approach, all project emissions of particulate matter were assumed to be in the form of PM_{10}.

N/A = Not applicable

FPC, 1999

TABLE 7-2

SUMMARY OF MAXIMUM MODELED IMPACTS VS. PSD CLASS I SIGNIFICANCE VALUES

Pollutant	Averaging Period	Highest Modeled Concentration (ug/m^3)	PSD Class I Signif. Level (ug/m^3)	Significance
Sulfur Dioxide (SO_2)	3-Hour	0.91	1.0	NO
	24-Hour	0.23	0.2	NO*
	Annual	0.01	0.1	NO
Particulate Matter (PM_{10})	24-Hour	0.04	0.3	NO
	Annual	0.002	0.2	NO
Nitrogen Dioxide (NO_2)	Annual	0.03	0.1	NO

* Refer to discussion in Section 7.2.2

8.0 ADDITIONAL IMPACTS

8.1 INTRODUCTION

The PSD guidelines indicate that, in addition to demonstrating that the proposed source will neither cause nor contribute to violations of the applicable PSD increments and AAQS, an additional impacts analysis must be conducted for those pollutants subject to PSD review. As indicated in Table 3-2, those pollutants include CO, NO_X, SO_2, PM, VOC (O_3), and sulfuric acid mist. This additional impacts analysis includes an analysis of air quality impacts due to growth induced by the project, an analysis of air quality impacts on soils and vegetation, and an analysis of project impacts on visibility.

As has been demonstrated in Section 7.0 of this application, the proposed project will have an insignificant impact at the NWA, located from 113 to 128 km from the proposed sources. In spite of this distance, FPC is providing a general assessment of the impact of Units P12 - P14 on air quality-related values (AQRV) as a part of this application.

8.2 IMPACTS DUE TO GROWTH

The growth analysis considers air quality impacts due to emissions resulting from the industrial, commercial, and residential growth associated with the project. Only impacts related to permanent growth are considered; emissions from temporary sources and mobile sources are not addressed in the growth analysis.

Negligible growth is expected to occur as a result of the proposed units. The units are being added to a facility that already contains 11 combustion turbine units. Therefore, existing facility staff will operate the units.

Development of industries supporting the new facility are expected to be negligible. Raw materials consumed by the facility (fuels, supplies, etc.) will be delivered to the site in usable form from outside of the region.

Electricity sales, on the other hand, will be spread out over a large region as part of FPC's generating capacity that will serve to meet increasing residential, commercial, and industrial demand throughout its system, which covers a large portion of the state of Florida.

In summary, there will be little residential growth associated with the FPC project, and there is little potential for new industrial development nearby as a result of the new facility. Impacts resulting from the new development are expected to be small and well-distributed throughout the area.

8.3 VEGETATION, SOILS, AND WILDLIFE ANALYSES

As previously discussed, the expected maximum impacts from Units P12 - P14 on the NWA are less than the PSD Class I and Class II significance levels. Therefore, the project will have a negligible impact on the soils, vegetation, wildlife, and visibility of the area surrounding the plant as well as the more distant Class I area. A general discussion of air quality-related values (AQRVs) of the NWA follows.

The U.S. Department of the Interior (National Park Service) in 1978 administratively defined AQRVs to be: All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality. Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are assets that are to be preserved if the area is to achieve the purposes for which it was set aside.

In a November 1996 report entitled "Air Quality and Air Quality Related Values in Chassahowitzka National Wildlife Refuge and Wilderness Area," the US Fish and Wildlife Service discussed vegetation, soils, wildlife, visibility, and water quality as potential AQRVs in the NWA. Effects from air pollution on visibility have been evaluated in the NWA, but the other potential AQRVs have not been specifically evaluated by the Fish and Wildlife Service for Chassahowitzka. Since specific AQRVs have not been identified for the Chassahowitzka NWA, this AQRV analysis evaluates the effects of air quality on general vegetation types and wildlife found on the Chassahowitzka NWA. Vegetation type AQRVs and their representative species types have been defined as:

Marshlands - black needlerush, saw grass, salt grass, and salt marsh cordgrass

Marsh Islands - cabbage palm and eastern red cedar

Estuarine Habitat - black needlerush, salt marsh cordgrass, wax myrtle

Hardwood Swamp - red maple, red bay, sweet bay and cabbage palm

Upland Forests - live oak, scrub oak, longleaf pine, slash pine, wax myrtle and saw palmetto

Mangrove Swamp - red, white and black mangrove

Wildlife AQRVs included: endangered species, waterfowl, marsh and waterbirds, shorebirds, reptiles and mammals.

A screening approach was used which compared the maximum predicted ambient concentration of air pollutants of concern in the Chassahowitzka NWR with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted which specifically addressed the effects of air contaminants on plant species reported to occur in the NWR. While the literature search focused on such species as cabbage palm, eastern red cedar, lichens and species of the hardwood swamplands and mangrove forest, no specific citations that addressed these species were found. It was recognized that effect threshold information is not available for all species found in the Chassahowitzka NWR, although studies have been performed on a few of the common species and on other similar species which can be used as models. Maximum concentrations and depositions were predicted using the ISCST model and five years of meteorological data as described in Sections 6.0 and 7.0.

8.3.1 Vegetation

The effects of air contaminants on vegetation occur primarily from sulfur dioxide, nitrogen dioxide, ozone, and particulates. Effects from minor air contaminants such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, carbon monoxide, and pesticides have been reported in the literature. However, most of these air contaminants have not resulted in major effects (i.e., crop damage). Some air contaminants, such as ethylene, are widely distributed but, due to low concentrations, do not result in injury to plants. Others such as CO do not cause damage at concentrations normally found under ambient concentrations. There are no predicted fluoride emissions from the proposed project.

Injury to vegetation from exposure to various levels of air contaminants can be termed acute, physiological or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms, while chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant.

Since expected maximum pollutant concentrations at the NWA are below significance levels, no adverse effects to vegetation will be caused by the proposed project.

8.3.2 Soils

Air contaminants can affect soils through fumigation by gaseous forms, accumulation of compounds transformed from the gaseous state, or by the direct deposition of particulate matter or particulate matter to which certain contaminants are absorbed. Gaseous fumigation of soils does not directly affect the soil but rather the organisms found in the soil. Concentrations several orders of magnitude higher than the predicted values are required before any adverse effects from fumigation are observed. It is more likely that effects on soils and the organisms (plants and animals) found in the soils could occur from the deposition of trace elements over the life of the project. Thus, this analysis of effects on soils specifically addresses the deposition of trace elements and potential pathways for movements into the vegetation.

8.3.2.1 Lead

Lead (Pb) is found naturally occurring in all plants, although it is nonessential for growth (Chapman, 1966; Valkovic, 1975; Gough and Shacklette, 1976). Plants vary in their sensitivity to lead. Many plants tolerate high concentrations of lead, while others exhibit retarded growth at 10 ppm in solution culture (Valkovic, 1975). Orange seedlings grown on soils with lead concentrations ranging from 150-200 ppm did not exhibit adverse effects (Chapman, 1966). Gough et al. (1979) reported that a lead soil concentration of 30 to 100 g/g generally retarded the growth of plants. The negligible amount of lead emissions from Units P12 - P14 will not contribute to a soil concentration toxic to plants.

8.3.2.2 Mercury

Mercury (Hg) is not an essential element for plant growth. It is typically used as a seed fungicide. In general, Hg is not concentrated in plants grown on soils containing normal levels of Hg. Soil bound Hg is typically not available for plant uptake, although many plants cannot prevent the uptake of gaseous Hg through the roots (Huckabee and Jansen, 1975). Most higher vascular plants are resistant to toxicity from high Hg concentrations even though high concentrations are present in plant tissue. Concentrations of 0.5-50 ppm (HgCl2) were found to inhibit the growth of cauliflower, lettuce, potato, and carrots (Bell and Rickard, 1974). Gough et al. (1979) noted apparently healthy spanish moss plants with a mercury content of 0.5 mg/kg. The extremely small amount of mercury emissions from the proposed units will not contribute to concentrations that are toxic to plants.

8.3.3 Wildlife

Compared with other threats to wildlife, such as pesticides, the toxicological relationships between air pollution and effects on wildlife are not well understood (Newman and Schreiber, 1988). The limited understanding is based primarily on reports of symptoms observed in the field and on information extrapolated from laboratory studies. Information on controlled wildlife studies is limited in the scientific literature. Most studies report symptoms of various air pollutants but do not provide toxicity levels. Those studies that do provide toxicity levels are limited to four air contaminants, SO_2, NO_2, O_3, and particulates.

Since the expected maximum pollutant impacts are less than Class I significance levels, no adverse impacts to wildlife will occur from the proposed facility emissions.

In addition to the impacts on wildlife from the primary pollutants, the Fish and Wildlife Service is concerned about the effects on wildlife resulting from acid deposition (FWS, 1992). Existing acid deposition conditions in Florida were investigated during the five year Florida Acid Deposition Study (ESE, 1986 and 1987) and the two year follow-up program called the Florida Acid Deposition Monitoring Program (ESE, 1988 and 1989). The data collected in these programs indicate that Florida precipitation is only about two-thirds as acidic as precipitation across the southeastern United States and less than half as acidic as precipitation in the midwestern and northeastern United States (ESE, 1988). There is no evidence of a temporal trend in precipitation acidity since the late 1970s (ESE, 1989). The Clean Air Act Amendments of 1990 require significant reductions in SO_2 and NO_2 emissions from existing uncontrolled utility plants nationwide and some of these reductions will occur at plants in the general vicinity of the NWA. These emission reductions will undoubtedly improve on the already good estimated acid deposition conditions in the NWR.

Due to the small emission increases that will be caused by the proposed project and the resulting insignificant concentrations, increase, if any in acid deposition will be negligible.

8.4 VISIBILITY IMPACTS

The maximum predicted SO_2 and NOx impacts from the proposed units have been determined to be less than the Class I significance levels. Therefore, there will be little, if any incremental impact to the area's visibility.

Florida
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FAXED TO ELLEN PORTER, F
ON 6/4 BY J. KOERNER

Date: 6/2/99

To: Jeff Koerner

FAX #: (850) 922-6979

Phone #: (   )

From: Mike Kennedy

FAX #: (727) 826-4216

Phone #: (727) 826-4334

10 Total number of pages including cover page.

Please notify ________________ at (727) 826 - __________ for any problems concerning the receipt of this FAX.

Comments:

Complete Sections 7 and 8 from the Intercession City PSD application. Sorry about the mistake. I'll send a clean copy through the mail.

7.0 AIR QUALITY IMPACT ANALYSIS RESULTS

This section summarizes the results of the modelling analyses conducted as described in Section 6.0.

7.1 Intercession City Units P12 - P14

7.1.1 Worst-case Operation Analysis

As indicated in Section 6.4.1, the proposed facility was evaluated for both the primary fuel (natural gas) and the back-up fuel (fuel oil) to determine the worst-case impacts. Since the emissions on fuel oil are higher for the criteria pollutants than for natural gas, the analysis of short-term impacts focused on the fuel oil case. Based on the results of the SCREEN3 analysis, it was determined that 100% load would produce the maximum ground-level impacts for NOx and SO_2. For PM, the worst-case impacts occur at 25% load, and for CO emissions the worst case occurred at 50% load.

For conservatism, all model analyses, including those for annual average concentrations, were run using the worst-case oil-firing emissions described above for year-round operation. In reality, oil-firing will occur a maximum equivalent of 1,000 hours per year per unit.

7.1.2 Significant Impact Analysis

Once the worst-case operating scenario was determined, the next step in the analysis was to determine whether the ambient air quality impact from the proposed units is considered significant under the PSD rules. The worst-case emissions scenario for each pollutant was modeled at the receptor locations described in Section 6.5.1.

The results of the significant impact analysis are presented in Table 7-1. As indicated in Table 7-1, there were no predicted impacts greater than the PSD significance thresholds. Thus, no further analysis is required for purposes of PSD increment consumption and AAQS compliance analysis. A complete set of the ISCST3 model output files have been submitted to the FDEP under separate cover.

7.2 PSD INCREMENT ANALYSIS

7.2.1 Class II Area

Because the maximum predicted ambient air quality impacts are less than the PSD significance levels, no additional PSD Class II increment analysis is required.

7.2.2 Class I Area

Although the proposed project will be located approximately 113 km from the nearest boundary of the nearest Class I PSD area, which is the Chassahowitzka National Wilderness Area (NWA), the impacts of the proposed project were modelled. In its proposed New Source Review reform package, EPA has proposed PSD significance levels for Class I areas. FDEP has approved the use of these proposed values for purposes of assessing significant impacts at Class I areas in. These values are listed in Table 7-2.

A summary of the project's maximum predicted impact on the Class I area is presented in Table 7-2. As indicated, the predicted maximum impacts are below the EPA significance values for particulate matter (PM), SO_2, and NO_2, with the exception of one 24-hour SO_2 average. This single value occurred on February 19, 1991, showing a predicted value of 0.23 ug/m^3. Examination of the meteorological data for this day reveals that 8 calm hours occurred during the day. The model conservatively assumes that, during calm periods, the wind direction remains constant when in fact the wind is not moving in any direction. It is unlikely that the plume from the Intercession City units could travel the 113-km distance to the NWA under such conditions. In addition, the model analysis assumes that all three units operated on oil at maximum load for the entire 24-hour period. Since these are peaking units, this scenario would not actually occur, so the analysis is quite conservative. All other modelled periods resulted in predicted concentrations well below the Class I significance levels. Therefore, the expected impact on the NWA is less than significant.

7.3 Air Toxics Analysis

Concentrations of sulfuric acid mist were modelled with ISCST3 in the same way that SO_2 was modelled. As with SO_2, highest emissions of this pollutant occur while using fuel oil. The predicted maximum 24-hour average concentration of sulfuric acid mist is 0.05 ug/m^3. This is well below the former FDEP ambient reference concentration (ARC) of 2.4 ug/m^3. Therefore, no adverse impacts will occur from emissions of sulfuric acid mist.

TABLE 7-1

SUMMARY OF SIGNIFICANT IMPACT ANALYSIS CONCENTRATIONS

PSD CLASS II AREAS

Pollutant	Averaging Period	Maximum [1] Predicted Concentration (ug/m³)	Location [2]		Year	Significance Level (ug/m³)	Distance to Significance (km)	Significant Impact (Yes/No)
			East (km)	North (km)				
Carbon Monoxide	1-Hour 8-Hour	73.6 17.2	447.45 433.31	3125.0 3133.5	1986 1991	2,000 500	None None	No No
Nitrogen Dioxide	Annual	0.13	437.64	3121.0	1990	1	None	No
Sulfur Dioxide	3-Hour 24-Hour Annual	2.44 0.50 0.04	427.51 433.31 437.64	3119.2 3133.5 3121.0	1988 1991 1990	25 5 1	None None None	No No No
Particulate Matter (PM_{10}) [3]	24-Hour Annual	0.16 0.01	433.31 446.30	3133.5 3131.0	1991 1991	5 1	None None	No No
Sulfuric Acid Mist	24-Hour	0.05	433.31	3133.5	1991	N/A	N/A	N/A

[1] Short-term values are highest values for this analysis.

[2] With respect to zero point of 446.30 km E; 3,126.0 km N.

[3] As a conservative approach, all project emissions of particulate matter were assumed to be in the form of PM_{10}.

N/A = Not applicable

FPC, 1999

TABLE 7-2
SUMMARY OF MAXIMUM MODELED IMPACTS VS.
PSD CLASS I SIGNIFICANCE VALUES

Pollutant	**Averaging Period**	**Highest Modeled Concentration ($\mu g/m^3$)**	**PSD Class I Signif. Level ($\mu g/m^3$)**	**Significance**
Sulfur Dioxide (SO_2)	3-Hour	0.91	1.0	NO
	24-Hour	0.23	0.2	NO*
	Annual	0.01	0.1	NO
Particulate Matter (PM_{10})	24-Hour	0.04	0.3	NO
	Annual	0.002	0.2	NO
Nitrogen Dioxide (NO_2)	Annual	0.03	0.1	NO

* Refer to discussion in Section 7.2.2

8.0 ADDITIONAL IMPACTS

8.1 INTRODUCTION

The PSD guidelines indicate that, in addition to demonstrating that the proposed source will neither cause nor contribute to violations of the applicable PSD increments and AAQS, an additional impacts analysis must be conducted for those pollutants subject to PSD review. As indicated in Table 3-2, those pollutants include CO, NO_X, SO_2, PM, VOC (O_3), and sulfuric acid mist. This additional impacts analysis includes an analysis of air quality impacts due to growth induced by the project, an analysis of air quality impacts on soils and vegetation, and an analysis of project impacts on visibility.

As has been demonstrated in Section 7.0 of this application, the proposed project will have an insignificant impact at the NWA, located from 113 to 128 km from the proposed sources. In spite of this distance, FPC is providing a general assessment of the impact of Units P12 - P14 on air quality-related values (AQRV) as a part of this application.

8.2 IMPACTS DUE TO GROWTH

The growth analysis considers air quality impacts due to emissions resulting from the industrial, commercial, and residential growth associated with the project. Only impacts related to permanent growth are considered; emissions from temporary sources and mobile sources are not addressed in the growth analysis.

Negligible growth is expected to occur as a result of the proposed units. The units are being added to a facility that already contains 11 combustion turbine units. Therefore, existing facility staff will operate the units.

Development of industries supporting the new facility are expected to be negligible. Raw materials consumed by the facility (fuels, supplies, etc.) will be delivered to the site in usable form from outside of the region.

Electricity sales, on the other hand, will be spread out over a large region as part of FPC's generating capacity that will serve to meet increasing residential, commercial, and industrial demand throughout its system, which covers a large portion of the state of Florida.

In summary, there will be little residential growth associated with the FPC project, and there is little potential for new industrial development nearby as a result of the new facility. Impacts resulting from the new development are expected to be small and well-distributed throughout the area.

8.3 VEGETATION, SOILS, AND WILDLIFE ANALYSES

As previously discussed, the expected maximum impacts from Units P12 - P14 on the NWA are less than the PSD Class I and Class II significance levels. Therefore, the project will have a negligible impact on the soils, vegetation, wildlife, and visibility of the area surrounding the plant as well as the more distant Class I area. A general discussion of air quality-related values (AQRVs) of the NWA follows.

The U.S. Department of the Interior (National Park Service) in 1978 administratively defined AQRVs to be: All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality. Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are assets that are to be preserved if the area is to achieve the purposes for which it was set aside.

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Marshlands - black needlerush, saw grass, salt grass, and salt marsh cordgrass

Marsh Islands - cabbage palm and eastern red cedar

Estuarine Habitat - black needlerush, salt marsh cordgrass, wax myrtle

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8.3.1 Vegetation

The effects of air contaminants on vegetation occur primarily from sulfur dioxide, nitrogen dioxide, ozone, and particulates. Effects from minor air contaminants such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, carbon monoxide, and pesticides have been reported in the literature. However, most of these air contaminants have not resulted in major effects (i.e., crop damage). Some air contaminants, such as ethylene, are widely distributed but, due to low concentrations, do not result in injury to plants. Others such as CO do not cause damage at concentrations normally found under ambient concentrations. There are no predicted fluoride emissions from the proposed project.

Injury to vegetation from exposure to various levels of air contaminants can be termed acute, physiological or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms, while chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant.

Since expected maximum pollutant concentrations at the NWA are below significance levels, no adverse effects to vegetation will be caused by the proposed project.

8.3.2 Soils

Air contaminants can affect soils through fumigation by gaseous forms, accumulation of compounds transformed from the gaseous state, or by the direct deposition of particulate matter or particulate matter to which certain contaminants are absorbed. Gaseous fumigation of soils does not directly affect the soil but rather the organisms found in the soil. Concentrations several orders of magnitude higher than the predicted values are required before any adverse effects from fumigation are observed. It is more likely that effects on soils and the organisms (plants and animals) found in the soils could occur from the deposition of trace elements over the life of the project. Thus, this analysis of effects on soils specifically addresses the deposition of trace elements and potential pathways for movements into the vegetation.

8.3.2.1 Lead

Lead (Pb) is found naturally occurring in all plants, although it is nonessential for growth (Chapman, 1966; Valkovic, 1975; Gough and Shacklette, 1976). Plants vary in their sensitivity to lead. Many plants tolerate high concentrations of lead, while others exhibit retarded growth at 10 ppm in solution culture (Valkovic, 1975). Orange seedlings grown on soils with lead concentrations ranging from 150-200 ppm did not exhibit adverse effects (Chapman, 1966). Gough et al. (1979) reported that a lead soil concentration of 30 to 100 g/g generally retarded the growth of plants. The negligible amount of lead emissions from Units P12 - P14 will not contribute to a soil concentration toxic to plants.

8.3.2.2 Mercury

Mercury (Hg) is not an essential element for plant growth. It is typically used as a seed fungicide. In general, Hg is not concentrated in plants grown on soils containing normal levels of Hg. Soil bound Hg is typically not available for plant uptake, although many plants cannot prevent the uptake of gaseous Hg through the roots (Huckabee and Jansen, 1975). Most higher vascular plants are resistant to toxicity from high Hg concentrations even though high concentrations are present in plant tissue. Concentrations of 0.5-50 ppm (HgCl2) were found to inhibit the growth of cauliflower, lettuce, potato, and carrots (Bell and Rickard, 1974). Gough et al. (1979) noted apparently healthy spanish moss plants with a mercury content of 0.5 mg/kg. The extremely small amount of mercury emissions from the proposed units will not contribute to concentrations that are toxic to plants.

8.3.3 Wildlife

Compared with other threats to wildlife, such as pesticides, the toxicological relationships between air pollution and effects on wildlife are not well understood (Newman and Schreiber, 1988). The limited understanding is based primarily on reports of symptoms observed in the field and on information extrapolated from laboratory studies. Information on controlled wildlife studies is limited in the scientific literature. Most studies report symptoms of various air pollutants but do not provide toxicity levels. Those studies that do provide toxicity levels are limited to four air contaminants, SO_2, NO_2, O_3, and particulates.

Since the expected maximum pollutant impacts are less than Class I significance levels, no adverse impacts to wildlife will occur from the proposed facility emissions.

In addition to the impacts on wildlife from the primary pollutants, the Fish and Wildlife Service is concerned about the effects on wildlife resulting from acid deposition (FWS, 1992). Existing acid deposition conditions in Florida were investigated during the five year Florida Acid Deposition Study (ESE, 1986 and 1987) and the two year follow-up program called the Florida Acid Deposition Monitoring Program (ESE, 1988 and 1989). The data collected in these programs indicate that Florida precipitation is only about two-thirds as acidic as precipitation across the southeastern United States and less than half as acidic as precipitation in the midwestern and northeastern United States (ESE, 1988). There is no evidence of a temporal trend in precipitation acidity since the late 1970s (ESE, 1989). The Clean Air Act Amendments of 1990 require significant reductions in SO_2 and NO_2 emissions from existing uncontrolled utility plants nationwide and some of these reductions will occur at plants in the general vicinity of the NWA. These emission reductions will undoubtedly improve on the already good estimated acid deposition conditions in the NWR.

Due to the small emission increases that will be caused by the proposed project and the resulting insignificant concentrations, increase, if any in acid deposition will be negligible.

8.4 VISIBILITY IMPACTS

The maximum predicted SO_2 and NOx impacts from the proposed units have been determined to be less than the Class I significance levels. Therefore, there will be little, if any incremental impact to the area's visibility.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of
Environmental Protection

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Jeb Bush
Governor

David B. Struhs
Secretary

May 26, 1999

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA – Region IV
61 Forsyth Street
Atlanta, Georgia 30303

Re: Florida Power Corporation – Intercession City Facility
0970014-003-AC, PSD-FL-268

Dear Mr. Worley:

Enclosed for your review and comment is an application for the above mentioned project. It consists of the addition of three nominal 87 MW GE Frame 7EA simple cycle combustion turbines to provide additional peaking power to the existing FPC plant.

The applicant has requested a NOx limit of 9ppm while operating on gas and 42ppm while operating on oil (1000 hours).

Your comments can be forwarded to my attention at the letterhead address or faxed to me at (850)922-6979. If you have any questions, please contact Jeff Koerner at (850)414-7268.

Sincerely,

5/26

A. A. Linero, P.E.
Administrator
New Source Review Section

AAL/kt

Enclosures

cc: Jeff Koerner, BAR

FLORIDA

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

May 26, 1999

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS-Air Quality Division
Post Office Box 25287
Denver, CO 80225

Re: Florida Power Corporation – Intercession City Facility
0970014-003-AC, PSD-FL-268

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for the above mentioned project. It consists of the addition of three GE Frame 7EA combustion turbines to provide additional peaking power to the existing FPC plant.

Your comments can be forwarded to my attention at the letterhead address or faxed to the Bureau at (850)922-6979. If you have any questions, please contact Jeff Koerner at (850)414-7268.

Sincerely,

5/2

A. A. Linero, P.E.
Administrator
New Source Review Section

AAL/kt

Enclosures

cc: Jeff Koerner, BAR

Florida Power
CORPORATION

May 21, 1999

RECEIVED
MAY 25 1999
BUREAU OF
AIR REGULATION

Administrator, New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Attention: Mr. A. A. Linero, P.E.

RE: AIR PERMIT APPLICATION AND PREVENTION OF SIGNIFICANT DETERIORATION ANALYSIS
FLORIDA POWER CORPORATION - INTERCESSION CITY FACILITY
OSCEOLA COUNTY, FLORIDA

0970014-003-AC
PSD-FI-268

Dear Mr. Linero:

This letter serves to transmit four copies of the Air Permit Application and Prevention of Significant Deterioration Analysis for the Intercession City Site, Osceola County, Florida. In addition, attached is a check for $7,500 to cover the cost of processing the application.

Please call Messrs. Mike Kennedy at (727) 826-4334 or Scott Osbourn at (727) 826-4258 if you have any questions regarding this submittal.

Sincerely,

W. Jeffrey Pardue, C.E.P.
Director, Environmental Services

Enclosures

cc: Len Kozlov, DEP Central District
Robert C. McCann, Jr., Golder Associates

One Power Plaza • 263 – 13th Avenue South • St. Petersburg • Florida 33701-5511
P.O. Box 14042 • St. Petersburg • Florida 33733-4042 • (727) 820-5151
A Florida Progress Company

Department of
Environmental Protection

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Identification of Facility Addressed in This Application

1. Facility Owner/Company Name :
Florida Power Corporation

2. Site Name :
Intercession City Plant

3. Facility Identification Number : 0970014 [ ] Unknown
0970014-003-AC

4. Facility Location :
PSD-FL-268
Intercession City

Street Address or Other Locator : 6525 Osceola Polk Co. Line Rd.
City : Intercession City County : Osceola Zip Code : 33848

5. Relocatable Facility?
[ ] Yes [X] No

6. Existing Permitted Facility?
[X] Yes [ ] No

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official :

Name : W. Jeffrey Pardue, C.E.P.
Title : Director, Environmental Services

2. Owner or Authorized Representative or Responsible Official Mailing Address :

Organization/Firm : Florida Power Corporation
Street Address : P.O. Box 14042, MAC BB1A
City : St. Petersburg
State : FL Zip Code : 33733

3. Owner/Authorized Representative or Responsible Official Telephone Numbers :

Telephone : (727)826-4301 Fax : (727)826-4216

4. Owner/Authorized Representative or Responsible Official Statement :

I, the undersigned, am the owner or authorized representative of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions units.*

W. JEFFREY PARDUE

Pardue
Signature

5/23/99
Date

* Attach letter of authorization if not currently on file.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type
Unknown	GE Frame 7EA CT Peaking Unit Number 12	AC1A
Unknown	GE Frame 7EA CT Peaking Unit Number 13	AC1A
Unknown	GE Frame 7EA CT Peaking Unit Number 14	AC1A

Purpose of Application and Category

ategory I : All Air Operation Permit Applications Subject to Processing Under Chapter 62-213, .A.C.

This Application for Air Permit is submitted to obtain :

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for an existing facility which is classified as a Title V source.

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number :

[ ] Air operation permit renewal under Chapter 62-213, F.A.C., for a Title V source.

Operation permit to be renewed :

[ ] Air operation permit revision for a Title V source to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number :

Operation permit to be revised :

[ ] Air operation permit revision or administrative correction for a Title V source to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application.

Operation permit to be revised/corrected :

[ ] Air operation permit revision for a Title V source for reasons other than construction or modification of an emissions unit.

Operation permit to be revised :

Reason for revision :

ategory II : All Air Operation Permit Applications Subject to Processing Under Rule 2-210.300(2)(b), F.A.C.

This Application for Air Permit is submitted to obtain :

[ ] Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s) :

[ ] Renewal air operation permit under Fule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed :

[ ] Air operation permit revision for a synthetic non-Title V source.

Operation permit to be revised :

Reason for revision :

Category III : All Air Construction Permit Applications for All Facilities and Emissions Units

This Application for Air Permit is submitted to obtain :

[X] Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any :
0970014-001-AV

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

Current operation permit number(s) :

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Application Processing Fee

Check one :

[X] Attached - Amount : $7500.00 [ ] Not Applicable.

Construction/Modification Information

1. Description of Proposed Project or Alterations :

Construction of three nominal 87.2 MW capacity GE Frame 7EA combustion turbines. (Total nominal rating of 262 MW.) Propose installation of inlet cooling in order to improve performance at high ambie temperatures. See attached PSD Analysis.

2. Projected or Actual Date of Commencement of Construction : 01-Nov-1999

3. Projected Date of Completion of Construction : 01-Aug-2000

Professional Engineer Certification

1. Professional Engineer Name : Jennifer L. Tillman
Registration Number : 0052125

2. Professional Engineer Mailing Address :

Organization/Firm : Florida Power Corporation
Street Address : P.O. Box 14042, MAC BB1A
City : St. Petersburg State : FL Zip Code : 33733

3. Professional Engineer Telephone Numbers :
Telephone : (727)826-4132 Fax : (727)826-4216

4. Professional Engineer Statement :

I, the undersigned, hereby certify, except as particularly noted herein, that :*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollutant control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ] if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [X] if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ] if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Jennifer L. Tillman *
Signature
(seal)

62126

5/21/99
Date

* Attach any exception to certification statement.

I am certifying the technical content of the permit application, but not the engineering design / construction of the combustion turbine units manufactured by General Electric.

Application Contact

1. Name and Title of Application Contact :

Name : J. Michael Kennedy, Q.E.P.
Title : Manager, Air Programs

2. Application Contact Mailing Address :

Organization/Firm : Florida Power Corporation
Street Address : P.O. Box 14042, MAC BB1A
City : St. Petersburg
State : FL Zip Code : 33733

3. Application Contact Telephone Numbers :

Telephone : (727)826-4334 Fax : (727)826-4216

Application Comment

This application is for a permit to construct 3 new combustion turbine units. See attached PSD Analysis.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility, Location, and Type

3

1. Facility UTM Coordinates :
Zone : 17 East (km) : 446.30 North (km) : 3126.00

2. Facility Latitude/Longitude :
Latitude (DD/MM/SS) : 28 15 38 Longitude (DD/MM/SS) : 81 32 51

3. Governmental Facility Code : 0

4. Facility Status Code : A

5. Facility Major Group SIC Code : 49

6. Facility SIC(s) :

7. Facility Comment :

Project consists of 3 nominal 87.2 MW (at 59 deg. F) dual fuel, Frame 7EA combustion turbines that will use dry low-NOx (DLN) combustion technology when firing natural gas and water injection for NOx control when firing fuel oil. Total CT operation will be limited to an average of 3,390 hr/yr/CT. Fuel oil use will be limited to the equivalent of 1,000 hr/yr/CT at full load.

Facility Contact

1. Name and Title of Facility Contact :
M. J. Drango
Asset Manager

2. Facility Contact Mailing Address :
Organization/Firm : Florida Power Corporation
Street Address : 6525 Osceola Polk Co. Line Rd.
City : Intercession City State : FL Zip Code : 33848

3. Facility Contact Telephone Numbers :
Telephone : (407)396-2111 Fax : (407)678-4453

Facility Regulatory Classifications

1. Small Business Stationary Source?	N
2. Title V Source?	Y
3. Synthetic Non-Title V Source?	N
4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	Y
5. Synthetic Minor Source of Pollutants Other than HAPs?	N
6. Major Source of Hazardous Air Pollutants (HAPs)?	N
7. Synthetic Minor Source of HAPs?	N
8. One or More Emissions Units Subject to NSPS?	Y
9. One or More Emission Units Subject to NESHAP?	N
10. Title V Source by EPA Designation?	N

11. Facility Regulatory Classifications Comment :

Combustion Turbine Units 12 through 14, to which this application applies, are subject to NSPS for stationary gas turbines (40 CFR Part 60, Subpart GG).

B. FACILITY REGULATIONS

Rule Applicability Analysis

Not Applicable

B. FACILITY REGULATIONS

List of Applicable Regulations

Refer to Attachment IC-FE-B

C. FACILITY POLLUTANTS

Facility Pollutant Information

1. Pollutant Emitted	2. Pollutant Classification
PM10	A
NOX	A
PM	A
CO	A
SO2	A
VOC	A
SAM	A

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 1

1. Pollutant Emitted : PM10		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 2

1. Pollutant Emitted :	NOX
2. Requested Emissions Cap :	(lbs/hour) (tons/year)
3. Basis for Emissions Cap Code :	
4. Facility Pollutant Comment :	

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 3

1. Pollutant Emitted : PM

2. Requested Emissions Cap :
(lbs/hour) (tons/year)

3. Basis for Emissions Cap Code :

4. Facility Pollutant Comment :

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 4

1. Pollutant Emitted : CO		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 5

1. Pollutant Emitted : SO2
2. Requested Emissions Cap : (lbs/hour) (tons/year)
3. Basis for Emissions Cap Code :
4. Facility Pollutant Comment :

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 6

1. Pollutant Emitted : VOC

2. Requested Emissions Cap :
(lbs/hour) (tons/year)

3. Basis for Emissions Cap Code :

4. Facility Pollutant Comment :

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Information Pollutant 7

1. Pollutant Emitted : SAM		
2. Requested Emissions Cap :	(lbs/hour)	(tons/year)
3. Basis for Emissions Cap Code :		
4. Facility Pollutant Comment :		

D. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location :	IC-FE-1
2. Facility Plot Plan :	IC-FE-2
3. Process Flow Diagram(s) :	IC-FE-3
4. Precautions to Prevent Emissions of Unconfined Particulate Matter :	NA
5. Fugitive Emissions Identification :	NA
6. Supplemental Information for Construction Permit Applica	PSD Analysis

Additional Supplemental Requirements for Category I Applications Only

7. List of Proposed Exempt
8. List of Equipment/Activities Regulated under
9. Alternative Methods of Operation :
10. Alternative Modes of Operation (Emissions
11. Identification of Additional Applicable
12. Compliance Assurance Monitoring
13. Risk Management Plan Verification :
14. Compliance Report and Plan :
15. Compliance Certification (Hard-copy Require

ATTACHMENT IC-FE-B

FACILITY REGULATIONS

ATTACHMENT IC-FE-B

FACILITY REGULATIONS

Applicable Requirements Listing - Power Plants

FACILITY: FPC Intercession City Plant

FDEP Rules:

General Permits:

62-4.030	
62-4.040(1)(a)	- Exemptions from permitting
62-4.040(1)(b)	- Exemptions from permitting
62-4.100	
62-4.130	

Asbestos NESHAP:

62-204.800(8)(b)8.(State Only)	- Asbestos Removal
62-204.800(8)(d) (State Only)	- General Provisions (Asbestos)
62-204.800(19) (State Only)	- CFCs; Part 82

Stationary Sources-General:

62-210.300(2)

Exemptions - Plant Specific:

62-210.300(3)(a)4.	- comfort heating < 1 mmBtu/hr
62-210.300(3)(a)5.	- mobile sources
62-210.300(3)(a)7.	- non-industrial vacuum cleaning
62-210.300(3)(a)8.	- refrigeration equipment
62-210.300(3)(a)9.	- vacuum pumps for labs
62-210.300(3)(a)10.	- steam cleaning equipment
62-210.300(3)(a)11.	- sanders < 5 ft2
62-210.300(3)(a)12.	- space heating equip.; (non-boilers)
62-210.300(3)(a)14.	- bakery ovens
62-210.300(3)(a)15.	- lab equipment
62-210.300(3)(a)16.	- brazing, soldering or welding
62-210.300(3)(a)17.	- laundry dryers
62-210.300(3)(a)20.	- emergency generators < 32,000 gal/yr
62-210.300(3)(a)21.	- general purpose engines < 32,000 gal.yr
62-210.300(3)(a)22.	- fire and safety equipment
62-210.300(3)(a)23.	- surface coating >5% VOC; 6 gal/month
62-210.300(3)(a)24.	- surface coating <5% VOC
62-210.300(3)(b)	- Temporary Exemptions
62-210.370(3)	- AORs
62-210.900(5)	- AOR Form

Title V Permits:
62-213.205(1)(a) - Fees
62-213.205(1)(b)
62-213.205(1)(c)
62-213.205(1)(e)
62-213.205(1)(f)
62-213.205(1)(g)
62-213.205(1)(I)
62-213.205(1)(j)
62-213.400 - Permits/Revisions
62-213.410 - Changes without permit revisions
62-213.420.(1)(b)2. - Permits-allows continued operation
62-213.420.(1)(b)3. - Permits-additional information
62-213.460 - Permit Shield
62-213.900(1) - Fee Form

Open Burning:
62-256.300 - Prohibitions
62-256.700 - Open burning Allowed

Asbestos Removal:
62-257.301 - Notification and Fee
62-257.400 - Fee Schedule
62-257.900 - Form

Stationary Sources-Emission Standards:
62-296.320(2) (State Only) - Odor
62-296.320(3)(b) (State Only) - Emergency Open Burning
62-296.320(4)(b) - General VE Standard
62-296.320(4)(c) - Unconfined Emissions of Particulate Matter

Stationary Sources-Emission Monitoring
62-297.310(7)(a)10. - Exemption of annual VE for 210.300(3)(a) sources/Gen. Per.

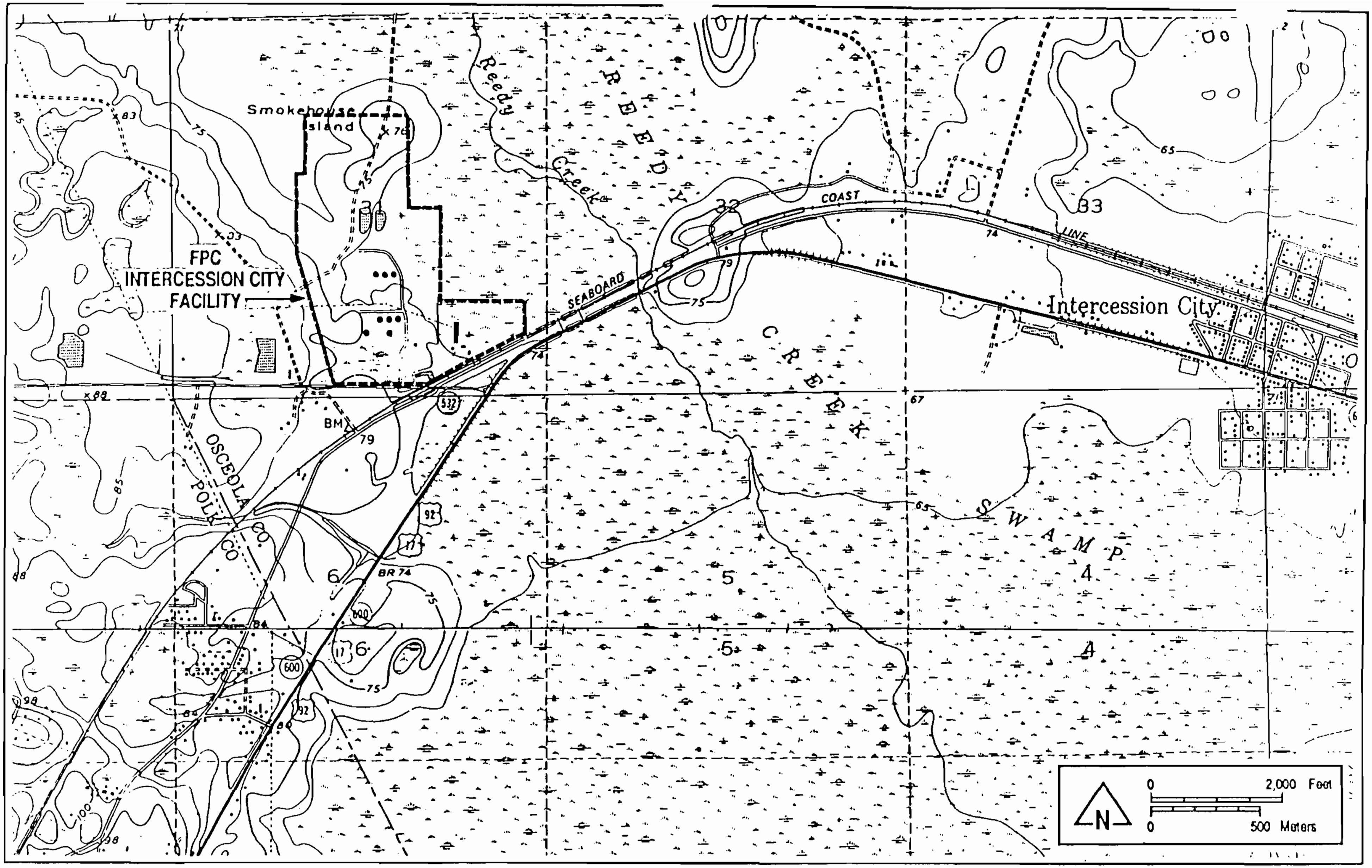
Federal Regulations:

Asbestos Removal:
40 CFR 61.05 - Prohibited Activities
40 CFR 61.12(b) - Compliance with work practice standard
40 CFR 61.14 - Monitoring Requirements (if required)
40 CFR 61.19 - Circumvention
40 CRF 61.145 - Demolition and Renovation
40 CFR 61.148 - Standard for Insulating Material

CFCs > 50 lb:
40 CFR 82.166(k) - Service Documentation
40 CFR 82.166(m) - Recordkeeping

ATTACHMENT IC-FE-1

AREA MAP

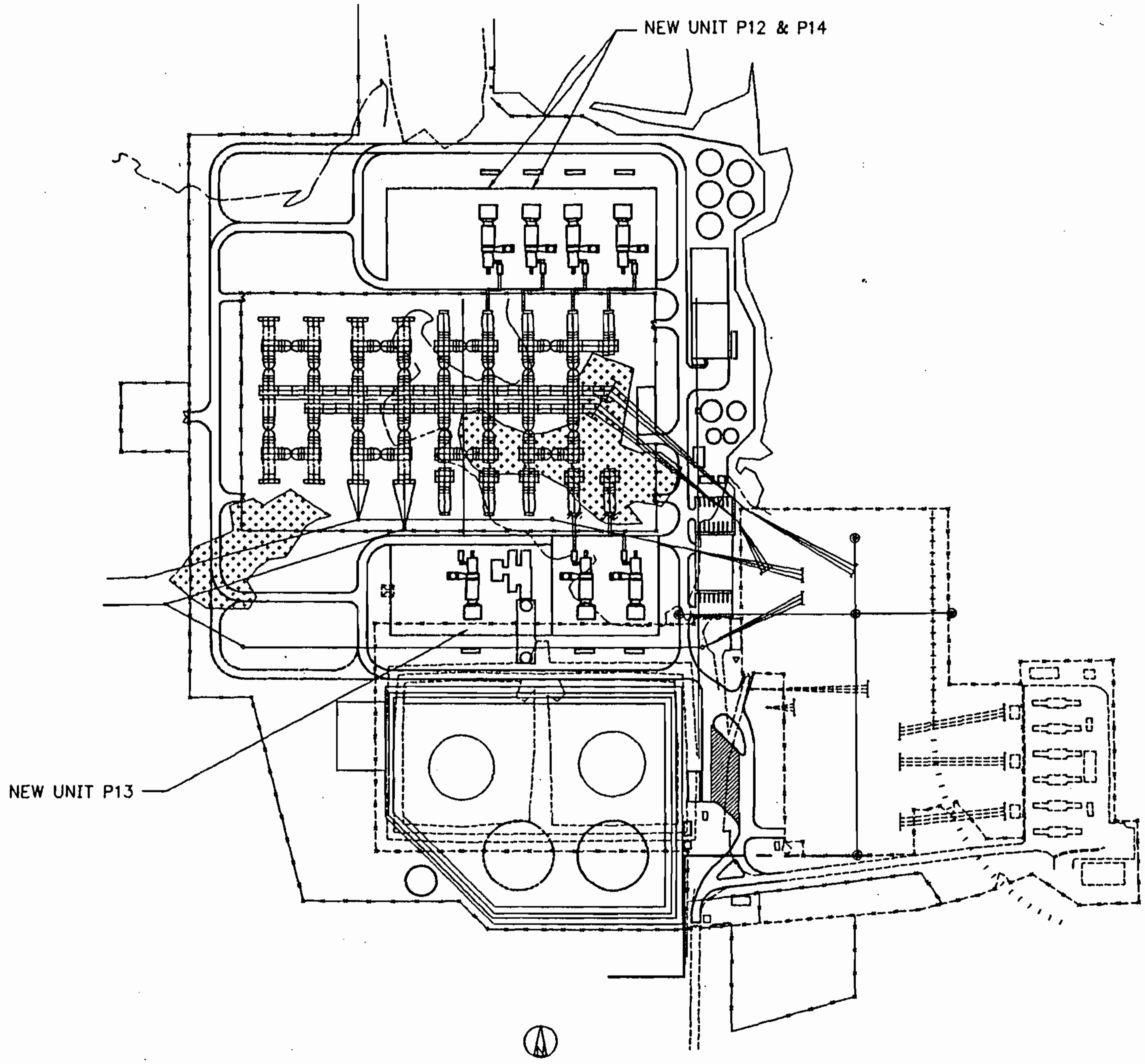


LOCATION OF THE FPC INTERCESSION CITY FACILITY

KBN

ATTACHMENT IC-FE-2

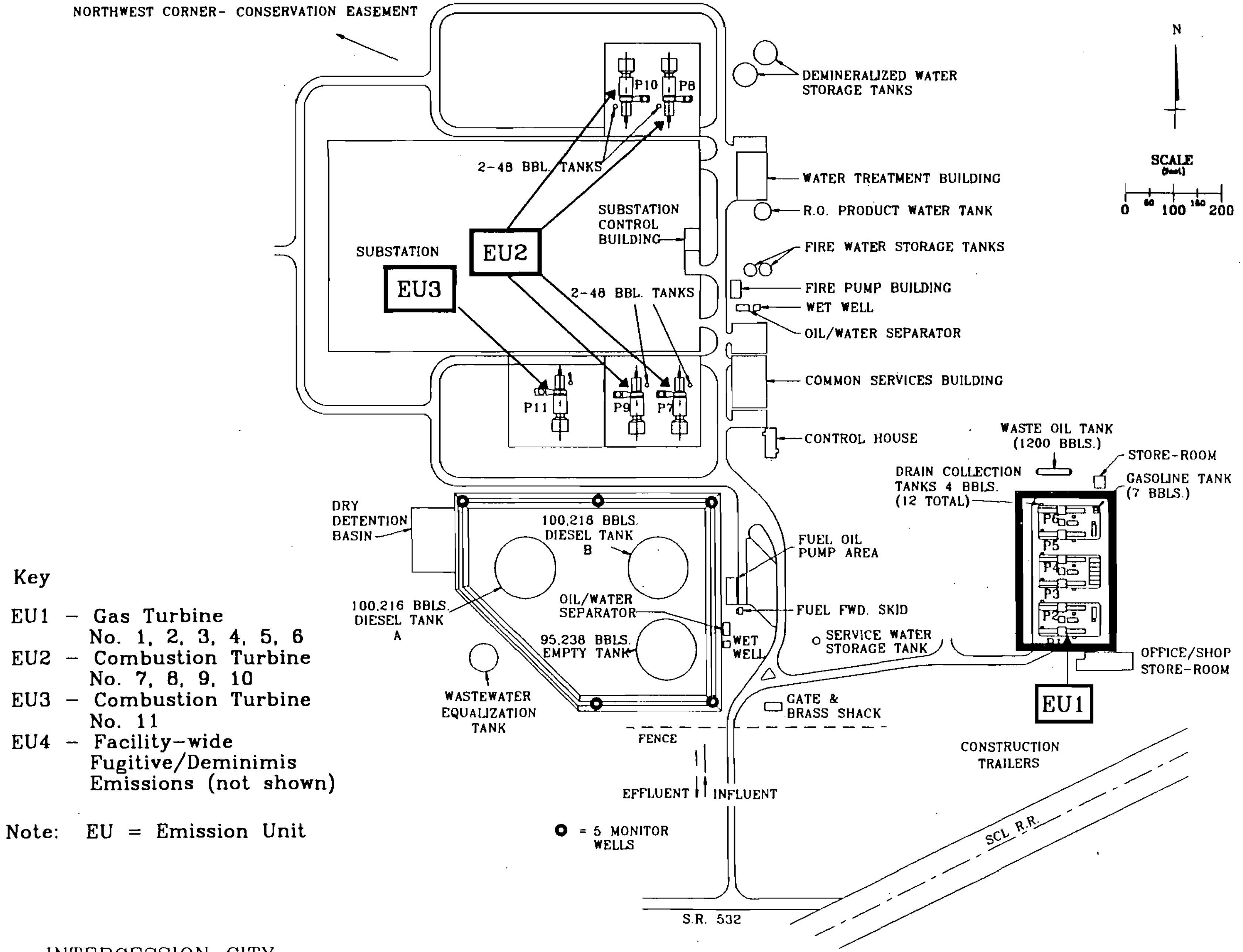
FACILITY PLOT PLAN



FLORIDA POWER CORPORATION
INTERCESSION CITY TURBINE ADDITIONS

GENERAL SITE LAYOUT

FILENAME ICP08239



Key

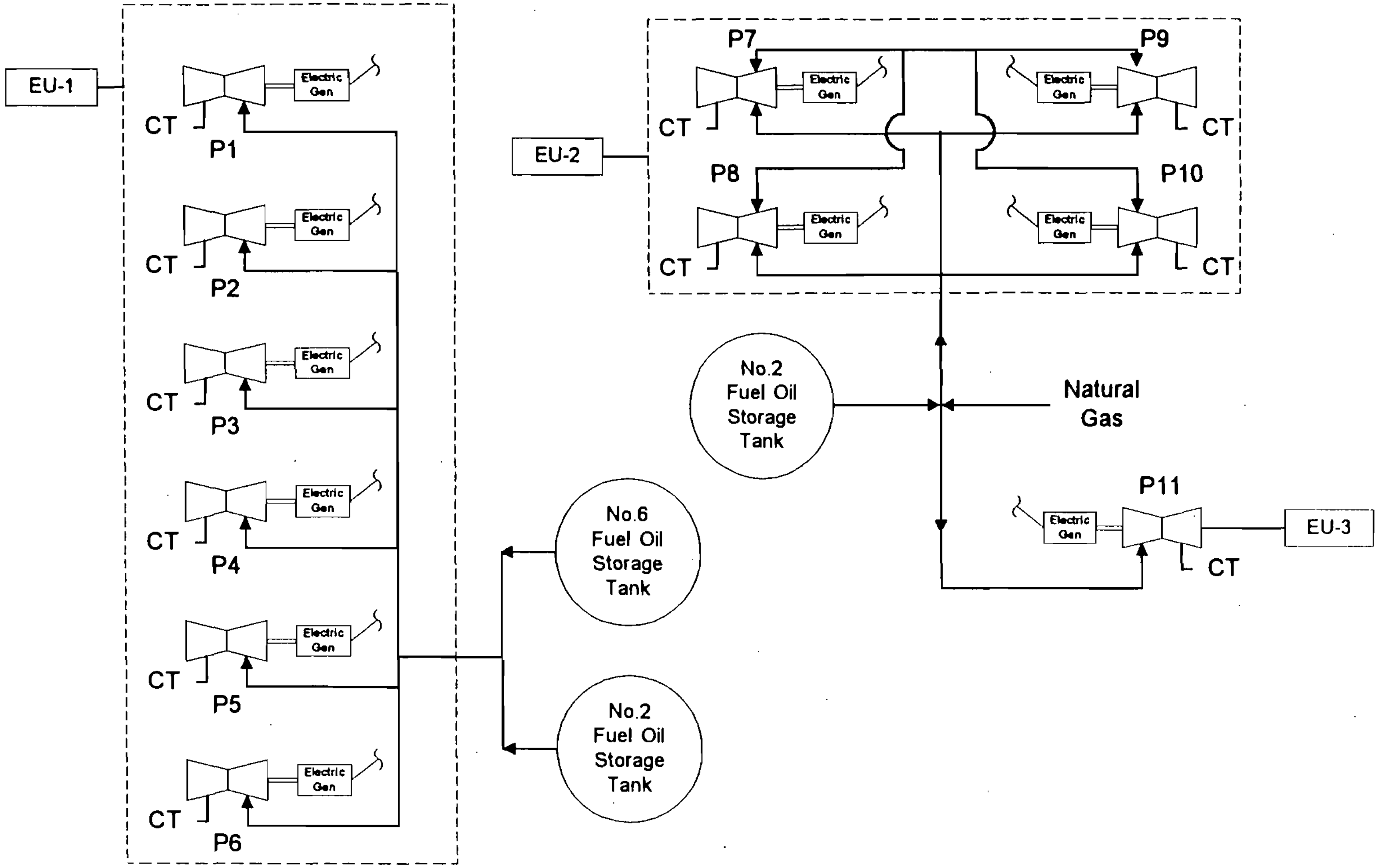
EU1 – Gas Turbine No. 1, 2, 3, 4, 5, 6
EU2 – Combustion Turbine No. 7, 8, 9, 10
EU3 – Combustion Turbine No. 11
EU4 – Facility-wide Fugitive/Deminimis Emissions (not shown)

Note: EU = Emission Unit

INTERCESSION CITY
ICPCOMP.DWG

ATTACHMENT IC-FE-3

PROCESS FLOW DIAGRAM



Note:
CT = Gas Turbine
EU = Emission Unit Number
See segment section for the operating rate of each emission unit
EU 4 - Facility-wide Fugitive/Deminimis Emissions not shown

Florida Power Corporation		*Emission Unit:* Significant Units *Process Area:* Overall Plant	KBN Engineering and Applied Sciences, Inc.
Emission Units	Intercession City	*Filename:* FPCIC1.VSD *Latest Revision Date:* 6/3/96 03:45 PM	

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 1

GE Frame 7EA CT Peaking Unit Number 12

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

2. Single Process, Group of Processes, or Fugitive Only? Check one :

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

Emissions Unit Information Section 1

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section :

GE Frame 7EA CT Peaking Unit Number 12

2. Emissions Unit Identification Number :
[ ] No Corresponding ID [X] Unknown

3. Emissions Unit Status Code : C	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code : 49

6. Emissions Unit Comment :

This emissions unit is a GE Frame 7EA dual fuel combustion turbine operating in simple cycle mode. See attached PSD Analysis.

Emissions Unit Information Section 1

GE Frame 7EA CT Peaking Unit Number 12

Emissions Unit Control Equipment 1

1. Description :
   Dry low-NOx combustors - natural gas

2. Control Device or Method Code : 25

Emissions Unit Information Section 1

GE Frame 7EA CT Peaking Unit Number 12

Emissions Unit Control Equipment 2

1. Description :
   Water injection - oil firing

2. Control Device or Method Code : 28

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Emissions Unit Details

1. Initial Startup Date :

2. Long-term Reserve Shutdown Date :

3. Package Unit :
Manufacturer : General Electric Model Number : PG 7121EA

4. Generator Nameplate Rating : 87 MW

5. Incinerator Information :
Dwell Temperature : Degrees Fahrenheit
Dwell Time : Seconds
Incinerator Afterburner Temperature : Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate : 954 mmBtu/hr

2. Maximum Incinerator Rate : lb/hr tons/day

3. Maximum Process or Throughput Rate :

4. Maximum Production Rate :

5. Operating Capacity Comment :
See Attachment IC-EU1-C5. Max. heat input at ISO conditions and distillate oil firing (LHV); max. for natural gas firing is 885 mmBtu/hr (ISO, LHV)

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule :
hours/day days/week
weeks/year 3,390 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 1

GE Frame 7EA CT Peaking Unit Number 12

Rule Applicability Analysis

Not Applicable

List of Applicable Regulations

See Attachment IC-EU1-D
See attached PSD Analysis

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 1

GE Frame 7EA CT Peaking Unit Number 12

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : Attached figure

2. Emission Point Type Code : 1

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking :
(limit to 100 characters per point)

`Emissions exhausted through a single stack.`

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common :

5. Discharge Type Code : V

6. Stack Height : 56 feet

7. Exit Diameter : 16.1 feet

8. Exit Temperature : 993 °F

9. Actual Volumetric Flow Rate : 1436310 acfm

10. Percent Water Vapor : 0.00 %

11. Maximum Dry Standard Flow Rate : 0 dscfm

12. Nonstack Emission Point Height : 0 feet

13. Emission Point UTM Coordinates :

Zone : 0 East (km) : 446.300 North (km) : 3126.000

14. Emission Point Comment :
Exit temperature and flow rate given for a single CT at an ambient temperature of 59 deg. F (oil firing). Stack height 56 feet.

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

GE Frame 7EA CT Peaking Unit Number 12

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Distillate fuel oil.	
2. Source Classification Code (SCC) : 20100101	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 8.04	5. Maximum Annual Rate : 7,227.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash : 0.10
9. Million Btu per SCC Unit : 132	
10. Segment Comment : Based on 7.1 lb/gal; LHV of 18,300 btu/lb; max. hourly rate at 20 deg. F for 1 CT. Annual rate based on hourly rate at 59 deg. F and equivalent of 1,000 hr/yr/CT at full load.	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

GE Frame 7EA CT Peaking Unit Number 12

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) :

   Natural gas

2. Source Classification Code (SCC) : 20100201

3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)

4. Maximum Hourly Rate : 1.03

5. Maximum Annual Rate : 3,159.00

6. Estimated Annual Activity Factor :

7. Maximum Percent Sulfur :

8. Maximum Percent Ash :

9. Million Btu per SCC Unit : 950

10. Segment Comment :

    Maximum % sulfur: 1 grain/100 cf. 1) Max. hourly rate at 20 deg. F for one CT. Annual rate based on hourly rate at 59 deg. F and equivalent of 3390 hr/yr/CT. Heat content is LHV.

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
6 - VOC			EL
7 - SAM			EL
1 - SO2			EL
2 - NOX	025	028	EL
3 - PM			EL
4 - PM10			EL
5 - CO			EL

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **SO2**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 55.0000000 lb/hour	27.9000000 tons/year
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor 0.05 Reference : Application	Units :% S
7. Emissions Method Code : 2	
8. Calculations of Emissions : See attached PSD Analysis, Appendix A. Equivalent TPY for single CT; 3 CTs have a limit of 83.7 TPY.	
9. Pollutant Potential/Estimated Emissions Comment : Max. hourly emissions based on inlet temp. of 20 deg. F; oil firing, 100% load. Ann. emissions based on 2,390 hr/yr nat. gas firing and 1,000 hr/yr oil firing at 59 deg. F. 1 gr S/100 cf; .05% S oil	

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 0.05 % S max.

4. Equivalent Allowable Emissions :

   55.00 lb/hour 27.90 tons/year

5. Method of Compliance :

   Fuel analysis

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   The TPY allowable is requested to be 83.7 TPY, representing an aggregate limit for the 3 CTs.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

GE Frame 7EA CT Peaking Unit Number 12

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **NOX**

2. Total Percent Efficiency of Control : 80.00 %

3. Potential Emissions :
186.0000000 lb/hour 121.7000000 tons/year

4. Synthetically Limited?
[ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor 42 Units : ppmvd@15% O2
Reference : Application

7. Emissions Method Code : 2

8. Calculations of Emissions :

See attached PSDAnalysis. Equivalent TPY for 1 CT; 3 CTs have aggregate limit of 365.1 TPY.

9. Pollutant Potential/Estimated Emissions Comment :

Max. hourly emissions based on inlet temp. of 20 deg. F, oil firing, 100% load. Annual emissions based on 2,390 hr/ yr gas firing and 1,000 hr/yr oil firing at 59 deg. F. NSPS FBN allowance requested

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER		
2. Future Effective Date of Allowable Emissions :			
3. Requested Allowable Emissions and Units :	1.00	grain S/100 CF	
4. Equivalent Allowable Emissions :	2.95	lb/hour	tons/year
5. Method of Compliance : Fuel analysis-vendor supplied			
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Pipeline natural gas; 1 grain S/100 cf; 20 deg. F inlet temp; 100% load			

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Pollutant Information Section 2

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 186.00 lb/hr @ 20 deg.

4. Equivalent Allowable Emissions :

   186.00 lb/hour 121.70 tons/year

5. Method of Compliance :

   CEM - 24 hr block avg. of lb/hr limit.

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   The TPY allowable is requested to be 365.1, representing an aggregate limit for the 3 CTs.

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Pollutant Information Section 2

Allowable Emissions 2

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 36.00 lb/hr @ 20 deg.

4. Equivalent Allowable Emissions :

   36.00 lb/hour tons/year

5. Method of Compliance :

   CEM - 24 hr block avg. of lb/hr limit.

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   No applicable annual emission limit (TPY) for 1 CT;3 CTs have a limit of 365.1 TPY, based on equivalent of 1,000 hr/yr/CT of oil firing and 2,390 hr/yr/CT of gas firing.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Pollutant Potential/Estimated Emissions : Pollutant 3

1. Pollutant Emitted : **PM**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 10.0000000 lb/hour	11.0000000 tons/year
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor 10 Reference : Application	Units : lb/hr
7. Emissions Method Code : 2	
8. Calculations of Emissions : See attched PSD Analysis, Appendix A. Equivalent TPY for 1 CT; 3 CTs have aggregate limit of 33 TPY.	
9. Pollutant Potential/Estimated Emissions Comment : Max. hourly emissions based on inlet temp. of 20 deg. F, oil firing, 100% load. Annual emissions based on 2,390 hr/yr gas firing and 1,000 hr/yr oil firing at 59 deg.	

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Pollutant Information Section 3

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 10.00 lb/hr @ 20 deg.

4. Equivalent Allowable Emissions :

   10.00 lb/hour 11.00 tons/year

5. Method of Compliance :

   Initial compliance test, EPA Mthd 5 or VE < 10% at full load

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   The TPY allowable is requested to be 33.0 TPY, representing an aggregate for the 3 CTs.

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Pollutant Information Section 3

Allowable Emissions 2

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 5.00 lb/hr

4. Equivalent Allowable Emissions :

   5.00 lb/hour tons/year

5. Method of Compliance :

   VE, EPA Method 9

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   If VE < 10%, stack test not required. No applicable annual emissions limit (TPY) for 1 CT; 3 CTs limited to 33.0 TPY, based on the equivalent of 1,000 hr/yr/CT of oil firing and 2,390 hr/yr/CT gas.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **PM10**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
10.0000000 lb/hour 11.0000000 tons/year

4. Synthetically Limited?
[ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor 10 Units : lb/hr
Reference : Application

7. Emissions Method Code : 2

8. Calculations of Emissions :

See attached PSD Analysis. Equivalent TPY for single CT; 3 CTs have an aggregate limit of 33.0 TPY.

9. Pollutant Potential/Estimated Emissions Comment :

Max. hourly emissions based on inlet temp. of 20 deg. F, oil firing, 100% load. Annual emissions based on 2,390 hr/yr gas firing and 1,000 hr/yr oil firing at 59 deg. F.

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 10.00 lb/hr @ 20 deg.

4. Equivalent Allowable Emissions :
10.00 lb/hour 11.00 tons/year

5. Method of Compliance :
Initial compliance test, EPA Mthd 5

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :
If VE < 10%, stack test not required. No applicable annual emission limit for 1 CT; 3 CTs limited to 33.0 TPY.

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Pollutant Information Section 4

Allowable Emissions 2

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 5.00 lb/hr

4. Equivalent Allowable Emissions :

   5.00 lb/hour tons/year

5. Method of Compliance :

   VE, EPA Method 9

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   If VE < 10%, stack test not required. No applicable annual emissions limit for 1 CT; 3 CTs limited to 33.0 TPY, based on the equivalent of 1,000 hr/yr/CT of oil firing and 2,390 hr/yr/CT of gas.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

GE Frame 7EA CT Peaking Unit Number 12

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **CO**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
59.0000000 lb/hour 86.5000000 tons/year

4. Synthetically Limited?
[ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor 25 Units : ppmvd
Reference : Application

7. Emissions Method Code : 2

8. Calculations of Emissions :

See attched PSD Analysis. Equivalent TPY for 1 CT; 3 CTs limited to 259.5 TPY.

9. Pollutant Potential/Estimated Emissions Comment :

Max. hourly emissions based on inlet temp. of 20 deg. F, gas firing, 100% load. Annual emissions based on 2,390 hr/yr/CT gas firing and 1,000 hr/yr/CT oil firing at 59 deg. F.

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Pollutant Information Section 5

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	59.00	lb.hr @ 20 deg		
4. Equivalent Allowable Emissions :	59.00	lb/hour	86.50	tons/year
5. Method of Compliance : Annual compliance test, EPA Method 10 at full load				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : No applicable annual emissions limit for 1 CT; 3 CTs have aggregate limit of 259.5 TPY.				

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Pollutant Information Section 5

Allowable Emissions 2

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 48.00 lb/hr

4. Equivalent Allowable Emissions :

   48.00 lb/hour tons/year

5. Method of Compliance :

   Annual compliance test, EPA Meth. 10, if > 400 hr oil firing

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   Oil-firing @ 20 deg. F, full load. No applicable annual limit for 1 CT; 3 CTs limited to 259.5 TPY, based on equivalent of 1,000 hr/yr/CT of oil firing and 2,390 hr/yr/CT of gas firing.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **VOC**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
10.0000000 lb/hour 15.3000000 tons/year

4. Synthetically Limited?
[ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor 7 Units : ppmvw
Reference : Application

7. Emissions Method Code : 2

8. Calculations of Emissions :

See attached PSD Analysis. Equivalent TPY for 1 CT; 3 CTs limited to an aggregate of 45.9 TPY.

9. Pollutant Potential/Estimated Emissions Comment :

Max. hourly emissions based on inlet temp. of 20 deg. F, gas or oil firing, 100% load. Annual emissions based on 2,390 hr/yr/CT gas firing & 1,000 hr/yr/CT oil firing at 59 deg. F.

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Pollutant Information Section 6

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 10.00 lb/hr @ 20 deg.

4. Equivalent Allowable Emissions :

10.00	lb/hour	15.30	tons/year

5. Method of Compliance :

Annual test, EPA Mthd 25A, full load; not req'd if CO met.

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

No applicable annual emission limit for 1 CT; 3 CTs limited to aggregate of 45.9 TPY. VOC test not req'd if CO limit met.

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Pollutant Information Section 6

Allowable Emissions 2

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 10.00 lb/hr @ 20deg.

4. Equivalent Allowable Emissions :

   10.00 lb/hour tons/year

5. Method of Compliance :

   Annual test, EPA Mthd 25A, full load; not req'd if CO met.

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   Oil or gas firing; 20 deg. F, full load. No applicable annual emission limit for 1 CT; 3 CTs limited to 45.9 TPY. VOC test not req'd if CO limit met.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Pollutant Potential/Estimated Emissions : Pollutant 7

1. Pollutant Emitted : **SAM**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 5.5000000 lb/hour	2.9000000 tons/year
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor 0.05 Reference : Application	Units :% S
7. Emissions Method Code : 2	
8. Calculations of Emissions : See attached PSD Analysis, Appendix A. Equivalent TPY for single CT; 3 CTs have limit of 8.6 TPY.	
9. Pollutant Potential/Estimated Emissions Comment : Max. hourly emissions based on inlet temp. of 20 deg. F, oil firing, 100% load. Annual emissions based on 2,390 hr/yr/CT gas firing & 1,000 hr/yr/CT oil firing @ 59 deg. F.	

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Pollutant Information Section 7

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.05	% S @ 20 deg.		
4. Equivalent Allowable Emissions :	5.50	lb/hour	2.90	tons/year
5. Method of Compliance : Fuel sampling and analysis				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : No annual emiss. limit for 1 CT; 3 CTs have limit of 8.6 TPY. Fuel sampling and analysis for compliance.				

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Pollutant Information Section 7

Allowable Emissions 2

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 1.00 grain S/100 cf

4. Equivalent Allowable Emissions :
lb/hour tons/year

5. Method of Compliance :

   Fuel sampling and analysis- vendor supplied

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   Natural gas-firing @ 20 deg. F. No applicable annual emission limit for 1 CT; 3 CTs limited to 8.6 TPY.

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype : 20

2. Basis for Allowable Opacity : RULE

3. Requested Allowable Opacity :

Normal Conditions :	20	%
Exceptional Conditions :	0	%
Maximum Period of Excess Opacity Allowed :		min/hour

4. Method of Compliance :

Annual compliance test, EPA Method 9 if > 400 hr oil firing

5. Visible Emissions Comment :

VE limit while firing oil under normal conditions at full load.

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Visible Emissions Limitation : Visible Emissions Limitation 2

1. Visible Emissions Subtype : 99

2. Basis for Allowable Opacity : RULE

3. Requested Allowable Opacity :

Normal Conditions :		%
Exceptional Conditions :	100	%
Maximum Period of Excess Opacity Allowed :	60	min/hour

4. Method of Compliance :

EPA Method 9

5. Visible Emissions Comment :

1. Rule 62-210.700. 2. Max. period of excess opacity allowed - 2 hours/24 hours for startup, shutdown, malfunction.

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
GE Frame 7EA CT Peaking Unit Number 12

Continuous Monitoring System Continuous Monitor 1

1. Parameter Code : EM	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Not yet determined Model Number : Serial Number :	
5. Installation Date :	
6. Performance Specification Test Date :	
7. Continuous Monitor Comment : NOx CEM proposed to meet requirements. Format to be 24 hr block average based on lb/hr limit.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 1

GE Frame 7EA CT Peaking Unit Number 12

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[X] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :

PM : C   SO2 : C   NO2 : C

4. Baseline Emissions :

PM :	lb/hour	tons/year
SO2 :	lb/hour	tons/year
NO2 :		tons/year

5. PSD Comment :

See attached PSD Sections 1-8.

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 1

GE Frame 7EA CT Peaking Unit Number 12

Supplemental Requirements for All Applications

1. Process Flow Diagram :	IC-EU1-L1
2. Fuel Analysis or Specification :	IC-EU1-L2
3. Detailed Description of Control Equipment :	IC-EU1-L3
4. Description of Stack Sampling Facilities :	IC-EU1-L4
5. Compliance Test Report :	NA
6. Procedures for Startup and Shutdown :	IC-EU1-L6
7. Operation and Maintenance Plan :	NA
8. Supplemental Information for Construction Permit Application :	PSD Sec. 1-8
9. Other Information Required by Rule or Statue :	PSD Sec. 1-8

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :

Refer to Attachment IC-EU1-L10

11. Alterntive Modes of Operation (Emissions Trading) :

12. Identification of Additional Applicable Requirements :
13. Compliance Assurance Monitoring Plan :
14. Acid Rain Application (Hard-copy Required) : Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) New Unit Exemption (Form No. 62-210.900(1)(a)2.) Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

ATTACHMENT IC-EU1-C5

OPERATING CAPACITY COMMENT

ATTACHMENT IC-EU1-C5

OPERATING CAPACITY COMMENT

The maximum heat input rate is based on the permit limit at 59°F for one combustion turbine (CT). The three turbines are permitted to operate up to the equivalent of 3,390 hours per year per CT at peak or other lesser loads (a 39 percent capacity factor), which is an aggregate of 10,170 hours per year for the three CTs. A single turbine can operate at more than 3,390 hours/year. Fuel oil usage will be limited to the equivalent of 1,000 hours per year per CT at full load. Fuel usage is not limited for a single turbine; usage requested up to 21,681,000 gallons per year (59°F) for all three CTs, based on 1,000 hours per year per CT at full load.

At high ambient temperature, the units cannot generate as much power because of lower compressor inlet density. To compensate for a portion of the loss of output (which can be on the order of 5-8 MW compared to referenced temperatures), inlet cooling is proposed to be installed ahead of the combustion turbine inlet. Therefore, the 59°F temperature case represents a conservative average temperature condition for estimating annual emissions for the proposed Intercession City CTs, inclusive of potential inlet cooling.

ATTACHMENT IC-EU1-D

EMISSIONS UNIT REGULATIONS

ATTACHMENT IC-EU1-D

EMISSIONS UNIT REGULATIONS

Applicable Requirements Listing – Power Plants

EMISSION UNIT: FPC Intercession City Plant – Combustion Turbines Nos. 12-14

FDEP Rules:

Air Pollution Control-General Provisions:
62-204.800(7)(b)37.(State Only) - NSPS Subpart GG
62-204.800(7)(d) (State Only) - NSPS General Provisions
62-204.800(12) (State Only) - Acid Rain Program
62-204.800(13) (State Only) - Allowances
62-204.800(14) (State Only) - Acid Rain Program Monitoring

Stationary Sources-General:
62-210.700(1) - Startup/shutdown/malfunction
62-210.700(4) - Maintenance
62-210.700(6)

Acid Rain:
62-214.300 - Acid Rain Units (Applicability)
62-214.320 - Acid Rain Units (Application Shield)
62-214.330 - Compliance Options (if 62-214.430)
62-214.350(2),(3),(6) - Acid Rain Units (Certification)
62-214.370 - Revisions; corrections; (potentially applicable)
62-214.430 - Acid Rain Units (Compliance Options)

Stationary Sources-Emission Monitoring (where stack test is required):
62-297.310(1) - Test Runs-Mass Emission
62-297.310(2)(b) - Operating Rate; other than CTs
62-297.310(3) - Calculation of Emission
62-297.310(4)(a) - Applicable Test Procedures; Sampling time
62-297.310(4)(b) - Sample Volume
62-297.310(4)(c) - Required Flow Rate Range-PM/H2SO4/F
62-297.310(4)(d) - Calibration
62-297.310(4)(e) - EPA Method 5-only
62-297.310(5) - Determination of Process Variables
62-297.310(6)(a) - Permanent Test Facilities-general
62-297.310(6)(c) - Sampling Ports
62-297.310(6)(d) - Work Platforms
62-297.310(6)(e) - Access
62-297.310(6)(f) - Electrical Power
62-297.310(6)(g) - Equipment Support
62-297.310(7)(a)2. - FFSG excess emissions
62-297.310(7)(a)3. - Permit Renewal Test Required

62-297.310(7)(a)4.	
62-297.310(7)(a)5.	- PM exemption if <400 hrs/yr
62-297.310(7)(a)6.	- PM exemption if < 200 hrs/6 month
62-297.310(7)(a)9.	- FDEP Notification - 15 days
62-297.310(7)(c)	- Waiver of Compliance Tests (fuel sampling)
62-297.310(8)	- Test Reports

Federal Rules:

NSPS General Requirements:

40 CFR 60.7(b)	- Notification/Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(f)	- Notification/Recordkeeping (maintain records-2 years)
40 CFR 60.8(c)	- Performance Tests (representative conditions)
40 CFR 60.8(e)	- Performance Tests (Provide stack sampling facilities)
40 CFR 60.8(f)	- Test Runs
40 CFR 60.11(a)	- Compliance (ref. S. 60.8)
40 CFR 60.11(d)	- Compliance (maintain air pollution control equipment)
40 CFR 60.12	- Circumvention

NSPS Subpart GG:

40 CFR 60.332(a)(1)	- NOx for Electric Utility Cts
40 CFR 60.333	- SO2 limits (0.8% sulfur)
40 CFR 60.334	- Monitoring of Operations (WTF ratio)
40 CFR 60.335	- Test Methods

Acid Rain-Permits:

40 CFR 72.9(a)	- Permit Requirements
40 CFR 72.9(b)	- Monitoring Requirements
40 CFR 72.9(c)(1)	- SO2 Allowances-hold allowances
40 CFR 72.9(c)(2)	- SO2 Allowances-violation
40 CFR 72.9(c)(1)(iv)	- SO2 Allowances- other utility units
40 CFR 72.9(c)(4)	- SO2 Allowances-allowances held in ATS
40 CFR 72.9(c)(5)	- SO2 Allowances-no deduction for 72.9(c)(1)(i)
40 CFR 72.9(e)	- Excess Emission Requirements
40 CFR 72.9(f)	- Recordkeeping and Reporting
40 CFR 72.9(g)	- Liability
40 CFR 72.20(a)	- Designated Representative; required
40 CFR 72.20(b)	- Designated Representative; legally binding
40 CFR 72.20(c)	- Designated Representative; certification requirements
40 CFR 72.21	- Submissions
40 CFR 72.22	- Alternate Designated Representative
40 CFR 72.23	- Changing representatives; owners
40 CFR 72.30(a)	- Requirements to Apply (operate)
40 CFR 72.30(c)	- Requirements to Apply (reapply before expiration)
40 CFR 72.30(d)	- Requirements to Apply (submittal requirements)
40 CFR 72.32	- Permit Application Shield
40 CFR 72.33(b)	- Dispatch System ID;unit/system ID
40 CFR 72.33(c)	- Dispatch System ID;ID requirements
40 CFR 72.33(d)	- Dispatch System ID;ID change
40 CFR 72.40(a)	- General; compliance plan
40 CFR 72.40(b)	- General; multi-unit compliance options
40 CFR 72.40(c)	- General; conditional approval

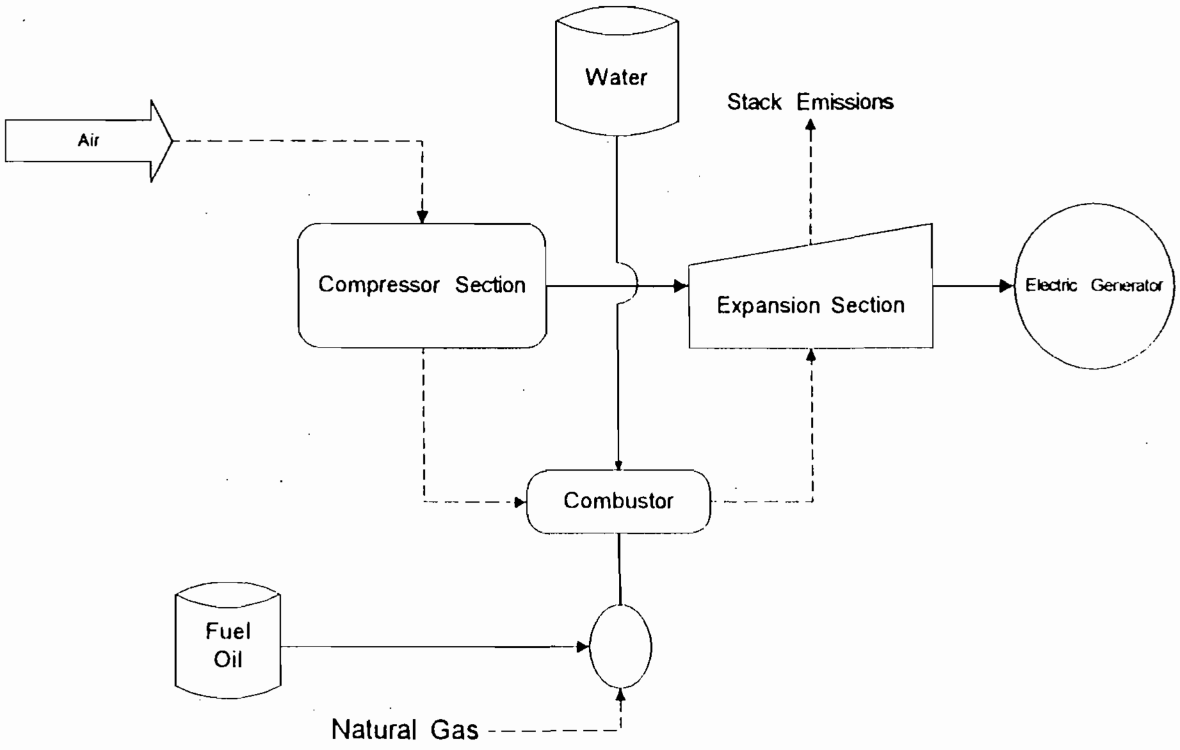
40 CFR 72.40(d) - General; termination of compliance options
40 CFR 72.51 - Permit Shield
40 CFR 72.90 - Annual Compliance Certification

Monitoring Part 75:
40 CFR 75.5 - Prohibitions
40 CFR 75.10(a)(2) - Primary Measurement; NOx; except 75.12&.17; Subpart E
40 CFR 75.10(b) - Primary Measurement; Performance Requirements
40 CFR 75.10(c) - Primary Measurement; Heat Input; Appendix F
40 CFR 75.10(f) - Primary Measurement; Minimum Measurement
40 CFR 75.10(g) - Primary Measurement; Minimum Recording
40 CFR 75.11(d) - SO2 Monitoring; Gas- and Oil-fired units
40 CFR 75.11(e) - SO2 Monitoring; Gaseous fuel firing
40 CFR 75.12(b) - NOx Monitoring; Determination of NOx emission rate; Appendix F
40 CFR 75.20(a)(5) - Initial Certification Approval Process; Loss of Certification
40 CFR 75.20(b) - Recertification Procedures
40 CFR 75.20(c) - Certification Procedures
40 CFR 75.20(g) - Exceptions to CEMS; oil/gas/diesel; Appendix D & E
40 CFR 75.21(a) - QA/QC; CEMS;
40 CFR 75.21(b) - QA/QC; Opacity;
40 CFR 75.21(c) - QA/QC; Calibration Gases
40 CFR 75.21(d) - QA/QC; Notification of RATA
40 CFR 75.21(e) - QA/QC; Audits
40 CFR 75.21(f) - QA/QC; CEMS
40 CFR 75.22 - Reference Methods
40 CFR 75.24 - Out-of-Control Periods; CEMS
40 CFR 75.30(a)(3) - General Missing Data Procedures; NOx
40 CFR 75.32 - Monitoring Data Availability for Missing Data
40 CFR 75.33 - Standard Missing Data Procedures
40 CFR 75.36 - Missing Data Procedures for Heat Input
40 CFR 75.53 - Monitoring Plan (revisions)
40 CFR 75.54(a) - Recordkeeping-general
40 CFR 75.54(b) - Recordkeeping-operating parameter
40 CFR 75.54(d) - Recordkeeping-NOx
40 CFR 75.55(c);(e) - Recordkeeping; Special Situations (gas & oil firing)
40 CFR 75.56 - Certification; QA/QC Provisions
40 CFR 75.60 - Reporting Requirements-General
40 CFR 75.61 - Reporting Requirements-Notification cert/recertification
40 CFR 75.63 - Reporting Requirements-Certification/Recertification
40 CFR 75.64(a) - Reporting Requirements-Quarterly reports; submission
40 CFR 75.64(b) - Reporting Requirements-Quarterly reports; DR statement
40 CFR 75.64(c) - Rep. Req.; Quarterly reports; Compliance Certification
40 CFR 75.64(d) - Rep. Req.; Quarterly reports; Electronic format
Appendix A-3. - Performance Specifications
Appendix A-4. - Data Handling and Acquisition Systems
Appendix A-5. - Calibration Gases
Appendix A-6. - Certification Tests and Procedures
Appendix B - QA/QC Procedures
Appendix C-1. - Missing Data; SO2/NOx for controlled sources
Appendix C-2. - Missing Data; Load-Based Procedure; NOx & flow
Appendix F - Conversion Procedures

Appendix G-2.	- Determination of CO2; from combustion sources
Appendix H	- Traceability Protocol
40 CFR Part 77.3	- Offset Plans (future)
40 CFR Part 77.5(b)	- Deductions of Allowances (future)
40 CFR Part 77.6	- Excess Emissions Penalties SO2 and NOx

ATTACHMENT IC-EU1-L1

PROCESS FLOW DIAGRAM



Florida Power Corporation

Emission Units | Intercession City

Emission Unit: Combustion Turbines No. 7, 8, 9, 10, 11

Process Area: Overall Plant

Filename: FPCICB.VSD

Latest Revision Date: 6/8/96 03:15 PM

KBN Engineering and Applied Sciences, Inc.

ATTACHMENT IC-EU1-L2

FUEL ANALYSIS OR SPECIFICATION

ATTACHMENT IC-EU1-L2

FUEL ANALYSIS

No. 2 Fuel Oil

Parameter	Typical Value	Max Value
API gravity @ 60 F	30	-
Relative density	7.02 lb/gal [2]	
Heat content	18,400 Btu / lb (LHV)	
% sulfur	0.05	0.05
% nitrogen	0.025 - 0.03	
% ash	negligible	0.01

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) FPC's fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

ATTACHMENT IC-EU1-L2

FUEL ANALYSIS
NATURAL GAS ANALYSIS

Parameter	Typical Value	Max Value
Relative density	0.58 (compared to air)	
heat content	950 - 1124 Btu/cu ft.	
% sulfur	0.43 grains/CCF [1]	1 grain/100 CF
% nitrogen	0.8% by volume	
% ash	negligible	

Note: The values listed are "typical" values based upon information supplied to FPC by Florida Gas Transmission (FGT). However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

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[1] Data from laboratory analysis

ATTACHMENT IC-EU1-L3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

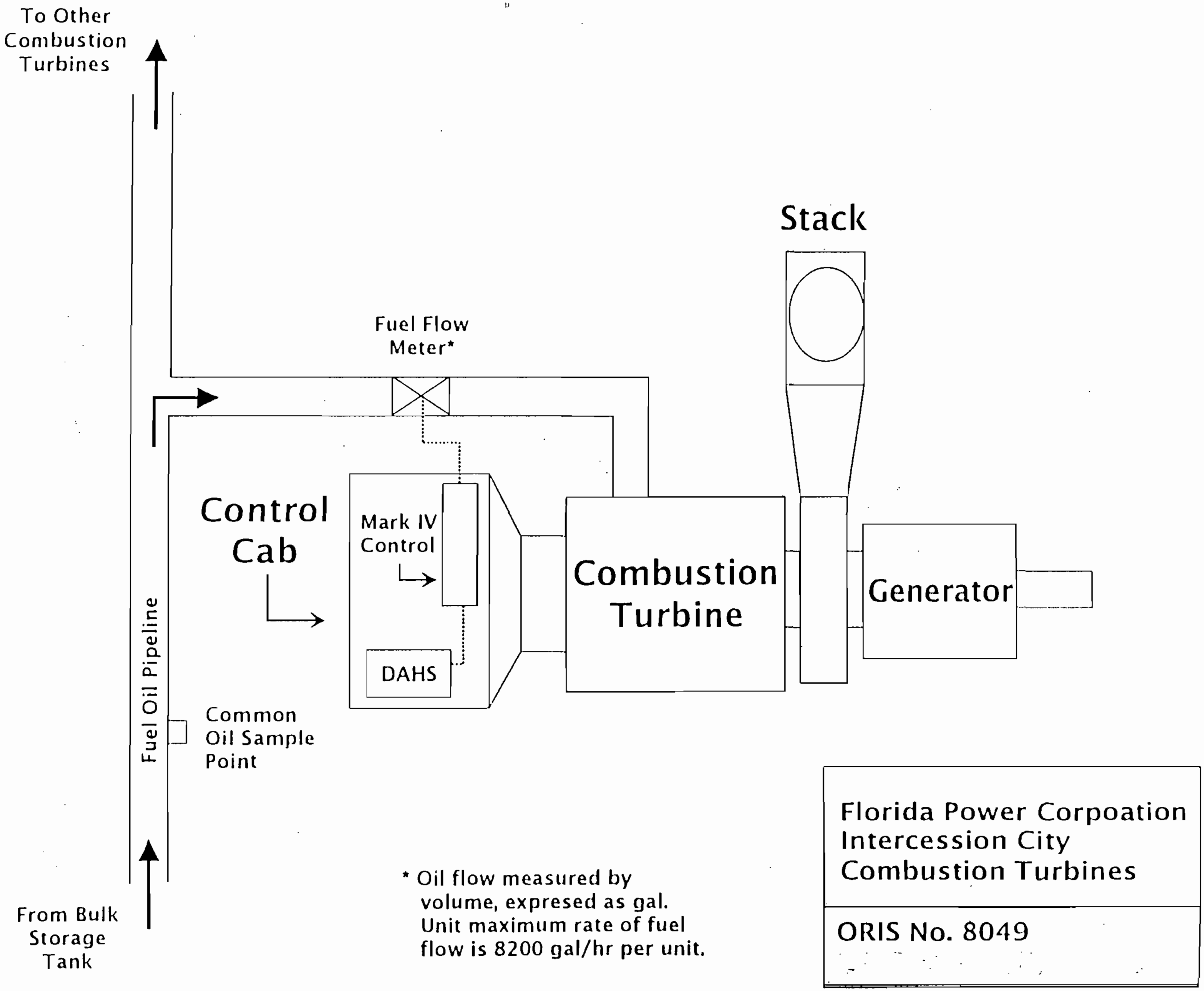
GE Mark V NOx Control Algorithm Description

The GE Mark V NOx control algorithm utilizes data from digital temperature and humidity monitors located at each combustion turbine. The algorithm receives and processes the ambient temperature and humidity on a continuous basis. A temperature/humidity correction is used in determining the amount of water to inject for NOx control. This correction accounts for the ambient water entering the combustion chamber, and then it adds the correct amount of injection water in order to ensure compliance with the unit's NO_x emission limit. This algorithm ensures compliance on a continuous basis regardless of the unit load and ambient weather conditions.

Additionally, each CT will be equipped with a NO_x CEM that will continuously monitor and record NO_x levels. A closed-loop design will be incorporated allowing the NO_x CEM output to be fed as input to the Mark V water injection logic. FPC requests the option to utilize the NO_x CEMS and closed-loop design as the method of compliance, rather than relying on specific water-to-fuel ratios.

ATTACHMENT IC-EU1-L4

DESCRIPTION OF STACK SAMPLING FACILITIES



* Oil flow measured by volume, expresed as gal. Unit maximum rate of fuel flow is 8200 gal/hr per unit.

Florida Power Corpoation
Intercession City
Combustion Turbines

ORIS No. 8049

ATTACHMENT IC-EU1-L6

PROCEDURES FOR STARTUP AND SHUTDOWN

ATTACHMENT IC-EU1-L6

PROCEDURES FOR STARTUP/SHUTDOWN

Startup and shutdown for these units are fully automatic.

Startup for the combustion turbine begins with "lighting off" of the machines on distillate oil.

Corrective actions may include switching the unit from automatic (remote) to local control, or changing fuel. Best Operating Practices are adhered to and all efforts to minimize both the level and duration of excess emissions are undertaken.

Shutdown is performed by reducing the unit load (electrical production) to a minimum level, opening the breaker (which disconnects the unit from the system electrical grid), shutting off the fuel and coasting down to stop. The CT is then put "on turning gear" to prevent possible disfiguration of the turbine components.

ATTACHMENT IC-EU1-L10

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT IC-EU1-L10
ALTERNATIVE METHODS OF OPERATION

The three combustion turbines (CT Nos. 12, 13, and 14) have a nominal rating of 87.2 megawatts (MW) at 59°F (GE PG7121EA). An average maximum capacity factor of 39 percent (3,390 hours per year per CT operating time) is requested. The total hours of operation for the turbines are not to exceed 10,170 unit hours per year (3 units times 3,390 hours per year per unit).

The maximum No. 2 fuel oil consumption shall not exceed 8,038 gallons per year per unit (20°F) or 21,681,000 gal per year based on 59°F and three CTs at the equivalent of 1,000 hours per year per CT at full load.

Therefore, any combination of the three combustion turbines may operate for up to 8,760 hours per year provided that both the hourly and annual emission limitations, aggregate annual capacity factors, and aggregate fuel oil consumption limits are met.

At high ambient temperature, the units cannot generate as much power because of lower compressor inlet density. To compensate for a portion of the loss of output (which can be on the order of 5-8 MW compared to referenced temperatures), inlet cooling is proposed to be installed ahead of the combustion turbine inlet. Therefore, the 59°F temperature case represents a conservative average temperature condition for estimating annual emissions for the proposed Intercession City CTs, inclusive of potential inlet cooling.

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 2

GE Frame 7EA CT Peaking Unit Number 13

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

2. Single Process, Group of Processes, or Fugitive Only? Check one :

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

Emissions Unit Information Section 2

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section :

GE Frame 7EA CT Peaking Unit Number 13

2. Emissions Unit Identification Number :
[ ] No Corresponding ID [X] Unknown

3. Emissions Unit Status Code : C	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code : 49

6. Emissions Unit Comment :

This emissions unit is a GE Frame 7EA dual fuel combustion turbine operating in simple cycle mode. See attached PSD Analysis.

Emissions Unit Information Section 2

GE Frame 7EA CT Peaking Unit Number 13

Emissions Unit Control Equipment 1

1. Description : Dry low-NOx combustors - natural gas
2. Control Device or Method Code : 25

Emissions Unit Information Section 2

GE Frame 7EA CT Peaking Unit Number 13

Emissions Unit Control Equipment 2

1. Description :
   Water injection - oil firing

2. Control Device or Method Code : 28

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Emissions Unit Details

1. Initial Startup Date :
2. Long-term Reserve Shutdown Date :
3. Package Unit : Manufacturer : General Electric Model Number : PG 7121EA
4. Generator Nameplate Rating : 87 MW
5. Incinerator Information : Dwell Temperature : Degrees Fahrenheit Dwell Time : Seconds Incinerator Afterburner Temperature : Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate : 954 mmBtu/hr
2. Maximum Incinerator Rate : lb/hr tons/day
3. Maximum Process or Throughput Rate :
4. Maximum Production Rate :
5. Operating Capacity Comment : See Attachment IC-EU1-C5. Max. heat input at ISO conditions and distillate oil firing (LHV); max. for natural gas firing is 885 mmBtu/hr (ISO, LHV)

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule : hours/day days/week weeks/year 3,390 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 2

GE Frame 7EA CT Peaking Unit Number 13

Rule Applicability Analysis

Not Applicable

List of Applicable Regulations

See Attachment IC-EU1-D
See attached PSD Analysis

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 2

GE Frame 7EA CT Peaking Unit Number 13

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : Attached figure

2. Emission Point Type Code : 1

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking :
(limit to 100 characters per point)

`Emissions exhausted through a single stack.`

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common :

5. Discharge Type Code : V

6. Stack Height : 56 feet

7. Exit Diameter : 16.1 feet

8. Exit Temperature : 993 °F

9. Actual Volumetric Flow Rate : 1436310 acfm

10. Percent Water Vapor : 0.00 %

11. Maximum Dry Standard Flow Rate : 0 dscfm

12. Nonstack Emission Point Height : 0 feet

13. Emission Point UTM Coordinates :

Zone : 0 East (km) : 446.300 North (km) : 3126.000

14. Emission Point Comment :
Exit temperature and flow rate given for a single CT at an ambient temperature of 59 deg. F (oil firing). Stack height 56 feet.

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 2

GE Frame 7EA CT Peaking Unit Number 13

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) :

   Distillate fuel oil.

2. Source Classification Code (SCC) : 20100101

3. SCC Units : Thousand Gallons Burned (all liquid fuels)

4. Maximum Hourly Rate : 8.04	5. Maximum Annual Rate : 7,227.00

6. Estimated Annual Activity Factor :

7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash : 0.10

9. Million Btu per SCC Unit : 132

10. Segment Comment :

    Based on 7.1 lb/gal; LHV of 18,300 btu/lb; max. hourly rate at 20 deg. F for 1 CT. Annual rate based on hourly rate at 59 deg. F and equivalent of 1,000 hr/yr/CT at full load.

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 2

GE Frame 7EA CT Peaking Unit Number 13

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Natural gas	
2. Source Classification Code (SCC) : 20100201	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 1.03	5. Maximum Annual Rate : 3,159.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 950	
10. Segment Comment : Maximum % sulfur: 1 grain/100 cf. 1) Max. hourly rate at 20 deg. F for one CT. Annual rate based on hourly rate at 59 deg. F and equivalent of 3390 hr/yr/CT. Heat content is LHV.	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - SO2			EL
2 - NOX	025	028	EL
3 - PM			EL
4 - PM10			EL
5 - CO			EL
6 - VOC			EL
7 - SAM			EL

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **SO2**
2. Total Percent Efficiency of Control : %
3. Potential Emissions : 55.0000000 lb/hour 27.9000000 tons/year
4. Synthetically Limited? [ ] Yes [X] No
5. Range of Estimated Fugitive/Other Emissions: to tons/year
6. Emissions Factor 0.05 Units :% S Reference : Application
7. Emissions Method Code : 2
8. Calculations of Emissions : See attached PSD Analysis, Appendix A. Equivalent TPY for single CT; 3 CTs have a limit of 83.7 TPY.
9. Pollutant Potential/Estimated Emissions Comment : Max. hourly emissions based on inlet temp. of 20 deg. F, oil firing, 100% load. Ann. emissions based on 2,390 hr/yr nat. gas firing and 1,000 hr/yr oil firing at 59 deg. F. 1 gr S/100 cf; .05% S oil

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **NOX**

2. Total Percent Efficiency of Control : 80.00 %

3. Potential Emissions :
186.0000000 lb/hour 121.7000000 tons/year

4. Synthetically Limited?
[ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor 42 Units : ppmvd@15% O2
Reference : Application

7. Emissions Method Code : 2

8. Calculations of Emissions :

See attached PSDAnalysis. Equivalent TPY for 1 CT; 3 CTs have aggregate limit of 365.1 TPY.

9. Pollutant Potential/Estimated Emissions Comment :

Max. hourly emissions based on inlet temp. of 20 deg. F, oil firing, 100% load. Annual emissions based on 2,390 hr/ yr gas firing and 1,000 hr/yr oil firing at 59 deg. F. NSPS FBN allowance requested

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Pollutant Information Section 2

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 186.00 lb/hr @ 20 deg.

4. Equivalent Allowable Emissions :

186.00	lb/hour	121.70	tons/year

5. Method of Compliance :

CEM - 24 hr block avg. of lb/hr limit.

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

The TPY allowable is requested to be 365.1, representing an aggregate limit for the 3 CTs.

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Pollutant Information Section 2

Allowable Emissions 2

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 36.00 lb/hr @ 20 deg.

4. Equivalent Allowable Emissions :

   36.00 lb/hour tons/year

5. Method of Compliance :

   CEM - 24 hr block avg. of lb/hr limit.

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   No applicable annual emission limit (TPY) for 1 CT;3 CTs have a limit of 365.1 TPY, based on equivalent of 1,000 hr/yr/CT of oil firing and 2,390 hr/yr/CT of gas firing.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Pollutant Potential/Estimated Emissions : Pollutant 3

1. Pollutant Emitted : **PM**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
10.0000000 lb/hour 11.0000000 tons/year

4. Synthetically Limited?
[ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor 10 Units : lb/hr
Reference : Application

7. Emissions Method Code : 2

8. Calculations of Emissions :

See attched PSD Analysis, Appendix A. Equivalent TPY for 1 CT; 3 CTs have aggregate limit of 33 TPY.

9. Pollutant Potential/Estimated Emissions Comment :

Max. hourly emissions based on inlet temp. of 20 deg. F, oil firing, 100% load. Annual emissions based on 2,390 hr/yr gas firing and 1,000 hr/yr oil firing at 59 deg.

Emissions Unit Information Section 2

GE Frame 7EA CT Peaking Unit Number 13

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 0.05 % S max.

4. Equivalent Allowable Emissions :

   55.00 lb/hour 27.90 tons/year

5. Method of Compliance :

   Fuel analysis

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   The TPY allowable is requested to be 83.7 TPY, representing an aggregate limit for the 3 CTs.

Emissions Unit Information Section 2

GE Frame 7EA CT Peaking Unit Number 13

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER		
2. Future Effective Date of Allowable Emissions :			
3. Requested Allowable Emissions and Units :	1.00	grain S/100 CF	
4. Equivalent Allowable Emissions :	2.95 lb/hour		tons/year
5. Method of Compliance : Fuel analysis - vendor supplied			
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Pipeline natural gas; 1 grain S/100 cf; 20 deg. F inlet temp; 100% load			

Emissions Unit Information Section 2

GE Frame 7EA CT Peaking Unit Number 13

Pollutant Information Section 3

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 10.00 lb/hr @ 20 deg.

4. Equivalent Allowable Emissions :

   10.00 lb/hour 11.00 tons/year

5. Method of Compliance :

   Initial compliance test, EPA Mthd 5 or VE < 10% at full load

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   The TPY allowable is requested to be 33.0 TPY, representing an aggregate for the 3 CTs.

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Pollutant Information Section 3

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER		
2. Future Effective Date of Allowable Emissions :			
3. Requested Allowable Emissions and Units :	5.00	lb/hr	
4. Equivalent Allowable Emissions :	5.00	lb/hour	tons/year
5. Method of Compliance : VE, EPA Method 9			
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : If VE < 10%, stack test not required. No applicable annual emissions limit (TPY) for 1 CT; 3 CTs limited to 33.0 TPY, based on the equivalent of 1,000 hr/yr/CT of oil firing and 2,390 hr/yr/CT gas.			

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **PM10**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
10.0000000 lb/hour 11.0000000 tons/year

4. Synthetically Limited?
[ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor 10 Units : lb/hr
Reference : Application

7. Emissions Method Code : 2

8. Calculations of Emissions :

See attached PSD Analysis. Equivalent TPY for single CT; 3 CTs have an aggregate limit of 33.0 TPY.

9. Pollutant Potential/Estimated Emissions Comment :

Max. hourly emissions based on inlet temp. of 20 deg. F, oil firing, 100% load. Annual emissions based on 2,390 hr/yr gas firing and 1,000 hr/yr oil firing at 59 deg. F.

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code :		OTHER		
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :		10.00	lb/hr @ 20 deg.	
4. Equivalent Allowable Emissions :	10.00	lb/hour	11.00	tons/year
5. Method of Compliance : Initial compliance test, EPA Mthd 5				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : If VE < 10%, stack test not required. No applicable annual emission limit for 1 CT; 3 CTs limited to 33.0 TPY.				

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Pollutant Information Section 4

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER		
2. Future Effective Date of Allowable Emissions :			
3. Requested Allowable Emissions and Units :	5.00	lb/hr	
4. Equivalent Allowable Emissions :	5.00	lb/hour	tons/year
5. Method of Compliance : VE, EPA Method 9			
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : If VE < 10%, stack test not required. No applicable annual emissions limit for 1 CT; 3 CTs limited to 33.0 TPY, based on the equivalent of 1,000 hr/yr/CT of oil firing and 2,390 hr/yr/CT of gas.			

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

GE Frame 7EA CT Peaking Unit Number 13

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **CO**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
59.0000000 lb/hour 86.5000000 tons/year

4. Synthetically Limited?
[ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor 25 Units : ppmvd
Reference : Application

7. Emissions Method Code : 2

8. Calculations of Emissions :

See attched PSD Analysis. Equivalent TPY for 1 CT; 3 CTs limited to 259.5 TPY.

9. Pollutant Potential/Estimated Emissions Comment :

Max. hourly emissions based on inlet temp. of 20 deg. F, gas firing, 100% load. Annual emissions based on 2,390 hr/yr/CT gas firing and 1,000 hr/yr/CT oil firing at 59 deg. F.

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Pollutant Information Section 5

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	59.00	lb.hr @ 20 deg		
4. Equivalent Allowable Emissions :	59.00	lb/hour	86.50	tons/year
5. Method of Compliance : Annual compliance test, EPA Method 10 at full load				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : No applicable annual emissions limit for 1 CT; 3 CTs have aggregate limit of 259.5 TPY.				

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Pollutant Information Section 5

Allowable Emissions 2

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 48.00 lb/hr

4. Equivalent Allowable Emissions :

   48.00 lb/hour tons/year

5. Method of Compliance :

   Annual compliance test, EPA Meth. 10, if > 400 hr oil firing

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   Oil-firing @ 20 deg. F, full load. No applicable annual limit for 1 CT; 3 CTs limited to 259.5 TPY, based on equivalent of 1,000 hr/yr/CT of oil firing and 2,390 hr/yr/CT of gas firing.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **VOC**
2. Total Percent Efficiency of Control : %
3. Potential Emissions : 10.0000000 lb/hour 15.3000000 tons/year
4. Synthetically Limited? [ ] Yes [X] No
5. Range of Estimated Fugitive/Other Emissions: to tons/year
6. Emissions Factor 7 Units : ppmvw Reference : Application
7. Emissions Method Code : 2
8. Calculations of Emissions : See attached PSD Analysis. Equivalent TPY for 1 CT; 3 CTs limited to an aggregate of 45.9 TPY.
9. Pollutant Potential/Estimated Emissions Comment : Max. hourly emissions based on inlet temp. of 20 deg. F, gas or oil firing, 100% load. Annual emissions based on 2,390 hr/yr/CT gas firing & 1,000 hr/yr/CT oil firing at 59 deg. F.

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Pollutant Information Section 6

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 10.00 lb/hr @ 20 deg.

4. Equivalent Allowable Emissions :

   10.00 lb/hour 15.30 tons/year

5. Method of Compliance :

   Annual test, EPA Mthd 25A, full load; not req'd if CO met.

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   No applicable annual emission limit for 1 CT; 3 CTs limited to aggregate of 45.9 TPY. VOC test not req'd if CO limit met.

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Pollutant Information Section 6

Allowable Emissions 2

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 10.00 lb/hr @ 20deg.

4. Equivalent Allowable Emissions :
10.00 lb/hour tons/year

5. Method of Compliance :
Annual test, EPA Mthd 25A, full load; not req'd if CO met.

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :
Oil or gas firing; 20 deg. F, full load. No applicable annual emission limit for 1 CT; 3 CTs limited to 45.9 TPY. VOC test not req'd if CO limit met.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

GE Frame 7EA CT Peaking Unit Number 13

Pollutant Potential/Estimated Emissions : Pollutant 7

1. Pollutant Emitted : **SAM**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
5.5000000 lb/hour 2.9000000 tons/year

4. Synthetically Limited?
[ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor 0.05 Units :% S
Reference : Application

7. Emissions Method Code : 2

8. Calculations of Emissions :

See attached PSD Analysis, Appendix A. Equivalent TPY for single CT; 3 CTs have limit of 8.6 TPY.

9. Pollutant Potential/Estimated Emissions Comment :

Max. hourly emissions based on inlet temp. of 20 deg. F, oil firing, 100% load. Annual emissions based on 2,390 hr/yr/CT gas firing & 1,000 hr/yr/CT oil firing @ 59 deg. F.

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Pollutant Information Section 7

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 0.05 % S @ 20 deg.

4. Equivalent Allowable Emissions :

   5.50 lb/hour 2.90 tons/year

5. Method of Compliance :

   Fuel sampling and analysis

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   No annual emiss. limit for 1 CT; 3 CTs have limit of 8.6 TPY. Fuel sampling and analysis for compliance.

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Pollutant Information Section 7

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	1.00	grain S/100 cf
4. Equivalent Allowable Emissions :	lb/hour	tons/year
5. Method of Compliance : Fuel sampling and analysis - vendor supplied		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Natural gas-firing @ 20 deg. F. No applicable annual emission limit for 1 CT; 3 CTs limited to 8.6 TPY.		

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype : 20

2. Basis for Allowable Opacity : RULE

3. Requested Allowable Opacity :

Normal Conditions : 20 %
Exceptional Conditions : 0 %
Maximum Period of Excess Opacity Allowed : min/hour

4. Method of Compliance :

Annual compliance test, EPA Method 9 if > 400 hr oil firing

5. Visible Emissions Comment :

VE limit while firing oil under normal conditions at full load.

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Visible Emissions Limitation : Visible Emissions Limitation 2

1. Visible Emissions Subtype : 99

2. Basis for Allowable Opacity : RULE

3. Requested Allowable Opacity :

Normal Conditions :		%
Exceptional Conditions :	100	%
Maximum Period of Excess Opacity Allowed :	60	min/hour

4. Method of Compliance :

EPA Method 9

5. Visible Emissions Comment :

1. Rule 62-210.700. 2. Max. period of excess opacity allowed - 2 hours/24 hours for startup, shutdown, malfunction.

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
GE Frame 7EA CT Peaking Unit Number 13

Continuous Monitoring System Continuous Monitor 1

1. Parameter Code : EM

2. Pollutant(s):

3. CMS Requirement RULE

4. Monitor Information

Manufacturer : Not yet determined
Model Number :
Serial Number :

5. Installation Date : [illegible]

6. Performance Specification Test Date : 19-Aug-[illegible]

7. Continuous Monitor Comment :

NOx CEM proposed to meet requirements. Format to be 24 hr block average based on lb/hr limit.

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 2

GE Frame 7EA CT Peaking Unit Number 13

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[X] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :

PM : C SO2 : C NO2 : C

4. Baseline Emissions :

PM : lb/hour tons/year
SO2 : lb/hour tons/year
NO2 : tons/year

5. PSD Comment :

See attached PSD Sections 1-8.

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 2

GE Frame 7EA CT Peaking Unit Number 13

Supplemental Requirements for All Applications

1. Process Flow Diagram :	IC-EU1-L1
2. Fuel Analysis or Specification :	IC-EU1-L2
3. Detailed Description of Control Equipment :	IC-EU1-L3
4. Description of Stack Sampling Facilities :	IC-EU1-L4
5. Compliance Test Report :	NA
6. Procedures for Startup and Shutdown :	IC-EU1-L6
7. Operation and Maintenance Plan :	NA
8. Supplemental Information for Construction Permit Application :	PSD Sec. 1-8
9. Other Information Required by Rule or Statue :	PSD Sec. 1-8

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations : Refer to Attachment IC-EU1-L10
11. Alterntive Modes of Operation (Emissions Trading) :

12. Identification of Additional Applicable Requirements :

13. Compliance Assurance Monitoring
Plan :

14. Acid Rain Application (Hard-copy Required) :

Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))

Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)

New Unit Exemption (Form No. 62-210.900(1)(a)2.)

Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 3

GE Frame 7EA CT Peaking Unit Number 14

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one :

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

2. Single Process, Group of Processes, or Fugitive Only? Check one :

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

Emissions Unit Information Section 3

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section :

GE Frame 7EA CT Peaking Unit Number 14

2. Emissions Unit Identification Number :
[ ] No Corresponding ID [X] Unknown

3. Emissions Unit Status Code : C	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code : 49

6. Emissions Unit Comment :

This emissions unit is a GE Frame 7EA dual fuel combustion turbine operating in simple cycle mode. See attached PSD Analysis.

Emissions Unit Information Section 3

GE Frame 7EA CT Peaking Unit Number 14

Emissions Unit Control Equipment 1

1. Description :
   Dry low-NOx combustors - natural gas

2. Control Device or Method Code : 25

Emissions Unit Information Section 3

GE Frame 7EA CT Peaking Unit Number 14

Emissions Unit Control Equipment 2

1. Description :
   Water injection - oil firing

2. Control Device or Method Code : 28

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
GE Frame 7EA CT Peaking Unit Number 14

Emissions Unit Details

1. Initial Startup Date : [illegible]

2. Long-term Reserve Shutdown Date :

3. Package Unit :
Manufacturer : General Electric Model Number : PG 7121EA

4. Generator Nameplate Rating : 87 MW

5. Incinerator Information :
Dwell Temperature : Degrees Fahrenheit
Dwell Time : Seconds
Incinerator Afterburner Temperature : Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate : 954 mmBtu/hr

2. Maximum Incinerator Rate : lb/hr tons/day

3. Maximum Process or Throughput Rate :

4. Maximum Production Rate :

5. Operating Capacity Comment :
See Attachment IC-EU1-C5. Max. heat input at ISO conditions and distillate oil firing (LHV); max. for natural gas firing is 885 mmBtu/hr (ISO, LHV)

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule :
hours/day days/week
weeks/year 3,390 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 3

GE Frame 7EA CT Peaking Unit Number 14

Rule Applicability Analysis

Not Applicable

List of Applicable Regulations

See Attachment IC-EU1-D
See attached PSD Analysis

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 3

GE Frame 7EA CT Peaking Unit Number 14

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : Attached figure

2. Emission Point Type Code : 1

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking :
(limit to 100 characters per point)
Emissions exhausted through a single stack.

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common :

5. Discharge Type Code : V

6. Stack Height : 56 feet

7. Exit Diameter : 16.1 feet

8. Exit Temperature : 993 °F

9. Actual Volumetric Flow Rate : 1436310 acfm

10. Percent Water Vapor : 0.00 %

11. Maximum Dry Standard Flow Rate : 0 dscfm

12. Nonstack Emission Point Height : 0 feet

13. Emission Point UTM Coordinates :
Zone : 0 East (km) : 446.300 North (km) : 3126.000

14. Emission Point Comment :
Exit temperature and flow rate given for a single CT at an ambient temperature of 59 deg. F (oil firing). Stack height 56 feet.

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 3

GE Frame 7EA CT Peaking Unit Number 14

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) :

   Distillate fuel oil.

2. Source Classification Code (SCC) : 20100101

3. SCC Units : Thousand Gallons Burned (all liquid fuels)

4. Maximum Hourly Rate : 8.04

5. Maximum Annual Rate : 7,227.00

6. Estimated Annual Activity Factor :

7. Maximum Percent Sulfur : 0.05

8. Maximum Percent Ash : 0.10

9. Million Btu per SCC Unit : 132

10. Segment Comment :

    Based on 7.1 lb/gal; LHV of 18,300 btu/lb; max. hourly rate at 20 deg. F for 1 CT. Annual rate based on hourly rate at 59 deg. F and equivalent of 1,000 hr/yr/CT at full load.

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 3

GE Frame 7EA CT Peaking Unit Number 14

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Natural gas	
2. Source Classification Code (SCC) : 20100201	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 1.03	5. Maximum Annual Rate : 3,159.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 950	
10. Segment Comment : Maximum % sulfur: 1 grain/100 cf. 1) Max. hourly rate at 20 deg. F for one CT. Annual rate based on hourly rate at 59 deg. F and equivalent of 3390 hr/yr/CT. Heat content is LHV.	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 3
GE Frame 7EA CT Peaking Unit Number 14

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - SO2			EL
2 - NOX	025	028	EL
3 - PM			EL
4 - PM10			EL
5 - CO			EL
6 - VOC			EL
7 - SAM			EL

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3
GE Frame 7EA CT Peaking Unit Number 14

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **SO2**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 55.0000000 lb/hour	27.9000000 tons/year
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor 0.05 Reference : Application	Units :% S
7. Emissions Method Code : 2	
8. Calculations of Emissions : See attached PSD Analysis, Appendix A. Equivalent TPY for single CT; 3 CTs have a limit of 83.7 TPY.	
9. Pollutant Potential/Estimated Emissions Comment : Max. hourly emissions based on inlet temp. of 20 deg. F, oil firing, 100% load. Ann. emissions based on 2,390 hr/yr nat. gas firing and 1,000 hr/yr oil firing at 59 deg. F. 1 gr S/100 cf; .05% S oil	

Emissions Unit Information Section 3
GE Frame 7EA CT Peaking Unit Number 14

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 0.05 % S max.

4. Equivalent Allowable Emissions :

   55.00 lb/hour 27.90 tons/year

5. Method of Compliance :

   Fuel analysis

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   The TPY allowable is requested to be 83.7 TPY, representing an aggregate limit for the 3 CTs.

Emissions Unit Information Section 3
GE Frame 7EA CT Peaking Unit Number 14

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER		
2. Future Effective Date of Allowable Emissions :			
3. Requested Allowable Emissions and Units :	1.00	grain S/100 CF	
4. Equivalent Allowable Emissions :	2.95	lb/hour	tons/year
5. Method of Compliance : Fuel analysis - `vendor supplied`			
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Pipeline natural gas; 1 grain S/100 cf; 20 deg. F inlet temp; 100% load			

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

GE Frame 7EA CT Peaking Unit Number 14

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **NOX**

2. Total Percent Efficiency of Control : 80.00 %

3. Potential Emissions :
186.0000000 lb/hour 121.7000000 tons/year

4. Synthetically Limited?
[ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor 42 Units : ppmvd@15% O2
Reference : Application

7. Emissions Method Code : 2

8. Calculations of Emissions :

See attached PSDAnalysis. Equivalent TPY for 1 CT; 3 CTs have aggregate limit of 365.1 TPY.

9. Pollutant Potential/Estimated Emissions Comment :

Max. hourly emissions based on inlet temp. of 20 deg. F, oil firing, 100% load. Annual emissions based on 2,390 hr/ yr gas firing and 1,000 hr/yr oil firing at 59 deg. F. NSPS FBN allowance requested

Emissions Unit Information Section 3

GE Frame 7EA CT Peaking Unit Number 14

Pollutant Information Section 2

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 186.00 lb/hr @ 20 deg.

4. Equivalent Allowable Emissions :

   186.00 lb/hour 121.70 tons/year

5. Method of Compliance :

   CEM - 24 hr block avg. of lb/hr limit.

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   The TPY allowable is requested to be 365.1, representing an aggregate limit for the 3 CTs.

Emissions Unit Information Section 3
GE Frame 7EA CT Peaking Unit Number 14

Pollutant Information Section 2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER	
2. Future Effective Date of Allowable Emissions :		
3. Requested Allowable Emissions and Units :	36.00	lb/hr @ 20 deg.
4. Equivalent Allowable Emissions : 36.00 lb/hour		tons/year
5. Method of Compliance : CEM - 24 hr block avg. of lb/hr limit.		
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : No applicable annual emission limit (TPY) for 1 CT;3 CTs have a limit of 365.1 TPY, based on equivalent of 1,000 hr/yr/CT of oil firing and 2,390 hr/yr/CT of gas firing.		

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3
GE Frame 7EA CT Peaking Unit Number 14

Pollutant Potential/Estimated Emissions : Pollutant 3

1. Pollutant Emitted : **PM**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
10.0000000 lb/hour 11.0000000 tons/year

4. Synthetically Limited?
[ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor 10 Units : lb/hr
Reference : Application

7. Emissions Method Code : 2

8. Calculations of Emissions :

See attched PSD Analysis, Appendix A. Equivalent TPY for 1 CT; 3 CTs have aggregate limit of 33 TPY.

9. Pollutant Potential/Estimated Emissions Comment :

Max. hourly emissions based on inlet temp. of 20 deg. F, oil firing, 100% load. Annual emissions based on 2,390 hr/yr gas firing and 1,000 hr/yr oil firing at 59 deg.

Emissions Unit Information Section 3

GE Frame 7EA CT Peaking Unit Number 14

Pollutant Information Section 3

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 10.00 lb/hr @ 20 deg.

4. Equivalent Allowable Emissions :

   10.00 lb/hour 11.00 tons/year

5. Method of Compliance :

   Initial compliance test, EPA Mthd 5 or VE < 10% at full load

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   The TPY allowable is requested to be 33.0 TPY, representing an aggregate for the 3 CTs.

Emissions Unit Information Section 3

GE Frame 7EA CT Peaking Unit Number 14

Pollutant Information Section 3

Allowable Emissions 2

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 5.00 lb/hr

4. Equivalent Allowable Emissions :

   5.00 lb/hour tons/year

5. Method of Compliance :

   VE, EPA Method 9

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   If VE < 10%, stack test not required. No applicable annual emissions limit (TPY) for 1 CT; 3 CTs limited to 33.0 TPY, based on the equivalent of 1,000 hr/yr/CT of oil firing and 2,390 hr/yr/CT gas.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

GE Frame 7EA CT Peaking Unit Number 14

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **PM10**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 10.0000000 lb/hour	11.0000000 tons/year
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions: to	tons/year
6. Emissions Factor 10 Reference : Application	Units : lb/hr
7. Emissions Method Code : 2	
8. Calculations of Emissions : See attached PSD Analysis. Equivalent TPY for single CT; 3 CTs have an aggregate limit of 33.0 TPY.	
9. Pollutant Potential/Estimated Emissions Comment : Max. hourly emissions based on inlet temp. of 20 deg. F, oil firing, 100% load. Annual emissions based on 2,390 hr/yr gas firing and 1,000 hr/yr oil firing at 59 deg. F.	

Emissions Unit Information Section 3
GE Frame 7EA CT Peaking Unit Number 14

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 10.00 lb/hr @ 20 deg.

4. Equivalent Allowable Emissions :

   10.00 lb/hour 11.00 tons/year

5. Method of Compliance :

   Initial compliance test, EPA Mthd 5

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   If VE < 10%, stack test not required. No applicable annual emission limit for 1 CT; 3 CTs limited to 33.0 TPY.

Emissions Unit Information Section 3
GE Frame 7EA CT Peaking Unit Number 14

Pollutant Information Section 4

Allowable Emissions 2

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 5.00 lb/hr

4. Equivalent Allowable Emissions :

   5.00 lb/hour tons/year

5. Method of Compliance :

   VE, EPA Method 9

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   If VE < 10%, stack test not required. No applicable annual emissions limit for 1 CT; 3 CTs limited to 33.0 TPY, based on the equivalent of 1,000 hr/yr/CT of oil firing and 2,390 hr/yr/CT of gas.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

GE Frame 7EA CT Peaking Unit Number 14

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **CO**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
59.0000000 lb/hour 86.5000000 tons/year

4. Synthetically Limited?
[ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor 25 Units : ppmvd
Reference : Application

7. Emissions Method Code : 2

8. Calculations of Emissions :

See attched PSD Analysis. Equivalent TPY for 1 CT; 3 CTs limited to 259.5 TPY.

9. Pollutant Potential/Estimated Emissions Comment :

Max. hourly emissions based on inlet temp. of 20 deg. F, gas firing, 100% load. Annual emissions based on 2,390 hr/yr/CT gas firing and 1,000 hr/yr/CT oil firing at 59 deg. F.

Emissions Unit Information Section 3
GE Frame 7EA CT Peaking Unit Number 14

Pollutant Information Section 5

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 59.00 lb.hr @ 20 deg

4. Equivalent Allowable Emissions :

   59.00 lb/hour 86.50 tons/year

5. Method of Compliance :

   Annual compliance test, EPA Method 10 at full load

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   No applicable annual emissions limit for 1 CT; 3 CTs have aggregate limit of 259.5 TPY.

Emissions Unit Information Section 3
GE Frame 7EA CT Peaking Unit Number 14

Pollutant Information Section 5

Allowable Emissions 2

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 48.00 lb/hr

4. Equivalent Allowable Emissions :

   48.00 lb/hour tons/year

5. Method of Compliance :

   Annual compliance test, EPA Meth. 10, if > 400 hr oil firing

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   Oil-firing @ 20 deg. F, full load. No applicable annual limit for 1 CT; 3 CTs limited to 259.5 TPY, based on equivalent of 1,000 hr/yr/CT of oil firing and 2,390 hr/yr/CT of gas firing.

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3
GE Frame 7EA CT Peaking Unit Number 14

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **VOC**

2. Total Percent Efficiency of Control : %

3. Potential Emissions :
10.0000000 lb/hour 15.3000000 tons/year

4. Synthetically Limited?
[ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:
to tons/year

6. Emissions Factor 7 Units : ppmvw
Reference : Application

7. Emissions Method Code : 2

8. Calculations of Emissions :

See attached PSD Analysis. Equivalent TPY for 1 CT; 3 CTs limited to an aggregate of 45.9 TPY.

9. Pollutant Potential/Estimated Emissions Comment :

Max. hourly emissions based on inlet temp. of 20 deg. F, gas or oil firing, 100% load. Annual emissions based on 2,390 hr/yr/CT gas firing & 1,000 hr/yr/CT oil firing at 59 deg. F.

Emissions Unit Information Section 3
GE Frame 7EA CT Peaking Unit Number 14

Pollutant Information Section 6

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	10.00	lb/hr @ 20 deg.		
4. Equivalent Allowable Emissions :	10.00	lb/hour	15.30	tons/year
5. Method of Compliance : Annual test, EPA Mthd 25A, full load; not req'd if CO met.				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : No applicable annual emission limit for 1 CT; 3 CTs limited to aggregate of 45.9 TPY. VOC test not req'd if CO limit met.				

Emissions Unit Information Section 3
GE Frame 7EA CT Peaking Unit Number 14

Pollutant Information Section 6

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER		
2. Future Effective Date of Allowable Emissions :			
3. Requested Allowable Emissions and Units :	10.00	lb/hr @ 20deg.	
4. Equivalent Allowable Emissions :	10.00	lb/hour	tons/year
5. Method of Compliance : Annual test, EPA Mthd 25A, full load; not req'd if CO met.			
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Oil or gas firing; 20 deg. F, full load. No applicable annual emission limit for 1 CT; 3 CTs limited to 45.9 TPY. VOC test not req'd if CO limit met.			

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3

GE Frame 7EA CT Peaking Unit Number 14

Pollutant Potential/Estimated Emissions : Pollutant 7

1. Pollutant Emitted : **SAM**
2. Total Percent Efficiency of Control : %
3. Potential Emissions : 5.5000000 lb/hour 2.9000000 tons/year
4. Synthetically Limited? [ ] Yes [X] No
5. Range of Estimated Fugitive/Other Emissions: to tons/year
6. Emissions Factor 0 Units :% S Reference : Application
7. Emissions Method Code : 2
8. Calculations of Emissions : See attached PSD Analysis, Appendix A. Equivalent TPY for single CT; 3 CTs have limit of 8.6 TPY.
9. Pollutant Potential/Estimated Emissions Comment : Max. hourly emissions based on inlet temp. of 20 deg. F, oil firing, 100% load. Annual emissions based on 2,390 hr/yr/CT gas firing & 1,000 hr/yr/CT oil firing @ 59 deg. F.

Emissions Unit Information Section 3
GE Frame 7EA CT Peaking Unit Number 14

Pollutant Information Section 7

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 0.05 % S @ 20 deg.

4. Equivalent Allowable Emissions :

   5.50 lb/hour 2.90 tons/year

5. Method of Compliance :

   Fuel sampling and analysis

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   No annual emiss. limit for 1 CT; 3 CTs have limit of 8.6 TPY. Fuel sampling and analysis for compliance.

Emissions Unit Information Section 3

GE Frame 7EA CT Peaking Unit Number 14

Pollutant Information Section 7

Allowable Emissions 2

1. Basis for Allowable Emissions Code : OTHER

2. Future Effective Date of Allowable Emissions :

3. Requested Allowable Emissions and Units : 1.00 grain S/100 cf

4. Equivalent Allowable Emissions :

   lb/hour tons/year

5. Method of Compliance :

   Fuel sampling and analysis- `vendor supplied`

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

   Natural gas-firing @ 20 deg. F. No applicable annual emission limit for 1 CT; 3 CTs limited to 8.6 TPY.

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
GE Frame 7EA CT Peaking Unit Number 14

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype : 20

2. Basis for Allowable Opacity : RULE

3. Requested Allowable Opacity :

Normal Conditions :	20	%
Exceptional Conditions :	0	%
Maximum Period of Excess Opacity Allowed :		min/hour

4. Method of Compliance :

Annual compliance test, EPA Method 9 if > 400 hr oil firing

5. Visible Emissions Comment :

VE limit while firing oil under normal conditions at full load.

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
GE Frame 7EA CT Peaking Unit Number 14

Visible Emissions Limitation : Visible Emissions Limitation 2

1. Visible Emissions Subtype : 99

2. Basis for Allowable Opacity : RULE

3. Requested Allowable Opacity :

Normal Conditions : %
Exceptional Conditions : 100 %
Maximum Period of Excess Opacity Allowed : 60 min/hour

4. Method of Compliance :

EPA Method 9

5. Visible Emissions Comment :

1. Rule 62-210.700. 2. Max. period of excess opacity allowed - 2 hours/24 hours for startup, shutdown, malfunction.

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
GE Frame 7EA CT Peaking Unit Number 14

Continuous Monitoring System Continuous Monitor 1

1. Parameter Code : EM	2. Pollutant(s):
3. CMS Requirement RULE	
4. Monitor Information Manufacturer : Not yet determined Model Number : Serial Number :	
5. Installation Date : 19-Aug-1993	
6. Performance Specification Test Date : 19-Aug-1993	
7. Continuous Monitor Comment : NOx CEM proposed to meet requirements. Format to be 24 hr block average based on lb/hr limit.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 3

GE Frame 7EA CT Peaking Unit Number 14

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[X] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :

PM : C SO2 : C NO2 : C

4. Baseline Emissions :

PM : lb/hour tons/year
SO2 : lb/hour tons/year
NO2 : tons/year

5. PSD Comment :

See attched PSD Sections 1-8.

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 3

GE Frame 7EA CT Peaking Unit Number 14

Supplemental Requirements for All Applications

1. Process Flow Diagram :	IC-EU1-L1
2. Fuel Analysis or Specification :	IC-EU1-L2
3. Detailed Description of Control Equipment :	IC-EU1-L3
4. Description of Stack Sampling Facilities :	IC-EU1-L4
5. Compliance Test Report :	NA
6. Procedures for Startup and Shutdown :	IC-EU1-L6
7. Operation and Maintenance Plan :	NA
8. Supplemental Information for Construction Permit Application :	PSD Sec. 1-8
9. Other Information Required by Rule or Statue :	PSD Sec. 1-8

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :

Refer to Attachment IC-EU1-L10

11. Alterntive Modes of Operation (Emissions Trading) :

12. Identification of Additional Applicable Requirements :

13. Compliance Assurance Monitoring Plan :

14. Acid Rain Application (Hard-copy Required) :

Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))

Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)

New Unit Exemption (Form No. 62-210.900(1)(a)2.)

Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

ATTACHMENT

INTERCESSION CITY PSD ANALYSIS

AIR PERMIT APPLICATION AND PREVENTION OF SIGNIFICANT DETERIORATION ANALYSIS FOR THE FLOIRDA POWER CORPORATION INTERCESSION CITY FACILITY OSCEOLA COUNTY, FLOIRDA

Prepared By:

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Environmental Services Department
Air Programs
One Power Plaza
263 – 13th Avenue South
St. Petersburg, FL 33701

TABLE OF CONTENTS

1.0 INTRODUCTION

Florida Power Corporation (FPC) is proposing to locate about 262 megawatts (MW) of simple cycle combustion turbines (CTs) at its existing Intercession City facility site. The Intercession City site is located in Osceola County about 3.5 miles west of Intercession City (Figure 1-1). The project will consist of three simple cycle CTs, each with a nominal rating of 87.2 MW at an ambient temperature of 59 degrees Fahrenheit (F). The three proposed CTs will be located adjacent to eleven (11) existing CTs, which have a name plate generating capacity of 882 MW (Figure 1-2).

Analyses were performed to determine compliance with prevention of significant deterioration (PSD) increments and preconstruction *de minimis* monitoring levels for the proposed plant. The PSD review included control technology review, source impact analysis, air quality analysis (monitoring), and additional impact analyses.

The existing Intercession City plant is considered to be an existing major facility because emissions of regulated pollutants exceed 250 tons per year (TPY). PSD review is required for any pollutant for which the net increase in emissions exceeds the PSD significant emission rates, which would constitute a major modification. The potential emissions from the proposed project will exceed the PSD significant emission rates for the following regulated pollutants: sulfur dioxide (SO_2), particulate matter as total suspended particulate [PM(TSP)], particulate matter with an aerodynamic diameter less than or equal to 10 micrometers (PM10), nitrogen dioxide (NO_2), carbon monoxide (CO), volatile organic compounds (VOC) and sulfuric acid mist (H_2SO_4 or SAM). Therefore, the project is subject to PSD review for these pollutants.

This report is presented in eight sections. Descriptions of the existing operation and proposed project are given in Section 2.0. The air quality review requirements and applicability of the project to the PSD and nonattainment regulations are presented in Section 3.0. The control technology review for the CTs applicable under the U.S. Environmental Protection Agency's (EPA's) current top-down approach is discussed in Section 4.0. Air quality monitoring requirements are discussed in Section 5.0. The air impact analysis approach is presented in Section 6.0. The results of the air quality analyses are summarized in Section 7.0. Additional impact analyses associated with the project's impacts on vegetation, soils, and associated growth are discussed in Section 8.0.

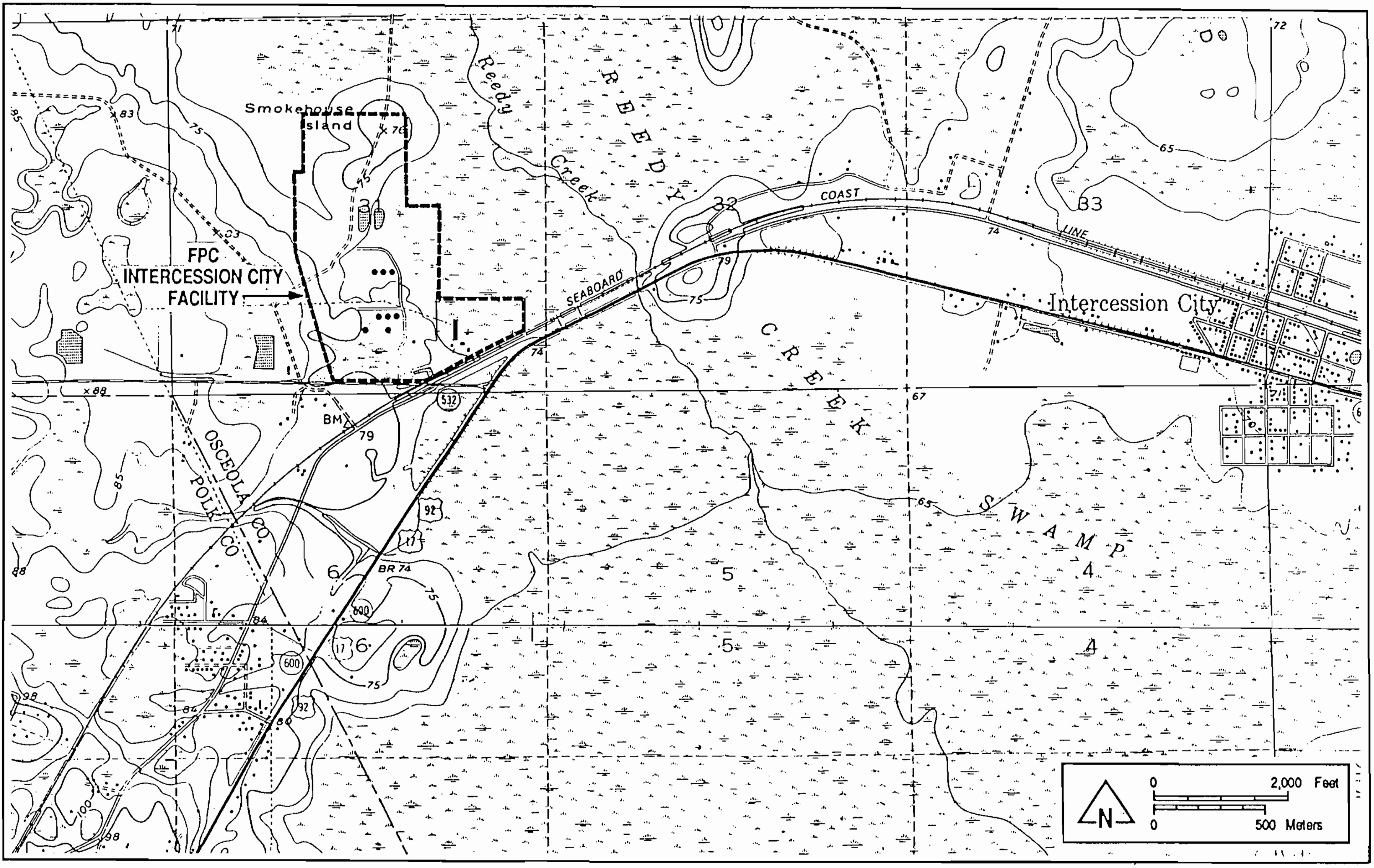
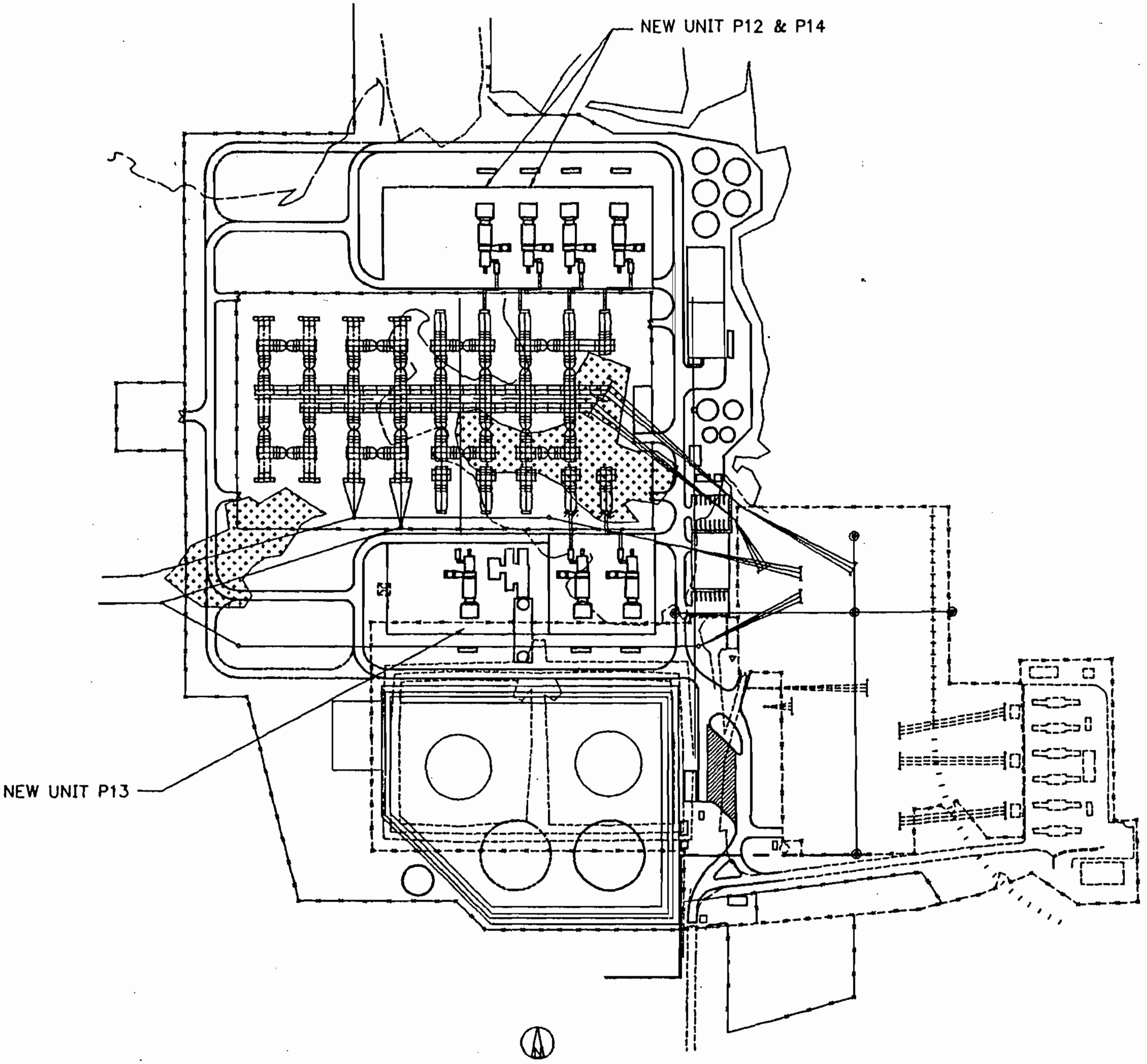


Figure 1-1 LOCATION OF THE FPC INTERCESSION CITY FACILITY



FLORIDA POWER CORPORATION
INTERCESSION CITY TURBINE ADDITIONS
GENERAL SITE LAYOUT

FILENAME ICP00230

Figure 1-2.

2.0 EXISTING OPERATION AND PROJECT DESCRIPTION

2.1 EXISTING OPERATION

The existing facility consists of eleven combustion turbine peaking units (P1-P11). Peaking units P1-P6 each consist of two gas turbines having a maximum permitted heat input rate of 708 million British thermal units per hour (MMBtu/hr) and 56.7 megawatt per hour (MW/hr) output. These units are fired with no. 2 fuel oil with a maximum sulfur content of 0.5 percent. Peaking units P7-P10 are GE Model 7EAs, each having a maximum permitted heat input rate of 1,140 MMBtu/hr on oil (1,200 MMBtu/hr on gas) and a rating of 96.3 MW/hr output (at 59 degrees F). These units can fire either natural gas or no. 2 fuel oil with a maximum sulfur content of 0.2 percent. Finally, peaking unit P11, a Siemens V84.3, has a maximum permitted heat input rating of 1,477 MMBtu/hr and a rating of 171 MW/hr output (at 59 degrees F). This unit fires only no. 2 fuel oil with a maximum sulfur content of 0.2 percent.

2.2 PROJECT DESCRIPTION

The proposed project will consist of three simple-cycle CT peaking units designed to burn natural gas or No. 2 distillate fuel oil. The operating and emission data for natural gas and oil firing were used to assess impacts and evaluate best available control technology (BACT), although natural gas is currently planned as the primary fuel. The three CTs (GE Frame 7EA) are of the advanced design and will have a generating capability of 87.2 MW at 59 degrees F, for a total rating of 262 MW. Design information and operating parameters for an individual CT when firing natural gas and distillate oil at ambient temperatures of 20, 59, and 100 degrees F are presented in Appendix A. Information is also provided for the EA type CTs operating at 100, 75, 50, and 25 percent load. The annual emissions presented in Appendix A are based on 3,390 hours of operation per year. The average requested operational time for all new CT units is 3,390 hours per year with the condition that the aggregate limit for all three CTs is 10,170 hours per year. The No. 2 fuel oil used in the proposed CTs will have a maximum sulfur content specification of 0.05 percent.

At high ambient temperature, the units cannot generate as much power because of lower compressor inlet density. To compensate for a portion of the loss of output (which can be on the order of 5-8 MW compared to referenced temperatures), inlet cooling is proposed to be installed ahead of the combustion turbine inlet. Therefore, the 59°F temperature case represents a conservative average temperature condition for estimating annual emissions for the proposed Intercession City CTs, inclusive of potential inlet cooling.

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal and state air regulatory requirements and their applicability to the proposed Intercession City project. These regulations must be satisfied before the proposed simple-cycle turbines can begin operation.

3.1 NATIONAL AND STATE AAQS

The existing applicable national and Florida AAQS are presented in Table 3-1. Primary national AAQS were promulgated to protect the public health, and secondary national AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Under federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a preconstruction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by EPA, and therefore PSD approval authority has been granted to the Florida Department of Environmental Regulation (FDEP).

A "major facility" is defined as any one of 28 named source categories which has the potential to emit 100 TPY or more, or any other stationary facility which has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. A "major modification" is defined under PSD regulations as a change at an existing major facility which increases emissions by greater than significant amounts. A comparison of the potential annual emissions (TPY) from the proposed CTs, to the PSD significant emission rates (TPY) are presented in Table 3-2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 52.21, Prevention of Significant Deterioration of Air Quality. The State of Florida has adopted PSD regulations by reference (Rule 62-212.400, F.A.C.). Major facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis (monitoring),
4. Source information, and
5. Additional impact analyses

In addition to these analyses, a new facility must also be reviewed with respect to Good Engineering Practice (GEP) stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

3.2.2 INCREMENTS/CLASSIFICATIONS

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality baseline concentration level of SO_2 and PM(TSP) concentrations would constitute significant deterioration. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have an impact. Three classifications were designated based on criteria established in the CAA Amendments. Initially, Congress promulgated areas as Class I (international parks, national wilderness areas, and memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. EPA then promulgated as regulations the requirements for classifications and area designations.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significant Impact Levels

		AAQS ($\mu g/m^3$)			PSD Increments ($\mu g/m^3$)		
Pollutant	Averaging Time	Primary Standard	Secondary Standard	Florida	Class I	Class II	Significant Impact Levels ($\mu g/m^3$) [b]
Particulate Matter[c] (PM10)	Annual Arithmetic Mean	50	50	50	4	17	1
	24-Hour Maximum	150	150	150	8	30	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum	365	NA	260	5	91	5
	3-Hour Maximum	NA	1,300	1,300	25	512	25
Carbon Monoxide	8-Hour Maximum	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone[c]	8-Hour Maximum[d]	157	157	157	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

Note: Particulate matter (PM10) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
NA = Not applicable, i.e., no standard exists.

[a] Short-term maximum concentrations are not to be exceeded more than once per year.

[b] Maximum concentrations are not to be exceeded.

[c] On July 18, 1997, EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, PM2.5 standards were introduced with a 24-hour standard of 65 g/m^3 (3-year average of 98th percentile) and an annual standard of 15 g/m^3 (3-year average at community monitors). Implementation of these standards are many years away.

[d] 0.08 ppm; achieved when 3-year average of 99th percentile is 0.08 ppm or less. FDEP has not yet adopted these standards.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50; 40 CFR 52.21.
Chapter 62-272, F.A.C.

TABLE 3-2
MAXIMUM POTENTIAL ANNUAL EMISSIONS (262 MW) AND PSD SIGNIFICANCE VALUES

Pollutant	Emission (TPY) *	PSD Significant Emission Rate (TPY)	PSD Review Required (Yes/No)
Carbon Monoxide	260	100	Yes
Nitrogen Oxides	365	40	Yes
Sulfur Dioxide	83.7	40	Yes
Particulate Matter (PM_{10})	33.0	15	Yes
Total Suspended Particulates	33.0	25	Yes
Volatile Organic Compounds	45.9	40	Yes
Sulfuric Acid Mist	8.6	7	Yes

* TPY = Tons per year for the proposed Intercession City CTs.

Basis: Full-load operation; 39% capacity factor; 59°F; equivalent of 1,000 hours per year per CT at full load on fuel oil and 2,390 hours per year per CT on gas.

On October 17, 1988, EPA promulgated regulations to prevent significant deterioration due to emissions of nitrogen oxides (NO_x) and established PSD increments for NO_2 concentrations. The EPA class designations and allowable PSD increments are presented in Table 3-1. FDEP has adopted the EPA class designations and allowable PSD increments for SO_2, PM(TSP), and NO_2 increments.

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition, in the PSD regulations as amended August 7, 1980, baseline concentration means the ambient concentration level that exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

1. The actual emissions representative of facilities in existence on the applicable baseline date; and
2. The allowable emissions of major stationary facilities that commenced construction before January 6, 1975, for SO_2 and PM(TSP) concentrations, or February 8, 1988, for NO_2 concentrations, but that were not in operation by the applicable baseline date.

The following emissions are not included in the baseline concentration and therefore affect PSD increment consumption:

1. Actual emissions from any major stationary facility on which construction commenced after January 6, 1975, for SO_2 and PM(TSP) concentrations, and after February 8, 1988, for NO_2 concentrations; and
2. Actual emission increases and decreases at any stationary facility occurring after the baseline date.

In reference to the baseline concentration, the term "baseline date" actually includes three different dates:

1. The major facility baseline date, which is January 6, 1975, in the cases of SO_2 and PM(TSP), and February 8, 1988, in the case of NO_2.
2. The minor facility baseline date, which is the earliest date after the trigger date on which a major stationary facility or major modification subject to PSD regulations submits a complete PSD application.
3. The trigger date, which is August 7, 1977, for SO_2 and PM(TSP), and February 8, 1988, for NO_2.

The minor source baseline date for SO_2 and PM(TSP) has been set as December 27, 1977, for the entire State of Florida. The minor source baseline date for NO_2 has been set as March 28, 1988.

3.2.3 CONTROL TECHNOLOGY REVIEW

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission limiting standards be met and that BACT be applied to control emissions from the source [Rule 62-212.410, F.A.C]. The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the significant emission rate (see Table 3-2).

BACT is defined in 52.21(b)(12) and Rule 62-210.200(40), F.A.C., as:

> An emissions limitation, including a visible emission 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 such pollutant. If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of a source or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the

application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice, or operation.

The requirements for BACT were promulgated within the framework of PSD in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in EPA's "Guidelines for Determining Best Available Control Technology (BACT)", (EPA, 1978) and in the "PSD Workshop Manual" (EPA, 1980). These guidelines were promulgated by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, as a minimum, demonstrate compliance with New Source Performance Standards (NSPS) for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

Historically, a "bottom-up" approach consistent with the BACT Guidelines and PSD Workshop Manual has been used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected. However, EPA developed a concern that the bottom-up approach was not providing the level of BACT decisions originally intended. As a result, in December 1987, the EPA Assistant Administrator for Air and Radiation mandated changes in the implementation of the PSD program including the adoption of a new "top-down" approach to BACT decision making.

The top-down BACT approach essentially starts with the most stringent (or top) technology and emissions limit that have been applied elsewhere to the same or a similar source category. The applicant must next provide a basis for rejecting this technology in favor of the next most stringent technology or propose to use it. Rejection of control alternatives may be based on technical or economic infeasibility. Such decisions are made on the basis of physical differences (e.g., fuel type), locational differences (e.g., availability of water), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between the proposed facility and the facility on which the control technique was applied previously must be justified. Recently, EPA issued a draft guidance document on the top-down approach entitled "Top-Down Best Available Control Technology Guidance Document" (EPA, 1990).

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of 40 Code of Federal Regulations (CFR) 52.21(m) and Rule 62-212.400(5)(f), F.A.C, any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2).

Ambient air monitoring for a period of up to 1 year is generally appropriate to satisfy the PSD monitoring requirements. A minimum of 4 months of data is required. Existing data from the vicinity of the proposed source may be utilized if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in EPA's "Ambient Monitoring Guidelines for Prevention of Significant Deterioration" (EPA, 1987a).

The regulations include an exemption which excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that FDEP may exempt a proposed major stationary facility or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2 [Rule 62-212.400(3), F.A.C.].

3.2.5 SOURCE IMPACT ANALYSIS

A source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the significant emission rate (Table 3-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Designated EPA models normally must be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication Guideline on Air Quality Models (Revised) (EPA, 1987b). The source impact analysis for criteria pollutants may be limited to only the new or modified source if the net increase in impacts due to the new or modified source is below significance levels.

The EPA has proposed significant impact levels for Class I areas, which are as follows:

Pollutant	Averaging Time	Proposed EPA PSD Class I Significant Impact Levels ($\mu g/m^3$)
SO_2	3-hour	1
	24-hour	0.2
	Annual	0.1
PM10	24-hour	0.3
	Annual	0.2
NO_2	Annual	0.1

[a] ($\mu g/m^3$) = micrograms per cubic meter.

Although these levels have not been officially promulgated as part of the PSD review process and may not be binding for states in performing PSD review, the proposed levels serve as a guideline in assessing a source's impact in a Class I area. The EPA action to incorporate Class I significant impact levels in the PSD process is part of implementing NSR provisions of the 1990 CAA Amendments. EPA believes that use of the proposed rules concerning the significant impact levels is appropriate in order to assist states in implementing the PSD permit process.

Various lengths of record for meteorological data can be utilized for impact analysis. A 5-year period can be used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. The term "highest, second-highest" (HSH) refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If less than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor normally must be used for comparison to air quality standards.

3.2.6 ADDITIONAL IMPACT ANALYSIS

In addition to air quality impact analyses, federal and State of Florida PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [40 CFR 52.21; Rule 62-212.400(5)(e), F.A.C.]. These analyses are to be conducted primarily for PSD Class I areas. Impacts due to general commercial, residential, industrial, and other growth associated with the source must also be addressed. These analyses are required for each pollutant emitted in significant amounts (Table 3-2).

3.2.7 GOOD ENGINEERING PRACTICE STACK HEIGHT

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). Identical regulations have been adopted by FDEP [Rule 62-210.550, F.A.C.]. GEP stack height is defined as the highest of:

1. 65 meters (m), or
2. A height established by applying the formula:

   $Hg = H + 1.5L$

   where: Hg = GEP stack height,

   H = Height of the structure or nearby structure, and

   L = Lesser dimension (height or projected width) of nearby structure(s), or
3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 kilometers (km). Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain which exceeds the height calculated by the GEP stack

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions (Rule 62-212.500, F.A.C.), all major new facilities and modifications to existing major facilities located in a nonattainment area must undergo nonattainment review. A new major facility is required to undergo this review if the proposed pieces of equipment have the potential to emit 100 TPY or more of thenonattainment pollutant. A major modification at a major facility is required to undergo review if it results in a significant net emission increase of 40 TPY or more of the nonattainment pollutant or the modification is major (i.e., 100 TPY or more).

For major facilities or major modifications that locate in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The area of influence is defined as anarea which is outside the boundary of a nonattainment area but within the locus of all points that are 50 km outside the boundary of the nonattainment area. Based on Rule 62-2.500(2)(c)2.a., F.A.C., all volatile organic compound (VOC) sources that are located within an area of influence are exempt from the provisions of new source review for nonattainment areas. Sources that emit other nonattainment pollutants and are located within the area of influence are subject to nonattainment review unless the maximum allowable emissions from the proposed source do not have a significant impact within the nonattainment area.

3.4 EMISSION STANDARDS

3.4.1 NEW SOURCE PERFORMANCE STANDARDS

The NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the CAA Amendments of 1977, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

The CTs will be subject to emission limitations covered under 40 CFR Part 60, Subpart GG, which limits NO_x and SO_2 emissions from all stationary combustion turbines with a heat input at peak load equal to 10.7 gigajoules per hour (10 MMBtu/hr), based on the lower heating value of the fuel fired.

NO_x emissions are limited to 75 ppmvd corrected to 15 percent oxygen and heat rate while sulfur dioxide emissions are limited to using a fuel with a sulfur content of 0.8 percent. In addition to emission limitations, there are requirements for notification, record keeping, reporting, performance testing and monitoring. These are summarized below:

40 CFR 60.7 Notification and Record Keeping

(a)(1)	Notification of the date of construction – 30 days after such date.
(a)(2)	Notification of the date of initial start-up – no more than 60 days or less than 30 days prior to date.
(a)(3)	Notification of actual date of initial start-up – within 15 days after such date.
(a)(5)	Notification of date which demonstrates CEM – not less than 30 days prior to date.
60.7 (b)	Maintain records of the start-up, shutdown, and malfunction quarterly.
60.7 (c)	Excess emissions reports – by the 30th day following end of quarter. (required even if no excess emissions occur)
60.7 (d)	Maintain file of all measurements for two years.

60.8 Performance Tests

- (a) Must be performed within 60 days after achieving maximum production rate but no later than 180 days after initial start-up.
- (d) Notification of Performance tests at least 30 days prior to them occurring.

40 CFR Subpart GG

60.334 Monitoring of Operations

- (a) Continuous monitoring system required for water-to-fuel ratio to meet NSPS system must be accurate within ± 5 percent.
- (b) Monitor sulfur and nitrogen content of fuel.
  Oil – (1): each occasion that fuel is transferred to bulk storage tank.
  Gas – (2): daily monitoring required.

3.4.2 FLORIDA RULES

The Florida DEP regulations for new stationary sources are covered in the F.A.C. The Florida DEP has adopted the EPA NSPS by reference in Rule 62-204.800(7); subsection (b)38 for stationary gas turbines. Therefore, the project is required to meet the same emissions, performance testings, monitoring, reporting, and record keeping as those described in Section 3.4.1. DEP has authority for implementing NSPS requirements in Florida.

3.4.3 FLORIDA AIR PERMITTING REQUIREMENTS

The Florida DEP regulations require any new source to obtain an air permit prior to construction. Major new sources must meet the appropriate PSD and nonattainment requirements as discussed previously. Required permits and approvals for air pollution sources include NSR for nonattainment areas, PSD, NSPS, National Emission Standards for Hazardous Air Pollutants (NESHAP), Permit to Construct, and Permit to Operate. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.052, 62-4.210, and 62-210.300(1), F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A. C.

3.5 SOURCE APPLICABILITY

3.5.1 AREA CLASSIFICATION

The Intercession City Plant is located in Osceola County, which has been designated by EPA and FDEP as an attainment area for all criteria pollutants. Osceola County and surrounding counties are designated as PSD Class II areas for $S0_2$, PM(TSP), and $N0_2$. The Intercession City site is located more than 100 km from any PSD Class I area. The nearest Class I areas to the site are the Everglades National Park and Chassahowitzka National Wildlife Refuge, which are approximately 280 km and 120 km, respectively, from the plant site.

3.5.2 PSD REVIEW

3.5.2.1 Pollutant Applicability

The existing Intercession City Plant is considered to be an existing major facility because emissions of regulated pollutants exceed 250 TPY (refer to Table 2-2); therefore, PSD review is required for any pollutant for which the net increase in emissions exceeds the PSD significant emission rates presented in Table 3-2 (i.e., major modification). As shown, potential emissions from the proposed project will exceed the PSD significant emission rates for the following regulated pollutants: $S0_2$, PM(TSP), PM10, $N0_2$, CO, VOCs and SAM. Therefore, the project is subject to PSD review for these pollutants.

3.5.2.2 Ambient Monitoring

Based upon the net increase in emissions from the proposed project, presented in Table 3-2, a PSD preconstruction ambient monitoring analysis is required for $S0_2$, PM(TSP), PM10, $N0_2$, CO and SAM. However, if the net increase in impact of a pollutant is less than the "deminimis" monitoring concentration, then an exemption from the preconstruction ambient monitoring requirement may be granted for that pollutant. In addition, ifan acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

If preconstruction monitoring data are required to be submitted, data collected at or near the project site can be submitted based on existing air quality data (e.g., FDEP) or the collection of on-site data.

Maximum predicted impacts due to the net increase associated with the proposed project are presented in Section 5.0, Table 5-1 for pollutants requiring PSD review. The methodology used to predict maximum impacts and the impact analysis results are presented in Sections 6.0 and 7.0. As shown in Table 5-1, the maximum net increase in impact is below the respective *de minimis* monitoring concentration for all pollutants. There is no acceptable ambient monitoring method for sulfuric acid mist; therefore, monitoring is not required for this pollutant.

3.5.2.3 GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 m high. The proposed stacks for the proposed turbines will be 56 feet (ft) in height (17.1 m) and, therefore, do not exceed the GEP stack height. The potential for downwash of the units' emissions due to nearby structures is discussed in Section 6.0, Air Quality Modeling Approach.

3.5.3 NONATTAINMENT REVIEW

The Intercession City plant is located in Osceola County, which is classified as an attainment area for all criteria pollutants. The plant is also located more than 50 km from any nonattainment area. Therefore, nonattainment requirements are not applicable.

3.5.4 OTHER CLEAN AIR ACT REQUIREMENTS

The 1990 CAA Amendments established a program to reduce potential precursors of acidic deposition. The Acid Rain Program was delineated in Title IV of the CAA Amendments and required EPA to develop the program. EPA's final regulations were promulgated on January 11, 1993, and included permit provisions (40 CFR Part 72), allowance system (Part 73), continuous emission monitoring (Part 75), excess emission procedures (Part 77), and appeal procedures (Part 78).

EPA's Acid Rain Program applies to all existing and new utility units except those serving a generator less than 25 MW, existing simple cycle CTs, and certain non-utility facilities; units which fall under the program are referred to as affected units. The EPA regulations would be applicable to the proposed project for the purposes for obtaining a permit and allowances, as well as emission monitoring. New units are required to obtain permits under the program by submitting a complete application 24 months before the later of January 1, 2000, or the date on which the unit begins serving an electric generator (greater than 25 MW).

The permit would provide SO_2 emission limitations (NO_x limitations are only applicable to coal-fired units) and the requirement to hold emission allowances. Emission limitations established in the Acid Rain Program are presumed to be less stringent than BACT or lowest achievable emission rate (LAER) for new units. An allowance is a market-based financial instrument that is equivalent to one ton of SO_2 emissions. Allowances can be sold, purchased, or traded.

Continuous emission monitoring (CEM) for SO_2 and NO_x is required for gas-fired and oil-fired affected units. When an SO_2 CEM is selected to monitor SO_2 mass emissions, a flow monitor is also required. Alternately, SO_2 emissions may be determined using procedures established in Appendix D, 40 CFR Part 75 (flow proportional oil sampling or manual daily oil sampling). CO_2 emissions must also be determined either through a CEM (e.g., as adiluent for NO_x monitoring) or calculation. Alternate procedures, test methods, and quality assurance/quality control (QA/QC) procedures for CEM are specified (Part 75 Appendices A through I). The CEM requirements including QA/QC procedures are, in general, more stringent than those specified in the NSPS for Subpart GG. New units are required to meet the requirements by the later of January 1, 1995, or not later than 90 days after the unit commences commercial operation.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The control technology review requirements of the PSD regulations are applicable to emissions of $S0_2$, PM, PM10, NO_x, CO, VOCs, and H_2SO_4 mist (see Section 3.0). This section presents the applicable NSPS and the proposed BACT for these pollutants. The approach to BACT analyses is based on the regulatory definitions of BACT, as well as EPA's current policy guidance requiring the top-down approach. A BACT determination requires an analysis of the economic, environmental, and energy impacts of the proposed and alternative control technologies [see 40 CFR 52.21(b)(12); and Rule 62-212.200(40), and Rule 62-214.410, F.A.C.]. The analysis must, by definition be specific to the project (i.e., case-by-case).

4.2 NEW SOURCE PERFORMANCE STANDARDS

The applicable NSPS for gas turbines are codified in 40 CFR 60, Subpart GG. These regulations apply to:

1. "Electric utility stationary gas turbines" with a heat input at peak load of greater than 100 X 10^6 Btu/hr [40 CFR 60.332 (b)];

2. "Stationary gas turbines" with a heat input at peak load between 10 and 100 X 10^6 Btu/hr [40 CFR 60.332 (c)]; or

3. "Stationary gas turbines" with a manufacturer's rate base load at ISO conditions of 30 MW or less [40 CFR 60.332 (d)].

The electric utility stationary gas turbine provisions apply to stationary gas turbines constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale (40 CFR 60.331 (q)]. The requirements for electric utility stationary gas turbines are applicable to the project and are the most stringent provision of the NSPS. These requirements are summarized in Table 4-1 and were considered in the BACT analysis.

As noted from Table 4-1, the NSPS NO_x emission limit can be adjusted upward to allow for fuel-bound nitrogen. For a fuel-bound nitrogen concentration of 0.015 percent or less, no increase in the NSPS is provided; for a fuel-bound nitrogen concentration of 0.03 percent, the NSPS is increased by 0.0012 percent or 12 parts per million (ppm).

For the Intercession City CTs, the NSPS emission limit would be 92ppm corrected to 15 percent oxygen at a fuel-bound nitrogen content of 0.015 percent for the Frame 7EA machines.

Table 4-1. Federal NSPS For Electric Utility Stationary Gas Turbines

Pollutant	Emission Limitation[a]
Sulfur Dioxide	Maximum of 0.015 percent by volume at 15 percent oxygen on a dry basis <u>or</u> sulfur in fuel no greater than 0.8 percent by weight
Nitrogen Oxides[b]	0.0075 percent by volume (75 ppm) at 15 percent 0_2 on a dry basis adjusted for heat rate and fuel nitrogen

[a] Applicable to electric utility gas turbines with a heat input at peak load of greater than 100 x 10^6 Btu/hr.

[b] Standard is multiplied by 14.4/Y; where Y is the manufacturer's rated heat rate inkilojoules per watt at rated load or actual measured heat rate based on the lower heating value of fuel measured at actual peak load; Y cannot be greater than 14.4. Standard is adjusted upward (additive) by the percent of nitrogen in the fuel:

Fuel-bound nitrogen (percent by weight)	Allowed Increase NO_x percent by volume
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N-0.1)
$N > 0.25$	0.005

where: N = the nitrogen content of the fuel (percent by weight).

Source: 40 CFR 60, Subpart GG.

4.3 BEST AVAILABLE CONTROL TECHNOLOGY

4.3.1 NITROGEN OXIDES

4.3.1.1 Identification of NO_x Control Technologies for CTs

NO_x emissions from combustion of fossil fuels consist of thermal NO_x and fuel-bound NO_x. Thermal NO_x is formed from the reaction of oxygen and nitrogen in the combustion air at combustion temperatures. Formation of thermal NO_x depends on the flame temperature, residence time, combustion pressure, and air-to-fuel ratios in the primary combustion zone. The design and operation of the combustion chamber dictates these conditions. Fuel-bound NO_x is created by the oxidation of volatilized nitrogen in the fuel. Nitrogen content in the fuel is the primary factor in its formation.

The most stringent NO_x controls for CTs established as LAER/BACT by state agencies are selective catalytic reduction (SCR) with dry low NO_x (DLN) Combustion and DLN Combustion alone. Reported and permitted NO_x removal efficiencies of SCR range from 40 to 80 percent. The most stringent emission limiting standards associated with SCR are approximately 2.5 ppm for natural gas firing. SCR has not been installed or permitted on simple-cycle CTs.

Wet injection and DLN Combustion technology are the primary methods of reducing NO_x emissions from CTs. The wet injection method of control was first mandated by the NSPS to reduce NO_x levels to 75 parts per million by volume, dry (ppmvd) (corrected to 15 percent 0_2 and heat rate). Development of improved wet injection combustors reduced NO_x concentrations to 25 ppmvd and 42 ppmvd (corrected to 15 percent 0_2) when burning natural gas and fuel oil, respectively. Recently, CT manufacturers have developed dry low NO_x combustors that can reduce NO_x concentrations to 9 ppmvd (corrected to 15 percent 0_2) when firing natural gas.

In Florida, a majority of the most recent PSD permits and BACT determinations for simple-cycle gas turbines have required either wet injection or DLN Combustion for NO_x control. The emission limits included in these permits and BACT determinations were 9 ppm and 42 ppm (corrected to 15 percent 0_2, dry conditions), respectively, for natural gas and fuel oil firing.

4.3.1.2 Technology Description and Feasibility

Selective Catalytic Reduction (SCR) –SCR uses ammonia (NH_3) to react with NO_x in the gas stream in the presence of a catalyst. NH_3, which is diluted with air to about 5 percent by volume, is introduced into the gas stream at reaction temperatures between 570 F and 750 degrees F. The reactions are as follows:

$$4NH_3 + 4NO + 0_2 = 4N_2 + 6H_20$$

$$4NH_3 + 2NO_2 + 0_2 = 3N_2 + 6H_20$$

SCR operating experience, as applied to gas turbines, consists primarily of baseload natural-gas-fired installations either of cogeneration or combined-cycle configuration; no simple-cycle facilities have SCR. Exhaust gas temperatures of simple-cycle CTs are generally in the range of 1,000 degrees F, which exceeds the optimum range for SCR. All current SCR applications have the catalyst placed in the heat recovery steam generators (HRSG) to achieve proper reaction conditions. This allows a relatively constant temperature for the reaction of NH_3 and NO_x on the catalyst surface.

The use of SCR has been limited to facilities that burn natural gas or small amounts of fuel oil since SCR catalysts are contaminated by sulfur-containing fuels (i.e., fuel oil). For most fuel oil burning facilities, catalyst operation is discontinued, or the exhaust bypasses the SCR system. While the operating experience has not been extensive, certain cost, technical, and environmental considerations have surfaced. These considerations are summarized in Table 4-2.

As presented in Table 4-2, ammonium bisulfate is formed by the reaction of NH_3 and sulfur trioxide ($S0_3$). Ammonium bisulfate can be corrosive and could cause damage to the HRSG surfaces that follow the catalyst, as well as to the stack. Corrosion protection for these areas would be required.

Zeolite catalysts, which are reported to be capable of operating in temperature ranges from 600 to 950 degrees F, have been available commercially only recently. Their application with SCR primarily has been limited to internal combustion engines. Optimum performance of an SCR system using a zeolite catalyst is reported to range from about 800 to 900 degrees F. The exhaust temperatures of the proposed CTs for the Intercession City site are expected to be in excess of 1,000 degrees F. At temperatures of 1,000 degrees F and above, thezeolite catalyst will be irreparably damaged. Therefore, application of an SCR system using a zeolite catalyst on a simple-cycle operation is technically infeasible without exhaust gas cooling. Moreover, since zeolite catalysts have not been operated continuously in combustion exhausts greater than 900 degrees F, the cooling system would have to reduce turbine exhaust temperatures about 200 degrees F, i.e., to around 800 degrees F.

Attemperation systems are neither commercially available nor have they been applied, even at a pilot stage, to SCR systems associated with simple-cycle CTs. Three types of potential attemperation systems include water sprays, air dilution, and indirect heat exchangers. The application of water sprays and air dilution would require sufficient distribution and mixing volume to assure uniform temperature throughout the catalyst. This would be extremely difficult to achieve in the size of CTs proposed because of their large and turbulent flowrate [approximately 1,500,000 actual cubic feet per minute (acfm) at 59 degrees F. If the temperature was not uniform, the catalyst would be irreversibly damaged in areas where the exhaust temperatures approach 1,000 degrees F. In addition, at temperatures above 950 degrees F, the ammonia injected to achieve the NO_x reduction could itself be oxidized to NO_x, the pollutant it was intended to remove. Indirect heat exchanges could reduce temperatures but have not been developed for this application. Application of any attemperation technique would require research and development that is beyond that considered appropriate by EPA regulations and guidelines.

Table 4-2. Cost, Technical, and Environmental Considerations of SCR Utilized on Combustion Turbines (Page 1 of 2)

Consideration	Description
COST:	
Catalyst Replacement	Catalyst life varies depending on the application. Cost ranges from 20 to 40 percent of total capital cost and is the dominant annual cost factor.
Ammonia	Ratio of at least 1:1 NH_3 to NO_x generally needed to obtain high removal efficiencies. Special storage and handling equipment required.
Space Requirements	For new installations, space in the catalyst is needed for replacement layers. Additional space is also required for catalyst maintenance and replacement.
Backup Equipment	Reliability requirements necessitate redundant systems such as ammonia control and vaporization equipment.
Catalyst Back Pressure Heat Rate Reduction	Addition of catalyst creates back-pressure on the turbine which reduces overall hear rate.
TECHNICAL:	
Ammonia Flow Distribution	NH_3 must be uniformly distributed in the exhaust stream to assure optimum mixing with NO_x prior to reaching the catalyst.
Temperature	The narrow temperature range that SCR systems operate within, i.e., about 100 degrees F, must be maintained even during load changes. Operational problems could occur if this range is not maintained. HRSG duct firing requires careful monitoring.

Table 4-2. Cost, Technical, and Environmental Considerations of SCR Utilized on Combustion Turbines (Page 2 of 2)

Consideration	Description
TECHNICAL (cont'd):	
Ammonia Control System	Quantity of NH_3 introduced must be carefully controlled. With too little NH_3, the desired control efficiency is not reached; with too much NH_3, NH_3 emissions (referred to as slip) occur.
Flow Control	The velocity through the catalyst must be within a range to assure satisfactory residence time.
ENVIRONMENTAL:	
Ammonia Slip	NH_3 slip, or NH_3 that passes unreacted through the catalyst and into the atmosphere, can occur if: 1) too much ammonia is added, 2) the flow distribution is not uniform, 3) the velocity is not within the optimum range, or the proper temperature is not maintained.
Ammonia Bisulfate	Ammonium bisulfate salts can lead to increased corrosion. These salts usually occur when firing fuel oil. These compounds are emitted as particulates.
N_2O and Nitrosoamines formation	The mechanism under which these compounds form is not totally understood. Secondary impacts can occur.

Wet Injection - The injection of water or steam in the combustion zone of CTs reduces the flame temperature with a corresponding decrease of NO_x emissions. The amount of NO_x reduction possible depends on the combustor design and the water-to-fuel ratio employed. An increase in the water-to-fuel ratio will cause a concomitant decrease in NO_x emissions until flame instability occurs. At this point, operation of the CT becomes inefficient and unreliable, and significant increases in products of incomplete combustion will occur (i.e., CO and VOC emissions).

For the CTs being considered for the Intercession City site, the combustion chamber design includes water injection while firing fuel oil, using GE "quiet combustor" for the Frame 7EA machines. This multiple-nozzle combustor was developed to increase the amount of steam or water injected into the combustion zone while reducing the dynamic pressure oscillations. High dynamic pressure oscillations in standard combustors lead to reduced combustor life. The lowest NO_x emission level guaranteed by GE for the quiet combustor is 42 ppmvd (corrected to 15 percent 0_2) when firing fuel oil.

Dry Low NO_x Combustor - In the last several years, CT manufacturers have offered and installed machines with dry low combustors. These combustors, which are offered on machines manufactured by GE, Siemens-Westinghouse, Kraftwork Union, and Asea Brown Boveri (ABB), can achieve NO_x concentrations of 15 ppmvd or less when firing natural gas. Thermal NO_x formation is inhibited by using combustion techniques where the natural gas and combustion air are pre-mixed prior to ignition. However, when firing oil, NO_x emissions are controlled only through water or steam injection to exhaust concentrations of 42 ppmvd.

NO_xOUT Process - The NO_xOUT process originated from the initial research by the Electric Power Research Institute (EPRI) in 1976 on the use of urea to reduce NO_x. EPRI licensed the proprietary process to Fuel Tech, Inc., for commercialization. In the NO_xOUT process, aqueous urea is injected into the flue gas stream ideally within a temperature range of 1,600 F to 1,900 degrees F. In the presence of oxygen, the following reaction results:

$$CO(NH_2)_2 + 2NO + 1/2\ 0_2 \dashrightarrow 2N_2 + C0_2 + 2H_20$$

The amount of urea required is most cost effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. In addition to the original EPRI urea patents, Fuel Tech claims to have a number of proprietary catalysts capable of expanding the effective temperature range of the reaction to between 1,000 F and 1,950 degrees F. Advantages of the system are as follows:

1. Low capital and operating costs due to utilization of urea injection, and
2. The proprietary catalysts used are nontoxic and nonhazardous, thus eliminating potential disposal problems.

Disadvantages of the system are as follows:

1. Formation of ammonia from excess urea treatment rates and/or improper use of reagent catalysts; and
2. $S0_3$, if present, will react with ammonia created from the urea to form ammonium bisulfate, potentially plugging the cold end equipment downstream.

To the best of our knowledge, commercial application of the NO_xOUT system is limited to three reported cases:

1. Trial demonstration on a 62.5-ton-per-hour (TPH) stoker-fired wood waste boiler with 60 to 65 percent NO_x reduction,
2. A 600 x 10^6 Btu CO boiler with 60 to 70 percent NO_x reduction, and
3. A 75 MW pulverized coal-fired unit with 65 percent NO_x reduction.

The NO_xOUT system has not been demonstrated on any stationary internal combustion engine.

The NO_xOUT process is not technically feasible for the proposed lean-burn engine due to the required high application temperature of 1,000 F to 1,950 degrees F. The exhaust gas temperature of the CT is about 1,000 degrees F. Raising the exhaust temperature the required amount essentially would require installation of a heater. This would be economically prohibitive and would result in an increase in fuel consumption, an increase in the volume of gases that must be treated by the control system, and an increase in uncontrolled air emissions, including NO_x.

Thermal DeNO$_x$ - Thermal DeNO$_x$ is Exxon Research and Engineering Company's patented process for NO_x reduction. The process is a high temperature selective noncatalytic reduction (SNCR) of NO_x using ammonia as the reducing agent. Thermal DeNO$_x$ requires the exhaust gas temperature to be above 1,800 degrees F. However, use of ammonia plus hydrogen lowers the temperature requirement to about 1,000 degrees F. For some applications, this must be achieved by additional firing in the exhaust stream prior to ammonia injection.

The only known commercial applications of Thermal DeNO$_x$ are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800 degrees F. There are no known applications on or experience with CTs. Temperatures of 1,800 degrees F require alloy materials constructed with very large size piping and components since the exhaust gas volume would be increased by several times. As with the NO$_x$OUT process, high capital, operating, and maintenance costs are expected because of construction-specified material, an additional duct burner system, and fuel consumption. Uncontrolled emissions would increase because of the additional fuel burning. Thus, because of its high application temperature, the Thermal DeNO$_x$ process is considered to be technically infeasible and will not be considered for the proposed project. The exhaust gas temperature of a lean-burn engine is typically about 1,000 degrees F; the cost to raise the exhaust gas to 1,800 degrees F is prohibitively expensive.

Nonselective Catalytic Reduction - Certain manufacturers, such as Engelhard, market a nonselective catalytic reduction system (NSCR) for NO_x control on reciprocating engines. The NSCR process requires a low oxygen content in the exhaust gas stream and high temperature (700 F to 1,400 degrees F) in order to be effective. CTs have the required temperature but also high oxygen levels (greater than 12 percent) and, therefore, cannot use the NSCR process. As a result, NSCR is not a technically feasible add-on NO_x control device for CTs.

Summary of Technically Feasible NO_x Control Methods - The available information suggests that SCR with wet injection is technically infeasible for simple-cycle operation. SCR with wet injection has not been applied to simple-cycle CTs.

A technical evaluation of tail gas controls (i.e., SCR, NO_xOUT, Thermal DENO_x, and NSCR) indicates that these processes have not been applied to simple-cycle CTs and are technically infeasible for the project due to process constraints (e.g., temperature). DLN combustors and wet injection are appropriate for the project, based on the technical factors discussed above.

Wet injection is a technically feasible alternative for the Intercession City CTs. The application of this technology has the following limitations:

1. Wet injection can be accomplished until a condition of maximum moisturization occurs; this design condition occurs at 42 ppm with fuel oil.

2. Wet injection will not reduce substantially NO_x formation caused by fuel-bound nitrogen. Any emission-limiting requirements must account for this effect.

3. Wet injection will increase the emissions of CO and VOC. Emissions are dependent on the water-to-fuel ratio.

For the BACT analysis, DLN combustion capable of achieving NO_x emission levels to 9 ppm while firing natural gas and wet injection capable of achieving NO_x emission levels to 42 ppm when firing fuel oil (corrected to 15 percent 0_2 dry conditions) was assumed. These emission levels are the most stringent being established as BACT for simple-cycle CTs.

4.3.1.3 Impact Analysis

A BACT determination requires an analysis of the economic, environmental, and energy impacts, of the proposed and alternative control technologies [see 40 CFR 52.21(b)(12), Rule 62-212.200(40), F.A.C., and Rule 62-214.410, F.A.C.]. The analysis must, by definition, be specific to the project, i.e., case-by-case. The BACT analysis was performed by comparing the technically feasible option identified (i.e., DLN combustors and wet injection) to SCR, even though SCR has not been demonstrated for simple-cycle CTs.

Economic - The emission estimates and reductions associated with the control technology options discussed are presented in Table 4-3. The estimated total capital and annualized capital cost for the proposed CT is presented in Table 4-4.

Environmental - The maximum predicted impacts of the alternative technologies are all considerably below the PSD increment for NO_x of 25 $\mu g/M^3$ annual average, and the AAQS for NO_x of 100 $\mu g/M^3$.

Energy - The use of the quiet combustor will affect energy production in two ways. First, the heat rate will increase about 1 percent (at ISO conditions) compared to an emission of 42 ppmvd, corrected to 15 percent 0_2, which requires more fuel to generate the same amount of power. This energy penalty will be about 500 British thermal units per kilowatt hour (Btu/kWh). Second, water injection will increase power by about 5 percent, for a net power benefit of about 4 MW for the Frame 7EA machine. Since the primary purpose of the Intercession City project is to provide peaking power, the benefit of increased power offsets the increased heat rate.

4.3.1.4 Proposed BACT and Rationale

The proposed BACT for the Intercession City CTs is DLN for gas firing and wet injection for fuel oil firing. The proposed NO_x emissions levels using DLN and wet injection are 9 ppmvd (corrected) when firing natural gas and 42 ppmvd (corrected) when firing fuel oil. This control technology is proposed for the following reasons:

1. SCR was rejected based on technical infeasibility, as well as economics. SCR has not been applied to or demonstrated on simple-cycle CTs.

2. The proposed BACT of DLN (gas) and wet injection (oil) provides the least costly control alternative and results in low environmental impacts (less than 1 percent of the allowable PSD increments and less than 1 percent of the AAQS for NO_x). DLN and wet injection at the proposed emissions levels have been adopted previously in BACT determinations. In addition, the CT manufacturer (i.e., GE) has been willing to guarantee this level of NO_x emissions.

Table 4-3. NO_x Emission Estimates (TPY) of BACT Alternative Technologies (per Unit)

Alternative BACT Control Technologies	Operating Mode[a]		
	Oil [b]	Gas	Total
NO_x Emission (TPY)			
Dry Low-NO_x (DLN) only	83.5	38.2	121.7
DLN with SCR [c]	33.4	15.3	48.7
Reduction	(50.1)	(22.9)	(73.0)
Basis of Emissions (ppmvd)			
DLN only	42	9	
DLN with SCR	16.8	3.6	
Hours of Operation	1,000	2,390	3,390

Note: DLN = Dry low-NO_x.
SCR = selective catalytic reduction.
TPY = tons per year.

[a] Emission rates were based on a Frame 7EA class combustion turbine operating at 39 percent capacity and firing natural gas for 2,390 hours and distillate fuel oil for 1,000 hours. Emission data are based on an ambient temperature of 59°F at maximum emission rates.

[b] In addition to the DLN design, water injection is assumed during fuel oil firing.

[c] Based on primary emissions with SCR; no account is made for additional emissions (secondary) due to lost energy from heat rate penalty and electrical usage for SCR operation.

Table 4-4. Comparison of Alternative BACT Control Technologies for NO_x (per Unit)

	Alternative BACT Control Technologies	
	DLN Only	SCR
Technical Feasibility	Feasible	Feasible for gas
Economic Impact[a]		
Capital Costs	Included	$3,605,475
Annualized Costs	Included	$ 941,081
Environmental Impact[b]		
Total NO_x (TPY)	121.7	48.7
NO_x Reduction (TPY)	NA	(73.0)
Cost Effectiveness		
$/ton of NO_x removed	NA	$12,890

[a] Capital and annualized costs were estimated at approximately 50 percent of those determined in a recent PSD application for a GE PG7241 FA (165 MW). See Appendix B.

[b] See emission data presented in Table 4-3.

The proposed BACT emission level should also account for fuel-bound nitrogen (FBN) content greater than 0.015 percent since there is no practicable means for reducing NO_x at higher FBN levels while firing fuel oil. The allowance specified in the NSPS for FBN levels greater than 0.015 percent is requested.

4.3.2 CARBON MONOXIDE (CO)

4.3.2.1 Emission Control Hierarchy

CO emissions are a result of incomplete or partial combustion of fossil fuel. Combustion design and catalytic oxidation are the control alternatives that are viable for the project.

Combustion design is the more common control technique used in CTs. Sufficient time, temperature, and turbulence are required within the combustion zone to maximize combustion efficiency and minimize the emissions of CO. Combustion efficiency is dependent upon combustor design. When wet NO_x control systems are employed, the amount of water or steam injected in the combustion zone also affects combustion efficiency. For theCTs being evaluated and with wet injection NO_x control, CO emissions will average about 20 ppm corrected to dry conditions.

Catalytic oxidation is a post-combustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection. These installations have been required to use LAER technology and typically have CO limits in the 10 ppm range (corrected to dry conditions).

4.3.2.2 Technology Description

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300 degrees F, with efficiencies above 90 percent occurring at temperatures above 600 degrees F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. ForCTs, the oxidation catalyst can be located within the heat recovery steam generator (HRSG), if so equipped. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency. The existing oxidation catalyst applications have primarily been limited to smaller cogeneration facilities burning natural gas.

Oxidation catalysts have not been used on fuel-oil-fired CTs or simple-cycle facilities. The use of sulfur-containing fuels in an oxidation catalyst system would result in an increase of $S0_3$ emissions and concomitant corrosive effects to the stack. In addition, trace metals in the fuel could result in catalyst poisoning during prolonged periods of operation.

Since the units likely will require numerous startups, variations in exhaust conditions will influence catalyst life and performance. Very little technical data exist to demonstrate the effect of such cycling.

The lack of demonstrated operation with oil firing suggests rejection of catalytic oxidation as a technically feasible alternative. However, the advent of a second generation catalyst suggests that an oxidation catalyst could be used.

Combustion design is dependent upon the manufacturer's operating specifications, which include the air-to-fuel ratio and the amount of water injected. The CTs proposed for the project have designs to optimize combustion efficiency and minimize CO emissions. Installations with an oxidation catalyst and combustion controls generally have controlled CO levels of 10 ppm as LAER and BACT.

For the Intercession City CTs, the following alternatives were evaluated for natural gas firing for BACT:

1. Oxidation catalyst at 10 ppmvd; maximum CO emissions are 37.3 TPY (59 degrees F).

2. Combustion controls at 25 ppmvd when firing natural gas (at base load) and 20 ppmvd when firing fuel oil at base load; maximum emissions are 86.5 TPY (59 degrees F).

4.3.2.3 Impact Analysis

Economic - The estimated annualized cost of a CO oxidation catalyst is $257,717 (Table 4-5), with a cost effectiveness of $5,238 per ton of CO removed. The cost effectiveness is based on assumptions presented in Table 4-5 and in Appendices A and B. No costs are associated with combustion techniques since they are inherent in the design.

Environmental - The air quality impacts of both oxidation catalyst control and combustion design control techniques are well below the significant impact levels for CO. Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst.

Energy - energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 2 inches water gauge would be expected. At a catalystback pressure of about 2 inches, an energy penalty of about 12,500,000 kWh/yr would result at 100 percent load. This energy penalty is sufficient to supply the electrical needs of about 1,000 residential customers over a year. Fuel oil usage would effectively increase by about 1,030,000 gallons/year.

Table 4-5. Comparison of Alternative BACT Control Technologies for CO (per Unit)

	Alternative BACT Control Technologies	
	Combustion Design	Oxidation Catalyst
Technical Feasibility	Feasible	Feasible for gas
Economic Impact[a]		
Capital Costs	Included	$960,566
Annualized Costs	Included	$257,717
Environmental Impact[b]		
Total CO (TPY)	86.5	37.3
CO Reduction (TPY)	NA	(49.2)
Cost Effectiveness		
$/ton of CO removed	NA	$5,238

[a] Capital and annualized costs were estimated at approximately 50 percent of those determined in a recent PSD application for a GE PG7241 FA (165 MW). See Appendix B.

[b] See Appendix A, Emissions Data and Calculations. Emission rate of 10 ppmvd with CO catalyst equal to 22 lb/hr (i.e., 50 percent of the emission rate on oil, which is 20 ppmvd and 44 lb.hr at 59°F).

4.3.2.4 Proposed BACT and Rationale

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on CTs. Catalytic oxidation is considered infeasible and unreasonable for the following reasons:

1. Catalytic oxidation has not been demonstrated on a continuous basis when using fuel oil; and

2. The economic impacts are significant (i.e., an annualized cost of $257,717, with a cost effectiveness of over $5,238 per ton of CO removed).

4.3.3 VOLATILE ORGANIC COMPOUNDS

VOCs will be emitted by the CT as a result of incomplete combustion. The proposed BACT for VOC emissions will be the use of combustion technology and the use of clean fuels so that emissions will not exceed 7.0 ppmvw when firing natural gas and distillate oil (about 10 lb/hr at 59 degrees F and base load operation). These emission levels are similar to the BACT emission levels established for other similar sources. Combustion controls and the use of clean fuels have been overwhelmingly approved as BACT for CTs. The environmental effect of further reducing emissions would not be significant.

4.3.4 PM/PM10, $S0_2$ AND OTHER REGULATED AND NONREGULATED POLLUTANT EMISSIONS

The PM/PMIO emissions from the CTs are a result of incomplete combustion and trace elements in the fuel. Beryllium and inorganic arsenic (As) would be included in the PM/PM10 emissions. The design of the CT ensures that particulate emissions will be minimized by combustion controls and the use of clean fuels. A review of EPA's BACT/LAER Clearinghouse Documents did not reveal any post-combustion particulate control technologies being used on gas- or oil-fired CTs.

The maximum particulate emissions from the CT will be lower in concentration than that normally specified for fabric filter designs (i.e., the grain loading associated with the maximum particulate emissions [about 10.0 pounds per hour (lb/hr) when firing fuel oil] is less than 0.01 grain per standard cubic foot (gr/scf), which is a typical design specification for a baghouse. This further demonstrates that no further particulate controls are necessary for the proposed project.

There are no technically feasible methods for controlling the emissions of these pollutants from CTs, other than the inherent quality of the fuel. Clean fuels, natural gas and distillate oil represent BACT for these pollutants. The use of natural gas and very low sulfur (0.05%) fuel oil will limit emissions of SO_2. Further, natural gas is the primary fuel and the use of fuel oil is proposed to be limited to the equivalent of 1,000 hours per year per CT at full load.

For the nonregulated pollutants, none of the control technologies evaluated for other pollutants (i.e., SCR) would reduce such emissions; thus, natural gas and distillate oil represent BACT because of their inherently low contaminant content.

5.0 AMBIENT AIR QUALITY MONITORING DATA ANALYSIS

5.1 PSD PRECONSTRUCTION MONITORING APPLICABILITY

Based on the worst-case proposed source emissions data and air quality modelling results for the proposed combustion turbines, ambient air quality monitoring is not required for SO_2, PM_{10}, or NO_2 because the maximum predicted impacts are less than the PSD pre-construction monitoring *de minimis* values for those pollutants (FDEP Rule 62-212.400). Table 5-1 compares the maximum predicted concentrations with the *de minimis* levels. For ozone (O_3), annual volatile organic compound (VOC) emissions from from Units P12 - P14 will be less than 100 tons per year, so ambient monitoring data for O_3 are not required.

TABLE 5-1

SUMMARY OF MAXIMUM MODELED IMPACTS VS. PSD MONITORING *DE MINIMIS* VALUES

Pollutant	Averaging Period	Highest Modeled Concentration (ug/m^3)	PSD Demin. Level (ug/m^3)	Significance
Sulfur Dioxide (SO_2)	24-Hour	2.44	13	NO
Particulate Matter (PM_{10})	24-Hour	0.16	10	NO
Nitrogen Dioxide (NO_2)	Annual	0.13	14	NO

FPC, 1999

6.0 AIR QUALITY MODELLING APPROACH

This section summarizes the air quality modelling protocol and input parameters utilized in the air impact determinations presented in Section 7.0. Included are descriptions of the models, meteorology, options selected, listings of modelling parameters for the proposed facilities and existing sources, receptor locations, and step-by-step procedures that were used to develop the necessary projected impacts.

The scope of the required modelling analysis is limited to those pollutants that were determined to be subject to PSD review in Section 3.0, Table 3-2 (CO, NO_x, SO_2, PM, VOC (O_3), and sulfuric acid mist). Not all of the pollutants will require the full PSD air quality analysis; for some, impact identification of the new facilities alone will be sufficient.

As indicated in Table 3-2, there will be a significant increase in VOC emissions, triggering PSD review for ozone. Ozone formation cannot be simulated with a simple Gaussian dispersion model. However, the U.S. EPA Guideline on Air Quality Models (EPA, 1990a) indicates that "the use of models incorporating complex chemical mechanisms should be considered only on a case-by-case basis with proper demonstration of applicability. These are generally regional models not designed for the evaluation of individual sources but used primarily for region-wide evaluations." The proposed facility is not subject to a VOC emissions impact assessment and an ozone modelling analysis is not appropriate.

The proposed source emissions of sulfuric acid mist are shown in Table 3-2 to be above the PSD significant emission rates. However, the PSD regulations do not define significant impact levels nor are ambient air quality standards established for this pollutant. Hence, the air quality impact assessment for sulfuric acid mist is limited to prediction of the maximum impacts from the proposed facility.

6.1 GENERAL MODELLING APPROACH

The PSD regulations require an air quality impact assessment consisting of a proposed source significant impact area analysis, a PSD increment consumption analysis, an ambient air quality standards impact analysis, and an additional impacts analysis. These analyses are discussed in greater detail in the following sections under specific modelling methodologies. The modelling approach followed EPA and FDEP guidelines for determining compliance with applicable PSD increments and ambient air quality standards.

A screening analysis was performed to determine the worst-case emissions case to be used as input to the refined modelling analysis. In the refined analysis, the worst-case and five years of meteorological data were used to predict the highest ambient concentrations of applicable criteria pollutants. These results were compared to the PSD significance levels for each pollutant in order to determine whether additional modelling was necessary. All predicted maximum concentrations were less than the PSD significance values.

6.2 MODEL SELECTION AND OPTIONS

6.2.1 Dispersion Model Selection

The area surrounding the Intercession City Facility has been determined to be a rural area based upon the technique for urban/rural determinations documented in the EPA "Guideline on Air Quality Models", which applies land use criteria. Based upon this determination, the rural dispersion option was used in both regulatory air quality dispersion models that were used for this application. The EPA SCREEN3 model was used to evaluate the load and ambient temperature conditions that are predicted to produce the highest ambient impacts. The resulting worst-case emissions were used as input to the refined ISCST3 dispersion model (Version98226) for a comprehensive evaluation of the ambient air impacts of the proposed combustion turbines. The ISCST3 model is a referenced EPA dispersion model recommended for use in urban or rural areas, and for application to point, area, and volume sources. The ISCST3 model can predict ambient pollutant concentrations and period of occurrence for 1-hour, 3-hour, 8-hour, 24hour, and annual averaging periods at each receptor for each full year of hourly meteorological data used.

6.2.2 Dispersion Model Options

The model's Regulatory Default option was used for this analysis. The ISCST3 model was applied without terrain adjustment data because the area in which the facility is located has very little relief. The ISCST3 model's building downwash options were applied because the stacks for the proposed sources will be less than the stack height at which downwash effects may occur.

For purposes of model input, the three stacks for Units P12 through P14 were co-located; therefore, one source was input to the model.

The air quality impact assessment for PM assumed that all PM emissions were PM_{10} emissions. This assumption simplified the PM modelling analysis and makes for a conservative approach to modelling PM impacts.

6.3 METEOROLOGICAL DATA

The air quality modelling analysis used hourly preprocessed National Weather Service (NWS) surface meteorological data from Orlando, Florida, and concurrent twice-daily upper air soundings from Ruskin, Florida, for the years 1987-1991. The meteorological data were supplied by FDEP in the preprocessed format required by the ISCST3 model. The preprocessed hourly meteorological data file for each year of record used in the analysis contains randomized wind direction, wind speed, ambient temperature, atmospheric stability using the Turner (1970) stability classification scheme, and mixing heights.

6.4 EMISSIONS INVENTORY

6.4.1 Proposed Sources

The proposed combustion turbines will have the capability of firing natural gas and low sulfur fuel oil. The fuel scenarios evaluated for the proposed source include natural gas and oil firing at 100%, 75%, 50% and 25% load at 20°F, 59°F, and 100°F ambient temperature.

The emissions inventories for the proposed source and fuel scenarios identified above are presented in Tables 6-1 through 6-8. The pollutant emission rates shown in those tables are representative of BACT as demonstrated in Section 4.0. The air quality modelling analysis for the proposed sources assumed that maximum design capacity emissions represent actual emissions for purposes of determining PSD increment consumption.

The proposed source worst-case fuel scenario was determined by modelling each temperature and load scenario for each fuel using the SCREEN3 model. In addition to the ambient temperature cases previously discussed, loads of 25%, 50%, 75%, and 100% were evaluated in the screening analysis. The results indicated that the full load case at 59°F. was the worst-case scenario for purposes of dispersion modelling for SO_2 and for NO_x while firing oil. For CO, the worst-case scenario was the 50% load case at 20°F while firing oil. For PM, the worst case was the 25% load case at 100°F, again while firing oil. Complete SCREEN3 model outputs have been included as Appendix C to this application.

6.4.2 Existing Sources

The results of the proposed source significant impact area analysis (which is described in Section 7.0) indicated that the proposed facility's air quality impacts are less than the PSD significant impact levels. Therefore, no additional significant impact modelling analysis for PSD Class II increment consumption or ambient air quality standard impact is necessary.

6.5 RECEPTOR LOCATIONS

A description of the receptor grids used in this modelling analysis is presented below.

6.5.1 Receptor Grid for Proposed Source Significant Impact Analysis

This modelling analysis used a polar receptor grid beginning at 350 meters (m) and extending out to cover a 50 kilometer (km) radius centered over the proposed source. The polar grid consisted of 36 radials, each separated by 10-degree increments and extending outward at ring distances of 500 m, 1 km, and 1.5, 2.0, 2.5, 5.0, 10.0, 15.0, 20.0, 25.0, 30.0, 35.0, 40.0, 45.0, and 50.0km with reference to the proposed source location. Additional polar coordinate receptors were placed at 10-degree intervals at the plant property line to assess concentrations near the plant boundary.

The modelling results indicated no significant impacts for the PSD pollutants.

6.5.2 Receptor Grid for Class I PSD Analysis

A network of 13 discrete receptors was placed at the boundary of the Chassahowitzka National Wilderness Area (NWA) in order to reassess the potential incremental impact of the proposed source on that Class I area. The NWA receptors were obtained from the FDEP, and the coordinates of these receptor points are listed in Table6-9.

6.6 BUILDING DOWNWASH EFFECTS

Based on the building dimensions associated with the structures associated with the proposed combustion turbines, the 17.1 meter stacks for Units P12 through P14 will be less than the calculated value (29.5 meters) at which downwash effects would not be expected to occur. Therefore, the potential for building downwash was considered in the modelling analysis.

The procedures used for addressing the effects of building downwash are those recommended in the ISC Dispersion Model User's Guide. The building height, length, and width are input to the Building Parameter Input Program (BPIP) model, which uses these parameters to create the effective wind direction-specific building dimensions for input to the model. For short stacks (i.e., physical stack height is less than $H_b + 0.5 L_b$, where H_b is the building height and L_b is the lesser of the building height or projected width), the Schulman and Scire (1980) method is used. If this method is used, then direction-specific building dimensions are input for H_b and L_b for 36 radial directions, with each direction representing a 10-degree sector.

For cases where the physical stack is greater than H_b + $0.5\ L_b$, the Huber-Snyder (1976) method is used. In the case of the proposed units, the turbine inlet structures are the dominant buildings of influence. The dimensions of these structures are 11.8meters high (H_b) and 7.1 meters wide (M_W). Since the proposed stack height of 17.1meters is more than H_b + $0.5\ L_b$, only the Huber-Snyder downwash algorithm is used by the ISCST model.

TABLE 6-1
COMBUSTION TURBINE UNIT (87 MW)
ESTIMATED (1) PERFORMANCE ON NATURAL GAS
100% LOAD

CONDITIONS			
Ambient Temperature (°F)	20	59	100
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	100	100	100
Maximum Heat Input Rate (MMBtu/hr)(2)	980	885	787
EMISSIONS (lb/hr)			
Carbon Monoxide (25 ppm)	59	54	48
Nitrogen Oxides (at 15% O_2) (9 ppmvd)(3)	36	32	29
Sulfur Dioxide	3	3	2
Particulate Matter (PM_{10})	5	5	5
Opacity (%)	10	10	10
Volatile Organic Compounds (7 ppmvw)	10	9	8
Sulfuric Acid Mist	0.3	0.3	0.2
STACK PARAMETERS			
Stack Height (ft)	56	56	56
Stack Diameter (ft)(equivalent)	16.1	16.1	16.1
Stack Gas Temperature (°F)	971	998	1026
Stack Gas Exit Velocity (ft/sec)	150	137	124

Notes:
(1) Emission estimates based on manufacturer's data
(2) For CTs the heat-input rate is based on the lower heating value (LHV) of the fuel (950 Btu/SCF).
(3) Not corrected to ISO conditions.
Neg. = Negligible

TABLE 6-2
COMBUSTION TURBINE UNIT (87 MW)
ESTIMATED $^{(1)}$ PERFORMANCE ON NATURAL GAS
75% LOAD

CONDITIONS			
Ambient Temperature (°F)	20	59	100
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	75	75	75
Maximum Heat Input Rate (MMBtu/hr)$^{(2)}$	783	718	651
EMISSIONS (lb/hr)			
Carbon Monoxide (25 ppm)	60	42	38
Nitrogen Oxides (at 15% O_2) (9 ppmvd)$^{(3)}$	28	26	24
Sulfur Dioxide	2	2	1.5
Particulate Matter (PM_{10})	5	5	5
Opacity (%)	10	10	10
Volatile Organic Compounds	18	9	7
Sulfuric Acid Mist	0.2	0.2	0.15
STACK PARAMETERS			
Stack Height (ft)	56	56	56
Stack Diameter (ft)	16.1	16.1	16.1
Stack Gas Temperature (°F)	1010	1045	1091
Stack Gas Exit Velocity (ft/sec)	117	108	98

Notes: (1) Emission estimates based on manufacturer's data

(2) For CTs the heat-input rate is based on the lower heating value (LHV) of the fuel (950 Btu/SCF).

(3) Not corrected to ISO conditions.

Neg. = Negligible

TABLE 6-3
COMBUSTION TURBINE UNIT (87 MW)
ESTIMATED (1) PERFORMANCE ON NATURAL GAS
50% LOAD

CONDITIONS			
Ambient Temperature (°F)	20	59	100
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	50	50	50
Maximum Heat Input Rate (MMBtu/hr)(2)	629	579	526
EMISSIONS (lb/hr)			
Carbon Monoxide	50	65	32
Nitrogen Oxides (at 15% O_2)(3)	23	21	100
Sulfur Dioxide	1.5	1.5	1
Particulate Matter (PM_{10})	5	5	5
Opacity (%)	10	10	10
Volatile Organic Compounds	15	20	6
Sulfuric Acid Mist	0.15	0.15	0.1
STACK PARAMETERS			
Stack Height (ft)	56	56	56
Stack Diameter (ft)	16.1	16.1	16.1
Stack Gas Temperature (°F)	1081	1100	1100
Stack Gas Exit Velocity (ft/sec)	93	88	83

Notes: (1) Emission estimates based on manufacturer's data

(2) For CTs the heat-input rate is based on the lower heating value (LHV) of the fuel (950 Btu/SCF).

(3) Not corrected to ISO conditions.

Neg. = Negligible

TABLE 6-4

COMBUSTION TURBINE UNIT (87 MW)

ESTIMATED (1) PERFORMANCE ON NATURAL GAS

25% LOAD

CONDITIONS			
Ambient Temperature (°F)	20	59	100
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	25	25	25
Maximum Heat Input Rate (MMBtu/hr)(2)	442	411	383
EMISSIONS (lb/hr)			
Carbon Monoxide	33	44	39
Nitrogen Oxides (at 15% O_2)(3)	80	65	41
Sulfur Dioxide	1	1	1
Particulate Matter (PM_{10})	5	5	5
Opacity (%)	10	10	10
Volatile Organic Compounds (7 ppmvd)	6	5	5
Sulfuric Acid Mist	0.1	0.1	0.1
STACK PARAMETERS			
Stack Height (ft)	56	56	56
Stack Diameter (ft)	16.1	16.1	16.1
Stack Gas Temperature (°F)	939	946	973
Stack Gas Exit Velocity (ft/sec)	83	81	76

Notes:

(1) Emission estimates based on manufacturer's data

(2) For CTs the heat-input rate is based on the lower heating value (LHV) of the fuel (950 Btu/SCF).

(3) Not corrected to ISO conditions.

Neg. = Negligible

TABLE 6-5

COMBUSTION TURBINE UNIT (87 MW)

ESTIMATED (1) PERFORMANCE ON FUEL OIL

100% LOAD

CONDITIONS			
Ambient Temperature (°F)	20	59	100
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	100	100	100
Maximum Heat Input Rate (MMBtu/hr)(2)	1,061	954	833
EMISSIONS (lb/hr)			
Carbon Monoxide (20 ppm)	48	44	39
Nitrogen Oxides (at 15% O_2) (42 ppmvd)(3)	186	167	146
Sulfur Dioxide	55.0	49.5	43.3
Particulate Matter (PM_{10})	10	10	10
Opacity (%)	20	20	20
Volatile Organic Compounds (7 ppmvd)	10	9	9
Sulfuric Acid Mist	6	5	4
STACK PARAMETERS			
Stack Height (ft)	56	56	56
Stack Diameter (ft)	16.1	16.1	16.1
Stack Gas Temperature (°F)	965	993	1023
Stack Gas Exit Velocity (ft/sec)	153	140	125

Notes: (1) Emission estimates based on manufacturer's data

(2) For CTs the heat-input rate is based on the lower heating value (LHV) of the fuel (18,300 Btu/LB).

(3) Not corrected to ISO conditions.

Neg. = Negligible

TABLE 6-6

COMBUSTION TURBINE UNIT (87 MW)

ESTIMATED (1) PERFORMANCE ON FUEL OIL

75% LOAD

CONDITIONS			
Ambient Temperature (°F)	20	59	100
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	75	75	75
Maximum Heat Input Rate (MMBtu/hr)(2)	829	753	667
EMISSIONS (lb/hr)			
Carbon Monoxide (20 ppm)	38	36	32
Nitrogen Oxides (at 15% O_2) (42 ppmvd)(3)	144	131	116
Sulfur Dioxide	43	39	34.5
Particulate Matter (PM_{10})	10	10	10
Opacity (%)	20	20	20
Volatile Organic Compounds (7 ppmvd)	8	8	7
Sulfuric Acid Mist	5	4	4
STACK PARAMETERS			
Stack Height (ft)	56	56	56
Stack Diameter (ft)	16.1	16.1	16.1
Stack Gas Temperature (°F)	964	985	1014
Stack Gas Exit Velocity (ft/sec)	122	114	104

Notes:
(1) Emission estimates based on manufacturer's data
(2) For CTs the heat-input rate is based on the lower heating value (LHV) of the fuel (18,300 Btu/LB).
(3) Not corrected to ISO conditions.
Neg. = Negligible

TABLE 6-7
COMBUSTION TURBINE UNIT (87 MW)
ESTIMATED (1) PERFORMANCE ON FUEL OIL
50% LOAD

CONDITIONS			
Ambient Temperature (°F)	20	59	100
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	50	50	50
Maximum Heat Input Rate (MMBtu/hr)(2)	598	550	497
EMISSIONS (lb/hr)			
Carbon Monoxide	522	364	244
Nitrogen Oxides (at 15% O_2) (42 ppmvd)(3)	102	94	85
Sulfur Dioxide	31	28.5	26
Particulate Matter (PM_{10})	10	10	10
Opacity (%)	20	20	20
Volatile Organic Compounds (7 ppmvd)	8	8	7
Sulfuric Acid Mist	3	3	3
STACK PARAMETERS			
Stack Height (ft)	56	56	56
Stack Diameter (ft)	16.1	16.1	16.1
Stack Gas Temperature (°F)	758	792	835
Stack Gas Exit Velocity (ft/sec)	121	113	104

Notes:
(1) Emission estimates based on manufacturer's data
(2) For CTs the heat-input rate is based on the lower heating value (LHV) of the fuel (18,300 Btu/LB).
(3) Not corrected to ISO conditions.
Neg. = Negligible

TABLE 6-8

COMBUSTION TURBINE UNIT (87 MW)

ESTIMATED (1) PERFORMANCE ON FUEL OIL

25% LOAD

CONDITIONS			
Ambient Temperature (°F)	20	59	100
Ambient Relative Humidity (%)	60	60	60
Load Condition (%)	25	25	25
Maximum Heat Input Rate (MMBtu/hr)(2)	403	378	351
EMISSIONS (lb/hr)			
Carbon Monoxide	54	36	33
Nitrogen Oxides (at 15% O_2) (42 ppmvd)(3)	68	64	59
Sulfur Dioxide	21	19.5	18
Particulate Matter (PM_{10})	10	10	10
Opacity (%)	20	20	20
Volatile Organic Compounds (7 ppmvd)	8	8	7
Sulfuric Acid Mist	2	2	2
STACK PARAMETERS			
Stack Height (ft)	56	56	56
Stack Diameter (ft)	16.1	16.1	16.1
Stack Gas Temperature (°F)	578	621	674
Stack Gas Exit Velocity (ft/sec)	120	113	103

Notes: (1) Emission estimates based on manufacturer's data

(2) For CTs the heat-input rate is based on the lower heating value (LHV) of the fuel (18,300 Btu/LB).

(3) Not corrected to ISO conditions.

Neg. = Negligible

TABLE 6-9
RECEPTOR GRID FOR PSD CLASS I AREA

Point	UTM Coordinates		Distance from Polk County Site *		
	East (km)	North (km)	X (km)	Y (km)	Distance (km)
1	340.3	3,165.7	-106.0	39.7	113.2
2	340.3	3,167.7	-106.0	41.7	113.9
3	340.3	3,169.8	-106.0	43.8	114.7
4	340.7	3,171.9	-105.6	45.9	115.1
5	342.0	3,174.0	-104.3	48.0	114.8
6	343.0	3,176.2	-103.3	50.2	114.9
7	343.7	3,178.3	-102.6	52.3	115.2
8	342.4	3,180.6	-103.9	54.6	117.4
9	341.1	3,183.4	-105.2	57.4	119.8
10	339.0	3,183.4	-107.3	57.4	121.7
11	336.5	3,183.4	-109.8	57.4	123.9
12	334.0	3,183.4	-112.3	57.4	126.1
13	331.5	3,183.4	-114.8	57.4	128.4

* Location of Intercession City facility is 446.300 km East; 3,126 km North

7.0 AIR QUALITY IMPACT ANALYSIS RESULTS

This section summarizes the results of the modelling analyses conducted as described in Section 6.0.

7.1 Intercession City Units P12 - P14

7.1.1 Worst-case Operation Analysis

As indicated in Section 6.4.1, the proposed facility was evaluated for both the primary fuel (natural gas) and the back-up fuel (fuel oil) to determine the worst-case impacts. Since the emissions on fuel oil are higher for the criteria pollutants than for natural gas, the analysis of short-term impacts focused on the fuel oil case. Based on the results of the SCREEN3 analysis, it was determined that 100% load would produce the maximum ground-level impacts for NOx and SO_2. For PM, the worst-case impacts occur at 25% load, and for CO emissions the worst case occurred at 50% load.

For conservatism, all model analyses, including those for annual average concentrations, were run using the worst-case oil-firing emissions described above for year-round operation. In reality, oil-firing will occur a maximum equivalent of 1,000 hours per year per unit.

7.1.2 Significant Impact Analysis

Once the worst-case operating scenario was determined, the next step in the analysis was to determine whether the ambient air quality impact from the proposed units is considered significant under the PSD rules. The worst-case emissions scenario for each pollutant was modeled at the receptor locations described in Section 6.5.1.

The results of the significant impact analysis are presented in Table 7-1. As indicated in Table 7-1, there were no predicted impacts greater than the PSD significance thresholds. Thus, no further analysis is required for purposes of PSD increment consumption and AAQS compliance analysis. A complete set of the ISCST3 model output files have been submitted to the FDEP under separate cover.

7.2 PSD INCREMENT ANALYSIS

7.2.1 Class II Area

Because the maximum predicted ambient air quality impacts are less than the PSD significance levels, no additional PSD Class II increment analysis is required.

7.2.2 Class I Area

Although the proposed project will be located approximately 113km from the nearest boundary of the nearest Class I PSD area, which is the Chassahowitzka National Wilderness Area (NWA), the impacts of the proposed project were modelled. In its proposed New Source Review reform package, EPA has proposed PSD significance levels for Class I areas. FDEP has approved the use of these proposed values for purposes of assessing significant impacts at Class I areas in. These values are listed in Table 7-2.

A summary of the project's maximum predicted impact on the ClassI area is presented in Table 7-2. As indicated, the predicted maximum impacts are below the EPA significance values for particulate matter (PM), SO_2, and NO_2, with the exception of one 24-hour SO_2 average. This single value occurred on February 19, 1991, showing a predicted value of 0.23 ug/m^3. Examination of the meteorological data for this day reveals that 8 calm hours occurred during the day. The model conservatively assumes that, during calm periods, the wind direction remains constant when in fact the wind is not moving in any direction. It is unlikely that the plume from the Intercession City units could travel the 113-km distance to the NWA under such conditions. In addition, the model analysis assumes that all three units operated on oil at maximum load for the entire 24-hour period. Since these are peaking units, this scenario would not actually occur, so the analysis is quite conservative. All other modelled periods resulted in predicted concentrations well below the Class I significance levels. Therefore, the expected impact on the NWA is less than significant.

7.3 Air Toxics Analysis

Concentrations of sulfuric acid mist were modelled with ISCST3 in the same way that SO_2 was modelled. As with SO_2, highest emissions of this pollutant occur while using fuel oil. The predicted maximum 24-hour average concentration of sulfuric acid mist is 0.05 ug/m^3. This is well below the former FDEP ambient reference concentration (ARC) of 2.4 ug/m^3. Therefore, no adverse impacts will occur from emissions of sulfuric acid mist.

TABLE 7-1
SUMMARY OF SIGNIFICANT IMPACT ANALYSIS CONCENTRATIONS
PSD CLASS II AREAS

Pollutant	Averaging Period	Maximum (1) Predicted Concentration (ug/m^3)	Location (2)		Year	Significance Level (ug/m^3)	Distance to Significance (km)	Significant Impact (Yes/No)
			East (km)	North (km)				
Carbon Monoxide	1-Hour	73.6	447.45	3125.0	1988	2,000	None	No
	8-Hour	17.2	433.31	3133.5	1991	500	None	No
Nitrogen Dioxide	Annual	0.13	437.64	3121.0	1990	1	None	No
Sulfur Dioxide	3-Hour	2.44	427.51	3119.2	1988	25	None	No
	24-Hour	0.50	433.31	3133.5	1991	5	None	No
	Annual	0.04	437.64	3121.0	1990	1	None	No
Particulate Matter (PM_{10}) (3)	24-Hour	0.16	433.31	3133.5	1991	5	None	No
	Annual	0.01	446.30	3131.0	1991	1	None	No
Sulfuric Acid Mist	24-Hour	0.05	433.31	3133.5	1991	N/A	N/A	N/A

(1) Short-term values are highest values for this analysis.

(2) With respect to zero point of 446.30 km E; 3,126.0 km N.

(3) As a conservative approach, all project emissions of particulate matter were assumed to be in the form of PM_{10}.

N/A = Not applicable

FPC, 1999

TABLE 7-2

SUMMARY OF MAXIMUM MODELED IMPACTS VS. PSD CLASS I SIGNIFICANCE VALUES

Pollutant	Averaging Period	Highest Modeled Concentration (ug/m^3)	PSD Class I Signif. Level (ug/m^3)	Significance
Sulfur Dioxide (SO_2)	3-Hour	0.91	1.0	NO
	24-Hour	0.23	0.2	NO*
	Annual	0.01	0.1	NO
Particulate Matter (PM_{10})	24-Hour	0.04	0.3	NO
	Annual	0.002	0.2	NO
Nitrogen Dioxide (NO_2)	Annual	0.03	0.1	NO

* Refer to discussion in Section 7.2.2

8.0 ADDITIONAL IMPACTS

8.1 INTRODUCTION

The PSD guidelines indicate that, in addition to demonstrating that the proposed source will neither cause nor contribute to violations of the applicable PSD increments and AAQS, an additional impacts analysis must be conducted for those pollutants subject to PSD review. As indicated in Table 3-2, those pollutants include CO, NO_x, SO_2, PM, VOC (O_3), and sulfuric acid mist. This additional impacts analysis includes an analysis of air quality impacts due to growth induced by the project, an analysis of air quality impacts on soils and vegetation, and an analysis of project impacts on visibility.

As has been demonstrated in Section 7.0 of this application, the proposed project will have an insignificant impact at the NWA, located from 113 to 128km from the proposed sources. In spite of this distance, FPC is providing a general assessment of the impact of Units P12 - P14 on air quality-related values (AQRV) as a part of this application.

8.2 IMPACTS DUE TO GROWTH

The growth analysis considers air quality impacts due to emissions resulting from the industrial, commercial, and residential growth associated with the project. Only impacts related to permanent growth are considered; emissions from temporary sources and mobile sources are not addressed in the growth analysis.

Negligible growth is expected to occur as a result of the proposed units. The units are being added to a facility that already contains 11 combustion turbine units. Therefore, existing facility staff will operate the units.

Development of industries supporting the new facility are expected to be negligible. Raw materials consumed by the facility (fuels, supplies, etc.) will be delivered to the site in usable form from outside of the region.

Electricity sales, on the other hand, will be spread out over a large region as part of FPC's generating capacity that will serve to meet increasing residential, commercial, and industrial demand throughout its system, which covers a large portion of the state of Florida.

In summary, there will be little residential growth associated with the FPC project, and there is little potential for new industrial development nearby as a result of the new facility. Impacts resulting from the new development are expected to be small and well-distributed throughout the area.

8.3 VEGETATION, SOILS, AND WILDLIFE ANALYSES

As previously discussed, the expected maximum impacts from Units P12 - P14 on the NWA are less than the PSD Class I and Class II significance levels. Therefore, the project will have a negligible impact on the soils, vegetation, wildlife, and visibility of the area surrounding the plant as well as the more distant Class I area. A general discussion of air quality-related values (AQRVs) of the NWA follows.

The U.S. Department of the Interior (National Park Service) in 1978 administratively defined AQRVs to be: All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality. Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are assets that are to be preserved if the area is to achieve the purposes for which it was set aside.

In a November 1996 report entitled "Air Quality and Air Quality Related Values in Chassahowitzka National Wildlife Refuge and Wilderness Area," the US Fish and Wildlife Service discussed vegetation, soils, wildlife, visibility, and water quality as potential AQRVs in the NWA. Effects from air pollution on visibility have been evaluated in the NWA, but the other potential AQRVs have not been specifically evaluated by the Fish and Wildlife Service for Chassahowitzka. Since specific AQRVs have not been identified for the Chassahowitzka NWA, this AQRV analysis evaluates the effects of air quality on general vegetation types and wildlife found on the Chassahowitzka NWA. Vegetation type AQRVs and their representative species types have been defined as:

Marshlands - black needlerush, saw grass, salt grass, and salt marsh cordgrass

Marsh Islands - cabbage palm and eastern red cedar

Estuarine Habitat - black needlerush, salt marsh cordgrass, wax myrtle

Hardwood Swamp - red maple, red bay, sweet bay and cabbage palm

Upland Forests - live oak, scrub oak, longleaf pine, slash pine, wax myrtle and saw palmetto

Mangrove Swamp - red, white and black mangrove

Wildlife AQRVs included: endangered species, waterfowl, marsh and waterbirds, shorebirds, reptiles and mammals.

A screening approach was used which compared the maximum predicted ambient concentration of air pollutants of concern in the Chassahowitzka NWR with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted which specifically addressed the effects of air contaminants on plant species reported to occur in the NWR. While the literature search focused on such species as cabbage palm, eastern red cedar, lichens and species of the hardwood swamplands and mangrove forest, no specific citations that addressed these species were found. It was recognized that effect threshold information is not available for all species found in the Chassahowitzka NWR, although studies have been performed on a few of the common species and on other similar species which can be used as models. Maximum concentrations and depositions were predicted using the ISCST model and five years of meteorological data as described in Sections 6.0 and 7.0.

8.3.1 Vegetation

The effects of air contaminants on vegetation occur primarily from sulfur dioxide, nitrogen dioxide, ozone, and particulates. Effects from minor air contaminants such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, carbon monoxide, and pesticides have been reported in the literature. However, most of these air contaminants have not resulted in major effects (i.e., crop damage). Some air contaminants, such as ethylene, are widely distributed but, due to low concentrations, do not result in injury to plants. Others such as CO do not cause damage at concentrations normally found under ambient concentrations. There are no predicted fluoride emissions from the proposed project.

Injury to vegetation from exposure to various levels of air contaminants can be termed acute, physiological or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms, while chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant.

Since expected maximum pollutant concentrations at the NWA are below significance levels, no adverse effects to vegetation will be caused by the proposed project.

8.3.2 Soils

Air contaminants can affect soils through fumigation by gaseous forms, accumulation of compounds transformed from the gaseous state, or by the direct deposition of particulate matter or particulate matter to which certain contaminants are absorbed. Gaseous fumigation of soils does not directly affect the soil but rather the organisms found in the soil. Concentrations several orders of magnitude higher than the predicted values are required before any adverse effects from fumigation are observed. It is more likely that effects on soils and the organisms (plants and animals) found in the soils could occur from the deposition of trace elements over the life of the project. Thus, this analysis of effects on soils specifically addresses the deposition of trace elements and potential pathways for movements into the vegetation.

8.3.2.1 Lead

Lead (Pb) is found naturally occurring in all plants, although it is nonessential for growth (Chapman, 1966; Valkovic, 1975; Gough and Shacklette, 1976). Plants vary in their sensitivity to lead. Many plants tolerate high concentrations of lead, while others exhibit retarded growth at 10 ppm in solution culture (Valkovic, 1975). Orange seedlings grown on soils with lead concentrations ranging from 150-200 ppm did not exhibit adverse effects (Chapman, 1966). Gough et al. (1979) reported that a lead soil concentration of 30 to 100g/g generally retarded the growth of plants. The negligible amount of lead emissions from Units P12 - P14 will not contribute to a soil concentration toxic to plants.

8.3.2.2 Mercury

Mercury (Hg) is not an essential element for plant growth. It is typically used as a seed fungicide. In general, Hg is not concentrated in plants grown on soils containing normal levels of Hg. Soil bound Hg is typically not available for plant uptake, although many plants cannot prevent the uptake of gaseous Hg through the roots (Huckabee and Jansen, 1975). Most higher vascular plants are resistant to toxicity from high Hg concentrations even though high concentrations are present in plant tissue. Concentrations of 0.5-50 ppm (HgCl2) were found to inhibit the growth of cauliflower, lettuce, potato, and carrots (Bell and Rickard, 1974). Gough et al. (1979) noted apparently healthy spanish moss plants with a mercury content of 0.5 mg/kg. The extremely small amount of mercury emissions from the proposed units will not contribute to concentrations that are toxic to plants.

8.3.3 Wildlife

Compared with other threats to wildlife, such as pesticides, the toxicological relationships between air pollution and effects on wildlife are not well understood (Newman and Schreiber, 1988). The limited understanding is based primarily on reports of symptoms observed in the field and on information extrapolated from laboratory studies. Information on controlled wildlife studies is limited in the scientific literature. Most studies report symptoms of various air pollutants but do not provide toxicity levels. Those studies that do provide toxicity levels are limited to four air contaminants, SO_2, NO_2, O_3, and particulates.

Since the expected maximum pollutant impacts are less than Class I significance levels, no adverse impacts to wildlife will occur from the proposed facility emissions.

In addition to the impacts on wildlife from the primary pollutants, the Fish and Wildlife Service is concerned about the effects on wildlife resulting from acid deposition (FWS, 1992). Existing acid deposition conditions in Florida were investigated during the five year Florida Acid Deposition Study (ESE, 1986 and 1987) and the two year follow-up program called the Florida Acid Deposition Monitoring Program (ESE, 1988 and 1989). The data collected in these programs indicate that Florida precipitation is only about two-thirds as acidic as precipitation across the southeastern United States and less than half as acidic as precipitation in the midwestern and northeastern United States (ESE, 1988). There is no evidence of a temporal trend in precipitation acidity since the late 1970s (ESE, 1989). The Clean Air Act Amendments of 1990 require significant reductions in SO_2 and NO_2 emissions from existing uncontrolled utility plants nationwide and some of these reductions will occur at plants in the general vicinity of the NWA. These emission reductions will undoubtedly improve on the already good estimated acid deposition conditions in the NWR.

Due to the small emission increases that will be caused by the proposed project and the resulting insignificant concentrations, increase, if any in acid deposition will be negligible.

8.4 VISIBILITY IMPACTS

The maximum predicted SO_2 and NOx impacts from the proposed units have been determined to be less than the Class I significance levels. Therefore, there will be little, if any incremental impact to the area's visibility.

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APPENDIX A

EMISSIONS DATA AND CALCULATIONS

Estimated Performance - PG7121(EA)

Florida Power Corp - Intercession City

ESTIMATED PERFORMANCE PG7121(EA)

Load Condition		BASE	75%	60%	50%	25%
Ambient Temp.	Deg F.	20.	20.	20.	20.	20.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,831	20,831	20,831	20,831	20,831
Fuel Temperature	Deg F	60	60	60	60	60
Output	kW	95,430.	71,570.	57,260.	47,710.	23,860.
Heat Rate (LHV)	Btu/kWh	10,270.	10,940.	12,070.	13,190.	18,540.
Heat Cons. (LHV) X 10^6	Btu/h	980.1	783.	691.1	629.3	442.4
Exhaust Flow X 10^3	lb/h	2578.	2007.	1760.	1600.	1438.
Exhaust Temp.	Deg F.	971.	1010.	1051.	1081.	939.
Exhaust Heat (LHV) X 10^6	Btu/h	617.3	508.1	468.1	440.7	340.8

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	9.	46.
NOx AS NO2	lb/h	36.	28.	25.	23.	80.
CO	ppmvd	25.	33.	29.	34.	25.
CO	lb/h	59.	60.	47.	50.	33.
UHC	ppmvw	7.	16.	14.	17.	7.
UHC	lb/h	10.	18.	14.	15.	6.
Particulates (TSP)	lb/h	5.0	5.0	5.0	5.0	5.0

EXHAUST ANALYSIS % VOL.

Argon	0.91	0.90	0.89	0.90	0.90
Nitrogen	75.49	75.45	75.45	75.45	76.01
Oxygen	13.91	13.79	13.79	13.81	15.39
Carbon Dioxide	3.27	3.33	3.33	3.32	2.59
Water	6.43	6.53	6.54	6.52	5.11

SITE CONDITIONS

Elevation	ft.	0.0
Site Pressure	psia	14.7
Inlet Loss	in Water	3.5
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7A6 Air-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

IPS- - 80883 version code- 1 . 5 . 0 Opt: N 71210696

Florida Power Corp - Intercession City
ESTIMATED PERFORMANCE PG7121(EA)

Load Condition		BASE	75%	60%	50%	25%
Ambient Temp.	Deg F.	59.	59.	59.	59.	59.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,831	20,831	20,831	20,831	20,831
Fuel Temperature	Deg F	60	60	60	60	60
Output	kW	84,320.	63,240.	50,590.	42,160.	21,080.
Heat Rate (LHV)	Btu/kWh	10,490.	11,360.	12,590.	13,740.	19,480.
Heat Cons. (LHV) X 10^6	Btu/h	884.5	718.4	636.9	579.3	410.6
Exhaust Flow X 10^3	lb/h	2362.	1860.	1636.	1510.	1388.
Exhaust Temp.	Deg F.	998.	1045.	1087.	1100.	946.
Exhaust Heat (LHV) X 10^6	Btu/h	563.1	474.3	438.5	411.5	319.7

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	9.	40.
NOx AS NO2	lb/h	32.	26.	23.	21.	65.
CO	ppmvd	25.	25.	25.	47.	35.
CO	lb/h	54.	42.	37.	65.	44.
UHC	ppmvw	7.	8.	8.	24.	7.
UHC	lb/h	9.	9.	7.	20.	5.
Particulates (TSP)	lb/h	5.0	5.0	5.0	5.0	5.0

EXHAUST ANALYSIS % VOL.

Argon	0.89	0.90	0.89	0.89	0.91
Nitrogen	74.93	74.88	74.87	74.92	75.47
Oxygen	13.86	13.72	13.71	13.83	15.45
Carbon Dioxide	3.22	3.28	3.29	3.23	2.48
Water	7.10	7.23	7.24	7.13	5.70

SITE CONDITIONS

Elevation	ft.	0.0
Site Pressure	psia	14.7
Inlet Loss	in Water	3.5
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7A6 Air-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

IPS- 80883 version code- 1 . 5 . 0 Opt: N 71210696

Florida Power Corp - Intercession City
ESTIMATED PERFORMANCE PG7121(EA)

Load Condition		BASE	75%	60%	50%	25%
Ambient Temp.	Deg F.	100.	100.	100.	100.	100.
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,831	20,831	20,831	20,831	20,831
Fuel Temperature	Deg F	60	60	60	60	60
Output	kW	72,110.	54,080.	43,260.	36,050.	18,030.
Heat Rate (LHV)	Btu/kWh	10,920.	12,040.	13,320.	14,580.	21,230.
Heat Cons. (LHV) X 10^6	Btu/h	787.4	651.1	576.2	525.6	382.8
Exhaust Flow X 10^3	lb/h	2125.	1684.	1524.	1428.	1310.
Exhaust Temp.	Deg F.	1026.	1091.	1100.	1100.	973.
Exhaust Heat (LHV) X 10^6	Btu/h	510.9	440.5	404.9	380.5	303.3

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	48.	27.
NOx AS NO2	lb/h	29.	24.	21.	100.	41.
CO	ppmvd	25.	25.	50.	25.	33.
CO	lb/h	48.	38.	69.	32.	39.
UHC	ppmvw	7.	7.	25.	7.	7.
UHC	lb/h	8.	7.	22.	6.	5.
Particulates (TSP)	lb/h	5.0	5.0	5.0	5.0	5.0

EXHAUST ANALYSIS % VOL.

Argon	0.86	0.87	0.87	0.88	0.89
Nitrogen	72.81	72.73	72.80	72.86	73.33
Oxygen	13.43	13.20	13.40	13.60	14.98
Carbon Dioxide	3.15	3.25	3.16	3.07	2.42
Water	9.75	9.95	9.78	9.60	8.39

SITE CONDITIONS

Elevation	ft.	0.0
Site Pressure	psia	14.7
Inlet Loss	in Water	3.5
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7A6 Air-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

IPS- - 80883 version code- 1 . 5 . 0 Opt: N 71210696

Florida Power Corp - Intercession City
ESTIMATED PERFORMANCE PG7121(EA)

Load Condition		BASE	75%	70%	50%	25%
Ambient Temp.	Deg F.	20.	20.	20.	20.	20.
Fuel Type		Dist.	Dist.	Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	18,300	18,300	18,300	18,300	18,300
Fuel Temperature	Deg F	60	60	60	60	60
Liquid Fuel H/C Ratio		1.8	1.8	1.8	1.8	1.8
Output	kW	98,820.	74,120.	69,180.	49,410.	24,710.
Heat Rate (LHV)	Btu/kWh	10,740.	11,190.	11,290.	12,100.	16,320.
Heat Cons. (LHV) X 10^6	Btu/h	1,061.3	829.4	781.	597.9	403.3
Exhaust Flow X 10^3	lb/h	2638.	2104.	2098.	2078.	2066.
Exhaust Temp.	Deg F.	965.	964.	922.	758.	578.
Exhaust Heat (LHV) X 10^6	Btu/h	632.7	509.9	484.5	389.4	291.1
Water Flow	lb/h	50,750.	33,980.	29,540.	15,150.	9,020.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.	42.	42.
NOx AS NO2	lb/h	186.	144.	135.	102.	68.
CO	ppmvd	20.	20.	20.	270.	28.
CO	lb/h	48.	38.	38.	522.	54.
UHC	ppmvw	7.	7.	7.	7.	7.
UHC	lb/h	10.	8.	8.	8.	8.
SO2	ppmvw	38.0	37.0	35.0	27.0	18.0
SO2	lb/h	220.0	172.0	162.0	124.0	84.0
SO3	ppmvw	2.0	2.0	2.0	1.0	1.0
SO3	lb/h	15.0	12.0	11.0	8.0	5.0
Sulfur Mist	lb/h	23.0	18.0	17.0	13.0	9.0
Particulates (TSP)	lb/h	10.0	10.0	10.0	10.0	10.0

EXHAUST ANALYSIS % VOL.

Argon	0.88	0.90	0.90	0.91	0.90
Nitrogen	73.92	74.35	74.69	75.88	76.62
Oxygen	13.19	13.49	13.95	15.67	17.40
Carbon Dioxide	4.61	4.48	4.23	3.26	2.21
Water	7.40	6.79	6.24	4.29	2.87

SITE CONDITIONS

Elevation	ft.	0.0
Site Pressure	psia	14.7
Inlet Loss	in Water	3.5
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7A6 Air-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.2 WT% Sulfur Content in the Fuel.

IPS- 80883 version code- 1 . 5 . 0 Opt: N 71210696

Florida Power Corp - Intercession City

ESTIMATED PERFORMANCE PG7121(EA)

Load Condition		BASE	75%	70%	50%	25%
Ambient Temp.	Deg F.	59.	59.	59.	59.	59.
Fuel Type		Dist.	Dist.	Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	18,300	18,300	18,300	18,300	18,300
Fuel Temperature	Deg F	60	60	60	60	60
Liquid Fuel H/C Ratio		1.8	1.8	1.8	1.8	1.8
Output	kW	87,220.	65,410.	61,050.	43,610.	21,800.
Heat Rate (LHV)	Btu/kWh	10,940.	11,510.	11,640.	12,610.	17,330.
Heat Cons. (LHV) X 10^6	Btu/h	954.2	752.9	710.6	549.9	377.8
Exhaust Flow X 10^3	lb/h	2413.	1966.	1961.	1945.	1935.
Exhaust Temp.	Deg F.	993.	985.	945.	792.	621.
Exhaust Heat (LHV) X 10^6	Btu/h	576.3	470.8	448.7	365.1	277.3
Water Flow	lb/h	43,080.	28,580.	24,860.	12,800.	8,090.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.	42.	42.
NOx AS NO2	lb/h	167.	131.	123.	94.	64.
CO	ppmvd	20.	20.	20.	202.	20.
CO	lb/h	44.	36.	36.	364.	36.
UHC	ppmvw	7.	7.	7.	7.	7.
UHC	lb/h	9.	8.	8.	8.	8.
SO2	ppmvw	37.0	36.0	34.0	27.0	18.0
SO2	lb/h	198.0	156.0	148.0	114.0	78.0
SO3	ppmvw	2.0	2.0	2.0	1.0	1.0
SO3	lb/h	13.0	11.0	9.0	8.0	6.0
Sulfur Mist	lb/h	21.0	16.0	16.0	12.0	8.0
Particulates (TSP)	lb/h	10.0	10.0	10.0	10.0	10.0

EXHAUST ANALYSIS % VOL.

Argon	0.88	0.89	0.89	0.91	0.90
Nitrogen	73.53	74.00	74.31	75.38	76.03
Oxygen	13.21	13.59	14.02	15.62	17.25
Carbon Dioxide	4.52	4.35	4.11	3.20	2.20
Water	7.86	7.18	6.67	4.90	3.62

SITE CONDITIONS

Elevation	ft.	0.0
Site Pressure	psia	14.7
Inlet Loss	in Water	3.5
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7A6 Air-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.2 WT% Sulfur Content in the Fuel.

IPS- 80883 version code- 1 . 5 . 0 Opt: N 71210696

Florida Power Corp - Intercession City
ESTIMATED PERFORMANCE PG7121(EA)

Load Condition		BASE	75%	70%	50%	25%
Ambient Temp.	Deg F.	100.	100.	100.	100.	100.
Fuel Type		Dist.	Dist.	Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	18,300	18,300	18,300	18,300	18,300
Fuel Temperature	Deg F	60	60	60	60	60
Liquid Fuel H/C Ratio		1.8	1.8	1.8	1.8	1.8
Output	kW	73,910.	55,430.	51,730.	36,950.	18,480.
Heat Rate (LHV)	Btu/kWh	11,270.	12,030.	12,200.	13,440.	18,980.
Heat Cons. (LHV) $X 10^6$	Btu/h	833.	666.8	631.1	496.6	350.8
Exhaust Flow $X 10^3$	lb/h	2160.	1798.	1795.	1784.	1780.
Exhaust Temp.	Deg F.	1023.	1014.	976.	835.	674.
Exhaust Heat (LHV) $X 10^6$	Btu/h	518.3	431.8	412.7	342.1	265.9
Water Flow	lb/h	29,040.	18,510.	15,780.	7,080.	4,770.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.	42.	42.
NOx AS NO2	lb/h	146.	116.	109.	85.	59.
CO	ppmvd	20.	20.	20.	150.	20.
CO	lb/h	39.	32.	32.	244.	33.
UHC	ppmvw	7.	7.	7.	7.	7.
UHC	lb/h	9.	7.	7.	7.	7.
SO2	ppmvw	36.0	35.0	33.0	26.0	18.0
SO2	lb/h	173.0	138.0	131.0	103.0	73.0
SO3	ppmvw	2.0	2.0	2.0	1.0	1.0
SO3	lb/h	11.0	10.0	9.0	7.0	5.0
Sulfur Mist	lb/h	18.0	15.0	14.0	11.0	8.0
Particulates (TSP)	lb/h	10.0	10.0	10.0	10.0	10.0

EXHAUST ANALYSIS % VOL.

Argon	0.87	0.86	0.88	0.88	0.88
Nitrogen	71.99	72.44	72.69	73.54	74.01
Oxygen	13.01	13.42	13.80	15.25	16.71
Carbon Dioxide	4.38	4.18	3.96	3.12	2.20
Water	9.76	9.11	8.68	7.21	6.20

SITE CONDITIONS

Elevation	ft.	0.0
Site Pressure	psia	14.7
Inlet Loss	in Water	3.5
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7A6 Air-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.2 WT% Sulfur Content in the Fuel.

IPS- . 80883 version code- 1 . 5 . 0 Opt: N 71210696

Calculations

Oil firing rate

20°F Heat input = 1,061 MMBtu/hr

$$\left(\frac{1{,}061\ \text{MMBtu}}{\text{hr}}\right)\left(\frac{\text{gal}}{132{,}000\ \text{Btu}}\right) = 8{,}038\ \text{gal/hr}$$

59°F Heat input = 954 MMBtu/hr

$$\left(\frac{954\ \text{MMBtu}}{\text{hr}}\right)\left(\frac{\text{gal}}{132{,}000\ \text{Btu}}\right) = 7{,}227\ \text{gal/hr}$$

$$\text{Maximum Annual Rate} = \left(\frac{7{,}227\ \text{gal}}{\text{hr}}\right)\left(\frac{1{,}000\ \text{hr}}{\text{yr}}\right) = 7{,}227{,}000\ \frac{\text{gal}}{\text{yr}}$$

Gas Firing Rate

20°F Heat input = 980 MMBtu/hr

$$\left(\frac{980\ \text{MMBtu}}{\text{hr}}\right)\left(\frac{\text{cf}}{950\ \text{Btu}}\right) = 1.032 \times 10^6\ \text{cf/hr}$$

59°F Heat input = 885 MMBtu/hr

$$\left(\frac{885\ \text{MMBtu}}{\text{hr}}\right)\left(\frac{\text{cf}}{950\ \text{Btu}}\right) = 0.932 \times 10^6\ \text{cf/hr}$$

$$\text{Maximum Annual Rate} = \left(\frac{0.932 \times 10^6\ \text{cf}}{\text{hr}}\right)\left(\frac{2390\ \text{hr}}{\text{yr}}\right) = 2.227 \times 10^9\ \frac{\text{cf}}{\text{yr}}$$

$\boxed{NO_x}$

20°F Oil - 186 lb/hr
Gas - 36 lb/hr

59°F Oil - 167 lb/hr
Gas - 32 lb/hr

Annual Emissions (59°F case)

$$\left[\left(\frac{167\ lb}{hr}\right)\left(\frac{1000\ hr}{yr}\right)+\left(\frac{32\ lb}{hr}\right)\left(\frac{2,390\ hr}{yr}\right)\right]\left(\frac{ton}{2,000\ lb}\right)$$

$$= 121.7\ TPY$$

$\boxed{PM/PM_{10}}$

20°F Oil - 10 lb/hr
Gas - 5 lb/hr

59°F Oil - 10 lb/hr
Gas - 5 lb/hr

Annual emissions (59°F case)

$$\left[\left(\frac{10\ lb}{hr}\right)\left(\frac{1,000\ hr}{yr}\right)+\left(\frac{5\ lb}{hr}\right)\left(\frac{2,390\ hr}{yr}\right)\right]\left(\frac{ton}{2,000\ lb}\right)$$

$$= 11.0\ TPY$$

CO

20°F Oil - 48 lb/hr

Gas - 59 lb/hr

59°F Oil - 44 lb/hr

Gas - 54 lb/hr

Annual Emissions (59°F case)

$$\left[\left(\frac{44\text{ lb}}{\text{hr}}\right)\left(\frac{1{,}000\text{ hr}}{\text{yr}}\right) + \left(\frac{54\text{ lb}}{\text{hr}}\right)\left(\frac{2{,}390\text{ hr}}{\text{yr}}\right)\right]\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)$$

= 86.5 TPY

VOC

20°F Oil - 10 lb/hr

Gas - 10 lb/hr

59°F Oil - 9 lb/hr

Gas - 9 lb/hr

Annual Emissions (59°F case)

$$\left[\left(\frac{9\text{ lb}}{\text{hr}}\right)\left(\frac{1{,}000\text{ hr}}{\text{yr}}\right) + \left(\frac{9\text{ lb}}{\text{hr}}\right)\left(\frac{2{,}390\text{ hr}}{\text{yr}}\right)\right]\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)$$

= 15.3 TPY

$\boxed{SO_2}$

20°F Oil - 220 lb/hr @ 0.2%S

$$= \frac{220}{4} = 55 \text{ lb/hr @ } 0.05\%S$$

59°F Oil - 198 lb/hr @ 0.2%S

$$= \frac{198}{4} = 49.5 \text{ lb/hr @ } 0.05\%S$$

59°F Gas -

$$\left(\frac{885 \times 10^6 \text{ Btu}}{\text{hr}}\right)\left(\frac{\text{cf}}{950 \text{ Btu}}\right)\left(\frac{1 \text{ gr S}}{100 \text{ cf}}\right)\left(\frac{\text{lb S}}{7{,}000 \text{ grains}}\right)\left(\frac{2 \text{ moles } SO_2}{\text{mole S}}\right) = 2.66 \text{ lb/hr}$$

Annual Emissions (59°F case)

$$\left[\left(\frac{49.5 \text{ lb}}{\text{hr}}\right)\left(\frac{1{,}000 \text{ hr}}{\text{yr}}\right) + \left(\frac{2.7 \text{ lb}}{\text{hr}}\right)\left(\frac{2{,}390 \text{ hr}}{\text{yr}}\right)\right]\left(\frac{\text{ton}}{2{,}000 \text{ lb}}\right)$$

= 27.9 TPY

$\boxed{\text{SAM}}$

(10% of SO_2 rates)

20°F Oil - (55 lb/hr)(.1) = 5.5 lb/hr

Gas - (2.95 lb/hr)(.1) = 0.3 lb/hr

59°F Oil - (49.5 lb/hr)(.1) = 5.0 lb/hr

Gas - (2.66 lb/hr)(.1) = 0.3 lb/hr

Annual Emissions (59°F case)

$$\left[(5 \text{ lb/hr})(1{,}000 \text{ hr/yr}) + (0.3 \text{ lb/hr})(2{,}390 \text{ hr/yr})\right]\left(\frac{\text{ton}}{2{,}000 \text{ lb}}\right)$$

= 2.9 TPY

APPENDIX B

BACT DOCUMENTATION

The cost tables in this appendix were obtained from the PSD application submitted by ECT for TECO's Polk Power Station. The Polk Power project proposes to install GE PG7241 FA units that are rated at approximately 165 MW each. As the units proposed for Intercession City are nominally rated at 87 MW, the costs associated with SCR were estimated at about 50 percent of the costs presented herein for the Polk Power Station project.

Table 5-16. Capital Costs for SCR System

Item	Dollars		OAQPS Factor
<u>Direct Costs</u>			
Purchased equipment	4,035,000	(A)	
Sales tax	242,100		0.06 × A
Freight	201,750		0.05 × A
Subtotal Purchase Equipment	**$4,478,850**		B
Installation			
Foundations and supports	358,308		0.08 × B
Handling and erection	627,039		0.14 × B
Electrical	179,154		0.04 × B
Piping	89,577		0.02 × B
Insulation for ductwork	44,789		0.01 × B
Painting	44,789		0.01 × B
Subtotal Installation Cost	**$1,343,655**		
Subtotal Direct Costs	**$5,822,505**		
<u>Indirect Costs</u>			
Engineering	447,885		0.10 × B
Construction and field expenses	223,943		0.05 × B
Contractor fees	447,885		0.10 × B
Start-up	89,577		0.02 × B
Performance test	44,789		0.01 × B
Contingency	134,366		0.15 × B
Subtotal Indirect Costs	**$1,388,444**		
TOTAL CAPITAL INVESTMENT	**$7,210,949**	(TCI)	

Sources: Engelhard, 1999.
ECT, 1999.

Table 5-17. Annual Operating Costs for SCR System

Item	Dollars		OAQPS Factor
Direct Costs			
Labor and material costs			
Operator	7,227	(A)	
Supervisor	1,084		0.15 × A
Maintenance			
Labor	7,227	(B)	
Materials	7,227		1.00 × B
Subtotal Labor, Material, and Maintenance Costs	**$22,765**	(C)	
Catalyst costs			
Replacement (materials and labor)	$2,088,000		
Annualized Catalyst Costs	**$544,491**		
Raw materials and utilities			
Electricity	17,722		
Aqueous NH_3	119,092		
Subtotal Raw Materials and Utilities	**$136,864**		
Energy penalties			
Turbine backpressure	208,138		
Subtotal Direct Costs	**$912,209**	(TDC)	
Indirect Costs			
Overhead	13,659		0.60 × C
Administrative charges	144,219		0.02 × TCI
Property taxes	72,110		0.01 × TCI
Insurance	72,110		0.01 × TCI
Capital recovery	667,855		
Subtotal Indirect Costs	**$969,952**		
TOTAL ANNUAL COST	**$1,882,161**		

Sources: Engelhard, 1999.
ECT, 1999.

Table 5-8. Capital Costs for Oxidation Catalyst System

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	1,075,000	A
Sales tax	64,500	0.06 × A
Freight	53,750	0.05 × A
Subtotal Purchased Equipment	**$1,193,250**	**B**
Installation		
Foundations and supports	95,460	0.08 × B
Handling and erection	167,055	0.14 × B
Electrical	47,730	0.04 × B
Piping	23,865	0.02 × B
Insulation for ductwork	11,933	0.01 × B
Painting	11,933	0.01 × B
Subtotal Installation Cost	**$357,975**	
Subtotal Direct Costs	**$1,551,225**	
Indirect Costs		
Engineering	119,325	0.10 × B
Construction and field expenses	59,663	0.05 × B
Contractor fees	119,325	0.10 × B
Start-up	23,865	0.02 × B
Performance test	11,933	0.01 × B
Contingency	35,798	0.03 × B
Subtotal Indirect Costs	**$369,908**	
TOTAL CAPITAL INVESTMENT	**$1,921,133** (TCI)	

Sources: Engelhard, 1999
ECT, 1999

Table 5-9. Annual Operating Costs for Oxidation Catalyst System

Item	Dollars		OAQPS Factor
Direct Costs			
Catalyst costs			
Replacement (materials and labor)	930,000		
Credit for used catalyst	(127,500)		
Subtotal Catalyst Costs	**$802,500**		
Annualized Catalyst Costs	**$209,269**		
Energy penalties			
Turbine backpressure	104,069		
Subtotal Direct Costs	**$313,338**	(TDC)	
Indirect Costs			
Administrative charges	38,423		0.02 × TCI
Property taxes	19,211		0.01 × TCI
Insurance	19,211		0.01 × TCI
Capital recovery	125,249		
Subtotal Indirect Costs	**$202,094**		
TOTAL ANNUAL COST	**$515,433**		

Sources: Engelhard, 1999
TEC, 1999.
ECT, 1999.

APPENDIX C

SCREEN3 MODEL OUTPUT

```
                                                                 05/15/99
                                                                 10:43:21
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 96043 ***

Int. City P12-14; 1 CT; NOx; 20 deg.; Base load; oil

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE              =        POINT
   EMISSION RATE (G/S)      =      23.4000
   STACK HEIGHT (M)         =      17.1000
   STK INSIDE DIAM (M)      =       4.9000
   STK EXIT VELOCITY (M/S)=      46.7000
   STK GAS EXIT TEMP (K)    =     791.0000
   AMBIENT AIR TEMP (K)     =     266.0000
   RECEPTOR HEIGHT (M)      =        .0000
   URBAN/RURAL OPTION       =        RURAL
   BUILDING HEIGHT (M)      =      11.8000
   MIN HORIZ BLDG DIM (M) =       7.1000
   MAX HORIZ BLDG DIM (M) =      18.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


BUOY. FLUX = 1824.445 M**4/S**3;  MOM. FLUX = 4402.214 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN AUTOMATED DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

  DIST     CONC             U10M   USTK  MIX HT   PLUME   SIGMA   SIGMA
   (M)   (UG/M**3)   STAB  (M/S)  (M/S)    (M)    HT (M)  Y (M)   Z (M)  DWASH
-------  ----------  ----  -----  -----  ------  ------  ------  ------  -----
     1.   .0000        1     1.0    1.0  3392.5 3391.47   13.13   13.12    NO
   100.   .9422        6     1.0    1.3 10000.0  281.59   75.68   75.60    NO
   200.   .9507        6     1.0    1.3 10000.0  281.59   75.96   75.68    NO
   300.   .9611        6     1.0    1.3 10000.0  281.59   76.40   75.78    NO
   400.   .9733        6     1.0    1.3 10000.0  281.59   76.97   75.90    NO
   500.   .9869        6     1.0    1.3 10000.0  281.59   77.67   76.03    NO
   600.   1.002        6     1.0    1.3 10000.0  281.59   78.49   76.19    NO
   700.   1.018        6     1.0    1.3 10000.0  281.59   79.43   76.35    NO
   800.   1.031        6     1.0    1.3 10000.0  281.59   80.46   76.51    NO
   900.   1.049        4    20.0   21.7  6400.0   94.94   61.88   29.47    SS
  1000.   2.294        1     3.0    3.1  1142.9 1141.89  275.17  488.00    NO
  1100.   4.131        1     3.0    3.1  1142.9 1141.89  296.72  587.26    NO
  1200.   5.636        1     3.0    3.1  1142.9 1141.89  317.91  697.63    NO
  1300.   6.515        1     3.0    3.1  1142.9 1141.89  338.77  819.17    NO
  1400.   6.822        1     3.0    3.1  1142.9 1141.89  359.33  951.97    NO
  1500.   6.760        1     3.0    3.1  1142.9 1141.89  379.63 1096.09    NO
  1600.   6.526        1     3.0    3.1  1142.9 1141.89  399.67 1251.58    NO
  1700.   6.245        1     3.0    3.1  1142.9 1141.89  419.49 1418.53    NO
  1800.   5.971        1     3.0    3.1  1142.9 1141.89  439.09 1596.99    NO
```

```
  1900.   5.719        1     3.0     3.1  1142.9 1141.89   458.49 1787.02    NO
  2000.   5.489        1     3.0     3.1  1142.9 1141.89   477.70 1988.70    NO
  2100.   5.279        1     3.0     3.1  1142.9 1141.89   496.74 2202.06    NO
  2200.   5.086        1     3.0     3.1  1142.9 1141.89   515.62 2427.18    NO
  2300.   4.908        1     3.0     3.1  1142.9 1141.89   534.33 2664.12    NO
  2400.   4.743        1     3.0     3.1  1142.9 1141.89   552.85 2912.91    NO
  2500.   4.632        1     3.0     3.1  1142.9 1141.89   566.19 3172.72    NO
  2600.   4.524        1     3.0     3.1  1142.9 1141.89   579.61 3444.64    NO
  2700.   4.421        1     3.0     3.1  1142.9 1141.89   593.10 3728.69    NO
  2800.   4.323        1     3.0     3.1  1142.9 1141.89   606.65 4024.91    NO
  2900.   4.228        1     3.0     3.1  1142.9 1141.89   620.24 4333.33    NO
  3000.   4.137        1     3.0     3.1  1142.9 1141.89   633.87 4653.99    NO
  3500.   3.733        1     3.0     3.1  1142.9 1141.89   702.48 5000.00    NO
  4000.   3.399        1     3.0     3.1  1142.9 1141.89   771.45 5000.00    NO
  4500.   3.120        1     3.0     3.1  1142.9 1141.89   840.44 5000.00    NO
  5000.   2.884        1     3.0     3.1  1142.9 1141.89   909.24 5000.00    NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND     1. M:
  1425.   6.833        1     3.0     3.1  1142.9 1141.89   364.23  985.52    NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****************************************
     *** REGULATORY (Default) ***
    PERFORMING CAVITY CALCULATIONS
  WITH ORIGINAL SCREEN CAVITY MODEL
          (BRODE, 1988)
****************************************


 *** CAVITY CALCULATION - 1 ***       *** CAVITY CALCULATION - 2 ***
  CONC (UG/M**3)      =    .0000       CONC (UG/M**3)      =    .0000
  CRIT WS @10M (M/S) =    99.99        CRIT WS @10M (M/S) =    99.99
  CRIT WS @ HS (M/S) =    99.99        CRIT WS @ HS (M/S) =    99.99
  DILUTION WS (M/S)  =    99.99        DILUTION WS (M/S)  =    99.99
  CAVITY HT (M)      =    20.44        CAVITY HT (M)      =    14.40
  CAVITY LENGTH (M)  =    32.44        CAVITY LENGTH (M)  =     8.06
  ALONGWIND DIM (M)  =     7.10        ALONGWIND DIM (M)  =    18.00

CAVITY CONC NOT CALCULATED FOR CRIT WS > 20.0 M/S.  CONC SET = 0.0

****************************************
      END OF CAVITY CALCULATIONS
****************************************


     ***************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ***************************************

 CALCULATION         MAX CONC     DIST TO   TERRAIN
  PROCEDURE         (UG/M**3)     MAX (M)    HT (M)
--------------    -----------    -------   -------
```

```
SIMPLE TERRAIN      6.833         1425.        0.

***************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
***************************************************
```

```
                                                                          05/15/99
                                                                          10:49:37
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 96043 ***

Int. City P12-14; 1 CT; NOx; 20 deg.; 75% load; oil

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE              =        POINT
   EMISSION RATE (G/S)      =      18.1000
   STACK HEIGHT (M)         =      17.1000
   STK INSIDE DIAM (M)      =       4.9000
   STK EXIT VELOCITY (M/S)=       37.2000
   STK GAS EXIT TEMP (K)    =     791.0000
   AMBIENT AIR TEMP (K)     =     266.0000
   RECEPTOR HEIGHT (M)      =        .0000
   URBAN/RURAL OPTION       =        RURAL
   BUILDING HEIGHT (M)      =      11.8000
   MIN HORIZ BLDG DIM (M) =         7.1000
   MAX HORIZ BLDG DIM (M) =        18.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


BUOY. FLUX = 1453.306 M**4/S**3;  MOM. FLUX = 2793.336 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN AUTOMATED DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

  DIST     CONC             U10M   USTK  MIX HT   PLUME   SIGMA   SIGMA
   (M)   (UG/M**3)   STAB   (M/S)  (M/S)    (M)   HT (M)  Y (M)   Z (M)  DWASH
-------  ----------  ----   -----  -----  ------  ------  ------  ------  -----
     1.    .0000       1      1.0    1.0  2962.0 2961.03   11.17   11.16    NO
   100.    .7941       6      1.0    1.3 10000.0  262.28   70.17   70.09    NO
   200.    .8026       6      1.0    1.3 10000.0  262.28   70.48   70.17    NO
   300.   1.007        4     20.0   21.7  6400.0   46.39   22.61   12.55    SS
   400.   1.448        4     20.0   21.7  6400.0   54.31   29.45   15.70    SS
   500.   1.738        4     20.0   21.7  6400.0   61.60   36.15   18.71    SS
   600.   1.912        4     20.0   21.7  6400.0   68.43   42.72   21.61    SS
   700.   2.006        4     20.0   21.7  6400.0   74.90   49.19   24.42    SS
   800.   2.048        4     20.0   21.7  6400.0   81.06   55.57   27.16    SS
   900.   2.055        4     20.0   21.7  6400.0   86.98   61.88   29.83    SS
  1000.   3.383        1      3.0    3.1   999.4  998.41  266.82  483.34    NO
  1100.   5.068        1      3.0    3.1   999.4  998.41  287.93  582.87    NO
  1200.   6.119        1      3.0    3.1   999.4  998.41  308.70  693.48    NO
  1300.   6.519        1      3.0    3.1   999.4  998.41  329.16  815.25    NO
  1400.   6.484        1      3.0    3.1   999.4  998.41  349.33  948.24    NO
  1500.   6.247        1      3.0    3.1   999.4  998.41  369.25 1092.54    NO
  1600.   5.959        1      3.0    3.1   999.4  998.41  388.93 1248.20    NO
  1700.   5.679        1      3.0    3.1   999.4  998.41  408.40 1415.29    NO
  1800.   5.424        1      3.0    3.1   999.4  998.41  427.66 1593.89    NO
```

```
  1900.    5.192         1     3.0     3.1    999.4  998.41   446.73 1784.04     NO
  2000.    4.982         1     3.0     3.1    999.4  998.41   465.62 1985.83     NO
  2100.    4.789         1     3.0     3.1    999.4  998.41   484.34 2199.30     NO
  2200.    4.617         1     3.0     3.1    999.4  998.41   502.44 2424.42     NO
  2300.    4.493         1     3.0     3.1    999.4  998.41   516.22 2660.54     NO
  2400.    4.376         1     3.0     3.1    999.4  998.41   530.07 2908.67     NO
  2500.    4.264         1     3.0     3.1    999.4  998.41   543.97 3168.83     NO
  2600.    4.158         1     3.0     3.1    999.4  998.41   557.93 3441.05     NO
  2700.    4.056         1     3.0     3.1    999.4  998.41   571.93 3725.38     NO
  2800.    3.959         1     3.0     3.1    999.4  998.41   585.96 4021.84     NO
  2900.    3.866         1     3.0     3.1    999.4  998.41   600.02 4330.48     NO
  3000.    3.777         1     3.0     3.1    999.4  998.41   614.11 4651.34     NO
  3500.    3.388         1     3.0     3.1    999.4  998.41   684.70 5000.00     NO
  4000.    3.071         1     3.0     3.1    999.4  998.41   755.30 5000.00     NO
  4500.    2.809         1     3.0     3.1    999.4  998.41   825.63 5000.00     NO
  5000.    2.716         2     3.0     3.1    999.4  998.41   700.07  697.75     NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND     1. M:
  1336.    6.543         1     3.0     3.1    999.4  998.41   336.25  860.51     NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****************************************
     *** REGULATORY (Default) ***
    PERFORMING CAVITY CALCULATIONS
  WITH ORIGINAL SCREEN CAVITY MODEL
          (BRODE, 1988)
****************************************


 *** CAVITY CALCULATION - 1 ***       *** CAVITY CALCULATION - 2 ***
  CONC (UG/M**3)       =    .0000      CONC (UG/M**3)       =    .0000
  CRIT WS @10M (M/S) =    99.99      CRIT WS @10M (M/S) =    99.99
  CRIT WS @ HS  (M/S) =    99.99      CRIT WS @ HS  (M/S) =    99.99
  DILUTION WS (M/S)   =    99.99      DILUTION WS (M/S)   =    99.99
  CAVITY HT (M)       =    20.44      CAVITY HT (M)       =    14.40
  CAVITY LENGTH (M)   =    32.44      CAVITY LENGTH (M)   =     8.06
  ALONGWIND DIM (M)   =     7.10      ALONGWIND DIM (M)   =    18.00

CAVITY CONC NOT CALCULATED FOR CRIT WS > 20.0 M/S.  CONC SET = 0.0

****************************************
      END OF CAVITY CALCULATIONS
****************************************


     ***************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ***************************************

 CALCULATION         MAX CONC    DIST TO   TERRAIN
  PROCEDURE         (UG/M**3)    MAX (M)    HT (M)
--------------    -----------   -------    -------
```

```
SIMPLE TERRAIN      6.543         1336.        0.

***************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
***************************************************
```

```
                                                                     05/15/99
                                                                     10:52:52
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 96043 ***

Int. City P12-14; 1 CT; NOx; 20 deg.; 50% load; oil

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE             =        POINT
   EMISSION RATE (G/S)     =      12.9000
   STACK HEIGHT (M)        =      17.1000
   STK INSIDE DIAM (M)     =       4.9000
   STK EXIT VELOCITY (M/S)=      36.8000
   STK GAS EXIT TEMP (K)   =     676.0000
   AMBIENT AIR TEMP (K)    =     266.0000
   RECEPTOR HEIGHT (M)     =        .0000
   URBAN/RURAL OPTION      =        RURAL
   BUILDING HEIGHT (M)     =      11.8000
   MIN HORIZ BLDG DIM (M)  =       7.1000
   MAX HORIZ BLDG DIM (M)  =      18.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


BUOY. FLUX = 1313.760 M**4/S**3;  MOM. FLUX = 3198.621 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN AUTOMATED DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

  DIST     CONC               U10M   USTK  MIX HT   PLUME   SIGMA   SIGMA
   (M)   (UG/M**3)    STAB   (M/S)  (M/S)    (M)    HT (M)   Y (M)   Z (M)  DWASH
-------  ----------   ----   -----  -----  ------   ------  ------  ------  -----
     1.    .0000        1      1.0    1.0  2789.0 2788.02   11.67   11.67    NO
   100.    .5870        6      1.0    1.3 10000.0  254.16   67.85   67.77    NO
   200.    .5937        6      1.0    1.3 10000.0  254.16   68.17   67.86    NO
   300.    .8102        4     20.0   21.7  6400.0   45.41   22.61   12.38    SS
   400.   1.215         4     20.0   21.7  6400.0   53.07   29.45   15.54    SS
   500.   1.484         4     20.0   21.7  6400.0   60.12   36.15   18.56    SS
   600.   1.646         4     20.0   21.7  6400.0   66.73   42.72   21.46    SS
   700.   1.732         4     20.0   21.7  6400.0   72.97   49.19   24.28    SS
   800.   1.769         4     20.0   21.7  6400.0   78.94   55.57   27.02    SS
   900.   1.773         4     20.0   21.7  6400.0   84.65   61.88   29.70    SS
  1000.   2.855         1      3.0    3.1   960.0  940.74  263.43  481.47    NO
  1100.   4.080         1      3.0    3.1   960.0  940.74  284.37  581.11    NO
  1200.   4.776         1      3.0    3.1   960.0  940.74  304.96  691.82    NO
  1300.   4.987         1      3.0    3.1   960.0  940.74  325.26  813.68    NO
  1400.   4.903         1      3.0    3.1   960.0  940.74  345.28  946.76    NO
  1500.   4.699         1      3.0    3.1   960.0  940.74  365.05 1091.12    NO
  1600.   4.473         1      3.0    3.1   960.0  940.74  384.58 1246.85    NO
  1700.   4.261         1      3.0    3.1   960.0  940.74  403.91 1414.00    NO
  1800.   4.068         1      3.0    3.1   960.0  940.74  423.03 1592.65    NO
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```
  1900.    3.894         1     3.0     3.1     960.0   940.74   441.96 1782.86    NO
  2000.    3.736         1     3.0     3.1     960.0   940.74   460.73 1984.68    NO
  2100.    3.591         1     3.0     3.1     960.0   940.74   479.32 2198.20    NO
  2200.    3.488         1     3.0     3.1     960.0   940.74   493.44 2422.57    NO
  2300.    3.392         1     3.0     3.1     960.0   940.74   507.46 2658.86    NO
  2400.    3.300         1     3.0     3.1     960.0   940.74   521.54 2907.13    NO
  2500.    3.213         1     3.0     3.1     960.0   940.74   535.67 3167.41    NO
  2600.    3.130         1     3.0     3.1     960.0   940.74   549.83 3439.75    NO
  2700.    3.051         1     3.0     3.1     960.0   940.74   564.03 3724.17    NO
  2800.    2.976         1     3.0     3.1     960.0   940.74   578.26 4020.73    NO
  2900.    2.905         1     3.0     3.1     960.0   940.74   592.50 4329.45    NO
  3000.    2.836         1     3.0     3.1     960.0   940.74   606.76 4650.37    NO
  3500.    2.538         1     3.0     3.1     960.0   940.74   678.12 5000.00    NO
  4000.    2.297         1     3.0     3.1     960.0   940.74   749.34 5000.00    NO
  4500.    2.099         1     2.5     2.6    1126.5  1125.47   838.66 5000.00    NO
  5000.    2.098         2     3.0     3.1     960.0   940.74   693.63  691.29    NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND     1. M:
  1310.    4.988         1     3.0     3.1     960.0   940.74   327.07  825.20    NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****************************************
     *** REGULATORY (Default) ***
    PERFORMING CAVITY CALCULATIONS
  WITH ORIGINAL SCREEN CAVITY MODEL
          (BRODE, 1988)
****************************************


 *** CAVITY CALCULATION - 1 ***       *** CAVITY CALCULATION - 2 ***
  CONC (UG/M**3)      =    .0000       CONC (UG/M**3)      =    .0000
  CRIT WS @10M (M/S) =    99.99       CRIT WS @10M (M/S) =    99.99
  CRIT WS @ HS (M/S) =    99.99       CRIT WS @ HS (M/S) =    99.99
  DILUTION WS (M/S)  =    99.99       DILUTION WS (M/S)  =    99.99
  CAVITY HT (M)      =    20.44       CAVITY HT (M)      =    14.40
  CAVITY LENGTH (M)  =    32.44       CAVITY LENGTH (M)  =     8.06
  ALONGWIND DIM (M)  =     7.10       ALONGWIND DIM (M)  =    18.00

CAVITY CONC NOT CALCULATED FOR CRIT WS > 20.0 M/S.  CONC SET = 0.0

****************************************
      END OF CAVITY CALCULATIONS
****************************************


     ***************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ***************************************

 CALCULATION         MAX CONC     DIST TO    TERRAIN
  PROCEDURE         (UG/M**3)     MAX (M)     HT (M)
--------------     -----------   -------    -------
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```
SIMPLE TERRAIN       4.988          1310.         0.

***************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
***************************************************
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                                                                   05/15/99
                                                                   10:55:27
  ***  SCREEN3 MODEL RUN  ***
  *** VERSION DATED 96043 ***

 Int. City P12-14; 1 CT; NOx; 20 deg.; 25% load; oil

 SIMPLE TERRAIN INPUTS:
    SOURCE TYPE             =        POINT
    EMISSION RATE (G/S)     =      8.60000
    STACK HEIGHT (M)        =      17.1000
    STK INSIDE DIAM (M)     =       4.9000
    STK EXIT VELOCITY (M/S)=       36.6000
    STK GAS EXIT TEMP (K)   =     576.0000
    AMBIENT AIR TEMP (K)    =     266.0000
    RECEPTOR HEIGHT (M)     =        .0000
    URBAN/RURAL OPTION      =        RURAL
    BUILDING HEIGHT (M)     =      11.8000
    MIN HORIZ BLDG DIM (M)  =       7.1000
    MAX HORIZ BLDG DIM (M)  =      18.0000

 THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
 THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


 BUOY. FLUX = 1159.448 M**4/S**3;  MOM. FLUX = 3713.244 M**4/S**2.

 *** FULL METEOROLOGY ***

 **********************************
 *** SCREEN AUTOMATED DISTANCES ***
 **********************************

 *** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

   DIST     CONC              U10M   USTK  MIX HT   PLUME   SIGMA   SIGMA
    (M)   (UG/M**3)   STAB   (M/S)  (M/S)    (M)   HT (M)   Y (M)   Z (M)  DWASH
 -------  ----------  ----   -----  -----  ------  ------  ------  ------  -----
      1.   .0000        1      1.0    1.0  2588.9 2587.88   12.27   12.26    NO
    100.   .4087        6      1.0    1.3 10000.0  244.49   65.10   65.01    NO
    200.   .4139        6      1.0    1.3 10000.0  244.49   65.43   65.10    NO
    300.   .6221        4     20.0   21.7  6400.0   44.25   22.61   12.18    SS
    400.   .9824        4     20.0   21.7  6400.0   51.59   29.45   15.35    SS
    500.   1.225        4     20.0   21.7  6400.0   58.36   36.15   18.37    SS
    600.   1.369        4     20.0   21.7  6400.0   64.69   42.72   21.28    SS
    700.   1.445        4     20.0   21.7  6400.0   70.69   49.19   24.11    SS
    800.   1.477        4     20.0   21.7  6400.0   76.41   55.57   26.85    SS
    900.   1.479        4     20.0   21.7  6400.0   81.89   61.88   29.53    SS
   1000.   1.994        1      3.0    3.1   960.0  874.03  259.48  479.32    NO
   1100.   2.794        1      3.0    3.1   960.0  874.03  280.21  579.09    NO
   1200.   3.244        1      3.0    3.1   960.0  874.03  300.62  689.92    NO
   1300.   3.376        1      3.0    3.1   960.0  874.03  320.72  811.88    NO
   1400.   3.357        1      2.5    2.6  1046.4 1045.41  363.82  953.67    NO
   1500.   3.258        1      2.5    2.6  1046.4 1045.41  384.28 1097.71    NO
   1600.   3.118        1      2.5    2.6  1046.4 1045.41  404.49 1253.13    NO
   1700.   2.975        1      2.5    2.6  1046.4 1045.41  424.47 1420.01    NO
   1800.   2.843        1      2.5    2.6  1046.4 1045.41  444.22 1598.41    NO
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  1900.    2.724         1      2.5     2.6  1046.4 1045.41   463.77 1788.39     NO
  2000.    2.614         1      2.5     2.6  1046.4 1045.41   483.14 1990.01     NO
  2100.    2.544         1      2.5     2.6  1046.4 1045.41   496.58 2202.03     NO
  2200.    2.476         1      2.5     2.6  1046.4 1045.41   510.06 2426.01     NO
  2300.    2.412         1      2.5     2.6  1046.4 1045.41   523.64 2661.99     NO
  2400.    2.351         1      2.5     2.6  1046.4 1045.41   537.29 2910.00     NO
  2500.    2.292         1      2.5     2.6  1046.4 1045.41   551.01 3170.05     NO
  2600.    2.236         1      2.5     2.6  1046.4 1045.41   564.80 3442.17     NO
  2700.    2.183         1      2.5     2.6  1046.4 1045.41   578.63 3726.41     NO
  2800.    2.132         1      2.5     2.6  1046.4 1045.41   592.50 4022.80     NO
  2900.    2.083         1      2.5     2.6  1046.4 1045.41   606.41 4331.37     NO
  3000.    2.036         1      2.5     2.6  1046.4 1045.41   620.35 4652.16     NO
  3500.    1.830         1      2.5     2.6  1046.4 1045.41   690.31 5000.00     NO
  4000.    1.661         1      2.5     2.6  1046.4 1045.41   760.38 5000.00     NO
  4500.    1.590         4     20.0    21.7  6400.0  133.01   266.06   83.21     SS
  5000.    1.581         4     20.0    21.7  6400.0  133.01   292.47   88.69     SS

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND     1. M:
  1307.    3.376         1      3.0     3.1   960.0  874.03   321.92  819.55     NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****************************************
     *** REGULATORY (Default) ***
    PERFORMING CAVITY CALCULATIONS
  WITH ORIGINAL SCREEN CAVITY MODEL
          (BRODE, 1988)
****************************************


 *** CAVITY CALCULATION - 1 ***        *** CAVITY CALCULATION - 2 ***
  CONC (UG/M**3)      =    .0000        CONC (UG/M**3)      =    .0000
  CRIT WS @10M (M/S) =    99.99        CRIT WS @10M (M/S) =    99.99
  CRIT WS @ HS (M/S) =    99.99        CRIT WS @ HS (M/S) =    99.99
  DILUTION WS (M/S)  =    99.99        DILUTION WS (M/S)  =    99.99
  CAVITY HT (M)      =    20.44        CAVITY HT (M)      =    14.40
  CAVITY LENGTH (M)  =    32.44        CAVITY LENGTH (M)  =     8.06
  ALONGWIND DIM (M)  =     7.10        ALONGWIND DIM (M)  =    18.00

CAVITY CONC NOT CALCULATED FOR CRIT WS > 20.0 M/S.  CONC SET = 0.0

****************************************
      END OF CAVITY CALCULATIONS
****************************************


     ***************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ***************************************

 CALCULATION         MAX CONC     DIST TO    TERRAIN
  PROCEDURE         (UG/M**3)     MAX (M)     HT (M)
--------------    -----------    -------    -------
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```
SIMPLE TERRAIN       3.376          1307.        0.

***************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
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                                                                 05/15/99
                                                                 11:16:41
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 96043 ***

Int. City P12-14; 1 CT; NOx; 100 deg.; Base load; oil

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE            =        POINT
   EMISSION RATE (G/S)    =      18.4000
   STACK HEIGHT (M)       =      17.1000
   STK INSIDE DIAM (M)    =       4.9000
   STK EXIT VELOCITY (M/S)=      38.2000
   STK GAS EXIT TEMP (K)  =     824.0000
   AMBIENT AIR TEMP (K)   =     310.0000
   RECEPTOR HEIGHT (M)    =        .0000
   URBAN/RURAL OPTION     =        RURAL
   BUILDING HEIGHT (M)    =      11.8000
   MIN HORIZ BLDG DIM (M) =       7.1000
   MAX HORIZ BLDG DIM (M) =      18.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


BUOY. FLUX = 1402.589 M**4/S**3;  MOM. FLUX = 3295.288 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN AUTOMATED DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

  DIST     CONC             U10M   USTK  MIX HT   PLUME   SIGMA   SIGMA
   (M)    (UG/M**3)   STAB  (M/S)  (M/S)    (M)   HT (M)   Y (M)   Z (M)  DWASH
-------  ----------   ----  -----  -----  ------  ------  ------  ------  -----
     1.   .0000         1     1.0    1.0  2900.0 2898.95   11.81   11.81    NO
   100.   .7727         6     1.0    1.3 10000.0  272.07   72.96   72.89    NO
   200.   .7803         6     1.0    1.3 10000.0  272.07   73.26   72.96    NO
   300.   .7896         6     1.0    1.3 10000.0  272.07   73.71   73.07    NO
   400.   1.248         4    20.0   21.7  6400.0   54.21   29.45   15.44    SS
   500.   1.595         4    20.0   21.7  6400.0   61.42   36.15   18.46    SS
   600.   1.823         4    20.0   21.7  6400.0   68.17   42.72   21.37    SS
   700.   1.961         4    20.0   21.7  6400.0   74.56   49.19   24.19    SS
   800.   2.036         4    20.0   21.7  6400.0   80.65   55.57   26.93    SS
   900.   2.068         4    20.0   21.7  6400.0   86.50   61.88   29.61    SS
  1000.   3.754         1     3.0    3.1   978.7  977.72  265.61  482.67    NO
  1100.   5.486         1     3.0    3.1   978.7  977.72  286.66  582.24    NO
  1200.   6.514         1     3.0    3.1   978.7  977.72  307.36  692.88    NO
  1300.   6.866         1     3.0    3.1   978.7  977.72  327.76  814.68    NO
  1400.   6.786         1     3.0    3.1   978.7  977.72  347.88  947.71    NO
  1500.   6.520         1     3.0    3.1   978.7  977.72  367.75 1092.03    NO
  1600.   6.212         1     3.0    3.1   978.7  977.72  387.38 1247.71    NO
  1700.   5.919         1     3.0    3.1   978.7  977.72  406.79 1414.83    NO
  1800.   5.652         1     3.0    3.1   978.7  977.72  426.00 1593.44    NO
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  1900.    5.411        1     3.0     3.1    978.7   977.72   445.02 1783.62     NO
  2000.    5.191        1     3.0     3.1    978.7   977.72   463.86 1985.42     NO
  2100.    4.990        1     3.0     3.1    978.7   977.72   482.54 2198.90     NO
  2200.    4.824        1     3.0     3.1    978.7   977.72   499.17 2423.74     NO
  2300.    4.693        1     3.0     3.1    978.7   977.72   513.03 2659.93     NO
  2400.    4.569        1     3.0     3.1    978.7   977.72   526.96 2908.11     NO
  2500.    4.451        1     3.0     3.1    978.7   977.72   540.95 3168.31     NO
  2600.    4.339        1     3.0     3.1    978.7   977.72   554.98 3440.58     NO
  2700.    4.231        1     3.0     3.1    978.7   977.72   569.05 3724.94     NO
  2800.    4.129        1     3.0     3.1    978.7   977.72   583.16 4021.43     NO
  2900.    4.031        1     3.0     3.1    978.7   977.72   597.28 4330.10     NO
  3000.    3.938        1     3.0     3.1    978.7   977.72   611.43 4650.98     NO
  3500.    3.529        1     3.0     3.1    978.7   977.72   682.30 5000.00     NO
  4000.    3.197        1     3.0     3.1    978.7   977.72   753.12 5000.00     NO
  4500.    2.923        1     3.0     3.1    978.7   977.72   823.65 5000.00     NO
  5000.    2.880        2     3.0     3.1    978.7   977.72   697.72  695.39     NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND     1. M:
  1323.    6.875        1     3.0     3.1    978.7   977.72   332.21  842.98     NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****************************************
     *** REGULATORY (Default) ***
    PERFORMING CAVITY CALCULATIONS
  WITH ORIGINAL SCREEN CAVITY MODEL
          (BRODE, 1988)
****************************************


 *** CAVITY CALCULATION - 1 ***       *** CAVITY CALCULATION - 2 ***
  CONC (UG/M**3)     =    .0000        CONC (UG/M**3)     =    .0000
  CRIT WS @10M (M/S) =    99.99        CRIT WS @10M (M/S) =    99.99
  CRIT WS @ HS (M/S) =    99.99        CRIT WS @ HS (M/S) =    99.99
  DILUTION WS (M/S)  =    99.99        DILUTION WS (M/S)  =    99.99
  CAVITY HT (M)      =    20.44        CAVITY HT (M)      =    14.40
  CAVITY LENGTH (M)  =    32.44        CAVITY LENGTH (M)  =     8.06
  ALONGWIND DIM (M)  =     7.10        ALONGWIND DIM (M)  =    18.00

CAVITY CONC NOT CALCULATED FOR CRIT WS > 20.0 M/S.  CONC SET = 0.0

****************************************
      END OF CAVITY CALCULATIONS
****************************************


     ****************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ****************************************

 CALCULATION         MAX CONC     DIST TO   TERRAIN
  PROCEDURE         (UG/M**3)     MAX (M)    HT (M)
--------------    -----------    -------    -------
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```
SIMPLE TERRAIN      6.875         1323.        0.

***************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
***************************************************
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                                                                       05/15/99
                                                                       11:23:01
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 96043 ***

Int. City P12-14; 1 CT; NOx; 100 deg.; 25% load; oil

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE              =        POINT
   EMISSION RATE (G/S)      =      7.40000
   STACK HEIGHT (M)         =      17.1000
   STK INSIDE DIAM (M)      =       4.9000
   STK EXIT VELOCITY (M/S)=        31.5000
   STK GAS EXIT TEMP (K)    =     630.0000
   AMBIENT AIR TEMP (K)     =     310.0000
   RECEPTOR HEIGHT (M)      =        .0000
   URBAN/RURAL OPTION       =        RURAL
   BUILDING HEIGHT (M)      =      11.8000
   MIN HORIZ BLDG DIM (M)   =       7.1000
   MAX HORIZ BLDG DIM (M)   =      18.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


BUOY. FLUX =  941.784 M**4/S**3;  MOM. FLUX = 2930.721 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN AUTOMATED DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

  DIST     CONC            U10M   USTK  MIX HT   PLUME   SIGMA   SIGMA
   (M)   (UG/M**3)   STAB  (M/S)  (M/S)   (M)    HT (M)  Y (M)   Z (M)  DWASH
-------  ----------  ----  -----  -----  ------  ------  ------  ------  -----
     1.   .0000        1     1.0    1.0  2287.4 2286.36   11.24   11.24    NO
   100.   .3583        6     1.0    1.3 10000.0  240.37   63.92   63.83    NO
   200.   1.554        4    20.0   21.7  6400.0   33.46   15.56    9.54    SS
   300.   2.158        4    20.0   21.7  6400.0   41.03   22.61   12.77    SS
   400.   2.518        4    20.0   21.7  6400.0   47.85   29.45   15.91    SS
   500.   2.637        4    20.0   21.7  6400.0   54.15   36.15   18.91    SS
   600.   2.632        4    20.0   21.7  6400.0   60.05   42.72   21.81    SS
   700.   2.563        4    20.0   21.7  6400.0   65.64   49.19   24.61    SS
   800.   2.466        4    20.0   21.7  6400.0   70.97   55.57   27.35    SS
   900.   2.356        4    20.0   21.7  6400.0   76.08   61.88   30.02    SS
  1000.   2.241        1     2.5    2.6   925.8  924.80  270.85  485.57    NO
  1100.   3.035        1     2.5    2.6   925.8  924.80  292.17  584.97    NO
  1200.   3.439        1     2.5    2.6   925.8  924.80  313.14  695.47    NO
  1300.   3.523        1     2.5    2.6   925.8  924.80  333.79  817.13    NO
  1400.   3.430        1     2.5    2.6   925.8  924.80  354.15  950.03    NO
  1500.   3.276        1     2.5    2.6   925.8  924.80  374.25 1094.24    NO
  1600.   3.116        1     2.5    2.6   925.8  924.80  394.11 1249.82    NO
  1700.   2.969        1     2.5    2.6   925.8  924.80  413.74 1416.84    NO
  1800.   2.836        1     2.5    2.6   925.8  924.80  433.16 1595.37    NO
```

```
  1900.   2.735         1      2.5      2.6    925.8   924.80   449.21 1784.67     NO
  2000.   2.653         1      2.5      2.6    925.8   924.80   463.06 1985.23     NO
  2100.   2.575         1      2.5      2.6    925.8   924.80   477.00 2197.69     NO
  2200.   2.502         1      2.5      2.6    925.8   924.80   491.02 2422.08     NO
  2300.   2.432         1      2.5      2.6    925.8   924.80   505.11 2658.41     NO
  2400.   2.366         1      2.5      2.6    925.8   924.80   519.25 2906.72     NO
  2500.   2.303         1      2.5      2.6    925.8   924.80   533.44 3167.04     NO
  2600.   2.243         1      2.5      2.6    925.8   924.80   547.66 3439.40     NO
  2700.   2.186         1      2.5      2.6    925.8   924.80   561.92 3723.85     NO
  2800.   2.132         1      2.5      2.6    925.8   924.80   576.19 4020.43     NO
  2900.   2.080         1      2.5      2.6    925.8   924.80   590.49 4329.17     NO
  3000.   2.031         1      2.5      2.6    925.8   924.80   604.79 4650.12     NO
  3500.   1.854         4     20.0     21.7   6400.0   117.53   212.19   71.48     SS
  4000.   1.855         4     20.0     21.7   6400.0   117.53   239.31   77.49     SS
  4500.   1.810         4     20.0     21.7   6400.0   117.53   266.06   83.21     SS
  5000.   1.741         4     20.0     21.7   6400.0   117.53   292.47   88.69     SS

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND      1. M:
  1285.   3.525         1      2.5      2.6    925.8   924.80   330.51  796.91     NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****************************************
     *** REGULATORY (Default) ***
    PERFORMING CAVITY CALCULATIONS
  WITH ORIGINAL SCREEN CAVITY MODEL
          (BRODE, 1988)
****************************************


 *** CAVITY CALCULATION - 1 ***       *** CAVITY CALCULATION - 2 ***
  CONC (UG/M**3)      =    .0000       CONC (UG/M**3)      =    .0000
  CRIT WS @10M (M/S) =    99.99       CRIT WS @10M (M/S) =    99.99
  CRIT WS @ HS (M/S) =    99.99       CRIT WS @ HS (M/S) =    99.99
  DILUTION WS (M/S)  =    99.99       DILUTION WS (M/S)  =    99.99
  CAVITY HT (M)      =    20.44       CAVITY HT (M)      =    14.40
  CAVITY LENGTH (M)  =    32.44       CAVITY LENGTH (M)  =     8.06
  ALONGWIND DIM (M)  =     7.10       ALONGWIND DIM (M)  =    18.00

CAVITY CONC NOT CALCULATED FOR CRIT WS > 20.0 M/S.  CONC SET = 0.0

****************************************
      END OF CAVITY CALCULATIONS
****************************************


     ***************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ***************************************

 CALCULATION         MAX CONC      DIST TO    TERRAIN
  PROCEDURE         (UG/M**3)      MAX (M)     HT (M)
--------------    -----------    -------    -------
```

```
SIMPLE TERRAIN      3.525         1285.        0.

***************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
***************************************************
```

```
                                                                   05/15/99
                                                                   11:41:19
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 96043 ***

Int. City P12-14; 1 CT; NOx; 59 deg.; Base load; oil

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE              =        POINT
   EMISSION RATE (G/S)      =      21.0000
   STACK HEIGHT (M)         =      17.1000
   STK INSIDE DIAM (M)      =       4.9000
   STK EXIT VELOCITY (M/S)=        42.7000
   STK GAS EXIT TEMP (K)    =     807.0000
   AMBIENT AIR TEMP (K)     =     288.0000
   RECEPTOR HEIGHT (M)      =        .0000
   URBAN/RURAL OPTION       =        RURAL
   BUILDING HEIGHT (M)      =      11.8000
   MIN HORIZ BLDG DIM (M) =         7.1000
   MAX HORIZ BLDG DIM (M) =        18.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


BUOY. FLUX = 1616.415 M**4/S**3;  MOM. FLUX = 3905.772 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN AUTOMATED DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

  DIST     CONC           U10M   USTK  MIX HT   PLUME   SIGMA   SIGMA
  (M)    (UG/M**3)   STAB  (M/S)  (M/S)   (M)    HT (M)   Y (M)   Z (M)  DWASH
-------  ----------  ----  -----  -----  ------  ------  ------  ------  -----
     1.   .0000        1     1.0    1.0  3156.0 3155.04   12.57   12.56   NO
   100.   .8593        6     1.0    1.3 10000.0  277.94   74.64   74.56   NO
   200.   .8673        6     1.0    1.3 10000.0  277.94   74.93   74.64   NO
   300.   .8771        6     1.0    1.3 10000.0  277.94   75.37   74.74   NO
   400.   .8885        6     1.0    1.3 10000.0  277.94   75.95   74.86   NO
   500.   .9013        6     1.0    1.3 10000.0  277.94   76.66   75.00   NO
   600.   1.111        4    20.0   21.7  6400.0   71.77   42.72   21.21   SS
   700.   1.263        4    20.0   21.7  6400.0   78.48   49.19   24.03   SS
   800.   1.368        4    20.0   21.7  6400.0   84.87   55.57   26.78   SS
   900.   1.436        4    20.0   21.7  6400.0   91.00   61.88   29.47   SS
  1000.   2.957        1     3.0    3.1  1064.1 1063.08  270.60  485.43   NO
  1100.   4.803        1     3.0    3.1  1064.1 1063.08  291.91  584.84   NO
  1200.   6.118        1     3.0    3.1  1064.1 1063.08  312.87  695.34   NO
  1300.   6.753        1     3.0    3.1  1064.1 1063.08  333.51  817.01   NO
  1400.   6.863        1     3.0    3.1  1064.1 1063.08  353.86  949.92   NO
  1500.   6.686        1     3.0    3.1  1064.1 1063.08  373.94 1094.13   NO
  1600.   6.405        1     3.0    3.1  1064.1 1063.08  393.79 1249.72   NO
  1700.   6.112        1     3.0    3.1  1064.1 1063.08  413.41 1416.75   NO
  1800.   5.840        1     3.0    3.1  1064.1 1063.08  432.83 1595.28   NO
```

```
  1900.    5.592         1     3.0     3.1   1064.1 1063.08   452.04 1785.38     NO
  2000.    5.366         1     3.0     3.1   1064.1 1063.08   471.08 1987.11     NO
  2100.    5.159         1     3.0     3.1   1064.1 1063.08   489.95 2200.54     NO
  2200.    4.969         1     3.0     3.1   1064.1 1063.08   508.65 2425.71     NO
  2300.    4.801         1     3.0     3.1   1064.1 1063.08   526.48 2662.56     NO
  2400.    4.680         1     3.0     3.1   1064.1 1063.08   540.07 2910.51     NO
  2500.    4.565         1     3.0     3.1   1064.1 1063.08   553.72 3170.52     NO
  2600.    4.455         1     3.0     3.1   1064.1 1063.08   567.44 3442.61     NO
  2700.    4.349         1     3.0     3.1   1064.1 1063.08   581.21 3726.81     NO
  2800.    4.248         1     3.0     3.1   1064.1 1063.08   595.02 4023.17     NO
  2900.    4.151         1     3.0     3.1   1064.1 1063.08   608.88 4331.72     NO
  3000.    4.059         1     3.0     3.1   1064.1 1063.08   622.76 4652.49     NO
  3500.    3.650         1     3.0     3.1   1064.1 1063.08   692.47 5000.00     NO
  4000.    3.316         1     3.0     3.1   1064.1 1063.08   762.35 5000.00     NO
  4500.    3.038         1     3.0     3.1   1064.1 1063.08   832.09 5000.00     NO
  5000.    2.804         1     3.0     3.1   1064.1 1063.08   901.53 5000.00     NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND      1. M:
  1377.    6.872         1     3.0     3.1   1064.1 1063.08   349.00  916.99     NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****************************************
     *** REGULATORY (Default) ***
    PERFORMING CAVITY CALCULATIONS
  WITH ORIGINAL SCREEN CAVITY MODEL
          (BRODE, 1988)
****************************************


 *** CAVITY CALCULATION - 1 ***        *** CAVITY CALCULATION - 2 ***
  CONC (UG/M**3)       =    .0000        CONC (UG/M**3)       =    .0000
  CRIT WS @10M (M/S) =    99.99         CRIT WS @10M (M/S) =    99.99
  CRIT WS @ HS (M/S) =    99.99         CRIT WS @ HS (M/S) =    99.99
  DILUTION WS (M/S)  =    99.99         DILUTION WS (M/S)  =    99.99
  CAVITY HT (M)      =    20.44         CAVITY HT (M)      =    14.40
  CAVITY LENGTH (M)  =    32.44         CAVITY LENGTH (M)  =     8.06
  ALONGWIND DIM (M)  =     7.10         ALONGWIND DIM (M)  =    18.00

CAVITY CONC NOT CALCULATED FOR CRIT WS > 20.0 M/S.  CONC SET = 0.0

****************************************
      END OF CAVITY CALCULATIONS
****************************************


     ****************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ****************************************

 CALCULATION          MAX CONC     DIST TO    TERRAIN
  PROCEDURE          (UG/M**3)     MAX (M)     HT (M)
--------------     -----------    -------    -------
```

```
SIMPLE TERRAIN       6.872          1377.         0.

***************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
***************************************************
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                                                                   05/15/99
                                                                   11:01:29
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 96043 ***

Int. City P12-14; 1 CT; PM; 20 deg.; Base load; oil

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE             =        POINT
   EMISSION RATE (G/S)     =      1.30000
   STACK HEIGHT (M)        =      17.1000
   STK INSIDE DIAM (M)     =       4.9000
   STK EXIT VELOCITY (M/S)=       46.7000
   STK GAS EXIT TEMP (K)   =     791.0000
   AMBIENT AIR TEMP (K)    =     266.0000
   RECEPTOR HEIGHT (M)     =        .0000
   URBAN/RURAL OPTION      =        RURAL
   BUILDING HEIGHT (M)     =      11.8000
   MIN HORIZ BLDG DIM (M)  =       7.1000
   MAX HORIZ BLDG DIM (M)  =      18.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


BUOY. FLUX = 1824.445 M**4/S**3;  MOM. FLUX = 4402.214 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN AUTOMATED DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

  DIST      CONC              U10M   USTK  MIX HT   PLUME   SIGMA   SIGMA
   (M)    (UG/M**3)   STAB   (M/S)  (M/S)    (M)    HT (M)  Y (M)   Z (M)  DWASH
-------  ----------   ----   -----  -----  ------  ------  ------  ------  -----
     1.   .0000         1     1.0     1.0  3392.5 3391.47   13.13   13.12    NO
   100.   .5234E-01     6     1.0     1.3 10000.0  281.59   75.68   75.60    NO
   200.   .5282E-01     6     1.0     1.3 10000.0  281.59   75.96   75.68    NO
   300.   .5340E-01     6     1.0     1.3 10000.0  281.59   76.40   75.78    NO
   400.   .5407E-01     6     1.0     1.3 10000.0  281.59   76.97   75.90    NO
   500.   .5483E-01     6     1.0     1.3 10000.0  281.59   77.67   76.03    NO
   600.   .5566E-01     6     1.0     1.3 10000.0  281.59   78.49   76.19    NO
   700.   .5656E-01     6     1.0     1.3 10000.0  281.59   79.43   76.35    NO
   800.   .5729E-01     6     1.0     1.3 10000.0  281.59   80.46   76.51    NO
   900.   .5828E-01     4    20.0    21.7  6400.0   94.94   61.88   29.47    SS
  1000.   .1274         1     3.0     3.1  1142.9 1141.89  275.17  488.00    NO
  1100.   .2295         1     3.0     3.1  1142.9 1141.89  296.72  587.26    NO
  1200.   .3131         1     3.0     3.1  1142.9 1141.89  317.91  697.63    NO
  1300.   .3619         1     3.0     3.1  1142.9 1141.89  338.77  819.17    NO
  1400.   .3790         1     3.0     3.1  1142.9 1141.89  359.33  951.97    NO
  1500.   .3756         1     3.0     3.1  1142.9 1141.89  379.63 1096.09    NO
  1600.   .3626         1     3.0     3.1  1142.9 1141.89  399.67 1251.58    NO
  1700.   .3470         1     3.0     3.1  1142.9 1141.89  419.49 1418.53    NO
  1800.   .3317         1     3.0     3.1  1142.9 1141.89  439.09 1596.99    NO
```

```
  1900.   .3177        1     3.0    3.1  1142.9 1141.89  458.49 1787.02    NO
  2000.   .3050        1     3.0    3.1  1142.9 1141.89  477.70 1988.70    NO
  2100.   .2933        1     3.0    3.1  1142.9 1141.89  496.74 2202.06    NO
  2200.   .2825        1     3.0    3.1  1142.9 1141.89  515.62 2427.18    NO
  2300.   .2726        1     3.0    3.1  1142.9 1141.89  534.33 2664.12    NO
  2400.   .2635        1     3.0    3.1  1142.9 1141.89  552.85 2912.91    NO
  2500.   .2573        1     3.0    3.1  1142.9 1141.89  566.19 3172.72    NO
  2600.   .2514        1     3.0    3.1  1142.9 1141.89  579.61 3444.64    NO
  2700.   .2456        1     3.0    3.1  1142.9 1141.89  593.10 3728.69    NO
  2800.   .2402        1     3.0    3.1  1142.9 1141.89  606.65 4024.91    NO
  2900.   .2349        1     3.0    3.1  1142.9 1141.89  620.24 4333.33    NO
  3000.   .2298        1     3.0    3.1  1142.9 1141.89  633.87 4653.99    NO
  3500.   .2074        1     3.0    3.1  1142.9 1141.89  702.48 5000.00    NO
  4000.   .1888        1     3.0    3.1  1142.9 1141.89  771.45 5000.00    NO
  4500.   .1733        1     3.0    3.1  1142.9 1141.89  840.44 5000.00    NO
  5000.   .1602        1     3.0    3.1  1142.9 1141.89  909.24 5000.00    NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND     1. M:
  1425.   .3796        1     3.0    3.1  1142.9 1141.89  364.23  985.52    NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****************************************
     *** REGULATORY (Default) ***
    PERFORMING CAVITY CALCULATIONS
  WITH ORIGINAL SCREEN CAVITY MODEL
          (BRODE, 1988)
****************************************


 *** CAVITY CALCULATION - 1 ***       *** CAVITY CALCULATION - 2 ***
  CONC (UG/M**3)     =    .0000        CONC (UG/M**3)     =    .0000
  CRIT WS @10M (M/S) =    99.99        CRIT WS @10M (M/S) =    99.99
  CRIT WS @ HS (M/S) =    99.99        CRIT WS @ HS (M/S) =    99.99
  DILUTION WS (M/S)  =    99.99        DILUTION WS (M/S)  =    99.99
  CAVITY HT (M)      =    20.44        CAVITY HT (M)      =    14.40
  CAVITY LENGTH (M)  =    32.44        CAVITY LENGTH (M)  =     8.06
  ALONGWIND DIM (M)  =     7.10        ALONGWIND DIM (M)  =    18.00

CAVITY CONC NOT CALCULATED FOR CRIT WS > 20.0 M/S.  CONC SET = 0.0

****************************************
      END OF CAVITY CALCULATIONS
****************************************


     ***************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ***************************************

 CALCULATION        MAX CONC    DIST TO   TERRAIN
  PROCEDURE        (UG/M**3)    MAX (M)    HT (M)
--------------    -----------   -------   -------
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```
SIMPLE TERRAIN      .3796         1425.        0.

***************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
***************************************************
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                                                                05/15/99
                                                                11:03:46
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 96043 ***

Int. City P12-14; 1 CT; PM; 20 deg.; 25% load; oil

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE            =        POINT
   EMISSION RATE (G/S)    =      1.30000
   STACK HEIGHT (M)       =      17.1000
   STK INSIDE DIAM (M)    =       4.9000
   STK EXIT VELOCITY (M/S)=      36.6000
   STK GAS EXIT TEMP (K)  =     576.0000
   AMBIENT AIR TEMP (K)   =     266.0000
   RECEPTOR HEIGHT (M)    =        .0000
   URBAN/RURAL OPTION     =        RURAL
   BUILDING HEIGHT (M)    =      11.8000
   MIN HORIZ BLDG DIM (M) =       7.1000
   MAX HORIZ BLDG DIM (M) =      18.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


BUOY. FLUX = 1159.448 M**4/S**3;  MOM. FLUX = 3713.244 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN AUTOMATED DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

  DIST     CONC              U10M   USTK  MIX HT   PLUME    SIGMA   SIGMA
   (M)   (UG/M**3)    STAB  (M/S)  (M/S)    (M)   HT (M)    Y (M)   Z (M)  DWASH
-------  ----------   ----  -----  -----  ------  ------   ------  ------  -----
     1.   .0000         1     1.0    1.0  2588.9 2587.88    12.27   12.26    NO
   100.   .6178E-01     6     1.0    1.3 10000.0  244.49    65.10   65.01    NO
   200.   .6256E-01     6     1.0    1.3 10000.0  244.49    65.43   65.10    NO
   300.   .9403E-01     4    20.0   21.7  6400.0   44.25    22.61   12.18    SS
   400.   .1485         4    20.0   21.7  6400.0   51.59    29.45   15.35    SS
   500.   .1851         4    20.0   21.7  6400.0   58.36    36.15   18.37    SS
   600.   .2069         4    20.0   21.7  6400.0   64.69    42.72   21.28    SS
   700.   .2185         4    20.0   21.7  6400.0   70.69    49.19   24.11    SS
   800.   .2232         4    20.0   21.7  6400.0   76.41    55.57   26.85    SS
   900.   .2235         4    20.0   21.7  6400.0   81.89    61.88   29.53    SS
  1000.   .3014         1     3.0    3.1   960.0  874.03   259.48  479.32    NO
  1100.   .4223         1     3.0    3.1   960.0  874.03   280.21  579.09    NO
  1200.   .4903         1     3.0    3.1   960.0  874.03   300.62  689.92    NO
  1300.   .5103         1     3.0    3.1   960.0  874.03   320.72  811.88    NO
  1400.   .5074         1     2.5    2.6  1046.4 1045.41   363.82  953.67    NO
  1500.   .4925         1     2.5    2.6  1046.4 1045.41   384.28 1097.71    NO
  1600.   .4713         1     2.5    2.6  1046.4 1045.41   404.49 1253.13    NO
  1700.   .4497         1     2.5    2.6  1046.4 1045.41   424.47 1420.01    NO
  1800.   .4298         1     2.5    2.6  1046.4 1045.41   444.22 1598.41    NO
```

```
   1900.    .4117         1     2.5     2.6  1046.4 1045.41   463.77 1788.39    NO
   2000.    .3952         1     2.5     2.6  1046.4 1045.41   483.14 1990.01    NO
   2100.    .3845         1     2.5     2.6  1046.4 1045.41   496.58 2202.03    NO
   2200.    .3744         1     2.5     2.6  1046.4 1045.41   510.06 2426.01    NO
   2300.    .3646         1     2.5     2.6  1046.4 1045.41   523.64 2661.99    NO
   2400.    .3554         1     2.5     2.6  1046.4 1045.41   537.29 2910.00    NO
   2500.    .3465         1     2.5     2.6  1046.4 1045.41   551.01 3170.05    NO
   2600.    .3381         1     2.5     2.6  1046.4 1045.41   564.80 3442.17    NO
   2700.    .3300         1     2.5     2.6  1046.4 1045.41   578.63 3726.41    NO
   2800.    .3223         1     2.5     2.6  1046.4 1045.41   592.50 4022.80    NO
   2900.    .3149         1     2.5     2.6  1046.4 1045.41   606.41 4331.37    NO
   3000.    .3078         1     2.5     2.6  1046.4 1045.41   620.35 4652.16    NO
   3500.    .2766         1     2.5     2.6  1046.4 1045.41   690.31 5000.00    NO
   4000.    .2511         1     2.5     2.6  1046.4 1045.41   760.38 5000.00    NO
   4500.    .2403         4    20.0    21.7  6400.0  133.01   266.06   83.21    SS
   5000.    .2390         4    20.0    21.7  6400.0  133.01   292.47   88.69    SS

 MAXIMUM 1-HR CONCENTRATION AT OR BEYOND     1. M:
   1307.    .5104         1     3.0     3.1   960.0  874.03   321.92  819.55    NO

  DWASH=   MEANS NO CALC MADE (CONC = 0.0)
  DWASH=NO MEANS NO BUILDING DOWNWASH USED
  DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
  DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
  DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

 ***************************************
      *** REGULATORY (Default) ***
     PERFORMING CAVITY CALCULATIONS
   WITH ORIGINAL SCREEN CAVITY MODEL
          (BRODE, 1988)
 ***************************************


  *** CAVITY CALCULATION - 1 ***       *** CAVITY CALCULATION - 2 ***
   CONC (UG/M**3)      =    .0000       CONC (UG/M**3)      =    .0000
   CRIT WS @10M (M/S) =    99.99       CRIT WS @10M (M/S) =    99.99
   CRIT WS @ HS (M/S) =    99.99       CRIT WS @ HS (M/S) =    99.99
   DILUTION WS (M/S)  =    99.99       DILUTION WS (M/S)  =    99.99
   CAVITY HT (M)      =    20.44       CAVITY HT (M)      =    14.40
   CAVITY LENGTH (M)  =    32.44       CAVITY LENGTH (M)  =     8.06
   ALONGWIND DIM (M)  =     7.10       ALONGWIND DIM (M)  =    18.00

 CAVITY CONC NOT CALCULATED FOR CRIT WS > 20.0 M/S.  CONC SET = 0.0

 ***************************************
       END OF CAVITY CALCULATIONS
 ***************************************


      ***************************************
      *** SUMMARY OF SCREEN MODEL RESULTS ***
      ***************************************

  CALCULATION         MAX CONC    DIST TO   TERRAIN
   PROCEDURE         (UG/M**3)    MAX (M)    HT (M)
 --------------    -----------   -------   -------
```

```
SIMPLE TERRAIN       .5104          1307.         0.

***************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
***************************************************
```

```
                                                                 05/15/99
                                                                 11:51:02
  ***  SCREEN3 MODEL RUN  ***
  *** VERSION DATED 96043 ***

 Int. City P12-14; 1 CT; PM; 59 deg.; 25% load; oil

 SIMPLE TERRAIN INPUTS:
    SOURCE TYPE            =        POINT
    EMISSION RATE (G/S)    =      1.30000
    STACK HEIGHT (M)       =      17.1000
    STK INSIDE DIAM (M)    =       4.9000
    STK EXIT VELOCITY (M/S)=      34.3000
    STK GAS EXIT TEMP (K)  =     600.0000
    AMBIENT AIR TEMP (K)   =     288.0000
    RECEPTOR HEIGHT (M)    =        .0000
    URBAN/RURAL OPTION     =        RURAL
    BUILDING HEIGHT (M)    =      11.8000
    MIN HORIZ BLDG DIM (M) =       7.1000
    MAX HORIZ BLDG DIM (M) =      18.0000

 THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
 THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


 BUOY. FLUX = 1049.853 M**4/S**3;  MOM. FLUX = 3389.703 M**4/S**2.

 *** FULL METEOROLOGY ***

 **********************************
 *** SCREEN AUTOMATED DISTANCES ***
 **********************************

 *** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

   DIST     CONC             U10M   USTK  MIX HT   PLUME   SIGMA   SIGMA
    (M)   (UG/M**3)   STAB  (M/S)  (M/S)    (M)    HT (M)   Y (M)   Z (M)  DWASH
 -------  ----------  ----  -----  -----  ------  ------  ------  ------  -----
      1.   .0000        1     1.0    1.0  2440.2 2439.19   11.86   11.85    NO
    100.   .6220E-01    6     1.0    1.3 10000.0  243.00   64.67   64.58    NO
    200.   .9554E-01    4    20.0   21.7  6400.0   34.85   15.56    9.15    SS
    300.   .1833        4    20.0   21.7  6400.0   42.74   22.61   12.42    SS
    400.   .2504        4    20.0   21.7  6400.0   49.83   29.45   15.58    SS
    500.   .2873        4    20.0   21.7  6400.0   56.37   36.15   18.60    SS
    600.   .3044        4    20.0   21.7  6400.0   62.50   42.72   21.50    SS
    700.   .3093        4    20.0   21.7  6400.0   68.29   49.19   24.32    SS
    800.   .3072        4    20.0   21.7  6400.0   73.82   55.57   27.06    SS
    900.   .3009        4    20.0   21.7  6400.0   79.13   61.88   29.74    SS
   1000.   .3227        1     3.0    3.1   960.0  824.46  256.53  477.73    NO
   1100.   .4459        1     2.5    2.6   986.9  985.94  296.49  587.14    NO
   1200.   .5290        1     2.5    2.6   986.9  985.94  317.67  697.52    NO
   1300.   .5581        1     2.5    2.6   986.9  985.94  338.52  819.07    NO
   1400.   .5524        1     2.5    2.6   986.9  985.94  359.07  951.87    NO
   1500.   .5312        1     2.5    2.6   986.9  985.94  379.35 1095.99    NO
   1600.   .5065        1     2.5    2.6   986.9  985.94  399.39 1251.49    NO
   1700.   .4829        1     2.5    2.6   986.9  985.94  419.19 1418.44    NO
   1800.   .4614        1     2.5    2.6   986.9  985.94  438.79 1596.91    NO
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  1900.   .4419        1     2.5     2.6    986.9  985.94  458.18 1786.94    NO
  2000.   .4280        1     2.5     2.6    986.9  985.94  473.06 1987.58    NO
  2100.   .4159        1     2.5     2.6    986.9  985.94  486.72 2199.82    NO
  2200.   .4045        1     2.5     2.6    986.9  985.94  500.46 2424.01    NO
  2300.   .3936        1     2.5     2.6    986.9  985.94  514.29 2660.17    NO
  2400.   .3833        1     2.5     2.6    986.9  985.94  528.19 2908.33    NO
  2500.   .3734        1     2.5     2.6    986.9  985.94  542.15 3168.52    NO
  2600.   .3640        1     2.5     2.6    986.9  985.94  556.15 3440.76    NO
  2700.   .3551        1     2.5     2.6    986.9  985.94  570.19 3725.11    NO
  2800.   .3465        1     2.5     2.6    986.9  985.94  584.26 4021.59    NO
  2900.   .3383        1     2.5     2.6    986.9  985.94  598.37 4330.25    NO
  3000.   .3305        1     2.5     2.6    986.9  985.94  612.49 4651.12    NO
  3500.   .2963        1     2.5     2.6    986.9  985.94  683.25 5000.00    NO
  4000.   .2777        4    20.0    21.7   6400.0  125.45  239.31   77.49    SS
  4500.   .2768        4    20.0    21.7   6400.0  125.45  266.06   83.21    SS
  5000.   .2707        4    20.0    21.7   6400.0  125.45  292.47   88.69    SS

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND      1. M:
  1325.   .5591        1     2.5     2.6    986.9  985.94  343.47  849.91    NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****************************************
     *** REGULATORY (Default) ***
    PERFORMING CAVITY CALCULATIONS
  WITH ORIGINAL SCREEN CAVITY MODEL
          (BRODE, 1988)
****************************************


 *** CAVITY CALCULATION - 1 ***       *** CAVITY CALCULATION - 2 ***
  CONC (UG/M**3)       =    .0000       CONC (UG/M**3)       =    .0000
  CRIT WS @10M (M/S) =    99.99       CRIT WS @10M (M/S) =    99.99
  CRIT WS @ HS (M/S) =    99.99       CRIT WS @ HS (M/S) =    99.99
  DILUTION WS (M/S)  =    99.99       DILUTION WS (M/S)  =    99.99
  CAVITY HT (M)      =    20.44       CAVITY HT (M)      =    14.40
  CAVITY LENGTH (M)  =    32.44       CAVITY LENGTH (M)  =     8.06
  ALONGWIND DIM (M)  =     7.10       ALONGWIND DIM (M)  =    18.00

CAVITY CONC NOT CALCULATED FOR CRIT WS > 20.0 M/S.  CONC SET = 0.0

****************************************
      END OF CAVITY CALCULATIONS
****************************************


     ***************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ***************************************

 CALCULATION         MAX CONC     DIST TO    TERRAIN
  PROCEDURE         (UG/M**3)     MAX (M)     HT (M)
--------------    -----------   -------    -------
```

```
SIMPLE TERRAIN       .5591          1325.         0.

***************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
***************************************************
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                                                                05/15/99
                                                                11:53:28
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 96043 ***

Int. City P12-14; 1 CT; PM; 100 deg.; 25% load; oil

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE              =        POINT
   EMISSION RATE (G/S)      =      1.30000
   STACK HEIGHT (M)         =      17.1000
   STK INSIDE DIAM (M)      =       4.9000
   STK EXIT VELOCITY (M/S)=        31.5000
   STK GAS EXIT TEMP (K)    =     630.0000
   AMBIENT AIR TEMP (K)     =     310.0000
   RECEPTOR HEIGHT (M)      =        .0000
   URBAN/RURAL OPTION       =        RURAL
   BUILDING HEIGHT (M)      =      11.8000
   MIN HORIZ BLDG DIM (M) =         7.1000
   MAX HORIZ BLDG DIM (M) =        18.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


BUOY. FLUX =  941.784 M**4/S**3;  MOM. FLUX = 2930.721 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN AUTOMATED DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

  DIST     CONC             U10M   USTK  MIX HT   PLUME   SIGMA   SIGMA
   (M)   (UG/M**3)   STAB  (M/S)  (M/S)    (M)   HT (M)   Y (M)   Z (M)  DWASH
 -------  ----------  ----  -----  -----  ------  ------  ------  ------  -----
     1.   .0000        1     1.0    1.0  2287.4 2286.36   11.24   11.24    NO
   100.   .6294E-01    6     1.0    1.3 10000.0  240.37   63.92   63.83    NO
   200.   .2730        4    20.0   21.7  6400.0   33.46   15.56    9.54    SS
   300.   .3791        4    20.0   21.7  6400.0   41.03   22.61   12.77    SS
   400.   .4424        4    20.0   21.7  6400.0   47.85   29.45   15.91    SS
   500.   .4633        4    20.0   21.7  6400.0   54.15   36.15   18.91    SS
   600.   .4623        4    20.0   21.7  6400.0   60.05   42.72   21.81    SS
   700.   .4503        4    20.0   21.7  6400.0   65.64   49.19   24.61    SS
   800.   .4332        4    20.0   21.7  6400.0   70.97   55.57   27.35    SS
   900.   .4140        4    20.0   21.7  6400.0   76.08   61.88   30.02    SS
  1000.   .3937        1     2.5    2.6   925.8  924.80  270.85  485.57    NO
  1100.   .5332        1     2.5    2.6   925.8  924.80  292.17  584.97    NO
  1200.   .6041        1     2.5    2.6   925.8  924.80  313.14  695.47    NO
  1300.   .6189        1     2.5    2.6   925.8  924.80  333.79  817.13    NO
  1400.   .6026        1     2.5    2.6   925.8  924.80  354.15  950.03    NO
  1500.   .5755        1     2.5    2.6   925.8  924.80  374.25 1094.24    NO
  1600.   .5475        1     2.5    2.6   925.8  924.80  394.11 1249.82    NO
  1700.   .5216        1     2.5    2.6   925.8  924.80  413.74 1416.84    NO
  1800.   .4982        1     2.5    2.6   925.8  924.80  433.16 1595.37    NO
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  1900.   .4804        1     2.5    2.6   925.8  924.80  449.21 1784.67    NO
  2000.   .4661        1     2.5    2.6   925.8  924.80  463.06 1985.23    NO
  2100.   .4524        1     2.5    2.6   925.8  924.80  477.00 2197.69    NO
  2200.   .4395        1     2.5    2.6   925.8  924.80  491.02 2422.08    NO
  2300.   .4273        1     2.5    2.6   925.8  924.80  505.11 2658.41    NO
  2400.   .4156        1     2.5    2.6   925.8  924.80  519.25 2906.72    NO
  2500.   .4046        1     2.5    2.6   925.8  924.80  533.44 3167.04    NO
  2600.   .3941        1     2.5    2.6   925.8  924.80  547.66 3439.40    NO
  2700.   .3841        1     2.5    2.6   925.8  924.80  561.92 3723.85    NO
  2800.   .3746        1     2.5    2.6   925.8  924.80  576.19 4020.43    NO
  2900.   .3655        1     2.5    2.6   925.8  924.80  590.49 4329.17    NO
  3000.   .3568        1     2.5    2.6   925.8  924.80  604.79 4650.12    NO
  3500.   .3257        4    20.0   21.7  6400.0  117.53  212.19   71.48    SS
  4000.   .3259        4    20.0   21.7  6400.0  117.53  239.31   77.49    SS
  4500.   .3180        4    20.0   21.7  6400.0  117.53  266.06   83.21    SS
  5000.   .3058        4    20.0   21.7  6400.0  117.53  292.47   88.69    SS

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND     1. M:
  1285.   .6193        1     2.5    2.6   925.8  924.80  330.51  796.91    NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****************************************
     *** REGULATORY (Default) ***
    PERFORMING CAVITY CALCULATIONS
  WITH ORIGINAL SCREEN CAVITY MODEL
          (BRODE, 1988)
****************************************


 *** CAVITY CALCULATION - 1 ***       *** CAVITY CALCULATION - 2 ***
  CONC (UG/M**3)      =    .0000        CONC (UG/M**3)      =    .0000
  CRIT WS @10M (M/S) =    99.99        CRIT WS @10M (M/S) =    99.99
  CRIT WS @ HS (M/S) =    99.99        CRIT WS @ HS (M/S) =    99.99
  DILUTION WS (M/S)  =    99.99        DILUTION WS (M/S)  =    99.99
  CAVITY HT (M)      =    20.44        CAVITY HT (M)      =    14.40
  CAVITY LENGTH (M)  =    32.44        CAVITY LENGTH (M)  =     8.06
  ALONGWIND DIM (M)  =     7.10        ALONGWIND DIM (M)  =    18.00

CAVITY CONC NOT CALCULATED FOR CRIT WS > 20.0 M/S.  CONC SET = 0.0

****************************************
      END OF CAVITY CALCULATIONS
****************************************


     ****************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ****************************************

 CALCULATION        MAX CONC    DIST TO   TERRAIN
  PROCEDURE        (UG/M**3)    MAX (M)    HT (M)
--------------    -----------   -------   -------
```

```
SIMPLE TERRAIN      .6193         1285.        0.

***************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
***************************************************
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                                                                05/15/99
                                                                11:33:30
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 96043 ***

Int. City P12-14; 1 CT; SO2; 100 deg.; Base load; oil

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE             =        POINT
   EMISSION RATE (G/S)     =      5.40000
   STACK HEIGHT (M)        =      17.1000
   STK INSIDE DIAM (M)     =       4.9000
   STK EXIT VELOCITY (M/S)=       38.2000
   STK GAS EXIT TEMP (K)   =     824.0000
   AMBIENT AIR TEMP (K)    =     310.0000
   RECEPTOR HEIGHT (M)     =        .0000
   URBAN/RURAL OPTION      =        RURAL
   BUILDING HEIGHT (M)     =      11.8000
   MIN HORIZ BLDG DIM (M) =        7.1000
   MAX HORIZ BLDG DIM (M) =       18.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


BUOY. FLUX = 1402.589 M**4/S**3;  MOM. FLUX = 3295.288 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN AUTOMATED DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

  DIST     CONC             U10M   USTK  MIX HT   PLUME   SIGMA   SIGMA
   (M)   (UG/M**3)   STAB   (M/S)  (M/S)    (M)   HT (M)   Y (M)   Z (M)  DWASH
-------  ----------  ----   -----  -----  ------  ------  ------  ------  -----
     1.   .0000        1     1.0    1.0  2900.0 2898.95   11.81   11.81    NO
   100.   .2268        6     1.0    1.3 10000.0  272.07   72.96   72.89    NO
   200.   .2290        6     1.0    1.3 10000.0  272.07   73.26   72.96    NO
   300.   .2317        6     1.0    1.3 10000.0  272.07   73.71   73.07    NO
   400.   .3663        4    20.0   21.7  6400.0   54.21   29.45   15.44    SS
   500.   .4682        4    20.0   21.7  6400.0   61.42   36.15   18.46    SS
   600.   .5350        4    20.0   21.7  6400.0   68.17   42.72   21.37    SS
   700.   .5754        4    20.0   21.7  6400.0   74.56   49.19   24.19    SS
   800.   .5975        4    20.0   21.7  6400.0   80.65   55.57   26.93    SS
   900.   .6069        4    20.0   21.7  6400.0   86.50   61.88   29.61    SS
  1000.   1.102        1     3.0    3.1   978.7  977.72  265.61  482.67    NO
  1100.   1.610        1     3.0    3.1   978.7  977.72  286.66  582.24    NO
  1200.   1.912        1     3.0    3.1   978.7  977.72  307.36  692.88    NO
  1300.   2.015        1     3.0    3.1   978.7  977.72  327.76  814.68    NO
  1400.   1.992        1     3.0    3.1   978.7  977.72  347.88  947.71    NO
  1500.   1.913        1     3.0    3.1   978.7  977.72  367.75 1092.03    NO
  1600.   1.823        1     3.0    3.1   978.7  977.72  387.38 1247.71    NO
  1700.   1.737        1     3.0    3.1   978.7  977.72  406.79 1414.83    NO
  1800.   1.659        1     3.0    3.1   978.7  977.72  426.00 1593.44    NO
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  1900.    1.588          1     3.0     3.1    978.7   977.72   445.02  1783.62     NO
  2000.    1.523          1     3.0     3.1    978.7   977.72   463.86  1985.42     NO
  2100.    1.464          1     3.0     3.1    978.7   977.72   482.54  2198.90     NO
  2200.    1.416          1     3.0     3.1    978.7   977.72   499.17  2423.74     NO
  2300.    1.377          1     3.0     3.1    978.7   977.72   513.03  2659.93     NO
  2400.    1.341          1     3.0     3.1    978.7   977.72   526.96  2908.11     NO
  2500.    1.306          1     3.0     3.1    978.7   977.72   540.95  3168.31     NO
  2600.    1.273          1     3.0     3.1    978.7   977.72   554.98  3440.58     NO
  2700.    1.242          1     3.0     3.1    978.7   977.72   569.05  3724.94     NO
  2800.    1.212          1     3.0     3.1    978.7   977.72   583.16  4021.43     NO
  2900.    1.183          1     3.0     3.1    978.7   977.72   597.28  4330.10     NO
  3000.    1.156          1     3.0     3.1    978.7   977.72   611.43  4650.98     NO
  3500.    1.036          1     3.0     3.1    978.7   977.72   682.30  5000.00     NO
  4000.    .9383          1     3.0     3.1    978.7   977.72   753.12  5000.00     NO
  4500.    .8580          1     3.0     3.1    978.7   977.72   823.65  5000.00     NO
  5000.    .8452          2     3.0     3.1    978.7   977.72   697.72   695.39     NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND     1. M:
  1323.    2.018          1     3.0     3.1    978.7   977.72   332.21   842.98     NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****************************************
     *** REGULATORY (Default) ***
    PERFORMING CAVITY CALCULATIONS
  WITH ORIGINAL SCREEN CAVITY MODEL
          (BRODE, 1988)
****************************************


 *** CAVITY CALCULATION - 1 ***          *** CAVITY CALCULATION - 2 ***
  CONC (UG/M**3)      =    .0000          CONC (UG/M**3)      =    .0000
  CRIT WS @10M (M/S) =    99.99          CRIT WS @10M (M/S) =    99.99
  CRIT WS @ HS (M/S) =    99.99          CRIT WS @ HS (M/S) =    99.99
  DILUTION WS (M/S)   =    99.99          DILUTION WS (M/S)   =    99.99
  CAVITY HT (M)       =    20.44          CAVITY HT (M)       =    14.40
  CAVITY LENGTH (M)   =    32.44          CAVITY LENGTH (M)   =     8.06
  ALONGWIND DIM (M)   =     7.10          ALONGWIND DIM (M)   =    18.00

CAVITY CONC NOT CALCULATED FOR CRIT WS > 20.0 M/S.  CONC SET = 0.0

****************************************
      END OF CAVITY CALCULATIONS
****************************************


     ***************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ***************************************

 CALCULATION         MAX CONC      DIST TO    TERRAIN
  PROCEDURE         (UG/M**3)     MAX (M)     HT (M)
--------------     -----------   -------    -------
```

```
SIMPLE TERRAIN      2.018         1323.        0.

***************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
***************************************************
```

```
                                                                  05/15/99
                                                                  11:36:01
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 96043 ***

Int. City P12-14; 1 CT; SO2; 59 deg.; Base load; oil

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE              =        POINT
   EMISSION RATE (G/S)      =      6.20000
   STACK HEIGHT (M)         =      17.1000
   STK INSIDE DIAM (M)      =       4.9000
   STK EXIT VELOCITY (M/S)=        42.7000
   STK GAS EXIT TEMP (K)    =     807.0000
   AMBIENT AIR TEMP (K)     =     288.0000
   RECEPTOR HEIGHT (M)      =        .0000
   URBAN/RURAL OPTION       =        RURAL
   BUILDING HEIGHT (M)      =      11.8000
   MIN HORIZ BLDG DIM (M) =         7.1000
   MAX HORIZ BLDG DIM (M) =        18.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


BUOY. FLUX = 1616.415 M**4/S**3;  MOM. FLUX = 3905.772 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN AUTOMATED DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

  DIST     CONC               U10M   USTK  MIX HT   PLUME   SIGMA   SIGMA
   (M)    (UG/M**3)    STAB   (M/S)  (M/S)    (M)   HT (M)  Y (M)   Z (M)  DWASH
-------  ----------    ----   -----  -----  ------  ------  ------  ------  -----
     1.   .0000          1     1.0    1.0  3156.0 3155.04   12.57   12.56    NO
   100.   .2537          6     1.0    1.3 10000.0  277.94   74.64   74.56    NO
   200.   .2560          6     1.0    1.3 10000.0  277.94   74.93   74.64    NO
   300.   .2589          6     1.0    1.3 10000.0  277.94   75.37   74.74    NO
   400.   .2623          6     1.0    1.3 10000.0  277.94   75.95   74.86    NO
   500.   .2661          6     1.0    1.3 10000.0  277.94   76.66   75.00    NO
   600.   .3279          4    20.0   21.7  6400.0   71.77   42.72   21.21    SS
   700.   .3728          4    20.0   21.7  6400.0   78.48   49.19   24.03    SS
   800.   .4038          4    20.0   21.7  6400.0   84.87   55.57   26.78    SS
   900.   .4240          4    20.0   21.7  6400.0   91.00   61.88   29.47    SS
  1000.   .8730          1     3.0    3.1  1064.1 1063.08  270.60  485.43    NO
  1100.   1.418          1     3.0    3.1  1064.1 1063.08  291.91  584.84    NO
  1200.   1.806          1     3.0    3.1  1064.1 1063.08  312.87  695.34    NO
  1300.   1.994          1     3.0    3.1  1064.1 1063.08  333.51  817.01    NO
  1400.   2.026          1     3.0    3.1  1064.1 1063.08  353.86  949.92    NO
  1500.   1.974          1     3.0    3.1  1064.1 1063.08  373.94 1094.13    NO
  1600.   1.891          1     3.0    3.1  1064.1 1063.08  393.79 1249.72    NO
  1700.   1.805          1     3.0    3.1  1064.1 1063.08  413.41 1416.75    NO
  1800.   1.724          1     3.0    3.1  1064.1 1063.08  432.83 1595.28    NO
```

```
  1900.   1.651        1     3.0     3.1  1064.1 1063.08   452.04 1785.38    NO
  2000.   1.584        1     3.0     3.1  1064.1 1063.08   471.08 1987.11    NO
  2100.   1.523        1     3.0     3.1  1064.1 1063.08   489.95 2200.54    NO
  2200.   1.467        1     3.0     3.1  1064.1 1063.08   508.65 2425.71    NO
  2300.   1.417        1     3.0     3.1  1064.1 1063.08   526.48 2662.56    NO
  2400.   1.382        1     3.0     3.1  1064.1 1063.08   540.07 2910.51    NO
  2500.   1.348        1     3.0     3.1  1064.1 1063.08   553.72 3170.52    NO
  2600.   1.315        1     3.0     3.1  1064.1 1063.08   567.44 3442.61    NO
  2700.   1.284        1     3.0     3.1  1064.1 1063.08   581.21 3726.81    NO
  2800.   1.254        1     3.0     3.1  1064.1 1063.08   595.02 4023.17    NO
  2900.   1.226        1     3.0     3.1  1064.1 1063.08   608.88 4331.72    NO
  3000.   1.198        1     3.0     3.1  1064.1 1063.08   622.76 4652.49    NO
  3500.   1.078        1     3.0     3.1  1064.1 1063.08   692.47 5000.00    NO
  4000.   .9789        1     3.0     3.1  1064.1 1063.08   762.35 5000.00    NO
  4500.   .8969        1     3.0     3.1  1064.1 1063.08   832.09 5000.00    NO
  5000.   .8278        1     3.0     3.1  1064.1 1063.08   901.53 5000.00    NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND     1. M:
  1377.   2.029        1     3.0     3.1  1064.1 1063.08   349.00  916.99    NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****************************************
     *** REGULATORY (Default) ***
    PERFORMING CAVITY CALCULATIONS
  WITH ORIGINAL SCREEN CAVITY MODEL
          (BRODE, 1988)
****************************************


 *** CAVITY CALCULATION - 1 ***       *** CAVITY CALCULATION - 2 ***
  CONC (UG/M**3)       =    .0000       CONC (UG/M**3)       =    .0000
  CRIT WS @10M (M/S)   =    99.99       CRIT WS @10M (M/S)   =    99.99
  CRIT WS @ HS (M/S)   =    99.99       CRIT WS @ HS (M/S)   =    99.99
  DILUTION WS (M/S)    =    99.99       DILUTION WS (M/S)    =    99.99
  CAVITY HT (M)        =    20.44       CAVITY HT (M)        =    14.40
  CAVITY LENGTH (M)    =    32.44       CAVITY LENGTH (M)    =     8.06
  ALONGWIND DIM (M)    =     7.10       ALONGWIND DIM (M)    =    18.00

CAVITY CONC NOT CALCULATED FOR CRIT WS > 20.0 M/S.  CONC SET = 0.0

****************************************
      END OF CAVITY CALCULATIONS
****************************************


     ***************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ***************************************

 CALCULATION        MAX CONC     DIST TO    TERRAIN
  PROCEDURE        (UG/M**3)     MAX (M)     HT (M)
--------------    -----------   -------    -------
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```
SIMPLE TERRAIN      2.029         1377.        0.

***************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
***************************************************
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                                                                05/15/99
                                                                11:38:17
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 96043 ***

Int. City P12-14; 1 CT; SO2; 20 deg.; Base load; oil

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE            =        POINT
   EMISSION RATE (G/S)    =      6.90000
   STACK HEIGHT (M)       =      17.1000
   STK INSIDE DIAM (M)    =       4.9000
   STK EXIT VELOCITY (M/S)=      46.7000
   STK GAS EXIT TEMP (K)  =     791.0000
   AMBIENT AIR TEMP (K)   =     266.0000
   RECEPTOR HEIGHT (M)    =        .0000
   URBAN/RURAL OPTION     =        RURAL
   BUILDING HEIGHT (M)    =      11.8000
   MIN HORIZ BLDG DIM (M) =       7.1000
   MAX HORIZ BLDG DIM (M) =      18.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


BUOY. FLUX = 1824.445 M**4/S**3;  MOM. FLUX = 4402.214 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN AUTOMATED DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

  DIST     CONC              U10M   USTK  MIX HT   PLUME   SIGMA   SIGMA
   (M)    (UG/M**3)   STAB  (M/S)  (M/S)    (M)   HT (M)   Y (M)   Z (M)  DWASH
-------  ----------   ----  -----  -----  ------  ------  ------  ------  -----
     1.    .0000        1     1.0    1.0  3392.5 3391.47   13.13   13.12    NO
   100.    .2778        6     1.0    1.3 10000.0  281.59   75.68   75.60    NO
   200.    .2803        6     1.0    1.3 10000.0  281.59   75.96   75.68    NO
   300.    .2834        6     1.0    1.3 10000.0  281.59   76.40   75.78    NO
   400.    .2870        6     1.0    1.3 10000.0  281.59   76.97   75.90    NO
   500.    .2910        6     1.0    1.3 10000.0  281.59   77.67   76.03    NO
   600.    .2954        6     1.0    1.3 10000.0  281.59   78.49   76.19    NO
   700.    .3002        6     1.0    1.3 10000.0  281.59   79.43   76.35    NO
   800.    .3041        6     1.0    1.3 10000.0  281.59   80.46   76.51    NO
   900.    .3093        4    20.0   21.7  6400.0   94.94   61.88   29.47    SS
  1000.    .6765        1     3.0    3.1  1142.9 1141.89  275.17  488.00    NO
  1100.    1.218        1     3.0    3.1  1142.9 1141.89  296.72  587.26    NO
  1200.    1.662        1     3.0    3.1  1142.9 1141.89  317.91  697.63    NO
  1300.    1.921        1     3.0    3.1  1142.9 1141.89  338.77  819.17    NO
  1400.    2.012        1     3.0    3.1  1142.9 1141.89  359.33  951.97    NO
  1500.    1.993        1     3.0    3.1  1142.9 1141.89  379.63 1096.09    NO
  1600.    1.924        1     3.0    3.1  1142.9 1141.89  399.67 1251.58    NO
  1700.    1.842        1     3.0    3.1  1142.9 1141.89  419.49 1418.53    NO
  1800.    1.761        1     3.0    3.1  1142.9 1141.89  439.09 1596.99    NO
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```
   1900.   1.687        1     3.0     3.1  1142.9 1141.89  458.49 1787.02    NO
   2000.   1.619        1     3.0     3.1  1142.9 1141.89  477.70 1988.70    NO
   2100.   1.557        1     3.0     3.1  1142.9 1141.89  496.74 2202.06    NO
   2200.   1.500        1     3.0     3.1  1142.9 1141.89  515.62 2427.18    NO
   2300.   1.447        1     3.0     3.1  1142.9 1141.89  534.33 2664.12    NO
   2400.   1.399        1     3.0     3.1  1142.9 1141.89  552.85 2912.91    NO
   2500.   1.366        1     3.0     3.1  1142.9 1141.89  566.19 3172.72    NO
   2600.   1.334        1     3.0     3.1  1142.9 1141.89  579.61 3444.64    NO
   2700.   1.304        1     3.0     3.1  1142.9 1141.89  593.10 3728.69    NO
   2800.   1.275        1     3.0     3.1  1142.9 1141.89  606.65 4024.91    NO
   2900.   1.247        1     3.0     3.1  1142.9 1141.89  620.24 4333.33    NO
   3000.   1.220        1     3.0     3.1  1142.9 1141.89  633.87 4653.99    NO
   3500.   1.101        1     3.0     3.1  1142.9 1141.89  702.48 5000.00    NO
   4000.   1.002        1     3.0     3.1  1142.9 1141.89  771.45 5000.00    NO
   4500.   .9201        1     3.0     3.1  1142.9 1141.89  840.44 5000.00    NO
   5000.   .8504        1     3.0     3.1  1142.9 1141.89  909.24 5000.00    NO

 MAXIMUM 1-HR CONCENTRATION AT OR BEYOND     1. M:
   1425.   2.015        1     3.0     3.1  1142.9 1141.89  364.23  985.52    NO

  DWASH=   MEANS NO CALC MADE (CONC = 0.0)
  DWASH=NO MEANS NO BUILDING DOWNWASH USED
  DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
  DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
  DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

 ****************************************
      *** REGULATORY (Default) ***
     PERFORMING CAVITY CALCULATIONS
   WITH ORIGINAL SCREEN CAVITY MODEL
          (BRODE, 1988)
 ****************************************


  *** CAVITY CALCULATION - 1 ***       *** CAVITY CALCULATION - 2 ***
   CONC (UG/M**3)      =    .0000       CONC (UG/M**3)      =    .0000
   CRIT WS @10M (M/S) =    99.99        CRIT WS @10M (M/S) =    99.99
   CRIT WS @ HS (M/S) =    99.99        CRIT WS @ HS (M/S) =    99.99
   DILUTION WS (M/S)  =    99.99        DILUTION WS (M/S)  =    99.99
   CAVITY HT (M)      =    20.44        CAVITY HT (M)      =    14.40
   CAVITY LENGTH (M)  =    32.44        CAVITY LENGTH (M)  =     8.06
   ALONGWIND DIM (M)  =     7.10        ALONGWIND DIM (M)  =    18.00

 CAVITY CONC NOT CALCULATED FOR CRIT WS > 20.0 M/S.  CONC SET = 0.0

 ****************************************
       END OF CAVITY CALCULATIONS
 ****************************************


      ***************************************
      *** SUMMARY OF SCREEN MODEL RESULTS ***
      ***************************************

  CALCULATION         MAX CONC     DIST TO   TERRAIN
   PROCEDURE         (UG/M**3)     MAX (M)    HT (M)
 --------------     -----------    -------   -------
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```
SIMPLE TERRAIN      2.015          1425.          0.

***************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
***************************************************
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                                                               05/15/99
                                                               12:03:26
  ***  SCREEN3 MODEL RUN  ***
  *** VERSION DATED 96043 ***

 Int. City P12-14; 1 CT; CO; 100 deg.; 50% load; oil

 SIMPLE TERRAIN INPUTS:
    SOURCE TYPE            =        POINT
    EMISSION RATE (G/S)    =      30.7000
    STACK HEIGHT (M)       =      17.1000
    STK INSIDE DIAM (M)    =       4.9000
    STK EXIT VELOCITY (M/S)=      31.6000
    STK GAS EXIT TEMP (K)  =     719.0000
    AMBIENT AIR TEMP (K)   =     310.0000
    RECEPTOR HEIGHT (M)    =        .0000
    URBAN/RURAL OPTION     =        RURAL
    BUILDING HEIGHT (M)    =      11.8000
    MIN HORIZ BLDG DIM (M) =       7.1000
    MAX HORIZ BLDG DIM (M) =      18.0000

 THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
 THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


 BUOY. FLUX = 1058.066 M**4/S**3;  MOM. FLUX = 2584.278 M**4/S**2.

 *** FULL METEOROLOGY ***

 **********************************
 *** SCREEN AUTOMATED DISTANCES ***
 **********************************

 *** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

   DIST     CONC              U10M   USTK  MIX HT   PLUME   SIGMA   SIGMA
    (M)   (UG/M**3)   STAB   (M/S)  (M/S)   (M)    HT (M)   Y (M)   Z (M)  DWASH
 -------  ----------  ----   -----  -----  ------  ------  ------  ------  -----
      1.    .0000       1      1.0    1.0  2451.5 2450.54   10.78   10.78    NO
    100.    1.428       6      1.0    1.3 10000.0  249.21   66.44   66.36    NO
    200.    6.003       4     20.0   21.7  6400.0   34.20   15.56    9.70    SS
    300.    7.700       4     20.0   21.7  6400.0   42.07   22.61   12.92    SS
    400.    8.765       4     20.0   21.7  6400.0   49.17   29.45   16.06    SS
    500.    9.095       4     20.0   21.7  6400.0   55.72   36.15   19.05    SS
    600.    9.047       4     20.0   21.7  6400.0   61.85   42.72   21.94    SS
    700.    8.812       4     20.0   21.7  6400.0   67.66   49.19   24.74    SS
    800.    8.487       4     20.0   21.7  6400.0   73.20   55.57   27.47    SS
    900.    8.125       4     20.0   21.7  6400.0   78.52   61.88   30.14    SS
   1000.    7.574       1      3.0    3.1   960.0  828.25  256.76  477.85    NO
   1100.    10.39       1      2.5    2.6   991.5  990.48  296.81  587.30    NO
   1200.    12.37       1      2.5    2.6   991.5  990.48  318.00  697.67    NO
   1300.    13.08       1      2.5    2.6   991.5  990.48  338.86  819.21    NO
   1400.    12.96       1      2.5    2.6   991.5  990.48  359.43  952.01    NO
   1500.    12.47       1      2.5    2.6   991.5  990.48  379.73 1096.12    NO
   1600.    11.89       1      2.5    2.6   991.5  990.48  399.78 1251.62    NO
   1700.    11.34       1      2.5    2.6   991.5  990.48  419.60 1418.56    NO
   1800.    10.84       1      2.5    2.6   991.5  990.48  439.20 1597.02    NO
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```
  1900.   10.38         1     2.5     2.6    991.5  990.48   458.61 1787.05     NO
  2000.   10.04         1     2.5     2.6    991.5  990.48   473.82 1987.77     NO
  2100.   9.763         1     2.5     2.6    991.5  990.48   487.45 2199.99     NO
  2200.   9.496         1     2.5     2.6    991.5  990.48   501.18 2424.16     NO
  2300.   9.241         1     2.5     2.6    991.5  990.48   514.99 2660.31     NO
  2400.   8.998         1     2.5     2.6    991.5  990.48   528.87 2908.45     NO
  2500.   8.767         1     2.5     2.6    991.5  990.48   542.81 3168.63     NO
  2600.   8.547         1     2.5     2.6    991.5  990.48   556.79 3440.87     NO
  2700.   8.337         1     2.5     2.6    991.5  990.48   570.82 3725.21     NO
  2800.   8.137         1     2.5     2.6    991.5  990.48   584.88 4021.68     NO
  2900.   7.945         1     2.5     2.6    991.5  990.48   598.97 4330.34     NO
  3000.   7.763         1     2.5     2.6    991.5  990.48   613.07 4651.20     NO
  3500.   6.960         1     2.5     2.6    991.5  990.48   683.78 5000.00     NO
  4000.   6.592         4    20.0    21.7   6400.0  125.20   239.31   77.49     SS
  4500.   6.566         4    20.0    21.7   6400.0  125.20   266.06   83.21     SS
  5000.   6.417         4    20.0    21.7   6400.0  125.20   292.47   88.69     SS

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND     1. M:
  1328.   13.11         1     2.5     2.6    991.5  990.48   344.45  853.96     NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****************************************
     *** REGULATORY (Default) ***
    PERFORMING CAVITY CALCULATIONS
  WITH ORIGINAL SCREEN CAVITY MODEL
          (BRODE, 1988)
****************************************


 *** CAVITY CALCULATION - 1 ***       *** CAVITY CALCULATION - 2 ***
  CONC (UG/M**3)      =    .0000       CONC (UG/M**3)      =    .0000
  CRIT WS @10M (M/S) =    99.99       CRIT WS @10M (M/S) =    99.99
  CRIT WS @ HS (M/S) =    99.99       CRIT WS @ HS (M/S) =    99.99
  DILUTION WS (M/S)  =    99.99       DILUTION WS (M/S)  =    99.99
  CAVITY HT (M)      =    20.44       CAVITY HT (M)      =    14.40
  CAVITY LENGTH (M)  =    32.44       CAVITY LENGTH (M)  =     8.06
  ALONGWIND DIM (M)  =     7.10       ALONGWIND DIM (M)  =    18.00

CAVITY CONC NOT CALCULATED FOR CRIT WS > 20.0 M/S.  CONC SET = 0.0

****************************************
      END OF CAVITY CALCULATIONS
****************************************


     ***************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ***************************************

 CALCULATION         MAX CONC     DIST TO    TERRAIN
  PROCEDURE          (UG/M**3)     MAX (M)     HT (M)
--------------     -----------   -------    -------
```

```
SIMPLE TERRAIN      13.11         1328.        0.

***************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
***************************************************
```

```
                                                                05/15/99
                                                                12:05:46
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 96043 ***

Int. City P12-14; 1 CT; CO; 59 deg.; 50% load; oil

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE              =        POINT
   EMISSION RATE (G/S)      =      45.9000
   STACK HEIGHT (M)         =      17.1000
   STK INSIDE DIAM (M)      =       4.9000
   STK EXIT VELOCITY (M/S)=      34.4000
   STK GAS EXIT TEMP (K)    =     695.0000
   AMBIENT AIR TEMP (K)     =     288.0000
   RECEPTOR HEIGHT (M)      =        .0000
   URBAN/RURAL OPTION       =        RURAL
   BUILDING HEIGHT (M)      =      11.8000
   MIN HORIZ BLDG DIM (M)   =       7.1000
   MAX HORIZ BLDG DIM (M)   =      18.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


BUOY. FLUX = 1185.767 M**4/S**3;  MOM. FLUX = 2943.451 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN AUTOMATED DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

  DIST     CONC              U10M   USTK  MIX HT   PLUME    SIGMA   SIGMA
   (M)    (UG/M**3)    STAB  (M/S)  (M/S)   (M)    HT (M)   Y (M)   Z (M)   DWASH
-------  ----------    ----  -----  -----  ------  ------  ------  ------  -----
     1.    .0000         1     1.0    1.0  2623.7 2622.73   11.32   11.31    NO
   100.    2.106         6     1.0    1.3 10000.0  252.35   67.34   67.25    NO
   200.    3.317         4    20.0   21.7  6400.0   35.62   15.56    9.36    SS
   300.    5.618         4    20.0   21.7  6400.0   43.84   22.61   12.61    SS
   400.    7.374         4    20.0   21.7  6400.0   51.23   29.45   15.76    SS
   500.    8.328         4    20.0   21.7  6400.0   58.04   36.15   18.77    SS
   600.    8.766         4    20.0   21.7  6400.0   64.42   42.72   21.67    SS
   700.    8.891         4    20.0   21.7  6400.0   70.46   49.19   24.48    SS
   800.    8.830         4    20.0   21.7  6400.0   76.21   55.57   27.21    SS
   900.    8.660         4    20.0   21.7  6400.0   81.74   61.88   29.89    SS
  1000.    10.51         1     3.0    3.1   960.0  885.64  260.17  479.70    NO
  1100.    14.82         1     3.0    3.1   960.0  885.64  280.94  579.44    NO
  1200.    17.24         1     3.0    3.1   960.0  885.64  301.37  690.25    NO
  1300.    17.97         1     3.0    3.1   960.0  885.64  321.51  812.19    NO
  1400.    17.65         1     3.0    3.1   960.0  885.64  341.39  945.34    NO
  1500.    17.09         1     2.5    2.6  1060.4 1059.35  385.43 1098.11    NO
  1600.    16.37         1     2.5    2.6  1060.4 1059.35  405.68 1253.52    NO
  1700.    15.62         1     2.5    2.6  1060.4 1059.35  425.70 1420.38    NO
  1800.    14.93         1     2.5    2.6  1060.4 1059.35  445.49 1598.76    NO
```

```
  1900.   14.31        1     2.5     2.6  1060.4 1059.35  465.08 1788.73    NO
  2000.   13.73        1     2.5     2.6  1060.4 1059.35  484.48 1990.33    NO
  2100.   13.33        1     2.5     2.6  1060.4 1059.35  498.94 2202.56    NO
  2200.   12.99        1     2.5     2.6  1060.4 1059.35  512.36 2426.50    NO
  2300.   12.65        1     2.5     2.6  1060.4 1059.35  525.88 2662.44    NO
  2400.   12.33        1     2.5     2.6  1060.4 1059.35  539.48 2910.40    NO
  2500.   12.03        1     2.5     2.6  1060.4 1059.35  553.15 3170.42    NO
  2600.   11.74        1     2.5     2.6  1060.4 1059.35  566.88 3442.52    NO
  2700.   11.46        1     2.5     2.6  1060.4 1059.35  580.66 3726.73    NO
  2800.   11.19        1     2.5     2.6  1060.4 1059.35  594.49 4023.09    NO
  2900.   10.94        1     2.5     2.6  1060.4 1059.35  608.35 4331.64    NO
  3000.   10.69        1     2.5     2.6  1060.4 1059.35  622.25 4652.42    NO
  3500.   9.614        1     2.5     2.6  1060.4 1059.35  692.01 5000.00    NO
  4000.   8.732        1     2.5     2.6  1060.4 1059.35  761.93 5000.00    NO
  4500.   8.328        4    20.0    21.7  6400.0  133.99  266.06   83.21    SS
  5000.   8.301        4    20.0    21.7  6400.0  133.99  292.47   88.69    SS

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND     1. M:
  1308.   17.97        1     3.0     3.1   960.0  885.64  322.91  821.15    NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****************************************
     *** REGULATORY (Default) ***
    PERFORMING CAVITY CALCULATIONS
  WITH ORIGINAL SCREEN CAVITY MODEL
          (BRODE, 1988)
****************************************


 *** CAVITY CALCULATION - 1 ***       *** CAVITY CALCULATION - 2 ***
  CONC (UG/M**3)      =    .0000       CONC (UG/M**3)      =    .0000
  CRIT WS @10M (M/S) =    99.99       CRIT WS @10M (M/S) =    99.99
  CRIT WS @ HS (M/S) =    99.99       CRIT WS @ HS (M/S) =    99.99
  DILUTION WS (M/S)  =    99.99       DILUTION WS (M/S)  =    99.99
  CAVITY HT (M)      =    20.44       CAVITY HT (M)      =    14.40
  CAVITY LENGTH (M)  =    32.44       CAVITY LENGTH (M)  =     8.06
  ALONGWIND DIM (M)  =     7.10       ALONGWIND DIM (M)  =    18.00

CAVITY CONC NOT CALCULATED FOR CRIT WS > 20.0 M/S.  CONC SET = 0.0

****************************************
      END OF CAVITY CALCULATIONS
****************************************


     ****************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ****************************************

 CALCULATION         MAX CONC     DIST TO    TERRAIN
  PROCEDURE         (UG/M**3)     MAX (M)     HT (M)
--------------    -----------    -------    -------
```

```
SIMPLE TERRAIN      17.97         1308.        0.

***************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
***************************************************
```

```
                                                                    05/15/99
                                                                    12:07:59
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 96043 ***

Int. City P12-14; 1 CT; CO; 20 deg.; 50% load; oil

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE            =        POINT
   EMISSION RATE (G/S)    =      65.8000
   STACK HEIGHT (M)       =      17.1000
   STK INSIDE DIAM (M)    =       4.9000
   STK EXIT VELOCITY (M/S)=      36.8000
   STK GAS EXIT TEMP (K)  =     676.0000
   AMBIENT AIR TEMP (K)   =     266.0000
   RECEPTOR HEIGHT (M)    =        .0000
   URBAN/RURAL OPTION     =        RURAL
   BUILDING HEIGHT (M)    =      11.8000
   MIN HORIZ BLDG DIM (M) =       7.1000
   MAX HORIZ BLDG DIM (M) =      18.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


BUOY. FLUX = 1313.760 M**4/S**3;  MOM. FLUX = 3198.621 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN AUTOMATED DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

  DIST     CONC              U10M   USTK  MIX HT   PLUME   SIGMA   SIGMA
   (M)    (UG/M**3)   STAB  (M/S)  (M/S)    (M)   HT (M)   Y (M)   Z (M)  DWASH
-------  ----------   ----  -----  -----  ------  ------  ------  ------  -----
     1.   .0000         1     1.0    1.0  2789.0 2788.02   11.67   11.67    NO
   100.   2.994         6     1.0    1.3 10000.0  254.16   67.85   67.77    NO
   200.   3.028         6     1.0    1.3 10000.0  254.16   68.17   67.86    NO
   300.   4.133         4    20.0   21.7  6400.0   45.41   22.61   12.38    SS
   400.   6.200         4    20.0   21.7  6400.0   53.07   29.45   15.54    SS
   500.   7.572         4    20.0   21.7  6400.0   60.12   36.15   18.56    SS
   600.   8.394         4    20.0   21.7  6400.0   66.73   42.72   21.46    SS
   700.   8.835         4    20.0   21.7  6400.0   72.97   49.19   24.28    SS
   800.   9.023         4    20.0   21.7  6400.0   78.94   55.57   27.02    SS
   900.   9.046         4    20.0   21.7  6400.0   84.65   61.88   29.70    SS
  1000.   14.56         1     3.0    3.1   960.0  940.74  263.43  481.47    NO
  1100.   20.81         1     3.0    3.1   960.0  940.74  284.37  581.11    NO
  1200.   24.36         1     3.0    3.1   960.0  940.74  304.96  691.82    NO
  1300.   25.44         1     3.0    3.1   960.0  940.74  325.26  813.68    NO
  1400.   25.01         1     3.0    3.1   960.0  940.74  345.28  946.76    NO
  1500.   23.97         1     3.0    3.1   960.0  940.74  365.05 1091.12    NO
  1600.   22.82         1     3.0    3.1   960.0  940.74  384.58 1246.85    NO
  1700.   21.73         1     3.0    3.1   960.0  940.74  403.91 1414.00    NO
  1800.   20.75         1     3.0    3.1   960.0  940.74  423.03 1592.65    NO
```

```
  1900.   19.86        1     3.0     3.1    960.0   940.74   441.96 1782.86     NO
  2000.   19.05        1     3.0     3.1    960.0   940.74   460.73 1984.68     NO
  2100.   18.31        1     3.0     3.1    960.0   940.74   479.32 2198.20     NO
  2200.   17.79        1     3.0     3.1    960.0   940.74   493.44 2422.57     NO
  2300.   17.30        1     3.0     3.1    960.0   940.74   507.46 2658.86     NO
  2400.   16.83        1     3.0     3.1    960.0   940.74   521.54 2907.13     NO
  2500.   16.39        1     3.0     3.1    960.0   940.74   535.67 3167.41     NO
  2600.   15.97        1     3.0     3.1    960.0   940.74   549.83 3439.75     NO
  2700.   15.56        1     3.0     3.1    960.0   940.74   564.03 3724.17     NO
  2800.   15.18        1     3.0     3.1    960.0   940.74   578.26 4020.73     NO
  2900.   14.82        1     3.0     3.1    960.0   940.74   592.50 4329.45     NO
  3000.   14.47        1     3.0     3.1    960.0   940.74   606.76 4650.37     NO
  3500.   12.95        1     3.0     3.1    960.0   940.74   678.12 5000.00     NO
  4000.   11.72        1     3.0     3.1    960.0   940.74   749.34 5000.00     NO
  4500.   10.70        1     2.5     2.6   1126.5  1125.47   838.66 5000.00     NO
  5000.   10.70        2     3.0     3.1    960.0   940.74   693.63  691.29     NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND     1. M:
  1310.   25.44        1     3.0     3.1    960.0   940.74   327.07  825.20     NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****************************************
     *** REGULATORY (Default) ***
    PERFORMING CAVITY CALCULATIONS
  WITH ORIGINAL SCREEN CAVITY MODEL
          (BRODE, 1988)
****************************************


 *** CAVITY CALCULATION - 1 ***       *** CAVITY CALCULATION - 2 ***
  CONC (UG/M**3)      =    .0000       CONC (UG/M**3)      =    .0000
  CRIT WS @10M (M/S) =    99.99       CRIT WS @10M (M/S) =    99.99
  CRIT WS @ HS (M/S) =    99.99       CRIT WS @ HS (M/S) =    99.99
  DILUTION WS (M/S)  =    99.99       DILUTION WS (M/S)  =    99.99
  CAVITY HT (M)      =    20.44       CAVITY HT (M)      =    14.40
  CAVITY LENGTH (M)  =    32.44       CAVITY LENGTH (M)  =     8.06
  ALONGWIND DIM (M)  =     7.10       ALONGWIND DIM (M)  =    18.00

CAVITY CONC NOT CALCULATED FOR CRIT WS > 20.0 M/S.  CONC SET = 0.0

****************************************
      END OF CAVITY CALCULATIONS
****************************************


     ***************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ***************************************

 CALCULATION          MAX CONC     DIST TO    TERRAIN
  PROCEDURE          (UG/M**3)     MAX (M)     HT (M)
--------------     -----------    -------    -------
```

```
SIMPLE TERRAIN      25.44         1310.        0.

***************************************************
** REMEMBER TO INCLUDE BACKGROUND CONCENTRATIONS **
***************************************************
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Z 031 391 899

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Jeffrey Pardue	
Street & Number PO Box 14042	
Post Office, State, & ZIP Code St. Petersburg Fl 33733	
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 12/13/99 - PSD-FI-268 0970014-003-AC	

PS Form **3800**, April 1995

Is your **RETURN ADDRESS** completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:

Mr. W. Jeffrey Pardue
Director of Envir. Services
FPC
PO Box 14042, MAC BB1A
St. Petersburg, Fl 33733

4a. Article Number
Z 031 391 899

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery ~~12/15/99~~ DEC 15 1999

5. Received By: *(Print Name)*

6. Signature *(Addressee or Agent)*
X

8. Addressee's Address *(Only if requested and fee is paid)*

PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

Thank you for using Return Receipt Service.

PROOF OF PUBLICATION

FROM

Osceola News-Gazette

Kissimmee, Florida
OSCEOLA COUNTY

In the Matter of

Public Notice
Of Intent To Issue
Air Construction
Permit

Filed . . . . . day of . . . . , 19 . . . . .
First Publication . . September 30 19 99 . .
Last Publication . . September 30 19 99 .

Make Remittance to Osceola News-Gazette
Kissimmee, Florida

PROOF OF PUBLICATION

STATE OF FLORIDA,
COUNTY OF OSCEOLA

Before me, the undersigned authority, personally appeared Dan L. Autrey, who on oath says that he is General Manager of the Osceola News-Gazette, a twice weekly newspaper published at Kissimmee, in Osceola County, Florida; that the attached copy of the advertisement was published weekly in the regular and entire edition of said newspaper in the issues of:

. . . September 30, 1999 . . .

. . . .

Affiant further says that the Osceola News-Gazette is a newspaper published in Kissimmee, in said Osceola County, Florida, and that the said newspaper has heretofore been continuously published in said Osceola County, Florida, each week and has been entered as periodicals postage matter at the post office in Kissimmee, in said Osceola County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

. . . . . . Dan L. Autrey . . . .

Sworn to and subscribed before me by Dan L. Autrey, who is personally known to me, this . . 30 . . day of

. . . . September 1999 . . .

. . Carol L. Gorrell
Carol L. Gorrell
(N.P. Seal)

Carol L. Gorrell
Notary Public, State of Florida
Commission No. CC 595830
My Commission Exp. 10/24/2000
Bonded Through Fla. Notary Service & Bonding Co.

PUBLIC NOTICE OF INTENT TO ISSUE
AIR CONSTRUCTION PERMIT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft Permit No. 097-0014-003-AC (PSD-FL-268)

FPC Intercession City Plant
Osceola County

Three New Peaking Simple-Cycle Combustion Turbines
New Emissions Units 018, 019, and 020

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to the Florida Power Corporation to increase peaking power at the existing FPC Intercession City Plant. This plant is located approximately 3.5 miles west of Intercession City at 6525 Osceola Polk County Line Road in Osceola County, Florida. The Draft Permit authorizes the installation of three simple cycle, dual-fuel, General Electric Model 7EA combustion turbines with electrical generator sets, each having an hourly capacity of 87 MW. A Best Available Control Technology (BACT) determination was required for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM10), sulfuric acid mist (SAM), and sulfur dioxide (SO2) pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD) of Air Quality. This project is not subject to review under Section 403.506 F.S. (Power Plant Siting Act), because it provides for no expansion in steam generating capacity. The applicant's authorized representative is Mr. W. Jeffrey Pardue, C.E.P., Director of Environmental Services for the Florida Power Corporation. The applicant's mailing address is P.O. Box 14042, MAC BB1A, St. Petersburg, FL 33733.

When firing natural gas, NOx emissions from each gas turbine will be controlled by dry low-NOx combustors capable of achieving emissions of 9 ppmvd corrected to 15% oxygen. When firing low sulfur distillate oil, NOx emissions will be controlled by water injection capable of achieving 42 ppmvd corrected to 15% oxygen. Base load carbon monoxide (CC) limits will be 20 ppmvd corrected to 15% oxygen for gas and oil firing. For the first 12 months of operation, the permit specifies a CO limit of 25 ppmvd corrected to 15% oxygen for gas firing: allow for tuning the gas turbines, dry-low NOx combustors and automated control system. Emissions of volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter will be very low because of the inherently low emissions of the General Electric 7EA gas turbine, the use of pipeline-quality natural gas as the primary fuel, and limited usage of low sulfur distillate oil. Total turbine operating hours for the three combined units are limited to 10,170 hours per year. Of this total, no more than 3000 turbine hours per year may occur when firing low sulfur distillate oil. The permit contains further restrictions if only one or two units are installed.

The following table summarizes the potential project emissions in tons per year and shows the corresponding PSD Significant Emissions Rate.

Pollutant	Project Potential Emissions (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? (Table 212.400-2)	Subject To BACT?
CO	260	100	Yes	Yes
NOx	365	40	Yes	Yes
PM/PM10	73	15	Yes	Yes
SAM	9	7	Yes	Yes
SO2	95	40	Yes	Yes
VOC	15	40	No	No

After the first 12 months, potential CO emissions will be reduced to 220 tons per year. An air quality impact analysis was conducted. The ambient impact analysis predicted all pollutant emissions to have an insignificant impact on Class I and Class II Areas. Emissions from the facility will not significantly contribute to or cause a violation of any state of federal ambient air quality standard. The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and request for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments and request for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known, (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact Al Linero, Administrator of the New Source Review Section, or the Department's reviewing engineer for this project, Jeff Koerner, at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

Z 333 618 141

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

Do not use for International Mail *(See reverse)*

Sent to	Doug Neeley
Street & Number	EPA
Post Office, State, & ZIP Code	Atlanta GA
Postage FPC	$ Inter. City
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	9-15-99 PSO-FI-268 0970014-003-AC

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:

Mr. Doug Neeley, Section Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA - Region IV
61 Forsyth Street
Atlanta, GA 30303

4a. Article Number
Z 333 618 141

4b. Service Type
☐ Registered ☒ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery

5. Received By: *(Print Name)*
JOYCE EVANS

6. Signature: *(Addressee or Agent)*
X SEP 17 1999

8. Addressee's Address *(Only if requested and fee is paid)*

Thank you for using Return Receipt Service.

PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

BEST AVAILABLE COPY

Z 333 618 142

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

Do not use for International Mail *(See reverse)*

Sent to Jeffrey Pardue	
Street & Number PO FPC	
Post Office, State, & ZIP Code St. Pete Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 9-15-99 0970014-003-AC PSO-Fl-268	

PS Form **3800**, April 1995

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reverse side?

SENDER:

- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Jeffrey Pardue, CEP
la. Power Corp
O Box 14042, MAC BB1A
St. Petersburg, Fl
33733

4a. Article Number Z 333 618 142

4b. Service Type

☐ Registered ☒ Certified

☐ Express Mail ☐ Insured

☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery SEP 17 1999

5. Received By: *(Print Name)*

8. Addressee's Address *(Only if requested and fee is paid)*

ignature: *(Addressee or Agent)*

Form **3811,** December 1994 102595-98-B-0229 Domestic Return Receipt

Thank you for using Return Receipt Service.

Z 333 618 164

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Jeff Pardue

Street & Number FPC

Post Office, State, & ZIP Code St. Pete Fl

Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$

Postmark or Date
P50-F1-268 6-22-99
0970014-003-AC

PS Form **3800**, April 1995

Fold at line over top of envelope to the right of the return address

SENDER:
- Complete items 1 and/o
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

h to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Jeffrey Pardue, CEP
FPC
PO Box 14042-MACBBIA
St. Pete, Fl
33733

4a. Article Number
Z 333 618 164

4b. Service Type
☐ Registered ☑ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
JUN 24 1999

5. Received By: *(Print Name)*

6. Signature: *(Addressee or Agent)*

8. Addressee's Address *(Only if requested and fee is paid)*

our **RETURN ADDRESS** completed on the reverse side?

Thank you for using Return Receipt Service.

Check Sheet

Company Name: FPC - Intercession City
Permit Number: 0970014-003-AC
PSD Number: 268
Permit Engineer: Jeff Koerner

Application: In folder

☒ Initial Application
  - ☑ Incompleteness Letters
  - ☑ Responses
  - ☐ Waiver of Department Action
  - ☐ Department Response
  - ☑ Other

Cross References:

☐
☐
☐

Intent:

☑ Intent to Issue
☑ Notice of Intent to Issue
☐ Technical Evaluation
☑ BACT Determination
☑ Unsigned Permit
Correspondence with:
  - ☑ EPA
  - ☐ Park Services
  - ☑ Other

☑ Proof of Publication
  - ☑ Petitions - (Related to [✓ extensions], hearings, etc.)
  - ☐ Waiver of Department Action
  - ☐ Other

Final Determination: Issued 13 Dec '99

☑ Final Determination
☑ Signed Permit
☑ BACT Determination
  - ☐ Other

Post Permit Correspondence:

  - ☐ Extensions/Amendments/Modifications
  - ☐ Other