Memorandum

Florida Department of Environmental Protection

TO: Michael G. Cooke, Division of Air Resource Management

THRU: Trina Vielhauer, Bureau of Air Regulation TV

FROM: Jeff Koerner, Air Permitting North Program JK

DATE: April 27, 2006

SUBJECT: Final Air Permit No. PSD-FL-363
Project No. 1050233-018-AC
TECO Polk Power Station
New Simple Cycle Gas Turbine Units 4 and 5

The Final Permit for this project is attached for your approval and signature. The permit authorizes the construction of two simple cycle gas turbine generators with a nominal output of 165 MW each at the existing Polk Power Station (SIC No. 4911). The facility is located approximately 11 miles south of the city of Mulberry (9995 State Route 37 South) in Polk County, Florida. In accordance with Rule 62-212.400(BACT), F.A.C., the simple cycle gas turbines are subject to determinations of the Best Available Control Technology (BACT) for nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), and sulfur dioxide (SO_2).

The Department distributed an "Intent to Issue Permit" package on March 6, 2006. The applicant published the "Public Notice of Intent to Issue" in *The Ledger* on March 20, 2006. The Department received the proof of publication on March 24, 2006. The applicant requested, and was granted, an extension of time to petition for an administrative hearing. On April 26, 2006, the applicant withdrew the request for an extension.

I recommend your approval of the attached Final Permit for this project.

Attachments

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Tampa Electric Company
PO Box 111
Tampa, Florida 33601-0111
Authorized Representative:
Mr. Mark J. Hornick, General Manager

Permit No. PSD-FL-363
Project No. 1050233-018-AC
TECO Polk Power Station
Simple Cycle Units 4 and 5
Polk County, Florida

Enclosed is Final Air Permit No. PSD-FL-363, which authorizes the construction of two simple cycle gas turbine generators with a nominal output of 165 MW each at the existing Polk Power Station (SIC No. 4911). The facility is located approximately 11 miles south of the city of Mulberry (9995 State Route 37 South) in Polk County, Florida. As noted in the attached Final Determination, only minor changes and clarifications were made. 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.

Trina L Vielhauer

Trina Vielhauer, 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 4/28/06 to the persons listed:

Mark J. Hornick, TECO*
Byron T. Burrows, TECO
Raisa Calderon, TECO
Tom Davis, ECT

Jason Waters, Southwest District Office
Hamilton Oven, DEP Siting Office
Gregg Worley, EPA Region 4
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.

Barbara J. Friday 4/28/06
(Clerk) (Date)

PERMITTEE

Tampa Electric Company
PO Box 111
Tampa, Florida 33601-0111

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation, Air Permitting South Program
2600 Blair Stone Road, MS #5505
Tallahassee, Florida, 32399-2400

PROJECT

Permit No. PSD-FL-363
Project No. 1050233-018-AC
TECO Polk Power Station – Construction of Simple Cycle Units 4 and 5

This permit authorizes the construction of two simple cycle gas turbine generators with a nominal output of 165 MW each at the existing Polk Power Station (SIC No. 4911). The facility is located approximately 11 miles south of the city of Mulberry (9995 State Route 37 South) in Polk County, Florida.

NOTICE AND PUBLICATION

The Department distributed an "Intent to Issue Permit" package on March 6, 2006. The applicant published the "Public Notice of Intent to Issue" in *The Ledger* on March 20, 2006. The Department received the proof of publication on March 24, 2006. The applicant requested, and was granted, an extension of time to petition for an administrative hearing. On April 26, 2006, the applicant withdrew the request for an extension.

COMMENTS

No comments on the Draft Permit were received from the public, the National Park Service, or the Department's Southwest District Office. On April 14, 2006, the Department received written comments from the applicant regarding the draft permit. The applicant's comments and the Department's responses are provided below.

Section II – Administrative Requirements

1. *Condition 9*: This condition requires the applicant to submit an application for a Title IV Acid Rain Permit. The applicant provided this application as an attachment to the comments provided. *Response*: No response necessary.

Section III - Emissions Unit Specific Conditions

2. *Condition 3*: The gas turbines selected for this project were specified in the application as existing units. The applicant requests correction of the identification of the gas turbine automated control system from the "Mark VI" to the "Mark V" system. *Response*: The Department agrees and corrected the model number.
3. *Condition 9*: This condition identifies the emissions standards and compliance methods. Condition 11 also specifies the compliance methods and allows the use of EPA Methods 7E or 20 to determine NOx emissions. Add Method 20 to Condition 9 as an acceptable compliance method for determining NOx emissions. *Response*: The Department agrees and added the test method for consistency.
4. *Condition 23*: The applicant requests a revision to recognize that the oxygen content will be determined by calculation based on data collected from an installed CO_2 monitor and the use of an F-factor for natural gas. *Response*: The Department notes that this is already allowed by Condition 22c. No changes were made.

Condition 23. The applicant also suggests several revisions to this condition to clarify monitor availability as well as the difference between a "valid" hourly average for purposes of complying with the BACT limit and a "valid" hourly average for purposes of meeting the Acid Rain monitoring provisions. After discussion, the applicant revised this request to base monitor availability on the NSPS Subpart GG requirements. *Response*: The permit does not define the CO and NOx monitor availability in the same manner as the Acid Rain program because the permitted emissions standards are concerned with short term emissions averages and the Acid Rain program is concerned with an annual emissions averages. The permit does not specify any Acid Rain program requirements, which will be included in the Title V air operation permit. In addition, NSPS Subpart GG requires the submittal of an excess emissions and monitoring systems performance report, which adequately defines monitor availability. To clarify the monitor availability issue, the Department made the following revisions.

Section II, Condition 9: "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 Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. This permit does not specify the Acid Rain program requirements. These will be included in the Title V air operation permit. [40 CFR 72]

Section III, Condition 23.

CEMS Data Requirements: The CEMS shall be installed, calibrated, maintained, and operated in the gas turbine stacks to measure and record the emissions of CO, and NO_X in a manner sufficient to demonstrate compliance with the CEMS-based emission limits of this section. The CEMS shall express the results in units of ppmvd corrected to 15% oxygen. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

a. *Valid Hourly Averages for Compliance*: Each CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour (except for the allowable NOx data exclusions), shall be used to calculate a 1-hour block average that begins at the top of each hour. Each 1-hour block average shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, a 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, there is insufficient data and the 1-hour block average is not valid. Also, if an allowable exclusion episode should occur over two separate hourly averages, only those minutes attributed to the specific episode shall be excluded from each hour. *{Permitting Note: For example, a 20-minute startup begins at 2:50 p.m. and ends at 3:10 pm. This means that 10 minutes of startup data would be excluded from the first hourly average and 10 minutes would be excluded from the second hourly average. The first hourly average (2:00 – 3:00 p.m.) is not a valid hourly average because there is insufficient data. The second hourly average (3:00 – 4:00 p.m.) is a valid hourly average consisting of 50 minutes of monitoring data.}*

b. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive valid hourly average concentration values. If a unit operates less than 24 hours during the block, or there are less than 24 valid hourly averages available, the 24-hour block average shall be the average of all available valid hourly average concentration values for the 24-hour block. *{Permitting Note: For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR Part 75, Subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block and periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance reports. For example, the "24-hr block average" may consist of only 6 valid operating hours for the day.}*

c. *12-Month Rolling Total*: By the end of each month, each CEMS shall determine a 12-month rolling total of CO emissions from each gas turbine and the combined total. The 12-month rolling total shall be based on all valid CO CEMS data collected, including startups, shutdowns, and malfunctions.

d. *Data Exclusion*: Except for monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each CEMS shall monitor and record emissions during all operations including episodes of startups, shutdowns, malfunctions, and DLN tuning. Limited amounts of NOx CEMS emissions data recorded during some of these episodes may be excluded from the corresponding compliance demonstration subject to the provisions of Condition No. 21 in this section. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable.

e. *Monitor Availability*. Monitor availability for each CEMS used to demonstrate compliance shall be 95% or greater in any calendar quarter. Monitor availability shall be calculated consistent with 40 CFR §60.334 and reported in the ~~quarterly~~ SIP and NSPS excess emissions reports required in Condition 29. 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, except as otherwise authorized by the Compliance Authority.

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

5. *Condition 25*: Although fuel consumption will be monitored, the permit restricts operation based on hours of operation. The applicant requests revising Condition 25 to remove the requirement to log monthly fuel consumption. *Response*: The Department agrees to the revision, but notes that annual fuel consumption must be reported in the Annual Operation Report.

6. *Condition 28*: The applicant requests revising Condition 28 to reflect that the federal requirements only require reports for Relative Accuracy Test Assessments (RATA) to be submitted when requested in writing. *Response*: Provided the Compliance Authority is notified in advance of a RATA and can request the report, the Department agrees to revise the condition as follows:

   CEMS RATA Reports: ~~Within 45 days of~~ At least 15 days prior to conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall notify ~~submit a report to~~ the Compliance Authority of the schedule (letter, email, fax, or phone call). ~~summarizing results of the RATA.~~ A summary of the RATA reports shall be provided upon written request of the Compliance Authority and in the SIP Excess Emissions Report as specified in Condition 29. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

7. *Condition 29*: The applicant requests that the excess emissions reporting requirements be reduced from a quarterly to a semiannual basis. *Response*: The NSPS general requirements allow for semiannual reporting provided the units show compliance in four consecutive quarters. The Department revised this condition as follows:

   Excess Emissions Reporting

   a. *Malfunction Notification:* If NOx data will be excluded due to a malfunction, the permittee shall notify the Compliance Authority within one 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 Compliance Authority may request a written summary report of the incident.

   b. *SIP ~~Quarterly~~ Excess Emissions Report*: Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Compliance Authority of the following for each gas turbine: a summary of the 24-hour NOx compliance periods for the quarter; a summary of NOx data excluded due to malfunctions for the quarter; a summary of the 12-month rolling CO emissions totals for the quarter;

a summary of any RATA tests performed during the quarter; and a summary of the CEMS systems monitor availability for the quarter.

(1) If four consecutive quarterly reports demonstrate compliance with the CEMS-based emissions standards, the reporting frequency may be reduced to semiannual reporting. As part of the fourth consecutive satisfactory quarterly report, the permittee shall provide written notification of its intent to reduce the reporting frequency to a semiannual basis. The notification shall include a statement that the units were in full compliance during the four consecutive quarters and that reporting will be reduced to a semiannual basis. Semiannual reports shall include above information required for each quarter in the semiannual period. The permittee shall continue to comply with all other record keeping and monitoring provisions.

(2) If reports are being submitted on a semiannual basis and a unit is not in compliance with the CEMS-based emissions standards, the permittee shall immediately (within one day of detection) notify the Compliance Authority of the compliance status and reestablish quarterly reporting beginning with the current quarter. If compliance is reestablished for four consecutive quarters, semiannual reporting may resume as specified above.

c. *NSPS ~~Semi-Annual~~ Excess Emissions Reports*: Within thirty (30) days following each calendar semiannual period, the permittee shall submit a report including any applicable periods of excess emissions and monitoring systems performance as defined in 40 CFR, Part 60, Subpart GG (Standards of Performance for Stationary Gas Turbines) that occurred during the previous semi-annual period to the Compliance Authority. *{Permitting Note: If there are no periods of excess emissions as defined in 40 CFR, Part 60, Subpart GG, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}*

[Rules 62-4.070(3), 62-4.130, 62-204.800, 62-210.700(6) and 62-212.400(BACT), F.A.C.; and 40 CFR 60.7 and 60.334]

On April 19, 2006, the Department also received the following emailed comment from the EPA Region 4 Office regarding the Technical Evaluation and Preliminary Determination (TEPD):

Comment: The Department's TEPD included a preliminary CO BACT determination (4.1 ppmvd). EPA Region 4 commented that this was confusing because the final project was not subject to PSD preconstruction review for CO emissions. EPA Region 4 requested that the TEPD be revised to reflect that no BACT determination was made for CO emission. *Response*: The original application indicated that CO emissions were subject to PSD preconstruction review and the applicant proposed 9 ppmvd as BACT for CO emissions. Subsequent discussions with the Department indicated that BACT determinations of 4.1 ppmvd @ 15% oxygen had recently been made for similar gas turbine projects. The applicant revised the application and requested a CO emissions cap to avoid PSD preconstruction review with compliance demonstrated by continuous monitoring. Immediately following the CO BACT discussion, the TEPD does include a detailed discussion of the revised application and the requested emissions cap. The Department believes it is important to document this history in the TEPD. This Final Determination will serve to clarify the Department's rationale for including the discussion regarding the preliminary CO BACT determination in the TEPD.

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

Colleen M. Castille
Secretary

PERMITTEE:

Tampa Electric Company
PO Box 111
Tampa, Florida 33601-0111
Authorized Representative:
Mark J. Hornick, General Manager

Permit No. PSD-FL-363
Project No. 1050233-018-AC
TECO Polk Power Station
Simple Cycle Units 4 and 5
Expires: October 1, 2008

PROJECT AND LOCATION

This permit authorizes the construction of two simple cycle gas turbine generators with a nominal output of 165 MW each at the existing Polk Power Station (SIC No. 4911). The facility is located approximately 11 miles south of the city of Mulberry (9995 State Route 37 South) in Polk County, Florida.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix BD. Final BACT Determinations and Emissions Standards

Appendix C. Common State Rules

Appendix GC. General Conditions

Appendix GG. NSPS Provisions - Subparts A and GG for Stationary Gas Turbines

STATEMENT OF BASIS

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. 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 of Environmental Protection (Department).

Michael G. Cooke, Director
Division of Air Resource Management

Effective Date: April 28, 2006

FACILITY DESCRIPTION

The regulated emissions units at the existing Polk Power Station include the following: a 260 MW integrated coal gasification and combined cycle gas turbine (Unit 1) capable of firing synthetic gas (syngas) or No. 2 fuel oil; an auxiliary boiler that fires No. 2 fuel oil; a sulfuric acid plant; a solid fuel handling system; and two nominal 165 MW simple cycle gas turbines (Units 2 and 3) capable of firing either natural gas or No. 2 fuel oil.

PROJECT DESCRIPTION

The project is for the addition of two General Electric PG7241(FA) simple cycle gas turbine generators with a nominal output of 165 MW each at the existing facility. Each unit may operate up to 4380 hours per year. The new units will be fired exclusively with natural gas, which will minimize SO_2 emissions. The units will be designed and constructed with dry low-NO_X burner technology for the control of NO_X emissions. The advanced burner design will reduce incomplete combustion and minimize CO, PM_{10}, and VOC emissions.

EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units:

EU No.	Emission Unit Description
011	Unit 4 – 165 MW General Electric PG7241 FA gas turbine-electrical generator
012	Unit 5 – 165 MW General Electric PG7241 FA gas turbine-electrical generator

REGULATORY CLASSIFICATION

Title III: The facility is not a major source of hazardous air pollutants (HAPs).

Title IV: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V: The facility is a Title V or "major source" of air pollution in accordance with Chapter 62-213, F.A.C.

PSD: The facility is a PSD-major facility pursuant to Rule 62-212, F.A.C.

NSPS: Units 4 and 5 are subject to 40 CFR 60, Subpart GG (Standards of Performance for Stationary Gas Turbines). They are not be subject to NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for which Construction is Commenced after February 18, 2005) because the purchase contract with General Electric was signed on July 21, 2000, which is prior to the NSPS effective date.

NESHAP: Units 4 and 5 are not subject to 40 CFR 63, Subpart YYYY (National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines) because the facility is not a major source of HAPs.

Siting: This plant is subject to certain requirements of Chapter 403, Part II, Florida Statutes, Electric Power Plant and Transmission Line Siting, including a modification of the conditions Site Certification PA92-32.

RELEVANT DOCUMENTS

The following relevant documents are not a part of this permit, but helped form the basis for this permitting action: the permit application and additional information received to make it complete; the draft permit package including the Department's Technical Evaluation and Preliminary Determination; publication and comments; and the Department's Final Determination and Best Available Control Technology (BACT) determinations.

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (DEP), at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications should be submitted to the Air Resources Section of the Department's Southwest District Office at 13051 N. Telecom Parkway, Temple Terrace, FL 33637-0926.

3. General Conditions: The permittee 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.]

4. 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, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 63, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. 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 permittee from compliance with any applicable federal, state, or local permitting or regulations.
[Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

5. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or 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. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. 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, 62-210.300(1), and 62-212.400(12), F.A.C.]

6. 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.]

7. Source Obligation.

   (a) Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit.

(b) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

(c) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

[Rule 62-212.400(12), F.A.C.]

8. 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. [Chapters 62-210 and 62-212, F.A.C.]
9. 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 Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. This permit does not specify the Acid Rain program requirements. These will be included in the Title V air operation permit. [40 CFR 72]
10. 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 emission units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation and a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. Simple Cycle Gas Turbine Units 4 and 5 (EU-011 and EU-012)

The specific conditions of this subsection apply to the following emissions units.

EU No.	Emission Unit Description
011	Unit 4 – 165 MW General Electric PG7241 FA gas turbine-electrical generator
012	Unit 5 – 165 MW General Electric PG7241 FA gas turbine-electrical generator

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Units 4 and 5 are subject to determinations of the Best Available Control Technology (BACT) for nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), and sulfur dioxide (SO_2). [Rule 62-212.400(BACT), F.A.C.]

2. NSPS Requirements: The gas turbines shall comply with the applicable New Source Performance Standards (NSPS) in 40 CFR 60, including: Subpart A (General Provisions) and Subpart GG (Standards of Performance for Stationary Gas Turbines). See Appendix GG of this permit. The BACT emissions standards are as stringent as or more stringent than the limits imposed by the applicable NSPS provisions. Some separate reporting and monitoring may be required by the individual subparts. 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. [Rule 62-204.800(7)(b), F.A.C.; 40 CFR 60, Subparts A and GG]

EQUIPMENT DESCRIPTION

3. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain two General Electric Model PG7241FA gas turbine-electrical generator sets with a nominal generating capacity of 165 MW each. Each gas turbine will be equipped with a DLN combustion system and an inlet air filtration system. The unit shall include a Speedtronic™ Mark V automated gas turbine control system (or equivalent). [Application No. 1050233-018-AC; Design]

CONTROL TECHNOLOGY

4. DLN Combustion: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NO_X emissions from the gas turbines when firing natural gas. Prior to the initial emissions performance tests required for the gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for CO and NO_X. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Application No. 1050233-018-AC; Design; Rule 62-212.400(BACT), F.A.C.]

PERFORMANCE REQUIREMENTS

5. Hours of Operation: Each gas turbine shall operate no more than 4380 hours during any consecutive 12 months. Restrictions on individual methods of operation are specified in separate conditions. [Application No. 1050233-018-AC; Rules 62-210.200(PTE) and 62-212.400(12), F.A.C.]

6. Permitted Capacity: The maximum heat input rate for each gas turbine is 1834 MMBtu per hour when firing natural gas based on a compressor inlet air temperature of 59° F, the higher heating value (HHV) of natural gas, and 100% load. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rules 62-4.070(3), 62-212.400(BACT), and 62-210.200(PTE), F.A.C.]

7. Authorized Fuels: Each gas turbine shall fire only natural gas containing no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

8. Simple Cycle, Intermittent Operation: Each turbine shall operate only in simple cycle mode not to exceed the permitted hours of operation allowed by this permit. This restriction is based on the permittee's request, which formed the basis of the PSD applicability and BACT determinations and resulted in the emission standards specified in this permit. For any request to convert this unit to combined cycle operation by installing/connecting to heat recovery steam generators, including changes to the fuel quality or quantity related to combined cycle conversion which may cause an increase in short or long-term emissions, the permittee may be required to submit a full PSD permit application complete with a new proposal of the best available control technology as if the unit had never been built. [Rules 62-212.400(12) and 62-212.400(BACT), F.A.C.]

EMISSIONS AND TESTING REQUIREMENTS

9. Emission Standards: Emissions from each gas turbine shall not exceed the following emissions standards.

Pollutant	Emission Standard [e]	Averaging Time	Compliance Method	Basis
CO [a]	99.0 tons (Emissions Cap)	12-month rolling total Both Units Combined	CEMS	Avoid PSD
	9.0 ppmvd @ 15% O_2 36.0 lb/hour	3-hour test avg.	Initial Only EPA Method 10 Test	
NO_X [b]	9.0 ppmvd @ 15% O_2	24-hour block, CEMS	CEMS	BACT
	60.9 lb/hour	3-hour test avg.	EPA Methods 7E/20 Test	
PM/PM_{10} [c]	10 % Opacity	6-minute block	EPA Method 9 Test	BACT
	2 grains S/100 SCF of gas	N/A	Record Keeping	
SO_2 [d]	2 grains S/100 SCF of gas	N/A	Record Keeping	BACT

a. The permittee shall conduct an initial test to demonstrate compliance with the short-term (ppmvd @ 15% O_2 and lb/hour) CO emissions limits for the unit as constructed. Thereafter, continuous compliance shall be demonstrated with the CO emissions cap by data collected from the required continuous emissions monitoring systems (CEMS) for both units combined.

b. The permittee shall conduct an initial test to demonstrate compliance with the short-term (ppmvd @ 15% O_2 and lb/hour) NOx emissions limits. Thereafter, continuous compliance shall be demonstrated with the 24-hour block NOx emissions limit by data collected from the required continuous emissions monitoring system (CEMS).

c. The fuel sulfur specifications combined with the efficient combustion design and operation of the gas turbine represents BACT for particulate matter (PM/PM_{10}) emissions. No stack tests are required. Compliance with the CO and visible emissions standards shall serve as indicators of good combustion. *{Permitting Note: Maximum expected PM/PM_{10} emissions from each gas turbine are approximately 18 lb/hour.}*

d. The fuel sulfur specifications effectively limit the potential emissions of sulfur dioxide (SO_2) from each gas turbine and represent BACT for SO_2 emissions. No stack tests are required. *{Permitting Note: Maximum expected SO_2 emissions from each gas turbine are approximately 9.5 lb/hour.}*

e. The mass emission rate standards are based on a turbine inlet condition of 59° F and the higher heating value of natural gas. Mass emission rates may be adjusted from actual test conditions in accordance with the performance curves and/or equations on file with the Department.

{Permitting Note: In combination with the annual restriction on hours of operation, the above emissions standards effectively limit annual potential emissions from both gas turbines to: 99 tons/year of CO, 267 tons/year of NOx, 79 tons/year of PM/PM_{10}, 42 tons/year of SO_2, 5 tons/year of SAM, and 12 tons/year of VOC.}

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

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

11. Test Methods: Any required stack tests shall be performed in accordance with the following methods.

Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental)
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources Note: The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

The methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used for compliance testing unless prior written approval is received from the Department. Tests shall be conducted in accordance with the appropriate test method, the applicable requirements specified in Appendix C of this permit, and the provisions in NSPS Subparts A and GG in 40 CFR 60. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Subparts A and GG, and Appendix A.]

12. Testing Requirements: Initial and subsequent performance tests shall be conducted between 90% and 100% of permitted capacity in accordance with the requirements of Rule 62-297.310(2), F.A.C. [Rule 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

13. Initial Compliance Demonstration: Initial compliance tests shall be conducted within 60 days after achieving the maximum production rate at which the units will be operated, but not later than 180 days after the initial startup. In accordance with the test methods specified in this permit, the turbine exhaust stack shall be tested to demonstrate compliance with the emission standards for CO, NO_X, and visible emissions. For each test run (including visible emissions tests), CO and NOx emissions recorded by the required CEMS shall be reported. The permittee shall provide the Compliance Authority with any other initial emissions performance tests conducted to satisfy vendor guarantees. [Rule 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

14. Annual Compliance Testing: During each federal fiscal year (October 1st to September 30th), annual compliance tests for visible emissions shall be conducted. For each visible emissions test, emissions of CO and NOx recorded by the CEMS shall also be reported. [Rules 62-297.310(7)(a) and (b), F.A.C.]

15. Continuous Compliance: Continuous compliance with the CO and NOx emissions standards shall be demonstrated with data collected from the required continuous emissions monitoring systems (CEMS). [Rules 62-297.310(7)(a) and (b), F.A.C.]

16. 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. The Department may, require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the DLN combustors, etc. [Rule 62-297.310(7)(b), F.A.C.]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 9 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal NSPS, NESHAP, or Acid Rain provision.}

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

18. Definitions: Rules 62-210.200(159), (230) and (245), F.A.C. define the following terms.

    a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

    b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.

    c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

19. 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. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

20. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

21. Allowable NOx Data Exclusions: Provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions are minimized, NO_X continuous monitoring data collected during periods of startup, shutdown, and malfunction may be excluded from the 24-hr block compliance demonstrations only in accordance with the following requirements. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, and DLN tuning) may be excluded. As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions replace the provisions in Rule 62-210.700(1), F.A.C.

    a. *Startup*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than the first 30 minutes of CEMS data shall be excluded for each gas turbine startup. For startups of less than 30 minutes in duration, only those minutes attributable to startup shall be excluded.

    b. *Shutdown*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than the first 20 minutes of CEMS data shall be excluded for each gas turbine shutdown. For shutdowns less than 20 minutes in duration, only those minutes attributable to shutdown shall be excluded.

c. *Malfunction*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than 120 minutes of CEMS data shall be excluded in a 24-hour period for each gas turbine due to malfunctions. Within one (1) working day of occurrence, the owner or operator shall notify the Compliance Authority of any malfunction resulting in the exclusion of CEMS data.

d. *DLN Tuning*: CEMS data collected during initial or other DLN tuning sessions shall be excluded from the compliance demonstrations provided the tuning session is performed in accordance with the manufacturer's specifications. Prior to performing any tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least one (1) day that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

The permittee shall notify the Compliance Authority within one working day of discovering any emissions in excess of a CEMS standard subject to the specified averaging period. All such reasonably preventable emissions shall be included in any CEMS compliance determinations. All valid emissions data (including data collected during startup, shutdown, malfunction, and DLN tuning) shall be used to report annual emissions for the Annual Operating Report and demonstration of compliance with the CO emissions cap. [Rules 62-4.070(3), 62-210.200, 62-212.400(BACT) and 62-210.700, F.A.C.]

CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS) REQUIREMENTS

22. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO_X from each gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. All continuous monitoring systems shall be installed and functioning within the required performance specification by the time of the initial performance tests.

a. *CO Monitor:* Each CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F. The annual and required RATA tests shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

b. *NO_X Monitor:* Each NO_X monitor shall be certified pursuant to the specifications of 40 CFR 75. Quality assurance procedures shall conform to the requirements of 40 CFR 75. The annual and required RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.

c. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

[Rules 62-4.070(3), 62-210.800, 62-212.400(BACT) and 62-297.520, F.A.C.]

23. CEMS Data Requirements: The CEMS shall be installed, calibrated, maintained, and operated in the gas turbine stacks to measure and record the emissions of CO, and NO_X in a manner sufficient to demonstrate compliance with the CEMS-based emission limits of this section. The CEMS shall express the results in units of ppmvd corrected to 15% oxygen. Upon request by the Department, the CEMS emission rates shall

be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

a. *Valid Hourly Averages for Compliance:* Each CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour (except for the allowable NOx data exclusions), shall be used to calculate a 1-hour block average that begins at the top of each hour. Each 1-hour block average shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, a 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, there is insufficient data and the 1-hour block average is not valid. Also, if an allowable exclusion episode should occur over two separate hourly averages, only those minutes attributed to the specific episode shall be excluded from each hour. *{Permitting Note: For example, a 20-minute startup begins at 2:50 p.m. and ends at 3:10 pm. This means that 10 minutes of startup data would be excluded from the first hourly average and 10 minutes would be excluded from the second hourly average. The first hourly average (2:00 – 3:00 p.m.) is not a valid hourly average because there is insufficient data. The second hourly average (3:00 – 4:00 p.m.) is a valid hourly average consisting of 50 minutes of monitoring data.}*

b. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive valid hourly average concentration values. If a unit operates less than 24 hours during the block, or there are less than 24 valid hourly averages available, the 24-hour block average shall be the average of all available valid hourly average concentration values for the 24-hour block. *{Permitting Note: For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR Part 75, Subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block and periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance reports. For example, the "24-hr block average" may consist of only 6 valid operating hours for the day.}*

c. *12-Month Rolling Total*: By the end of each month, each CEMS shall determine a 12-month rolling total of CO emissions from each gas turbine and the combined total. The 12-month rolling total shall be based on all valid CO CEMS data collected, including startups, shutdowns, and malfunctions.

d. *Data Exclusion*: Except for monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each CEMS shall monitor and record emissions during all operations including episodes of startups, shutdowns, malfunctions, and DLN tuning. Limited amounts of NOx CEMS emissions data recorded during some of these episodes may be excluded from the corresponding compliance demonstration subject to the provisions of Condition No. 21 in this section. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable.

e. *Monitor Availability*. Monitor availability for each CEMS used to demonstrate compliance shall be 95% or greater in any calendar quarter. Monitor availability shall be calculated consistent with 40 CFR §60.334 and reported in the SIP and NSPS excess emissions reports required in Condition 29. In the event that 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, except as otherwise authorized by the Compliance Authority.

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

REPORTING AND RECORD KEEPING REQUIREMENTS

24. Monitoring of Capacity: The permittee shall monitor and record the operating rate of the gas turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown, malfunction, and DLN tuning). This shall be achieved through monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D, and recording the data using a monitoring component of the CEMS system required above. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

25. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the gas turbine for the previous month of operation: hours of operation for the month and for the rolling 12-month total. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

26. Fuel Sulfur Records: Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions. These methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3), 62-212.400(BACT), F.A.C.]

27. Stack Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Compliance Authority on the results of each such test. The required test report shall be filed with the Compliance Authority as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Compliance Authority to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report shall provide the applicable information specified in Rule 62-297.310(8), F.A.C. and summarized in Appendix C. [Rule 62-297.310(8), F.A.C.]

28. CEMS RATA Reports: At least 15 days prior to conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall notify the Compliance Authority of the schedule (letter, email, fax, or phone call). A summary of the RATA reports shall be provided upon written request of the Compliance Authority and in the SIP Excess Emissions Report as specified in Condition 29. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

29. Excess Emissions Reporting

    a. *Malfunction Notification:* If NOx data will be excluded due to a malfunction, the permittee shall notify the Compliance Authority within one 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 Compliance Authority may request a written summary report of the incident.

    b. *SIP Excess Emissions Report*: Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Compliance Authority of the following for each gas turbine: a summary of the 24-hour NOx compliance periods for the quarter; a summary of NOx data excluded due to malfunctions for the quarter; a summary of the 12-month rolling CO emissions totals for the quarter; a summary of any RATA tests performed during the quarter; and a summary of the CEMS systems monitor availability for the quarter.

(1) If four consecutive quarterly reports demonstrate compliance with the CEMS-based emissions standards, the reporting frequency may be reduced to semiannual reporting. As part of the fourth consecutive satisfactory quarterly report, the permittee shall provide written notification of its intent to reduce the reporting frequency to a semiannual basis. The notification shall include a statement that the units were in full compliance during the four consecutive quarters and that reporting will be reduced to a semiannual basis. Semiannual reports shall include above information required for each quarter in the semiannual period. The permittee shall continue to comply with all other record keeping and monitoring provisions.

(2) If reports are being submitted on a semiannual basis and a unit is not in compliance with the CEMS-based emissions standards, the permittee shall immediately (within one day of detection) notify the Compliance Authority of the compliance status and reestablish quarterly reporting beginning with the current quarter. If compliance is reestablished for four consecutive quarters, semiannual reporting may resume as specified above.

c. *NSPS Excess Emissions Reports*: Within thirty (30) days following each calendar semiannual period, the permittee shall submit a report including any applicable periods of excess emissions and monitoring systems performance as defined in 40 CFR, Part 60, Subpart GG (Standards of Performance for Stationary Gas Turbines) that occurred during the previous semi-annual period to the Compliance Authority. *{Permitting Note: If there are no periods of excess emissions as defined in 40 CFR, Part 60, Subpart GG, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}*

[Rules 62-4.070(3), 62-4.130, 62-204.800, 62-210.700(6) and 62-212.400(BACT), F.A.C.; and 40 CFR 60.7 and 60.334]

30. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours 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.]

31. Startup/Shutdown Report: Within 30 days following the end of each calendar quarter, the permittee shall submit a report summarizing the following for each gas turbine: number of startups and shutdowns in the quarter; the duration of each startup and shutdown in the quarter; and the CO and NOx mass emission rates (lb/hour) during each 1-hour block that includes a startup or shutdown. This temporary report that shall be submitted to the Compliance Authority and the Bureau of Air Regulation only for the first four initial quarters of operation. [Rule 62-4.070(3), F.A.C.]

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Project Description

The applicant proposes to install two General Electric PG7241(FA) simple cycle gas turbine generators with a nominal output of 165 MW each at the existing Polk Power Station. Each gas turbine will fire natural gas as the exclusive fuel and will have a maximum operation of 4380 hours per year. In accordance with Rule 62-212.400, F.A.C., the existing plant is a major facility for the Prevention of Significant Deterioration (PSD) of Air Quality. The proposed project is subject to PSD preconstruction review for NOx, PM/PM_{10}, and SO_2 emissions.

Air Pollution Control Equipment

Each gas turbine will be equipped with a dry low-NOx combustion system capable of achieving low CO and NOx emissions with the lean, pre-mixed combustion of natural gas. Each gas turbine will employ continuous emissions monitoring systems (CEMS) to continuously demonstrate compliance with the CO and NOx emissions standards. As the only authorized fuel for the project, natural gas contains little ash or sulfur, which will minimize emissions of particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). Also, natural gas is readily combusted by the large frame gas turbines and will result in negligible emissions of volatile organic compounds (VOC).

Final BACT Determinations

In accordance with Rule 62-212.400, F.A.C., the Department establishes the following standards that represent the Best Available Control Technology (BACT).

Pollutant	Emission Standard [e]	Averaging Time	Compliance Method	Basis
CO [a]	99.0 tons (Emissions Cap)	12-month rolling total Both Units Combined	CEMS	Avoid PSD
	9.0 ppmvd @ 15% O_2 36.0 lb/hour	3-hour test avg.	Initial Only EPA Method 10 Test	
NO_X [b]	9.0 ppmvd @ 15% O_2	24-hour block, CEMS	CEMS	BACT
	60.9 lb/hour	3-hour test avg.	EPA Method 7E Test	
PM/PM_{10} [c]	10 % Opacity	6-minute block	EPA Method 9 Test	BACT
	2 grains S/100 SCF of gas	N/A	Record Keeping	
SO_2 [d]	2 grains S/100 SCF of gas	N/A	Record Keeping	BACT

a. The permittee shall conduct an initial test to demonstrate compliance with the short-term (ppmvd @ 15% O_2 and lb/hour) CO emissions limits for the unit as constructed. Thereafter, continuous compliance shall be demonstrated with the CO emissions cap by data collected from the required continuous emissions monitoring system (CEMS).

b. The permittee shall conduct an initial test to demonstrate compliance with the short-term (ppmvd @ 15% O_2 and lb/hour) NOx emissions limits. Thereafter, continuous compliance shall be demonstrated with the 24-hour ~~block~~ NOx emissions limit by data collected from the required continuous emissions monitoring system (CEMS).

c. The fuel sulfur specifications combined with the efficient combustion design and operation of the gas turbine represents BACT for particulate matter (PM/PM_{10}) emissions. No stack tests are required. Compliance with the CO and visible emissions standards shall serve as indicators of good combustion. *{Permitting Note: Maximum expected PM/PM_{10} emissions from each gas turbine are approximately 18 lb/hour.}*

d. The fuel sulfur specifications effectively limit the potential emissions of sulfur dioxide (SO_2) from each gas turbine and represent BACT for SO_2 emissions. No stack tests are required. *{Permitting Note: Maximum expected SO_2 emissions from each gas turbine are approximately 9.5 lb/hour.}*

e. The mass emission rate standards are based on a turbine inlet condition of 59° F and the higher heating value of natural gas. Mass emission rates may be adjusted from actual test conditions in accordance with the performance curves and/or

equations on file with the Department.

{Permitting Note: In combination with the annual restriction on hours of operation, the above emissions standards effectively limit annual potential emissions from both gas turbines to: 99 tons/year of CO, 267 tons/year of NOx, 79 tons/year of PM/PM_{10}, 42 tons/year of SO_2, 5 tons/year of SAM, and 12 tons/year of VOC.}

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

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 project. The final BACT determinations also consider comments received during public notice period as summarized in the Final Determination issued concurrently with the Final Permit.

FINAL BACT DETERMINATION AND EMISSION STANDARDS

Project Description

The applicant proposes to install two General Electric PG7241(FA) simple cycle gas turbine generators with a nominal output of 165 MW each at the existing Polk Power Station. Each gas turbine will fire natural gas as the exclusive fuel and will have a maximum operation of 4380 hours per year. In accordance with Rule 62-212.400, F.A.C., the existing plant is a major facility for the Prevention of Significant Deterioration (PSD) of Air Quality. The proposed project is subject to PSD preconstruction review for NOx, PM/PM_{10}, and SO_2 emissions.

Air Pollution Control Equipment

Each gas turbine will be equipped with a dry low-NOx combustion system capable of achieving low CO and NOx emissions with the lean, pre-mixed combustion of natural gas. Each gas turbine will employ continuous emissions monitoring systems (CEMS) to continuously demonstrate compliance with the CO and NOx emissions standards. As the only authorized fuel for the project, natural gas contains little ash or sulfur, which will minimize emissions of particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). Also, natural gas is readily combusted by the large frame gas turbines and will result in negligible emissions of volatile organic compounds (VOC).

Final BACT Determinations

In accordance with Rule 62-212.400, F.A.C., the Department establishes the following standards that represent the Best Available Control Technology (BACT).

Pollutant	Emission Standard [e]	Averaging Time	Compliance Method	Basis
CO [a]	99.0 tons (Emissions Cap)	12-month rolling total Both Units Combined	CEMS	Avoid PSD
	9.0 ppmvd @ 15% O_2 36.0 lb/hour	3-hour test avg.	Initial Only EPA Method 10 Test	
NO_X [b]	9.0 ppmvd @ 15% O_2	24-hour block, CEMS	CEMS	BACT
	60.9 lb/hour	3-hour test avg.	EPA Method 7E Test	
PM/PM_{10} [c]	10 % Opacity	6-minute block	EPA Method 9 Test	BACT
	2 grains S/100 SCF of gas	N/A	Record Keeping	
SO_2 [d]	2 grains S/100 SCF of gas	N/A	Record Keeping	BACT

a. The permittee shall conduct an initial test to demonstrate compliance with the short-term (ppmvd @ 15% O_2 and lb/hour) CO emissions limits for the unit as constructed. Thereafter, continuous compliance shall be demonstrated with the CO emissions cap by data collected from the required continuous emissions monitoring system (CEMS).

b. The permittee shall conduct an initial test to demonstrate compliance with the short-term (ppmvd @ 15% O_2 and lb/hour) NOx emissions limits. Thereafter, continuous compliance shall be demonstrated with the 24-hour ~~block~~ NOx emissions limit by data collected from the required continuous emissions monitoring system (CEMS).

c. The fuel sulfur specifications combined with the efficient combustion design and operation of the gas turbine represents BACT for particulate matter (PM/PM_{10}) emissions. No stack tests are required. Compliance with the CO and visible emissions standards shall serve as indicators of good combustion. *{Permitting Note: Maximum expected PM/PM_{10} emissions from each gas turbine are approximately 18 lb/hour.}*

d. The fuel sulfur specifications effectively limit the potential emissions of sulfur dioxide (SO_2) from each gas turbine and represent BACT for SO_2 emissions. No stack tests are required. *{Permitting Note: Maximum expected SO_2 emissions from each gas turbine are approximately 9.5 lb/hour.}*

e. The mass emission rate standards are based on a turbine inlet condition of 59° F and the higher heating value of natural gas. Mass emission rates may be adjusted from actual test conditions in accordance with the performance curves and/or

equations on file with the Department.

{Permitting Note: In combination with the annual restriction on hours of operation, the above emissions standards effectively limit annual potential emissions from both gas turbines to: 99 tons/year of CO, 267 tons/year of NOx, 79 tons/year of PM/PM_{10}*, 42 tons/year of* SO_2*, 5 tons/year of SAM, and 12 tons/year of VOC.}*

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

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 project. The final BACT determinations also consider comments received during public notice period as summarized in the Final Determination issued concurrently with the Final Permit.

COMMON STATE RULES

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the facility.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. 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.]
3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]
4. 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. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permitee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]
9. 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.]

GENERAL COMPLIANCE TESTING REQUIREMENTS

The focal point of a compliance test is the stack or duct which vents process and/or combustion gases and air pollutants from an emissions unit into the ambient air. [Rule 62-297.310, F.A.C.]

10. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

11. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate 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 purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. [Rule 62-297.310(2), F.A.C.]
12. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]
13. Applicable Test Procedures [Rule 62-297.310(4), F.A.C.]
    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.
        (2) Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
            (a) For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
            (b) The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.
            (c) The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
    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.
    c. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.
    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.
    e. *Allowed Modification to EPA Method 5.* When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
14. Determination of Process Variables [Rule 62-297.310(5), F.A.C.]
    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.
    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.

15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must also comply with all applicable Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E. [Rule 62-297.310(6), F.A.C.]

   a. *Permanent Test Facilities.* The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

   b. *Temporary Test Facilities.* The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

   c. *Sampling Ports.*

      (1) All sampling ports shall have a minimum inside diameter of 3 inches.

      (2) The ports shall be capable of being sealed when not in use.

      (3) The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

      (4) For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

      (5) On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

   d. *Work Platforms.*

      (1) Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

      (2) On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

      (3) On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

      (4) All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toe board, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

   e. *Access to Work Platform.*

      (1) Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

      (2) Walkways over free-fall areas shall be equipped with safety rails and toe boards.

   f. *Electrical Power.*

      (1) A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

      (2) If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

g. *Sampling Equipment Support.*

(1) A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

(a) The bracket shall be a standard 3 inch × 3 inch × one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

(b) A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

(c) The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

(2) A complete monorail or dualrail arrangement may be substituted for the eyebolt and bracket.

(3) When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

16. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required. [Rule 62-297.310(7), F.A.C.]

a. *General Compliance Testing.*

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to sub-subparagraph 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

(a) Did not operate; or

(b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours,

4. During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

(a) a. Visible emissions, if there is an applicable standard;

(b) b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

(c) c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
6. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.
7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.
8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.
10. An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., F.A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.

b. *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.

c. *Waiver of Compliance Test Requirements.* If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of paragraph 62-297.310(7)(b), F.A.C., shall apply.

RECORDS AND REPORTS

17. Test Reports [Rule 62-297.310(8), F.A.C.]

a. The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

b. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.

c. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information.

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.

6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

RECORDS AND REPORTS

18. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]
19. 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.]

CONSTRUCTION PERMIT GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

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.

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, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

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.

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.

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.

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.

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.

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.

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 extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

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.

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.

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

13. This permit also constitutes:

    a. Determination of Best Available Control Technology;
    b. Determination of Prevention of Significant Deterioration; and
    c. Compliance with New Source Performance Standards.

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:

        a. The date, exact place, and time of sampling or measurements;
        b. The person responsible for performing the sampling or measurements;
        c. The dates analyses were performed;
        d. The person responsible for performing the analyses;
        e. The analytical techniques or methods used; and
        f. The results of such analyses.

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.

NSPS SUBPART GG – REQUIREMENTS FOR GAS TURBINES

Simple cycle gas turbine Units 4 and 5 (Emissions Units 011 and 012) are subject to the following applicable federal New Source Performance Standards (NSPS) in 40 CFR 60.

SUBPART A - GENERAL PROVISIONS

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

SUBPART GG – STATIONARY GAS TURBINES

60.330 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

(b) (b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of §60.332.

[44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987; 65 FR 61759, Oct. 17, 2000]

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.

(c) Regenerative cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

(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.

(e) Emergency gas turbine means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(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.

(k) Fire-fighting turbine means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) Turbines employed in oil/gas production or oil/gas transportation means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m) A Metropolitan Statistical Area or MSA as defined by the Department of Commerce.

(n) Offshore platform gas turbines means any stationary gas turbine located on a platform in an ocean.

(o) Garrison facility means any permanent military installation.

(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.

(r) Emergency fuel is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.

(s) Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

(t) Excess emissions means a specified averaging period over which either:

(1) The NOX emissions are higher than the applicable emission limit in §60.332;

(2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.333; or

(3) The recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

(u) Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

(v) Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

(w) Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(y) Unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by §60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

NSPS SUBPART GG – REQUIREMENTS FOR GAS TURBINES

(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 ISO corrected (if required as given in §60.335(b)(1)) NOX emission concentration (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, and

F = NOX emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(2) 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:

$$STD = 0.0150\frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NOX emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated peak 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, and

F = NOX emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this section is optional. That is, the owner or operator may choose to apply a NOX allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

(4) If the owner or operator elects to apply a NOX emission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under §60.8 as follows:

Fuel-bound nitrogen (percent by weight)	F (NOX percent by volume)
N [le] 0.015	0
0.015 < N[le] 0.1	0.04(N)
0.1 < N [le] 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).

or:

Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by §60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the Federal Register.

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

(d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in §60.332(b) shall comply with paragraph (a)(2) of this section.

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) 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.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

(j) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour that commenced construction, modification, or reconstruction between the dates of October 3, 1977, and January 27, 1982, and were required in the September 10, 1979, Federal Register (44 FR 52792) to comply with paragraph (a)(1) of this section, except electric utility stationary gas turbines, are exempt from paragraph (a) of this section.

(k) Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from paragraph (a)(2) of this section when being fired with an emergency fuel.

(l) Regenerative cycle gas turbines with a heat input less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) are exempt from paragraph (a) of this section.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

60.333 Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by §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:

(a) 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 sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

[44 FR 52798, Sept. 10, 1979, as amended at 69 FR 41360, July 8, 2004]

60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NOX emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NOX emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NOX and O2 monitors. As an alternative, a CO2 monitor may be used to adjust the measured NOX concentrations to 15 percent O2 by either converting the CO_2 hourly averages to equivalent O_2 concentrations using Equation F–14a or F–14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O_2, or by using the CO_2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NOX and diluent monitors may be performed individually or on a combined basis, i.e., the relative accuracy tests of the CEMS may be performed either:

   (i) On a ppm basis (for NOX) and a percent O_2 basis for oxygen; or

   (ii) On a ppm at 15 percent O_2 basis; or

   (iii) On a ppm basis (for NOX) and a percent CO_2 basis (for a CO_2 monitor that uses the procedures in Method 20 to correct the NOX data to 15 percent O_2).

(2) As specified in §60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in §60.13(h).

   (i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both NOX and diluent, the data acquisition and handling system must calculate and record the hourly NOX emissions in the units of the applicable NOX emission standard under §60.332(a), i.e., percent NOX by volume, dry basis, corrected to 15 percent O_2 and International Organization for Standardization (ISO) standard conditions (if required as given in §60.335(b)(1)). For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations.

   (ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (Ta), and minimum combustor inlet absolute pressure (Po) into the ISO correction equation.

   (iii) If the owner or operator has installed a NOX CEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in §60.7(c).

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NOX emissions, the owner or operator may, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA or local permitting authority approval of a petition for an alternative procedure of continuously monitoring compliance with the applicable NOX emission limit under §60.332, that approved procedure may continue to be used, even if it deviates from paragraph (a) of this section.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control NOX emissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NOX CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NOX emissions may elect to use a NOX CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. An acceptable alternative to installing a CEMS is described in paragraph (f) of this section.

(f) The owner or operator of a new turbine who elects not to install a CEMS under paragraph (e) of this section, may instead perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NOX formation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in the lean premixed (low-NOX) combustion mode.

(3) For any turbine that uses SCR to reduce NOX emissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor NOX emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in §75.19(c)(1)(iv)(H) of this chapter.

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under §60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NOX emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in §75.19 of this chapter or the NOX emission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in §75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084–82, 94, D5504–01, D6228–98, or Gas Processors Association Standard 2377–86 (all of which are incorporated by reference-see §60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (i.e., if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in §60.332). The nitrogen content of the fuel shall be determined using methods described in §60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) *Gaseous fuel.* Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) *Custom schedules.* Notwithstanding the requirements of paragraph (i)(2) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (i)(3)(i) and (i)(3)(ii) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), subsequent sulfur content monitoring may be performed at 12 month intervals. If any of the samples taken at 12-month intervals has a total sulfur content between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(1) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(2) of this section.

(2) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(3) of this section.

(3) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (i.e., the maximum total sulfur content of natural gas as defined in §60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

(i) For turbines using water or steam to fuel ratio monitoring:

(A) An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.332, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

(B) A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in §60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using NOX and diluent CEMS:

(A) (A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NOX concentration exceeds the applicable emission limit in §60.332(a)(1) or (2). For the purposes of this subpart, a "4-hour rolling average NOX concentration" is the arithmetic average of the average NOX concentration measured by the CEMS for a given hour (corrected to 15 percent O2 and, if required under §60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NOX concentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NOX concentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(iv) For turbines required under paragraph (f) of this section to monitor combustion parameters or parameters that document proper operation of the NOX emission controls:

(A) An excess emission shall be a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(B) A period of monitor downtime shall be a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(3) Ice fog. Each period during which an exemption provided in §60.332(f) 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.

(4) Emergency fuel. Each period during which an exemption provided in §60.332(k) is in effect shall be included in the report required in §60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

(5) All reports required under §60.7(c) shall be postmarked by the 30th day following the end of each calendar quarter.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41360, July 8, 2004]

60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in §60.8, using either

(1) EPA Method 20,

(2) ASTM D6522–00 (incorporated by reference, see §60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine NOX and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for NOX and diluent pursuant to

(A) [Reserved]

(B) (B) The procedures specified in section 6.5.6.1(a) through (e) appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NOX concentrations, normalized to 15 percent O2, is within ±10 percent of the mean normalized concentration for all traverse points, then you may use 3 points (located either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The 3 points shall be located along the measurement line that exhibited the highest average normalized NOX concentration during the stratification test; or

(B) If each of the individual traverse point NOX concentrations, normalized to 15 percent O2, is within ±5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in §60.332 and shall meet the performance test requirements of §60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NOXo) corrected to 15 percent O2 shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

NOX=(NOXo)(Pr/Po)0.5 e19 (Ho−0.00633) (288°K/Ta)1.53

Where:

NOX = emission concentration of NOX at 15 percent O2 and ISO standard ambient conditions, ppm by volume, dry basis,

NOXo = mean observed NOX concentration, ppm by volume, dry basis, at 15 percent O2,

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

Po = observed combustor inlet absolute pressure at test, mm Hg,

Ho = observed humidity of ambient air, g H2O/g air,

e = transcendental constant, 2.718, and

Ta = ambient temperature, °K.

(2) The 3-run performance test required by §60.8 must be performed within ±5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these requirements, performance testing is not required for any emergency fuel (as defined in §60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NOX emissions after the duct burner rather than directly after the turbine. If the owner or

operator elects to use this alternative sampling location, the applicable NOX emission limit in §60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control NOX with no additional post-combustion NOX control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with §60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522–00 (incorporated by reference, see §60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.332 NOX emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in §60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in §60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NOX CEMS under §60.334(e), then the initial performance test required under §60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable NOX emission limit under §60.332 and to provide the required reference method data for the RATA of the CEMS described under §60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator is required under §60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NOX emission controls, the appropriate parameters shall be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597–94 (Reapproved 1999), D6366–99, D4629–02, D5762–02 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under §60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129–00, D2622–98, D4294–02, D1266–98, D5453–00 or D1552–01 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072–80, 90 (Reapproved 1994); D3246–81, 92, 96; D4468–85 (Reapproved 2000); or D6667–01 (all of which are incorporated by reference, see §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 prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section 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.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in §60.8 to ISO standard day conditions.

[69 FR 41363, July 8, 2004]

- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Mark J. Hornick
General Manager
Polk Power Station
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

B. Received by (Printed Name) OSMAN

C. Date of Delivery

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

MAY - 2 2006

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 (Transfer from service label) 7000 1670 0013 3110 0680

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

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

7000 1670 0013 3110 0680

Mr. Mark J. Hornick, General Manager

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

Postmark Here

Sent To
Mr. Mark J. Hornick, General Manager
Street, Apt. No.; or PO Box No.
P.O. Box 111
City, State, ZIP+4
Tampa, Florida 33601-0111

PS Form 3800, May 2000 See Reverse for Instructions

TAMPA ELECTRIC

March 23, 2006

Mr. Jeff Koerner
Florida Department of Environmental Protection
Division of Air Resource Management
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Via Fed Ex
Airbill No. 7926 9338 5505

Re: Tampa Electric Company
Polk Power Station
Polk Unit 4 & 5
Public Notice of Intent
Project No. 1050233-018- AC, PSD-FL-363

Dear Mr. Koerner:

Please find enclosed the original Affidavit of Publication from the Lakeland Ledger, as required by 62-110.106(5), F.A.C. This public notice was published in the legal section of the Lakeland Ledger on Monday, March 20, 2006. If you have any questions, please feel free to telephone Raiza Calderon or me at (813) 228-4369.

Sincerely,

for

Byron T. Burrows, P.E.
Manager - Air Programs
Environmental, Health & Safety

RECEIVED
MAR 24 2006
BUREAU OF AIR REGULATION

EHS/rlk/RC214

Enclosure

cc: Hamilton Oven, FDEP
Mr. Jerry Kissel - FDEP SW

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AFFIDAVIT OF PUBLICATION

THE LEDGER

Lakeland, Polk County, Florida

Case No:

STATE OF FLORIDA)
COUNTY OF POLK)

Before the undersigned authority personally appeared C. Morgan Miller, who on oath says that he is Display Advertising Manager of The Ledger, a daily newspaper published at Lakeland in Polk County, Florida; that the attached copy of advertisement, being an

Notice of Intent to Issue Air Permit

in the matter of **No. 1050233-018-AC/Draft Air Permit # PSD-FL-363**

concerning **Tampa Electric Company-Polk Power Station**

was published in said newspaper in the issues of **3-20; 2006**

Affiant further says that said The Ledger is a newspaper published at Lakeland, in said Polk County, Florida, and that the said newspaper has heretofore been continuously published in said Polk County, Florida, daily, and has been entered as second class matter at the post office in Lakeland, in said Polk 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.

Signed........C. Morgan Miller........
C. Morgan Miller
Display Advertising Manager
Who is personally known to me.

Sworn to and subscribed before me this..21st........................

day of March................ A.D. 20..06....

Patricia Ann Rouse
Notary Public

(Seal)

PATRICIA ANN ROUSE
MY COMMISSION # DD 330015
EXPIRES: October 17, 2008
Bonded Thru Notary Public Underwriters

My Commission Expires...

LC207377 P694

Attach Ad Here

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Project No. 1050233-018-AC/Draft Air Permit No. PSD-FL-363
Tampa Electric Company - Polk Power Station
New Simple Cycle Gas Turbine Units 4 and 5
Polk County, Florida

Applicant: The applicant for this project is the Tampa Electric Company. The applicant's authorized representative ad mailing address is: Mark J. Hornick, General Manger, Tampa Electric Company - Polk Power Station, PO Box 111; Tampa Florida 33601-0111.

Facility Location: The Tampa Electric Company operates the existing Polk Power Station, which is located approximately 11 miles south of the city of Mulberry (9995 State Route 37 South) in Palk County, Florida.

Project: The applicant proposes to install two General Electric PG7241(FA) simple cycle gas turbine generatars with a nominal output of 165 megawatts each at the existing power plant. Each gas turbine will fire natural gas as the exclusive fuel and will have a maximum operation of 4380 hours per year. Total potential annual project emissions will be: 99 tons/year of CO, 267 tons/year of NOx, 79 tons/year of PM/PM_{10}, 42 tons/year of SO_2, 5 tons/year of SAM, and 12 tons/year of VOC.

In accordance with Rule 62-212.400, F.A.C., the existing plant is a major facility for the Prevention of Significant Deterioration (PSD) of Air Quality. The proposed project is subject to PSD preconstruction review for NOx, PM/PM_{10}, and SO_2 emissions. The Department made the following draft determinations of the Best Available Control Technology (BACT): NOx emissions will be controlled by the efficient dry low-NOx combustion design of the General Electric gas turbines and the exclusive firing of natural gas; PM/PM_{10} emissions will be minimized by the exclusive firing of natural gas and the efficient combustion design; and SO_2 emissions will be minimized by the exclusive firing of natural gas which contains almost negligible amounts of sulfur. In addition, CO and VOC emissions will be minimized by the efficient combustion of natural gas. CO and NOx emissions from each gas turbine will be continuously monitored and recorded.

Based on the applicant's air quality modeling analysis, the maximum predicted air quality impacts due to emissions from the proposed project will be less than the applicable PSD Class II significant impact levels. Therefore a multi-source modeling analysis is not required. Also, the maximum predicted impacts in the Chassahowitzka National Wilderness Area will be less than the applicable, PSD Class I significant impact levels. Therefore, multi-source Class I PSD increment modeling analysis is not required. The applicant has provided the Department with reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florid Statutes (F.S.) and Chapters 62-4, 62-210 and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for the project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all applicable provisions of Chapters 62-4, 62-204, 62-210, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comments received in accordance with this notice results in a different decision or a significant change of terms conditions.

Comments: The Permitting Authority will accept written comments concerning the draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on ths permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location on the Department's official web site for notices at http://tlhora6.dep.state.fl.us/onw and in a newspaper of general circulation in the area affected by the permitting action. For additional, contact the Permitting Authority at the above address of phone number. If comments received result in a significant change to the Draft Permit, The Permitting Authority will issue a Revised Dratt Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241; Fax:850/245-2303). 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 this Public Notice or receipt, of a written notice, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within fourteen (14) 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 ths proceeding and participate as a port 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, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and cash agency's file or identification number, if know; (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 shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interest will be affected by the

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LC207377 P694

filed with (received by) the Departmen[illegible] Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241; Fax:850/245-2303). 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 this Public Notice or receipt, of a written notice, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within fourteen (14) 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 ths proceeding and participate as a part 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, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and cash agency's file or identification number, if know; (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 shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interest will be affected by the agency determination; (c) A statement of how and when each petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact; (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 several or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency' proposed action. A petition that does not dispute the material facts upon which the Permitting Authority'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, filing of petition means that the Permitting Authority's final action may be different from the position taken by it in this Written Notice of Intent to Issue Air Permit. Persons whose substantial interest will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with requirements set forth above.

Mediation: Mediation is not available in this proceeding.

P694 3-20; 2006

TECO
TAMPA ELECTRIC

March 16, 2006

RECEIVED
MAR 27 2006
BUREAU OF AIR REGULATION

Ms. Lea Crandall
Agency Clerk – Office of the General Counsel
Florida Department of Environmental Protection
3900 Commonwealth Boulevard, MS #35
Tallahassee, FL 32399-3000

Via FedEx
Airbill No. 790851940292

Re: **Tampa Electric Company – Polk Power Station**
Draft Air Permit No. PSD-FL-363 – Simple Cycle Units 4 & 5
Project No. 1050233-018-AC
Intent to Issue Air Construction Permit

Dear Ms. Crandall:

By letter dated March 6, 2006 and received by Tampa Electric Company on March 7, 2006 via email, the Florida Department of Environmental Protection (FDEP) announced its intent to issue an air construction permit for the referenced project at the Polk Power Station located in Polk County, Florida. Tampa Electric Company has had an opportunity to review the intent to issue the construction permit along with the proposed conditions and are currently evaluating the conditions of this proposed permit.

To accommodate discussions with staff of the FDEP on these issues, we request that the time for Tampa Electric Company to petition for a formal administrative hearing be extended by an additional 45 days from the deadline set forth in the Intent to Issue Air Construction Permit pursuant to Rule 62-110.106(4), Florida Administrative Code. Tampa Electric Company believes that this time will be sufficient to amicably resolve the issues without the necessity of pursuing a formal administrative hearing.

Thank you for your consideration of this request. If you have any questions or comments, please contact Raiza Calderon or me at (813) 228-4369.

Sincerely,

Byron T. Burrows, P.E.
Manager - Air Programs
Environmental, Health & Safety

EHS/rlk/SSC237

c: Mr. Jeff Koerner, FDEP
Mr. Doug Beason, Esquire

TAMPA ELECTRIC COMPANY
P.O. BOX 111 TAMPA, FL 33601-0111
(813) 228-4111

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OUTSIDE HILLSBOROUGH COUNTY 1 (888) 223-0800

Florida Department of
Environmental Protection

Memorandum

TO: Trina Vielhauer, Chief - Bureau of Air Regulation

FROM: Jeff Koerner, Air Permitting North JK

DATE: March 6, 2006

SUBJECT: Draft Air Permit No. PSD-FL-363
Project No. 1050233-018-AC
TECO Polk Power Station
New Simple Cycle Gas Turbine Units 4 and 5

Attached for your review are the following items:

- Intent to Issue Permit and Public Notice Package;
- Technical Evaluation and Preliminary Determination (with BACT Determination);
- Draft PSD Permit; and
- P.E. Certification

The P.E. certification briefly summarizes the proposed permit project. The Technical Evaluation and Preliminary Determination provide a detailed description of the project, rationale, and conclusion. Day #74 is March 6, 2006. I recommend your approval of the attached Draft Permit for this project.

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

Colleen M. Castille
Secretary

March 6, 2006

Mark J. Hornick, General Manager
Tampa Electric Company – Polk Power Station
PO Box 111
Tampa, Florida 33601-0111

Re: Draft Air Permit No. PSD-FL-363
Project No. 1050233-018-AC
TECO Polk Power Station
Simple Cycle Units 4 and 5

Dear Mr. Hornick:

The Tampa Electric Company applied for a PSD air construction permit to install two General Electric PG7241(FA) simple cycle gas turbine generators with a nominal output of 165 MW each at the existing Polk Power Station, which is located approximately 11 miles south of the city of Mulberry (9995 State Route 37 South) in Polk County, Florida. Enclosed are the following documents: "Technical Evaluation and Preliminary Determination", "Draft Permit", "Written Notice of Intent to Issue Air Permit", and "Public Notice of Intent to Issue Air Permit".

The "Technical Evaluation and Preliminary Determination" summarizes the Bureau of Air Regulation's technical review of the application and provides the rationale for making the preliminary determination to issue a draft permit. The proposed "Draft Permit" includes the specific conditions that regulate the emissions units covered by the proposed project. The "Written Notice of Intent to Issue Air Permit" provides important information regarding: the Permitting Authority's intent to issue an air permit for the proposed project; the requirements for publishing a Public Notice of the Permitting Authority's intent to issue an air permit; the procedures for submitting comments on the Draft Permit; the process for filing a petition for an administrative hearing; and the availability of mediation. The "Public Notice of Intent to Issue Air Permit" is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project.

If you have any questions, please contact the Project Engineer, Jeff Koerner, at 850/894-4912.

Sincerely,

Jeffery J. Koerner

For Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

Tampa Electric Company
PO Box 111
Tampa, Florida 33601-0111

Authorized Representative:
Mark J. Hornick, General Manager

Permit No. PSD-FL-363
Project No. 1050233-018-AC
TECO Polk Power Station
Simple Cycle Units 4 and 5
Polk County, Florida

Facility Location: The Tampa Electric Company operates the existing Polk Power Station, which is located approximately 11 miles south of the city of Mulberry (9995 State Route 37 South) in Polk County, Florida.

Project: The applicant proposes to install two General Electric PG7241(FA) simple cycle gas turbine generators with a nominal output of 165 megawatts each at the existing power plant. The new peaking units will fire only natural gas and will be restricted to 4380 hours per year of operation. Details of the project are provided in the application and the enclosed "Technical Evaluation and Preliminary Determination".

Permitting Authority: Applications for air construction permits are subject to review in accordance with 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 proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all applicable provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comments received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Section 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed "Public Notice of Intent to Issue Air Permit" (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet 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 Permitting Authority at the address or phone number listed above. Pursuant to Rule 62-110.106(5), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within seven (7) days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location on the Department's official web site for notices at http://tlhora6.dep.state.fl.us/onw and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting

Authority at the above address or phone number. If comments received result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241; Fax: 850/245-2303). Petitions filed by the applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit. 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 attached Public Notice or within fourteen (14) days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within fourteen (14) 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, F.A.C.

A petition that disputes the material facts on which the Permitting Authority'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 each petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact; (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 the 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 Permitting Authority'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 Permitting Authority's final action may be different from the position taken by it in this Written Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Jeffery J. Koerner

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this "Written Notice of Intent to Issue Air Permit" package (including the Public Notice, the 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 3/6/06 to the persons listed below.

Mark J. Hornick, TECO*
Byron T. Burrows, TECO
Raisa Calderon, TECO
Tom Davis, ECT
Jason Waters, Southwest District Office
Hamilton Oven, DEP Siting Office
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

(Clerk) 3/6/06 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Project No. 1050233-018-AC / Draft Air Permit No. PSD-FL-363
Tampa Electric Company – Polk Power Station
New Simple Cycle Gas Turbine Units 4 and 5
Polk County, Florida

Applicant: The applicant for this project is the Tampa Electric Company. The applicant's authorized representative and mailing address is: Mark J. Hornick, General Manager; Tampa Electric Company – Polk Power Station; PO Box 111; Tampa, Florida 33601-0111.

Facility Location: The Tampa Electric Company operates the existing Polk Power Station, which is located approximately 11 miles south of the city of Mulberry (9995 State Route 37 South) in Polk County, Florida.

Project: The applicant proposes to install two General Electric PG7241(FA) simple cycle gas turbine generators with a nominal output of 165 megawatts each at the existing power plant. Each gas turbine will fire natural gas as the exclusive fuel and will have a maximum operation of 4380 hours per year. Total potential annual project emissions will be: 99 tons/year of CO, 267 tons/year of NOx, 79 tons/year of PM/PM_{10}, 42 tons/year of SO_2, 5 tons/year of SAM, and 12 tons/year of VOC.

In accordance with Rule 62-212.400, F.A.C., the existing plant is a major facility for the Prevention of Significant Deterioration (PSD) of Air Quality. The proposed project is subject to PSD preconstruction review for NOx, PM/PM_{10}, and SO_2 emissions. The Department made the following draft determinations of the Best Available Control Technology (BACT): NOx emissions will be controlled by the efficient dry low-NOx combustion design of the General Electric gas turbines and the exclusive firing of natural gas; PM/PM_{10} emissions will be minimized by the exclusive firing of natural gas and the efficient combustion design; and SO_2 emissions will be minimized by the exclusive firing of natural gas, which contains almost negligible amounts of sulfur. In addition, CO and VOC emissions will be minimized by the efficient combustion of natural gas. CO and NOx emissions from each gas turbine will be continuously monitored and recorded.

Based on the applicant's air quality modeling analysis, the maximum predicted air quality impacts due to emissions from the proposed project will be less than the applicable PSD Class II significant impact levels. Therefore, a multi-source modeling analysis is not required. Also, the maximum predicted impacts in the Chassahowitzka National Wilderness Area will be less than the applicable PSD Class I significant impact levels. Therefore, a multi-source Class I PSD increment modeling analysis is not required. The applicant has provided the Department with reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment.

Permitting Authority: Applications for air construction permits are subject to review in accordance with 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 proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all applicable provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comments received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be post-marked by the close of business (5:00 p.m.), on or before the end of this 30-day period by the Permitting Authority at the above address. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location on the Department's official web site for notices at http://tlhora6.dep.state.fl.us/onw and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If comments received result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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Mediation: Mediation is not available in this proceeding.

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

PROJECT

Draft Permit No. PSD-FL-363
Project No. 1050233-018-AC

Tampa Electric Company
Polk Power Station

Two New Simple Cycle Gas Turbines
Nominal 165 MW Each

COUNTY

Polk County, Florida

APPLICANT

Tampa Electric Company
9995 State Route 37 South
Mulberry, Florida 33860-0775

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation - Air Permitting North
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399-2400

March 6, 2006

1. APPLICATION INFORMATION

Facility Location

The Polk Power Station is located approximately 11 miles south of the city of Mulberry on State Route 37 in Polk County. The site is 120 km from the nearest federal Prevention of Significant Deterioration (PSD) Class I Area, the Chassahowitzka National Wildlife Refuge. The UTM coordinates for this site are 402.45 km East and 3067.35 km North. The locations of Mulberry and the Polk Power Station are shown below.

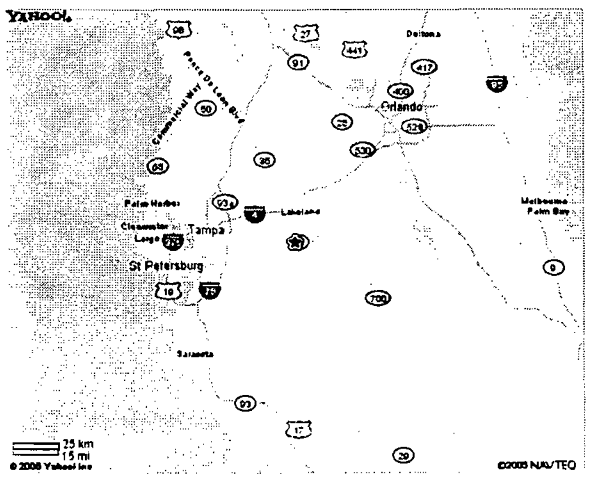

Figure 1.1 Location of Mulberry

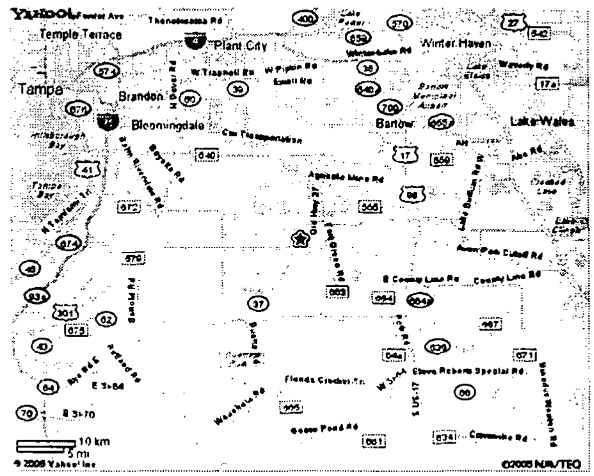

Figure 1.2 Location of Polk Power Station

Facility Description

The Polk Power Station is an existing electrical power generating plant (SIC No. 4911). The regulated emissions units include: a 260 MW integrated coal gasification and combined cycle gas turbine (Unit 1) that fires synthetic gas (syngas) or No. 2 fuel oil; an auxiliary boiler that fires No. 2 fuel oil; a sulfuric acid plant; a solid fuel handling system; and two nominal 165 MW simple cycle gas turbines (Units 2 and 3) that fire natural gas or No. 2 fuel oil.

Regulatory Categories

Title III: The facility is not a major source of hazardous air pollutants (HAPs).

Title IV: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V: The facility is a Title V or "major source" of air pollution in accordance with Chapter 62-213, F.A.C.

PSD: The facility is a PSD-major facility pursuant to Rule 62-212, F.A.C.

NSPS: Units 4 and 5 are subject to 40 CFR 60, Subpart GG (Standards of Performance for Stationary Gas Turbines). They are not be subject to NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for which Construction is Commenced after February 18, 2005) because the purchase contract with General Electric was signed on July 21, 2000, which is prior to the NSPS effective date.

NESHAP: Units 4 and 5 are not subject to 40 CFR 63, Subpart YYYY (National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines) because the facility is not a major source of HAPs.

Siting: This plant is subject to certain requirements of Chapter 403, Part II, Florida Statutes, Electric Power Plant and Transmission Line Siting, including a modification of the conditions Site Certification PA92-32.

Processing Schedule

- Application for air construction permit received on October 18, 2005;
- Addendum to application for air construction permit received October 24, 2005;
- Department's request for additional information dated November 17, 2005;
- Applicant's response to request for additional information received December 23, 2005; complete.

Project Description

At the existing facility, the applicant proposes to install two General Electric PG7241(FA) simple cycle gas turbine generators, each with a nominal output of 165 MW. Each unit may operate up to 4380 hours per year. The new units will be fired exclusively with natural gas which will minimize SO_2 emissions. The units will be constructed using dry low-NO_X burner technology for the control of NO_X emissions and advanced burner design with good operating practices to minimize incomplete combustion and CO, PM_{10}, and VOC emissions. Figure 1.3 identifies the key components of the GE MS 7001 FA, a predecessor of the PG 7241(FA).

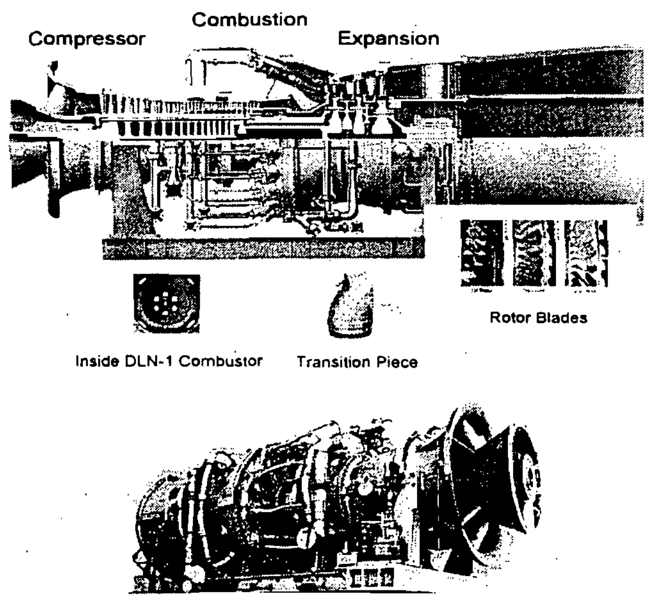

Figure 1.3 Internal and External Views of Early GE 7FA

At an ambient temperature of 59° F and 100% load, the maximum heat input rate to each gas turbine is 1834 MMBtu per hour (HHV). Each unit will have a stack that is 114 feet tall with an exit diameter of 18 feet. Exhaust gases will exit the stack at 1117° F with a flow rate of 2,393,587 acfm.

Process Description

Much of the following discussion is from a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas turbines. Project specific information is interspersed where appropriate.

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressor of the GE 7FA where it is compressed by a pressure ratio of about 15 times atmospheric pressure. The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 14 separate can-annular combustors. Flame temperatures in a typical combustor section can reach 3600° F. Units such as the 7FA operate at lower flame temperatures to minimize NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine -section at temperatures of approximately 2500° F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50% is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator. The gas turbine exhaust is discharged at a temperature greater than 1000° F with excess oxygen and is available for additional energy recovery.

2. RULE APPLICABILITY

State Regulations

The 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 rules in the F.A.C.

Chapter	Description
62-4	Permitting Requirements
62-17	Electrical Power Plant Siting
62-204	Air Pollution Control (Includes Adoption of Federal Regulations)
62-210	Stationary Sources – General Requirements
62-212	Stationary Sources – Preconstruction Review (including PSD Requirements)
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Stationary Sources – Emission Limiting Standards
62-297	Stationary Sources – Emissions Monitoring

Federal Regulations

This project is also subject to certain applicable federal provisions regarding air quality as established by the EPA in the Code of Federal Regulations (CFR) and summarized below.

Title 40	Description
Part 60	New Source Performance Standards (NSPS)
Part 72	Acid Rain – Permits Regulation
Part 73	Acid Rain – Sulfur Dioxide Allowance System
Part 75	Acid Rain – Continuous Emissions Monitoring
Part 76	Acid Rain – Nitrogen Oxides Emissions Reduction Program
Part 77	Acid Rain – Excess Emissions

Note: Acid rain requirements will be included in the Title V air operation permit.

PSD Preconstruction Review Requirements

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) of Air Quality program, as defined in Rule 62-212.400, F.A.C. A PSD preconstruction review is only required in areas that are currently in attainment with the National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" such pollutants. A PSD-major facility is one that emits or has the potential to emit: 250 tons per year or more of any regulated air pollutant; or 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 Major Facility Categories; or 5 tons per year of lead.

For new PSD-major facilities and modifications to existing PSD-major facilities, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates identified in Rule 62-210.200(243), 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 such pollutant and evaluate the air quality impacts. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it is required to install BACT controls for each "PSD-significant" pollutant. In accordance with Rule 62-212.400(4), F.A.C., the applicant must provide the following information:

(a) A description of the nature, location, design capacity, and typical operating schedule of the source or modification, including specifications and drawings showing its design and plant layout;

(b) A detailed schedule for construction of the source or modification;

(c) A detailed description as to what system of continuous emission reduction is planned for the source or modification, emission estimates, and any other information necessary to determine best available control technology (BACT) including a proposed BACT;

(d) The air quality impact of the source or modification, including meteorological and topographical data necessary to estimate such impact and an analysis of "good engineering practice" stack height; and

(e) The air quality impacts, and the nature and extent of any or all general commercial, residential, industrial, and other growth which has occurred since August 7, 1977, in the area the source or modification would affect.

"Best Available Control Technology" or "BACT" as is defined in Rule 62-210.200(38), F.A.C. as follows:

(a) An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted, which the Department, on a case by case basis, taking into account:

1. Energy, environmental and economic impacts, and other costs;

2. All scientific, engineering, and technical material and other information available to the Department; and

3. The emission limiting standards or BACT determinations of Florida and any other state;

determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

(b) If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit 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.

(c) Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

(d) In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.

The Department conducts case-by-case BACT determinations in accordance with the requirements given above. Additionally, the Department generally conducts such reviews so that the determinations are consistent with those conducted using the "Top-Down Methodology" described by EPA.[1]

In addition to the required BACT determinations, a PSD preconstruction review also requires an Air Quality Analysis for each PSD-significant pollutant. The Air Quality Analysis consists of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of predicted project concentrations with the National Ambient Air Quality Standards (NAAQS) and PSD increments; an analysis of the air quality impacts from the 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.

PSD Applicability for the Project

The project will result in emissions of carbon monoxide (CO), nitrogen oxides (NOx), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), volatile organic compounds (VOC), and lead. In the original application, the applicant proposed 750 operating hours of firing distillate oil in addition to the 4380 hours of firing natural gas for each gas turbine. The applicant later withdrew the request to fire distillate oil. The following table summarizes the annual potential emissions in tons per year (TPY) based on the applicant's proposed emissions standards and excluding distillate oil firing.

Table 2A. Applicant's Estimated Potential Annual Emissions

Pollutant	Project Emissions (TPY)	PSD Significant Emission Rates (TPY)	PSD Review Required?
NO_x	267	40	**Yes**
SO_2	42	40	**Yes**
CO	99	100	No
PM	79	25	**Yes**
PM_{10}	79	15	**Yes**
VOC	12	40	No
SAM	5	7	No
Mercury	N/A	0.1	No
Lead	0.125	0.6	No

Based on the above estimated annual emissions, the project is subject to PSD preconstruction review for the following pollutants: NOx, SO_2, and PM/PM_{10}.

3. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) - DRAFT DETERMINATIONS

Nitrogen Oxides (NO_X)

Discussion of NOx Emissions

Nitrogen oxides form during the combustion process in a gas turbine as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @ 15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @ 15% O_2 for a GE 7FA gas turbine.[2] There are three primary mechanisms of NOx formations: thermal NOx, prompt NOx, and fuel NOx.

Thermal NO_X forms in the high temperature area of the combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen, also known as the equivalence ratio. By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. The changes in NO_X production as flame temperatures vary due to increasing/decreasing equivalence ratios can be seen in Figure 3.1. In most combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation is depicted in Figure 3.2, which is from a General Electric discussion on these principles.

Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not of great concern when combusting natural gas.

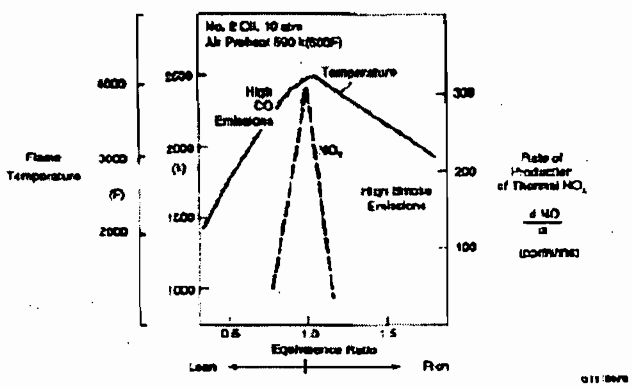

Figure 3.1 CO and NO_X vs. Flame Temperature[3]

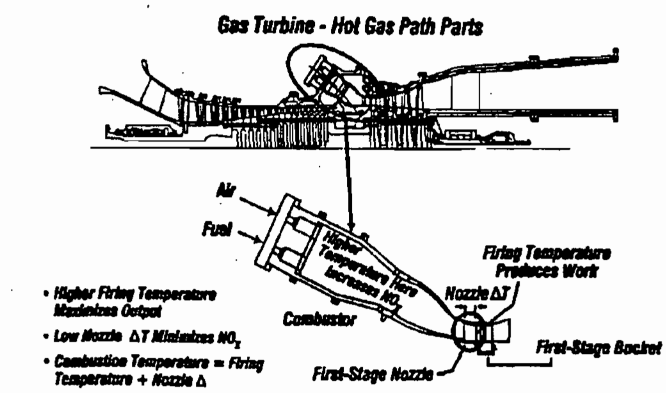

Figure 3.2 Flame Temperature and Firing Temperature

Available NOx Controls

Dry Low NO_X (DLN) Combustion. The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones. This principle is incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 3.3.

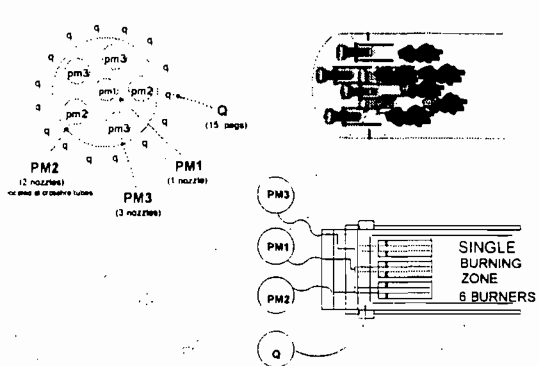

Figure 3.3 DLN-2.6 Fuel Nozzle Arrangement

Each combustor includes six nozzles within which fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor "can" known as quaternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability. Design NO_X, CO, and VOC emission characteristics of the DLN-2.6 combustor while firing natural gas are given in the graph on the left side of Figure 3.4 for a unit tuned to meet a 9 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen). The graph on the right hand side is from a GE publication and is a plot of NO_X data from actual installations or possibly a test facility.

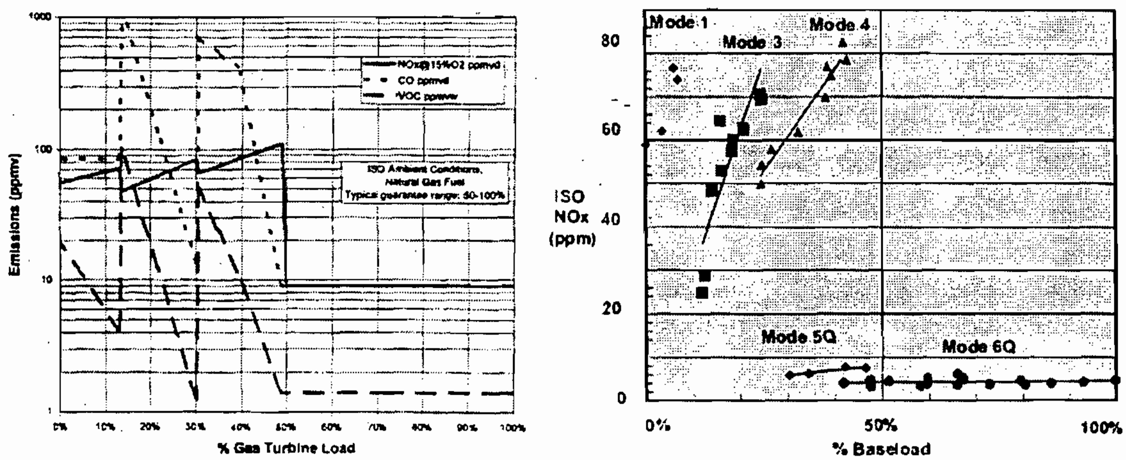

Figure 3.4 Emissions Characteristics for DLN-2.6

The combustor emits NO_X at concentrations of 9 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd may occur at less than 50 percent of capacity. This suggests the need to minimize the duration of operation at low load. Note also that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane. Actual emissions of CO and VOC have proven to be much less than suggested by the diagram.

The following table summarizes the results of the new and clean tests conducted on one of the dual-fuel GE PG7241FA gas turbines operating in simple cycle mode and burning natural gas at the existing Tampa Electric Polk Power Station.[3] The DLN 2.6 combustors for this project (Units 2 and 3) were guaranteed to achieve a NO_X rate of 9 ppmvd @ 15% O_2 while burning natural gas although the permit limit is 10.5 ppmvd @ 15% O_2.

Table 3A. TECO Polk Power Station Emission Test Results

Percent of Full Load	NO_X (ppmvd @ 15% O_2)	CO (ppmvd)	VOC (ppmvd)
50	5.3	1.6	0.5
70	6.3	0.5	0.4
85	6.2	0.4	0.2
100	7.6	0.3	0.1
Limit	10.5	15	7

The above test results confirm NO_X, CO, and VOC emissions less than the emission characteristics published by General Electric in Figure 3.4 above.

Further NO_X reductions related to flame temperature control are possible such as closed loop steam cooling. This feature is available only in G or H Class units, which are larger units than planned for this project at the Polk Power Station. It is more feasible for a combined cycle unit with a heat recovery steam generator (HRSG).

In simple cycle, a once-through steam generator would be required. Steam is circulated through the internal portion of the nozzle component, the transition piece between the combustor and the nozzle, or certain turbine blades. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures (refer back to Figure 3.1). At the same time, thermal efficiency should be greater when employing steam cooling instead of air cooling.

Numerous 7FA units with DLN combustion technology for NO_X control have been installed in Florida and throughout the United States with guarantees of 9 ppmvd. This represents a reduction of approximately 95% compared with uncontrolled emissions and a reduction greater than 90% compared with the previously mentioned NSPS limit of approximately 105 ppmvd.

Catalytic Combustion – XONON™. Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[4] In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical. There has been increased interest in catalytic combustion as a result of technological improvements and incentives to reduce NO_X emissions without the use of add-on control equipment and reagents.

Catalytica has developed a system know as XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X production) followed by flameless catalytic combustion to further attenuate NO_X formation.

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[5] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. This turbine and XONON™ system successfully completed over 18,000 hours of commercial operation.[6] By now, at least five such units are operating or under construction with emission limits ranging from 3 to 20 ppmvd.

Emission tests conducted through the EPA's Environmental Technology Verification Program (ETV) confirm NO_X emissions slightly greater than 1 ppm.[7] Despite the very low emission potential of XONON, the technology has not yet been demonstrated to achieve similarly low emissions on large turbines. It is difficult to apply XONON on large units because they require relatively large combustors and would not likely deliver the same power as a unit relying on conventional diffusion flame or lean premixed combustion. This technology is not feasible at this time for this project.

Wet Injection. Fuel and air are mixed within traditional combustors and the combustion actually occurs on the boundaries of the flame. This is termed "diffusion flame" combustion. Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. 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 gas turbine. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection may increase emissions of both of these pollutants.

Advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can achieve NO_X emissions in the range of 30 to 42 ppmvd when employing wet injection for backup fuel oil firing. Wet injection results in control efficiencies on the order of 80 to 90% for oil firing. These values often form the basis, particularly in combined cycle gas turbines, for further reduction to BACT limits by other techniques as discussed below. During dry low-NOx combustion for gas firing, wet injection is not employed.

Selective Catalytic Reduction (SCR). Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water according to the following simplified reaction:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium (V) and titanium oxide (TiO_2) formulations and account for most installations. At high temperatures, vanadium can contribute to ammonia oxidation forming more NO_X or forming nitrogen (N_2) without reducing NO_X according to:

$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O \text{ and}$$

$$4NH_3 + 3O_2 \rightarrow 2N_2 + 6H_2O$$

For high temperature applications (hot SCR up to 1100 °F), such as large frame simple cycle turbines, special formulations or strategies are required. SCR technology has progressed considerably over the last decade with Zeolite catalyst now being used for high temperature applications. SCR systems are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available as evidenced by both hot and conventional installations at coal-fired plants. Such improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR (low temperature) catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

There are several examples of conventional SCR systems operating in Florida including:

- Kissimmee Utilities Authority Unit 3. 3.5 ppmvd NO_X on gas, 12 ppmvd on fuel oil.
- Progress Energy Hines Block 2. 3.5 ppmvd on gas and 12 ppmvd on fuel oil.
- JEA Brandy Branch. 3.5 ppmvd on gas and 12 ppmvd on fuel oil.
- TEC Bayside – seven gas turbines. 3.5 ppmvd on gas.
- FPL Manatee Unit 3. 2.5 ppmvd on gas and 10 ppmvd on fuel oil
- FPL Martin Unit 8. 2.5 ppmvd on gas and 10 ppmvd on fuel oil.

There are several other approved projects now under construction in Florida that require conventional SCR systems. Most recently, DEP issued a permit for Turkey Point Unit 5 with NO_X limits of 2.0 ppmvd on gas and 8.0 ppmvd on fuel oil. SCR is a commercially available, demonstrated control technology currently employed on numerous large combined cycle gas turbine projects permitted with very low NO_X emissions (< 2.5/10 ppmvd for gas/oil firing).

SCONO$_X$™. This technology is a NO_X and CO control system developed by Goal Line Environmental Technologies. Alstom Power is the distributor of the technology for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce NO_X emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which exists within the heat recovery steam generator (HRSG) of a combined cycle gas turbine unit.

SCONO$_X$™ systems were installed at seven sites ranging in capacity from 5 to 43 MW.[8] None were installed at large facilities. SCONO$_X$™ technology (at 2.0 ppmvd) has been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. SCONOx™ has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. SCONOx™ systems also oxidize emissions of CO and VOC for additional emission reductions. SCONO$_X$™ can match the performance of SCR without ammonia slip. On the other hand, the catalyst must be intermittently regenerated while on-line through the use of hydrogen produced on-site from a natural gas reforming unit.

Table 3B contains averaged cost values for $SCONO_X$™ and SCR developed by the California Air Resources Board for their Legislature.[9] The comparison is for a 500-MW combined-cycle power plant consisting of two combustion gas turbines and one steam turbine meeting BACT requirements.

Table 3B. Cost Comparison between SCR and $SCONO_X$ for a 500 MW Combined Cycle Gas Turbine System

Capital Cost ($)		Annual O&M Cost ($)	
SCR + Oxidation Catalyst	$SCONO_X$™	SCR + Oxidation Catalyst	$SCONO_X$™
6,259,857	20,747,637	1,355,253	3,027,653

The cost of an oxidation catalyst for CO control is included with the SCR system for comparable evaluation with $SCONO_X$™ multi-pollutant reduction capabilities. Cost figures show that the SCR + oxidation catalyst package costs much less than the $SCONO_X$™ system. The report cautions that the values should be used only for relative comparison and not intended for use in detailed engineering. While the Department does not accept or reject these figures, it appears that $SCONO_X$™ is not cost-effective for the present project.

Applicant's NOx BACT Proposal

For the proposed large simple cycle gas turbine project, the applicant evaluated the remaining available combustion and post-combustion technologies for the control of NO_X emissions: DLN combustors and an SCR system. The applicant estimated the capital cost of a hot SCR system at $15,721 and the total annualized costs including operation to be $4,140,900. Assuming approximately a 70% reduction in NOx emissions, the applicant estimated that a hot SCR system could reduce NOx emissions by 383.2 tons per year. The cost effectiveness for a hot SCR system was estimated to be $10,807 per ton of NOx removed. (The analysis was based on the original proposal of 750 hours of oil firing.) The applicant concluded that a hot SCR system was not cost effective for this project. Therefore, the applicant proposed a NOx BACT standard of 10.5 ppmvd @ 15% O_2 based on dry low-NOx combustion and the exclusive firing of natural gas. The applicant later revised this request to "9.0 ppmvd @ 15% O_2".

Department's Review and Draft NOx BACT Determination

The Department recognizes a hot SCR system as the "top" available and feasible control technology for the large simple cycle gas turbine project. Although the Department does not fully endorse the applicant's SCR cost estimate, it agrees that the installation of a hot SCR system on such a project with restricted operation is not cost effective. However, it is noted that a hot SCR system begins to approach the level of cost effectiveness with the elevated number of hours of requested operation for each simple cycle gas turbine (4380 hrs per year).

The proposed gas turbines are existing units originally constructed for a project in another state. Although the gas turbines have a guaranteed NOx emissions rate of "9 ppmvd @ 15% O_2", the applicant contends that this is for "new and clean" units. The applicant's request for a NOx standard of "10.5 ppmvd @ 15% O_2" is to recognize the possibility for slight degradation of the units due to the frequent startups and shutdowns needed for simple cycle operation. In addition, the proposed NOx standard is consistent with the most recently permitted simple cycle unit at this plant.

Numerous General Electric PG7241(FA) simple cycle gas turbine have been permitted throughout Florida and the United States with NOx emissions standards of "9 ppmvd @ 15% O_2". Many of these have completed construction and are currently in operation. These units have been able to continuously demonstrate compliance with the permitted NOx emissions standards. The following table shows several such BACT determinations for other units similar to those proposed for this project.

Table 3C. Recent NO_X Standards for F-Class Simple Cycle Gas Turbine Projects

Project Location	Capacity (MW)	NO_X Limit ppmvd @ 15% O2	Technology	Comments
El Paso Manatee, FL	350	9 NG	DLN	2x175 MW GE 7FA CTs (Gas only
El Paso Deerfield, FL	525	9 - NG	DLN	3x175 MW GE 7FA CTs Draft 8/2001. Gas Only
Enron Deerfield, FL	510	9 - NG 36 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Draft 06/01. 500 hrs on oil
Enron Pompano, FL	510	9 - NG 36 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Revised Draft 06/01. 500 hrs on oil
Midway St. Lucie, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 2/01. 1000 hrs on oil
DeSoto County, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 7/00. 1000 hrs on oil
Shady Hills Pasco, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 1/00. 1000 hrs on oil
Vandolah Hardee, FL	680	9 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE 7FA CTs Issued 11/99. 1000 hrs on oil
Oleander Brevard, FL	850	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE 7FA CTs Issued 11/99. 1000 hrs on oil
JEA Baldwin, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE 7FA CTs Issued 10/99. 750 hrs on oil
TEC Polk Power, FL	330	10.5 – NG 42 – No. 2 F.O.	DLN WI	2x165 MW GE 7FA GTs Issued 10/99. 750 hrs on oil
Dynegy, FL	510	15 – NG	DLN	3x170 MW WH 501F GTs Issued. Gas only
Dynegy Heard, GA	510	15 – NG	DLN	3x170 MW WH 501F GTs Issued. Gas only
Thomaston, GA	680	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE 7FA GTs Issued. 1687 hrs on oil
Dynegy Reidsville, NC	900	15 – NG (by 2002) 42 – No. 2 FO	DLN WI	5x180 MW WH 501F GTs Initially 25 ppm NO_X limit on gas Issued. 1000 hrs on oil.
Southern Energy, WI	525	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE 7FA GTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
Lakeland, FL	250 CON	9/9 – NG (by 2002) 42/15 - No. 2 FO	DLN/HSCR WI/HSCR	250 MW WH 501G GT Initially 25 ppm NO_X limit on gas Issued 7/98. 250 hrs on oil.

Notes:

CON = Continuous
SC = Simple Cycle
INT = Intermittent
DB = Duct Burner

DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
HSCR = Hot SCR
GT = Gas Turbine

FO = Fuel Oil
NG = Natural Gas
WI = Water or Steam Injection

GE = General Electric
WH = Westinghouse
ABB = Asea Brown Bovari

Below, Figure 3.5 is a representation of hourly readings (including startup and shutdown) from the TECO Polk Unit 2 acid rain NO_X CEMS. This unit is identical to the proposed unit. It can be seen that the bulk of the readings (representing steady state operation) are below 10 ppmvd.

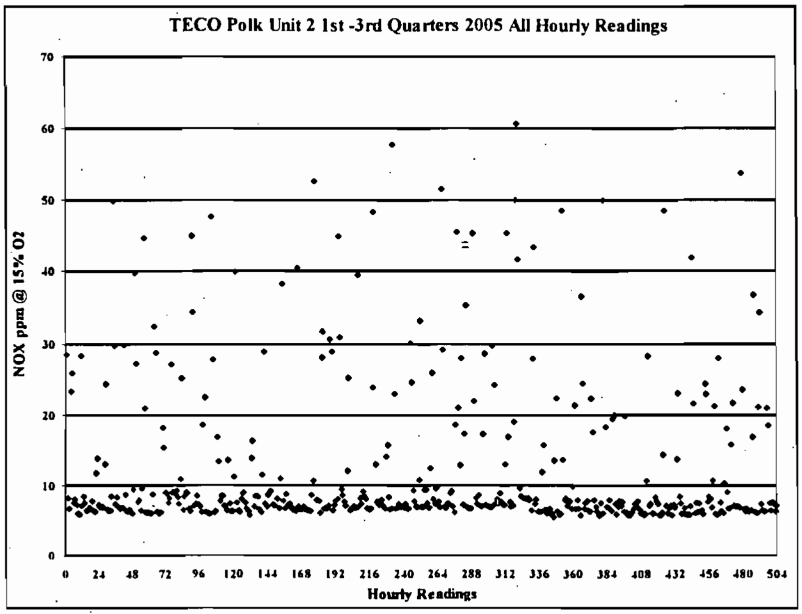

Figure 3.5 TEC Polk Unit 2 Hourly Readings

Figure 3.6 represents the same data with hourly readings attributed to startup and shutdown removed. Only two hourly readings are above 10 ppmvd and most of the readings are well below 9 ppmvd.

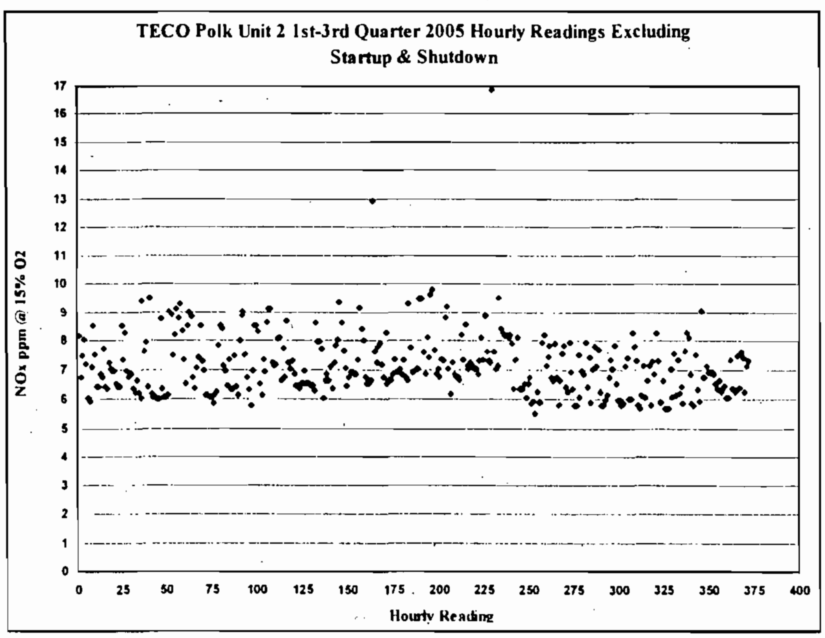

Figure 3.6 TEC Polk Unit 2 Hourly Readings Excluding

It should be noted that Polk Power Unit 2 is permitted at 10.5 ppmvd while still achieving these low NOx values. Acid Rain data can be obtained for other similar units that have been permitted at 9 ppmvd. Clearly these units are capable of operating below NOx limit guaranteed by General Electric. The Department considered recently permitted similar projects, data from existing similar units, the requested frequent operation, and the initial vendor guaranteed emissions rate. Based on this information, the Department's draft NOx BACT determination is 9.0 ppmvd @ 15% O_2 (24-hour daily average) based on dry low-NOx combustion and the exclusive firing of natural gas. The averaging time provides sufficient consideration for any "degradation" due to the frequent startups and shutdowns associated with simple cycle operation expressed as a concern by the applicant.

Initial CO BACT Review

Descriptions of CO Emissions

Carbon monoxide is a product of incomplete combustion of carbon-containing fuels such as natural gas and distillate oil. Factors adversely affecting the combustion process are low temperatures, insufficient turbulence and residence times, and inadequate amounts of excess air. Most gas turbines incorporate efficient combustion designs featuring high temperatures and sufficient time, turbulence, and excess air to minimize CO emissions. Additional control can be obtained by installation of oxidation catalyst, particularly on gas turbines that do not perform well at low load conditions.

Despite the relatively high BACT limits typically proposed when using combustion controls, much lower emissions are reported for large gas turbines at full load without use of oxidation catalyst. As discussed under the NO_X technology section above, the GE 7FA Unit 2 at the TECO Polk Power Station has achieved CO emissions in the range of 0.3 to 1.6 ppmvd (new and clean) when firing gas at loads between 50% and 100%. This level of performance has been corroborated by recent tests at numerous new projects throughout the state. Notably, the emissions of the GE 7FA units without oxidation catalyst matched those of the ABB units at ANP Blackstone that were equipped with oxidation catalyst.

Some of the more recent turbine projects within the state have been permitted with continuous emissions monitoring (CEM) requirements for CO emissions. Continuous data from these units verify the ability of the GE 7FA gas turbine to operate continuously with CO emission rates well below the manufacturer's guarantee. A summary of CO CEMS data for four GE 7FA units at TECO's Bayside Power Station is shown in the following table.

Table 3D. CO CEMS Data – TECO Bayside Combined Cycle Unit 1

Quarter	Gas Turbine	CO Emissions in ppmvd		
		Maximum 24-hour Block	Minimum 24-hour Block	Quarterly Average
3rd Quarter 2003	1A	4.3	0.3	0.83
	1B	1.7	0	1
	1C	2.1	0	0.8
4th Quarter 2003	1A	2.2	0	0.76
	1B	1.9	0	1.14
	1C	1.2	0	0.74

CO and VOC emissions should be low because of the very high combustion temperatures, excess air, and turbulence characteristics of the GE 7FA. Performance guarantees are only now "catching up" with the field experience. In fact, General Electric recently published a report supporting the elimination of oxidation catalyst requirements for CO control on its units.[10] The following statement was taken from the report:

> *"GE is offering CO guarantees of 5 ppmvd for the GE PG7241FA DLN on a case-by-case basis following a detailed evaluation of the situation – thus validating its position that oxidation catalysts are not economically justified for CO emissions reduction for the GE PG7241FA DLN units while firing natural gas."*

The following figure from GE's article is consistent with the data collected by the Department and supports the Department's analysis of this technical issue.

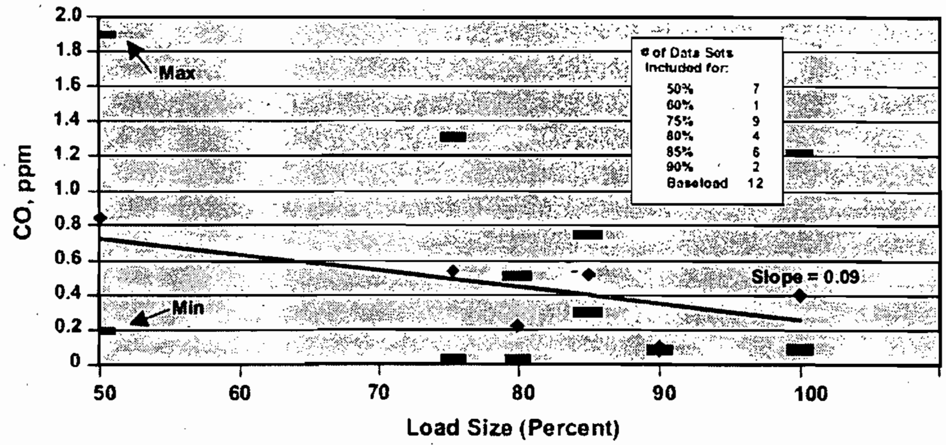

Figure 3.7 Average Raw CO Emissions vs. Percent Load for GE 7FA Units

Applicant's CO BACT Proposal

For the proposed large simple cycle gas turbine project, the applicant evaluated an oxidation catalyst plus the dry low-NOX combustion controls as the top control option for the project. The applicant estimated the capital cost of oxidation catalyst systems for the project at \$6,263,142 and the total annualized costs to be \$1,266,415. Assuming a 90% reduction in CO emissions, the applicant estimated that an oxidation catalyst could reduce CO emissions by 204 tons per year, which results in a cost effectiveness of \$6203 per ton of CO removed. (This analysis included oil 750 hours of firing with much higher CO emissions.) The applicant concluded that an oxidation catalyst was not cost effective for this project. Therefore, the applicant proposes a CO BACT standard of 9.0 ppmvd @ 15% O_2 (24-hour average) based on the dry low-NOx combustion characteristics of the GE 7FA gas turbine and the exclusive firing of natural gas.

Department's CO Review

Table 3E summarizes several CO BACT determinations for recent projects in Florida and other states. TECO's proposal is included for comparison. Most of the projects cited required an oxidation catalyst. The "top" emission limit is considered by the Department to be 2.0 ppmvd @ 15% O_2 on a 1-hour average. The limit is achievable by use of oxidation catalyst.

Table 3E. CO Standards for "F-Class" Combined Cycle Units

Project Location	CO Standards, ppmvd @ 15% O_2
FPL Bellingham, MA	2.0 (3-hr – Ox-Cat)
Sithe Mystic, MA	2.0 (1-hr – Ox-Cat)
Duke Santan, AZ	2.0 (3-hr – Ox-Cat)
Duke Morro, CA	2.0 (Ox-Cat)
ANP Blackstone, MA	3.0 (Ox-Cat)
FPL LLC Tesla, CA	4.0 – NG (3-hr – Ox-Cat)
FPL Turkey Pt., FL	4.1 – NG (DB off, AnnualTest) 7.6 – NG (DB on, Annual Test)

Project Location	CO Standards, ppmvd @ 15% O_2
	14 – NG (DB+PA) 8.0 – FO (Annual Test) 8.0 – 24-hr (All Modes) 6.0 - 12-month (all modes)
Polk Power Station, FL	9.0 NG (24-hr block)
Milford Power, CT	13 – 52 lb/hr (Ox-Cat)
Calpine OEC, PA	10 (1-hr)
Cogen Tech, NJ	2.0 (1-hr – Ox-Cat)
FPL Manatee, FL	8 – NG (DB off) 10 – NG (DB, PA)
FPL Martin, FL	7.4 – NG (New, Clean) 8.0 – NG (DB off) 10 – (DB, PA)
PGN Hines IV, FL	8.0 - NG 12.0 – FO
El Paso Manatee, FL	2.5 – NG (3-hr – Ox-Cat) 4 – NG (3-hr, PA)
Metcalf Energy, CA	6 - NG (100% load)
Enron/Ft. Pierce, FL	3.5 – NG (Cat-Ox) 10 - Low Load 8 - FO

Notes: NG = Natural Gas DB = Duct Burner PA = Power Augmentation
FO = Fuel Oil GE = General Electric WH = Westinghouse ABB = Asea Brown Bovari

With an oxidation catalyst, a GE 7FA unit will likely achieve CO values below 2 ppmvd @ 15% O_2. Although General Electric will guarantee the GE 7FA gas turbine for 4.1 ppmvd @ 15% O_2, the data suggest actual emissions without an oxidation catalyst will be approximately equal to the "top" emission limit of 2 ppmvd @ 15% O_2. For a unit firing only natural gas that does not experience a wide range of various operating modes, it is straightforward to conclude that it would not be cost effective to install an oxidation catalyst to reduce "permitted emissions" from 5 to 2 ppmvd @ 15% O_2. This is in agreement with the conclusion in General Electric's paper cited in the discussion above. Therefore, at this time, the Department's draft CO BACT determination would be 4.1 ppmvd @ 15% O_2 (24-hour daily average) based on dry low-NOx combustion and the exclusive firing of natural gas. The averaging time provides sufficient consideration for any "degradation" due to the frequent startups and shutdowns associated with simple cycle operation expressed as a concern by the applicant.

Application Revision – CO Emissions Cap

During the processing of this application, the applicant requested a CO emissions cap of 99.0 tons per consecutive 12 months to avoid PSD preconstruction review for the project. TECO operates numerous General Electric 7FA units and has available CO CEMS emission data related to startups and shutdowns. The Department has some information related to CO emission levels during these periods. Some important items for consideration are:

- The General Electric 7FA unit can achieve full lean pre-mix combustion in less than 20 minutes and shutdown in less than 15 minutes.
- In general, both CO and NOx emissions follow steep "saw-tooth" profiles at the low loads experienced during startup. See Figure 3.8 below.

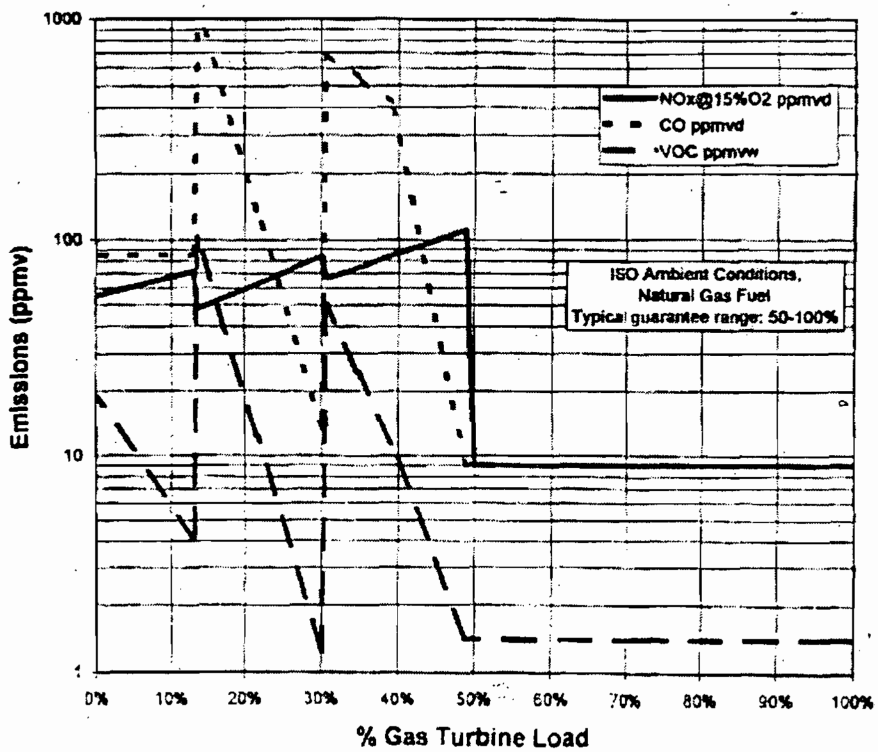

Figure 3.8 CO and NOx Emissions at Low Loads

- Operation at each of the low load, high emissions peaks is very short in duration. Low loads mean reduced fuel firing and less exhaust flow. This means that, although the pollutant concentrations may be much higher, the influence in mass emissions rate will not be as great. [11]
- Given an ambient temperature of 55° F, General Electric specification sheets from 1999 conservatively indicate CO emissions of 29 lb/hour (9 ppmvd) at 100% load, 24 lb/hour (9 ppmvd) at 75% load, 20 lb/hour (9 ppmvd) at 50% load, and 92 lb/hour (47 ppmvd) at 25 % load.
- CO emissions during normal operation (above 50% load) are typically much less than 2 ppmvd @ 15% O2, which would be approximately 7.5 lb/hour.

As a "reality check", the Department made the following assumptions and estimates.

	CO, ppmvd	CO, lb/hour	Frequency	Duration	Hours	CO, TPY
Startup	---	184 [a]	366 [b]	20 min. [c]	122	11.2
Shutdown	---	184 [a]	366 [b]	15 min. [c]	91.5	8.4
Normal	3.9 [d]	14.6 [d]	---	---	4075	29.7
Total	---		---		4380	49.3
	---		---		2 Units	98.6

Notes:

a. Assume that the CO mass emission rate during a startup or shutdown is twice that recognized by General Electric at 25% load.

b. Assume that a unit will have 366 startups and shutdowns each year.

c. Assume that a unit will average 20 minutes to startup and 15 minutes to shutdown.

d. Assume that the CO emissions rate during normal operation is nearly twice that experienced by similar units operating above 50% load.

Based on this rough estimation, it appears that the plant can manage operation of the new simple cycle units below the CO significant emissions rate of 100 tons per year to avoid PSD preconstruction review. Therefore, the draft permit will include the following emissions limits:

Emissions Cap: As determined by a certified CEMS, CO emissions from Units 4 and 5 (combined) shall not exceed 99.0 tons during any consecutive 12 months, rolling total. All valid emissions data shall be used to demonstrate compliance with the emissions cap, including startups, shutdowns, and malfunctions.

Initial Limit: CO emissions shall not exceed 9.0 ppmvd @ 15% O_2 (36.0 lb/hour) as determined by initial tests for the units as constructed.

Sulfur Dioxide (SO_2) BACT Determination

The control of sulfur dioxide (SO_2) and sulfuric acid mist (SAM) emissions can be divided into five categories: restricting fuel sulfur content; absorption by scrubbing solution; adsorption on a solid bed; direct conversion to sulfur; or direct conversion to sulfuric acid. A review of BACT determinations for gas turbines on EPA's RCAT/BACT/LAER Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the "top control" option for SO_2 and SAM emissions. Gas turbines typically fire clean, low fuel sulfur fuels to prevent fouling turbine blades causing excessive maintenance. The combination of low sulfur fuels with high exhaust flow rates makes add-on controls prohibitively costly. For the project, the applicant proposes the exclusive firing of natural gas containing no more than 2 grains per 100 scf as SO2 BACT. The Department agrees and the draft SO_2 BACT standard is the proposed fuel specification.

Particulate Matter (PM/PM_{10}) BACT Determination

Particulate matter (PM/PM_{10}) is emitted from gas turbines due to ash present in the fuels fired and incomplete fuel combustion. Particulate matter emissions are minimized by the use of clean fuels, an efficient combustion design, and good combustion practices. For the project, the applicant proposes to fire natural gas as the exclusive fuel. Natural gas is a clean fuel, contains little or no ash, and is efficiently combusted a gas turbine. Again, clean fuels are necessary for gas turbines to avoid damaging turbine blades and other components already exposed to very high temperatures and pressures. The applicant proposes a PM/PM_{10} BACT for as the efficient combustion design of the GE 7FA gas turbine and the exclusive firing of natural gas with a sulfur content of no more than 2 grains per 100 scf. In addition, visible emissions from the stack will be limited to no more than 10% opacity based on a 6-minute average. The Department agrees and the draft PM/PM_{10} BACT standard is the proposed fuel specification as well as the proposed opacity standard.

Summary of Department's Draft BACT Determinations

The Department establishes the following standards as the Best Available Control Technology (BACT) for the simple cycle gas turbine Units 4 and 5 at the TECO Polk Power Station.

Table 3F. Draft BACT Determinations – TECO Polk Power Station Simple Cycle Units 4 and 5

Pollutant	Emission Standard [e]	Averaging Time	Compliance Method	Basis
CO [a]	99.0 tons (Emissions Cap)	12-month rolling total Both Units Combined	CEMS	Avoid PSD
	9.0 ppmvd @ 15% O_2 36.0 lb/hour	3-hour test avg.	Initial Only EPA Method 10 Test	
NO_X [b]	9.0 ppmvd @ 15% O_2	24-hour block, CEMS	CEMS	BACT
	60.9 lb/hour	3-hour test avg.	EPA Method 7E Test	
PM/PM_{10} [c]	10 % Opacity	6-minute block	EPA METHOD 9 TEST	BACT
	2 grains S/100 SCF of gas	N/A	RECORD KEEPING	
SO_2 [d]	2 grains S/100 SCF of gas	N/A	Record Keeping	BACT

a. The permittee shall conduct an initial test to demonstrate compliance with the short-term (ppmvd @ 15% O_2 and lb/hour) CO emissions limits for the unit as constructed. Thereafter, continuous compliance shall be demonstrated with the CO emissions cap by data collected from the required continuous emissions monitoring system (CEMS).

b. The permittee shall conduct an initial test to demonstrate compliance with the short-term (ppmvd @ 15% O_2 and lb/hour) NOx emissions limits. Thereafter, continuous compliance shall be demonstrated with the 24-hour block NOx emissions limit by data collected from the required continuous emissions monitoring system (CEMS).

c. The fuel sulfur specifications combined with the efficient combustion design and operation of the gas turbine represents BACT for particulate matter (PM/PM_{10}) emissions. No stack tests are required. Compliance with the CO and visible emissions standards shall serve as indicators of good combustion. *{Permitting Note: Maximum expected PM/PM_{10} emissions from each gas turbine are approximately 18 lb/hour.}*

d. The fuel sulfur specifications effectively limit the potential emissions of sulfur dioxide (SO_2) from each gas turbine and represent BACT for SO_2 emissions. No stack tests are required. *{Permitting Note: Maximum expected SO_2 emissions from each gas turbine are approximately 9.5 lb/hour.}*

e. The mass emission rate standards are based on a turbine inlet condition of 59° F and the higher heating value of natural gas. Mass emission rates may be adjusted from actual test conditions in accordance with the performance curves and/or equations on file with the Department.

{Permitting Note: In combination with the annual restriction on hours of operation, the above emissions standards effectively limit annual potential emissions from both gas turbines to: 99 tons/year of CO, 267 tons/year of NOx, 79 tons/year of PM/PM_{10}, 42 tons/year of SO_2, 5 tons/year of SAM, and 12 tons/year of VOC.}

4. NEW SOURCE PERFORMANCE STANDARDS (NSPS)

Gas Turbines – NSPS Subpart GG

Stationary gas turbines are subject to the federal New Source Performance Standards in Subpart GG of 40 CFR 60. These provisions result in the following standards based on compressor inlet conditions of 59° F, full load, and 60% relative humidity.

- $NO_X \leq 109.2$ ppmvd @ 15% O_2 corrected for a heat rate of 9370 Btu/KW-h LHV at peak load;
- $SO_2 \leq 0.015\%$ by volume at 15% O_2 on a dry basis (150 ppmvd @ 15% O_2) or the use of a fuel with a sulfur content $\leq 0.8\%$ sulfur by weight (8000 ppmw).

A more recent standard, Subpart KKKK, was proposed by EPA on February 18, 2004. The proposed standard would require compliance with a NO_X standard of ≤ 0.39 lb/MW-hour. For this project, this is approximately equal to 11 ppmvd @ 15% O_2. However, the final rule will not be applicable to the Units 4 and 5 at the Polk Power Station because a purchase contract with General Electric was signed on July 21, 2000 for these units, which is prior to the NSPS effective date.

The Department considers the draft BACT standards to be more stringent than the existing or the proposed NSPS standards. However, the NSPS also has other specific requirements for notification, record keeping, performance testing, and monitoring of operations. An Appendix to the permit will summarize applicable federal requirements.

5. PERIODS OF EXCESS EMISSIONS

Excess Emissions Prohibited

In accordance with Rule 62-210.700(4), F.A.C., "Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited." All such preventable emissions shall be included in the compliance determinations for CO and NO_X emissions.

Excess Emissions Allowances

In accordance with Rule 62-210.700, F.A.C., "Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration." In addition, the rule states that, "... 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." Therefore, the Department has the authority to regulate defined periods of operation that may result in emissions in excess of the proposed BACT standards based on the given characteristics of the specific project.

The General Electric Frame 7FA gas turbines operate with low NOx emissions in full lean pre-mix mode, which is achieved in the range of 40% to 50% of base load conditions. Simple cycle gas turbines are designed for quick startup and operate at high load levels. Operation of the large frame gas turbines is generally automated and malfunctions have been infrequent. Also, the units require some tuning to maintain the low emissions levels. Tuning involves stepping the gas turbine from low load operation through base load operation to collect data on existing operating levels. During tuning, it is possible to have elevated emissions while collecting emission data used in the tuning process. However, the duration of data collection is relatively short and, once tuned, the gas turbine emissions will be minimized. Based on information from General Electric regarding startup and shutdown, the Department establishes the following conditions for excess emissions for each gas turbine for which a limited amount of data may be excluded from the continuous compliance determinations for NO_X emissions.

<u>Definitions</u>: Rules 62-210.200(159), (230) and (245), F.A.C. define the following terms.

a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.

c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

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. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

Allowable NOx Data Exclusions: Provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions are minimized, NO_X continuous monitoring data collected during periods of startup, shutdown, and malfunction may be excluded from the 24-hr block compliance demonstrations only in accordance with the following requirements. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, and DLN tuning) may be excluded. As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions replace the provisions in Rule 62-210.700(1), F.A.C.

a. *Startup*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than the first 30 minutes of CEMS data shall be excluded for each gas turbine startup. For startups of less than 30 minutes in duration, only those minutes attributable to startup shall be excluded.

b. *Shutdown*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than the first 20 minutes of CEMS data shall be excluded for each gas turbine shutdown. For shutdowns less than 20 minutes in duration, only those minutes attributable to shutdown shall be excluded.

c. *Malfunction*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than 120 minutes of CEMS data shall be excluded in a 24-hour period for each gas turbine due to malfunctions. Within one (1) working day of occurrence, the owner or operator shall notify the Compliance Authority of any malfunction resulting in the exclusion of CEMS data.

d. *DLN Tuning*: CEMS data collected during initial or other DLN tuning sessions shall be excluded from the compliance demonstrations provided the tuning session is performed in accordance with the manufacturer's specifications. Prior to performing any tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least one (1) day that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

The permittee shall notify the Compliance Authority within one working day of discovering any emissions in excess of a CEMS standard subject to the specified averaging period. All such reasonably preventable emissions shall be included in any CEMS compliance determinations. All valid emissions data (including data collected during startup, shutdown, malfunction, and DLN tuning) shall be used to report annual emissions for the Annual Operating Report and demonstration of compliance with the CO emissions cap. [Rules 62-4.070(3), 62-210.200, 62-212.400(BACT) and 62-210.700, F.A.C.]

6. AIR QUALITY IMPACT ANALYSIS

Introduction

The proposed project will result in emissions of three criteria pollutants in excess of PSD significant emission rates for NO_X, PM_{10}, SO_2. Each pollutant is a criteria pollutant with regulations defining national and state ambient air quality standards (AAQS), PSD increments, significant impact levels and de minimis monitoring levels. Note: Based on the revised request, the project is no longer subject to PSD review for CO emissions.

However, CO was originally modeled and this information is provided in this summary.

Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates 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 satisfied 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 St. Petersburg/Clearwater International Airport and Ruskin respectively (surface and upper air data). The 5-year period of meteorological data was from 1992 through 1996. These 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.

In reviewing this permit application, 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.

PSD Class I Area

The closest PSD Class I area is the Chassahowitzka National Wilderness Area (CNWA), which is greater than 50 km from the proposed facility. Therefore, long-range transport modeling was required for the Class I impact assessment. The California Puff (CALPUFF) dispersion model was used to evaluate the potential impact of the proposed pollutant emissions on the PSD Class I increments and on one Air Quality Related Value (AQRV): regional haze. CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources. It is also suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanisms.

The meteorological data used in the CALPUFF model was processed by the California Meteorological (CALMET) model. The CALMET model utilizes data from multiple meteorological stations and produces a three-dimensional modeling grid domain of hourly temperature and wind fields. The wind field is enhanced by the use of terrain data, which is also input into the model. Two-dimensional fields such as mixing heights, dispersion properties, and surface characteristics are produced by the CALMET model as well. Meteorological data were obtained and processed for the calendar years of 1990, 1992 and 1996, the years for which MM4 and MM5 data are available. The CALMET wind field and the CALPUFF model options used were consistent with the suggestions of the federal land managers.

Significant Impact Analyses

A significant impact analysis was performed for PM_{10}, NO_X, SO_2, and CO emissions. For this analysis, inputs to the models are based on the potential emissions from the project at worst-case load conditions. The models used in this analysis and any required subsequent modeling analyses are described in *Models and Meteorological Data Used in the Air Quality Analysis*, later in this section. Based on the modeling analysis, the highest predicted short-term concentrations and the highest predicted annual averages are compared to the corresponding significant impact levels for the Class I and Class II Areas. If modeling at worst-case load conditions shows significant impacts, additional modeling to include emissions from nearby facilities (multi-source modeling) is required to determine the project's impacts on any applicable AAQS or PSD increments. If no significant impacts are shown, no further modeling is required.

Class II Significant Impact Analysis

For the simple cycle gas turbine project firing only natural gas, the applicant's air quality impact analyses predicts impacts from all pollutants to be much less than the regulatory "significant impact levels." The results of the modeling analysis are summarized in the following table and compared with the National Ambient Air Quality Standards.

Table 6A. Maximum Predicted Impacts Compared to the PSD Class II Significant Impact Levels and AAQS

Pollutant	Averaging Time	Maximum Predicted Impacts (ug/m^3)	Significant Impact Levels (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
SO_2	Annual	0.002	1	60	No
	24-Hour	0.03	5	260	No
	3-Hour	0.2	25	1300	No
PM_{10}	Annual	0.005	1	50	No
	24-Hour	0.08	5	150	No
NO_2	Annual	0.01	1	100	No
CO	8-hour	0.3	500	10,000	No
	1-Hour	0.8	2000	40,000	No

As shown in the table, the maximum predicted impacts from the project are much less than the respective ambient air quality standards and significant impact levels. Therefore, no further modeling is necessary.

Class I Significant Impact Analysis

The nearest PSD Class I Area is the Chassahowitzka National Wilderness Area (CNWA), which is located about 120 km to the north. The applicant's initial PM_{10}, NO_X and SO_2 air quality impact analyses for this project predicted maximum impacts from all pollutants to be less than the applicable "significant impact levels" for the Class I Area. The results of the modeling analysis are summarized in the following table.

Table 6B. Maximum Predicted Impacts Compared with PSD Class I (CNWA) Significant Impact Levels

Pollutant	Averaging Time	Maximum Predicted Impacts (ug/m^3)	Class I Significant Impact Levels (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.002	0.2	No
	24-hour	0.03	0.3	No
NO_2	Annual	0.004	0.1	No

Pollutant	Averaging Time	Maximum Predicted Impacts (ug/m^3)	Class I Significant Impact Levels (ug/m^3)	Significant Impact?
SO_2	Annual	0.004	0.1	No
	24-hour	0.07	0.2	No
	3-hour	0.3	1	No

Note that the maximum predicted impacts from the project are miniscule when compared with the ambient air quality standards shown in the previous table. Because the predicted impacts are much less than the respective significant impact levels, no further modeling analysis is necessary for the Class I Area.

Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is done for each pollutant with a regulatory de minimis impact level. If the de minimis levels are exceeded, the Department may require pre-construction ambient monitoring. For this analysis, inputs to the models are based on the potential emissions from the project at worst-case load conditions. As shown in the following table, the maximum predicted impacts for all pollutants are less than the regulatory de minimis impact levels. Therefore, no pre-construction monitoring is required.

Table 6C. Maximum Predicted Impacts Compared to the De Minimis Ambient Impact Levels

Pollutant	Averaging Time	Maximum Predicted Impacts (ug/m^3)	De Minimis Levels (ug/m^3)	Maximum Baseline Concentrations (ug/m^3)	Impacts Greater Than De Minimis?
PM_{10}	24-hour	0.08	10	~ 80	No
NO_2	Annual	0.01	14	~ 20	No
SO_2	24-hour	0.07	13	~ 45	No
CO	8-hour	0.3	575	~3000	NO

Based on the preceding discussions, no further modeling analysis is necessary. However, the PSD regulations require an analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife

Very low emissions are expected from this natural gas-fired gas turbine in comparison with conventional power plants 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}, NO_X, SO_2, and CO 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 combination of low NO_X and VOC emissions insures that the project will not contribute significantly to regional ozone levels or to any impacts caused by such ozone levels.

The project impacts are also less than the significant impact levels for PM_{10}, NO_X,SO_2, and CO 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. The maximum predicted nitrogen (N) and sulfur (S) depositions are well below the significant impact levels for N and S deposition in the PSD Class I Area.

Impact On Visibility

Natural gas is a clean fuel and combustion results in very low particulate matter emissions. The very low NO_X

and SO_2 emissions will also minimize plume opacity and any effects on regional visibility. The Class I Chassahowitzka NWA, where visibility impacts are considered, is about 120 kilometers from the proposed site. A regional haze analysis using the CALPUFF model and natural gas emissions predicted impacts less than the federal land manager's visibility impairment criteria; therefore, impacts on visibility are expected to be insignificant.

Growth-Related Air Quality Impacts

According to the applicant, the project will require about 5 additional permanent employees, some of who will be drawn from the local labor force. Therefore, residential growth due to this project will be minimal. This project is a response to statewide and regional growth and also accommodates future growth. There are no adequate procedures under the PSD rules to fully assess these impacts. However, the type of project proposed has a small overall physical "footprint." After construction of the proposed project, Polk County is expected to remain below the National Ambient Air Quality Standards.

Hazardous Air Pollutants

The existing Polk Power Station is not a major source of hazardous air pollutants (HAPs). Therefore, the project is not subject to any maximum achievable control technology (MACT) requirements pursuant to Department rules or Section 112 of the Clean Air Act.

7. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft determinations of Best Available Control Technology (BACT), review of the air quality impact analyses, and the conditions specified in the draft permit. Jeff Koerner is the project review engineer and is responsible for preparing the draft permit. Cleve Holladay is the project meteorologist responsible for reviewing and validating the air quality impact analysis.

REFERENCES

1 Manual. EPA, Office of Air Quality Planning and Standards, "DRAFT New Source Review Workshop Manual", October 1990.

2 Technical Report GE 3695E. Badeer, G. H., General Electric. "GE Aeroderivative Gas Turbines – Design and Operating Features." 2000.

3 Report. Cubix Corporation. "Exhaust Emissions from a GE PG7241FA Simple Cycle Power Turbine at TEC Polk Power Station." September 2000.

4 Compliance Manual. California EPA, CARB Compliance Division. Gas Turbines. June 1996.

5 News Release. Catalytica. First Gas Turbine with Catalytica's XONON installed to Produce Electricity at a Utility. October 8, 1998.

6 News Release. Catalytica. Catalytica Energy Systems XONON Cool Combustion System Demonstrating NO_X Emissions Well Below its 3 ppm Guarantee in Commercial Gas Turbine Applications. February 17, 2004.

7 Statement. EPA and Research Triangle Institute. ETV Joint Verification Statement. XONON™ Cool Combustion. December, 2000.

8 White Paper. Emerachem. NO_X Abatement Technology for Stationary Gas Turbine Power Plants – An Overview of Selective Catalytic Reduction (SCR) and Catalytic Absorption ($SCONO_X$™) Emission Control Systems. September 19, 2002.

[9] Draft Report to the Legislature. California Air Resources Board. Gas -Fired Power Plant NO_X Emissions Controls and Related Environmental Impacts. March 2004.

[10] Technical Report GE 4213. Davis, L.B. and Black, S.H. GE Power Systems. "Support for Elimination of Oxidation Catalyst Requirements for GE PG7242FA DLN Combustion Turbines." August 2001.

[11] Technical Report GER-4249. Stephanie Wien, Jeanne Beres, and Brahim Richani. GE Energy. "Air Emissions Terms, Definitions and General Information". August 2005

DRAFT PERMIT

PERMITTEE:

Tampa Electric Company
PO Box 111
Tampa, Florida 33601-0111
Authorized Representative:
Mark J. Hornick, General Manager

Permit No. PSD-FL-363
Project No. 1050233-018-AC
TECO Polk Power Station
Simple Cycle Units 4 and 5
Expires: October 1, 2008

PROJECT AND LOCATION

This permit authorizes the construction of two simple cycle gas turbine generators with a nominal output of 165 MW each at the existing Polk Power Station (SIC No. 4911). The facility is located approximately 11 miles south of the city of Mulberry (9995 State Route 37 South) in Polk County, Florida.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix BD. Final BACT Determinations and Emissions Standards

Appendix C. Common State Rules

Appendix GC. General Conditions

Appendix GG. NSPS Provisions - Subparts A and GG for Stationary Gas Turbines

STATEMENT OF BASIS

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. 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 of Environmental Protection (Department).

DRAFT

Michael G. Cooke, Director
Division of Air Resource Management

Effective Date: ____________________

FACILITY DESCRIPTION

The regulated emissions units at the existing Polk Power Station include the following: a 260 MW integrated coal gasification and combined cycle gas turbine (Unit 1) capable of firing synthetic gas (syngas) or No. 2 fuel oil; an auxiliary boiler that fires No. 2 fuel oil; a sulfuric acid plant; a solid fuel handling system; and two nominal 165 MW simple cycle gas turbines (Units 2 and 3) capable of firing either natural gas or No. 2 fuel oil.

PROJECT DESCRIPTION

The project is for the addition of two General Electric PG7241(FA) simple cycle gas turbine generators with a nominal output of 165 MW each at the existing facility. Each unit may operate up to 4380 hours per year. The new units will be fired exclusively with natural gas, which will minimize SO_2 emissions. The units will be designed and constructed with dry low-NO_X burner technology for the control of NO_X emissions. The advanced burner design will reduce incomplete combustion and minimize CO, PM_{10}, and VOC emissions.

EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units:

EU No.	Emission Unit Description
011	Unit 4 – 165 MW General Electric PG7241 FA gas turbine-electrical generator
012	Unit 5 – 165 MW General Electric PG7241 FA gas turbine-electrical generator

REGULATORY CLASSIFICATION

Title III: The facility is not a major source of hazardous air pollutants (HAPs).

Title IV: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V: The facility is a Title V or "major source" of air pollution in accordance with Chapter 62-213, F.A.C.

PSD: The facility is a PSD-major facility pursuant to Rule 62-212, F.A.C.

NSPS: Units 4 and 5 are subject to 40 CFR 60, Subpart GG (Standards of Performance for Stationary Gas Turbines). They are not be subject to NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for which Construction is Commenced after February 18, 2005) because the purchase contract with General Electric was signed on July 21, 2000, which is prior to the NSPS effective date.

NESHAP: Units 4 and 5 are not subject to 40 CFR 63, Subpart YYYY (National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines) because the facility is not a major source of HAPs.

Siting: This plant is subject to certain requirements of Chapter 403, Part II, Florida Statutes, Electric Power Plant and Transmission Line Siting, including a modification of the conditions Site Certification PA92-32.

RELEVANT DOCUMENTS

The following relevant documents are not a part of this permit, but helped form the basis for this permitting action: the permit application and additional information received to make it complete; the draft permit package including the Department's Technical Evaluation and Preliminary Determination; publication and comments; and the Department's Final Determination and Best Available Control Technology (BACT) determinations.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (DEP), at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications should be submitted to the Air Resources Section of the Department's Southwest District Office at 13051 N. Telecom Parkway, Temple Terrace, FL 33637-0926.

3. General Conditions: The permittee 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.]

4. 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, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 63, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. 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 permittee from compliance with any applicable federal, state, or local permitting or regulations.
[Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

5. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or 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. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. 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, 62-210.300(1), and 62-212.400(12), F.A.C.]

6. 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.]

7. Source Obligation.

   (a) Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit.

(b) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

(c) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

[Rule 62-212.400(12), F.A.C.]

8. 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. [Chapters 62-210 and 62-212, F.A.C.]

9. 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 Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]

10. 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 emission units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation and a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

SECTION III - EMISSIONS UNITS SPECIFIC CONDITIONS

A. Simple Cycle Gas Turbine Units 4 and 5 (EU-011 and EU-012)

The specific conditions of this subsection apply to the following emissions units.

EU No.	Emission Unit Description
011	Unit 4 – 165 MW General Electric PG7241 FA gas turbine-electrical generator
012	Unit 5 – 165 MW General Electric PG7241 FA gas turbine-electrical generator

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Units 4 and 5 are subject to determinations of the Best Available Control Technology (BACT) for nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), and sulfur dioxide (SO_2). [Rule 62-212.400(BACT), F.A.C.]

2. NSPS Requirements: The gas turbines shall comply with the applicable New Source Performance Standards (NSPS) in 40 CFR 60, including: Subpart A (General Provisions) and Subpart GG (Standards of Performance for Stationary Gas Turbines). See Appendix GG of this permit. The BACT emissions standards are as stringent as or more stringent than the limits imposed by the applicable NSPS provisions. Some separate reporting and monitoring may be required by the individual subparts. 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. [Rule 62-204.800(7)(b), F.A.C.; 40 CFR 60, Subparts A and GG]

EQUIPMENT DESCRIPTION

3. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain two General Electric Model PG7241FA gas turbine-electrical generator sets with a nominal generating capacity of 165 MW each. Each gas turbine will be equipped with a DLN combustion system and an inlet air filtration system. The unit shall include a Speedtronic™ Mark VI automated gas turbine control system (or equivalent). [Application No. 1050233-018-AC; Design]

CONTROL TECHNOLOGY

4. DLN Combustion: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NO_X emissions from the gas turbines when firing natural gas. Prior to the initial emissions performance tests required for the gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for CO and NO_X. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Application No. 1050233-018-AC; Design; Rule 62-212.400(BACT), F.A.C.]

PERFORMANCE REQUIREMENTS

5. Hours of Operation: Each gas turbine shall operate no more than 4380 hours during any consecutive 12 months. Restrictions on individual methods of operation are specified in separate conditions. [Application No. 1050233-018-AC; Rules 62-210.200(PTE) and 62-212.400(12), F.A.C.]

6. Permitted Capacity: The maximum heat input rate for each gas turbine is 1834 MMBtu per hour when firing natural gas based on a compressor inlet air temperature of 59° F, the higher heating value (HHV) of natural gas, and 100% load. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rules 62-4.070(3), 62-212.400(BACT), and 62-210.200(PTE), F.A.C.]

7. Authorized Fuels: Each gas turbine shall fire only natural gas containing no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

8. Simple Cycle, Intermittent Operation: Each turbine shall operate only in simple cycle mode not to exceed the permitted hours of operation allowed by this permit. This restriction is based on the permittee's request, which formed the basis of the PSD applicability and BACT determinations and resulted in the emission standards specified in this permit. For any request to convert this unit to combined cycle operation by installing/connecting to heat recovery steam generators, including changes to the fuel quality or quantity related to combined cycle conversion which may cause an increase in short or long-term emissions, the permittee may be required to submit a full PSD permit application complete with a new proposal of the best available control technology as if the unit had never been built. [Rules 62-212.400(12) and 62-212.400(BACT), F.A.C.]

EMISSIONS AND TESTING REQUIREMENTS

9. Emission Standards: Emissions from each gas turbine shall not exceed the following emissions standards.

Pollutant	Emission Standard [e]	Averaging Time	Compliance Method	Basis
CO [a]	99.0 tons (Emissions Cap)	12-month rolling total Both Units Combined	CEMS	Avoid PSD
	9.0 ppmvd @ 15% O_2 36.0 lb/hour	3-hour test avg.	Initial Only EPA Method 10 Test	
NO_X [b]	9.0 ppmvd @ 15% O_2	24-hour block, CEMS	CEMS	BACT
	60.9 lb/hour	3-hour test avg.	EPA Method 7E Test	
PM/PM_{10} [c]	10 % Opacity	6-minute block	EPA Method 9 Test	BACT
	2 grains S/100 SCF of gas	N/A	Record Keeping	
SO_2 [d]	2 grains S/100 SCF of gas	N/A	Record Keeping	BACT

a. The permittee shall conduct an initial test to demonstrate compliance with the short-term (ppmvd @ 15% O_2 and lb/hour) CO emissions limits for the unit as constructed. Thereafter, continuous compliance shall be demonstrated with the CO emissions cap by data collected from the required continuous emissions monitoring systems (CEMS) for both units combined.

b. The permittee shall conduct an initial test to demonstrate compliance with the short-term (ppmvd @ 15% O_2 and lb/hour) NOx emissions limits. Thereafter, continuous compliance shall be demonstrated with the 24-hour block NOx emissions limit by data collected from the required continuous emissions monitoring system (CEMS).

c. The fuel sulfur specifications combined with the efficient combustion design and operation of the gas turbine represents BACT for particulate matter (PM/PM_{10}) emissions. No stack tests are required. Compliance with the CO and visible emissions standards shall serve as indicators of good combustion. *{Permitting Note: Maximum expected PM/PM_{10} emissions from each gas turbine are approximately 18 lb/hour.}*

d. The fuel sulfur specifications effectively limit the potential emissions of sulfur dioxide (SO_2) from each gas turbine and represent BACT for SO_2 emissions. No stack tests are required. *{Permitting Note: Maximum expected SO_2 emissions from each gas turbine are approximately 9.5 lb/hour.}*

e. The mass emission rate standards are based on a turbine inlet condition of 59° F and the higher heating value of natural gas. Mass emission rates may be adjusted from actual test conditions in accordance with the performance curves and/or equations on file with the Department.

{Permitting Note: In combination with the annual restriction on hours of operation, the above emissions standards effectively limit annual potential emissions from both gas turbines to: 99 tons/year of CO, 267 tons/year of NOx, 79 tons/year of PM/PM_{10}, 42 tons/year of SO_2, 5 tons/year of SAM, and 12 tons/year of VOC.}

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

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

11. Test Methods: Any required stack tests shall be performed in accordance with the following methods.

Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental)
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources Note: The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

The methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used for compliance testing unless prior written approval is received from the Department. Tests shall be conducted in accordance with the appropriate test method, the applicable requirements specified in Appendix C of this permit, and the provisions in NSPS Subparts A and GG in 40 CFR 60. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Subparts A and GG, and Appendix A.]

12. Testing Requirements: Initial and subsequent performance tests shall be conducted between 90% and 100% of permitted capacity in accordance with the requirements of Rule 62-297.310(2), F.A.C. [Rule 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

13. Initial Compliance Demonstration: Initial compliance tests shall be conducted within 60 days after achieving the maximum production rate at which the units will be operated, but not later than 180 days after the initial startup. In accordance with the test methods specified in this permit, the turbine exhaust stack shall be tested to demonstrate compliance with the emission standards for CO, NO_X, and visible emissions. For each test run (including visible emissions tests), CO and NOx emissions recorded by the required CEMS shall be reported. The permittee shall provide the Compliance Authority with any other initial emissions performance tests conducted to satisfy vendor guarantees. [Rule 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

14. Annual Compliance Testing: During each federal fiscal year (October 1st to September 30th), annual compliance tests for visible emissions shall be conducted. For each visible emissions test, emissions of CO and NOx recorded by the CEMS shall also be reported. [Rules 62-297.310(7)(a) and (b), F.A.C.]

15. Continuous Compliance: Continuous compliance with the CO and NOx emissions standards shall be demonstrated with data collected from the required continuous emissions monitoring systems (CEMS). [Rules 62-297.310(7)(a) and (b), F.A.C.]

16. 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. The Department may, require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the DLN combustors, etc. [Rule 62-297.310(7)(b), F.A.C.]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 9 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal NSPS, NESHAP, or Acid Rain provision.}

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

18. Definitions: Rules 62-210.200(159), (230) and (245), F.A.C. define the following terms.

    a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

    b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.

    c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner..

19. 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. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

20. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

21. Allowable NOx Data Exclusions: Provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions are minimized, NO_X continuous monitoring data collected during periods of startup, shutdown, and malfunction may be excluded from the 24-hr block compliance demonstrations only in accordance with the following requirements. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, and DLN tuning) may be excluded. As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions replace the provisions in Rule 62-210.700(1), F.A.C.

    a. *Startup*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than the first 30 minutes of CEMS data shall be excluded for each gas turbine startup. For startups of less than 30 minutes in duration, only those minutes attributable to startup shall be excluded.

    b. *Shutdown*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than the first 20 minutes of CEMS data shall be excluded for each gas turbine shutdown. For shutdowns less than 20 minutes in duration, only those minutes attributable to shutdown shall be excluded.

c. *Malfunction*: In accordance with the procedures described in the CEMS Data Requirements of this section, no more than 120 minutes of CEMS data shall be excluded in a 24-hour period for each gas turbine due to malfunctions. Within one (1) working day of occurrence, the owner or operator shall notify the Compliance Authority of any malfunction resulting in the exclusion of CEMS data.

d. *DLN Tuning*: CEMS data collected during initial or other DLN tuning sessions shall be excluded from the compliance demonstrations provided the tuning session is performed in accordance with the manufacturer's specifications. Prior to performing any tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least one (1) day that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

The permittee shall notify the Compliance Authority within one working day of discovering any emissions in excess of a CEMS standard subject to the specified averaging period. All such reasonably preventable emissions shall be included in any CEMS compliance determinations. All valid emissions data (including data collected during startup, shutdown, malfunction, and DLN tuning) shall be used to report annual emissions for the Annual Operating Report and demonstration of compliance with the CO emissions cap. [Rules 62-4.070(3), 62-210.200, 62-212.400(BACT) and 62-210.700, F.A.C.]

CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS) REQUIREMENTS

22. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO_X from each gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. All continuous monitoring systems shall be installed and functioning within the required performance specification by the time of the initial performance tests.

    a. *CO Monitor:* Each CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F. The annual and required RATA tests shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

    b. *NO_X Monitor:* Each NO_X monitor shall be certified pursuant to the specifications of 40 CFR 75. Quality assurance procedures shall conform to the requirements of 40 CFR 75. The annual and required RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.

    c. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

    [Rules 62-4.070(3), 62-210.800. 62-212.400(BACT) and 62-297.520. F.A.C.]

23. CEMS Data Requirements: The CEMS shall be installed, calibrated, maintained, and operated in the gas turbine stacks to measure and record the emissions of CO, and NO_X in a manner sufficient to demonstrate compliance with the emission limits of this section. The CEMS shall express the results in units of ppmvd corrected to 15% oxygen. Upon request by the Department, the CEMS emission rates shall be corrected to

ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

a. *Valid Hourly Averages:* Each CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour (except for the allowable NOx data exclusions), shall be used to calculate a 1-hour block average that begins at the top of each hour. Each 1-hour block average shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, a 1-hour average shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, there is insufficient data and the 1-hour block average is not valid. Also, if an allowable exclusion episode should occur over two separate hourly averages, only those minutes attributed to the specific episode shall be excluded from each hour. *{Permitting Note: For example, a 20-minute startup begins at 2:50 p.m. and ends at 3:10 pm. This means that 10 minutes of startup data would be excluded from the first hourly average and 10 minutes would be excluded from the second hourly average.}*

b. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive valid hourly average concentration values. If a unit operates less than 24 hours during the block, or there are less than 24 valid hourly averages available, the 24-hour block average shall be the average of all available valid hourly average concentration values for the 24-hour block. *{Permitting Note: For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR Part 75, Subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block and periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance reports. For example, the "24-hr block average" may consist of only 6 valid operating hours for the day.}*

c. *12-Month Rolling Total*: By the end of each month, each CEMS shall determine a 12-month rolling total of CO emissions from each gas turbine and the combined total. The 12-month rolling total shall be based on all valid CO CEMS data collected, including startups, shutdowns, and malfunctions.

d. *Data Exclusion*: Except for monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, each CEMS shall monitor and record emissions during all operations including episodes of startups, shutdowns, malfunctions, and DLN tuning. Limited amounts of NOx CEMS emissions data recorded during some of these episodes may be excluded from the corresponding compliance demonstration subject to the provisions of Condition No. 21 in this section. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable.

e. *Availability*. Monitor availability for each CEMS used to demonstrate compliance shall be 95% or greater in any calendar quarter. Monitor availability shall be reported in the quarterly excess emissions report. 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, except as otherwise authorized by the Compliance Authority.

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

Reporting and Record Keeping Requirements

24. Monitoring of Capacity: The permittee shall monitor and record the operating rate of the gas turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown, malfunction, and DLN tuning). This shall be achieved through monitoring daily rates of

consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D, and recording the data using a monitoring component of the CEMS system required above. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

25. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the gas turbine for the previous month of operation: fuel consumption, hours of operation, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]
26. Fuel Sulfur Records: Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions. These methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3), 62-212.400(BACT), F.A.C.]
27. Stack Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Compliance Authority on the results of each such test. The required test report shall be filed with the Compliance Authority as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Compliance Authority to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report shall provide the applicable information specified in Rule 62-297.310(8), F.A.C. and summarized in Appendix C. [Rule 62-297.310(8), F.A.C.]
28. CEMS RATA Reports: Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]
29. Excess Emissions Reporting
    a. *Malfunction Notification:* If NOx data will be excluded due to a malfunction, the permittee shall notify the Compliance Authority within one 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 Compliance Authority may request a written summary report of the incident.
    b. *SIP Quarterly Report*: Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Compliance Authority of the following for each gas turbine: a summary of the 24-hour NOx compliance periods for the quarter; a summary of NOx data excluded due to malfunctions for the quarter; a summary of the 12-month rolling CO emissions totals for the quarter; and a summary of the CEMS systems monitor availability for the quarter.
    c. *NSPS Semi-Annual Reports*: Within thirty (30) days following each calendar semiannual period, the permittee shall submit a report including any applicable periods of excess emissions as defined in 40 CFR, Part 60, Subpart GG (Standards of Performance for Stationary Gas Turbines) that occurred during the previous semi-annual period to the Compliance Authority. *{Permitting Note: If there are no periods of excess emissions as defined in 40 CFR, Part 60, Subpart GG, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}*

    [Rules 62-4.070(3), 62-4.130, 62-204.800, 62-210.700(6) and 62-212.400(BACT), F.A.C.; and 40 CFR 60.7 and 60.334]

30. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours 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.]

31. Startup/Shutdown Report: Within 30 days following the end of each calendar quarter, the permittee shall submit a report summarizing the following for each gas turbine: number of startups and shutdowns in the quarter; the duration of each startup and shutdown in the quarter; and the CO and NOx mass emission rates (lb/hour) during each 1-hour block that includes a startup or shutdown. This temporary report that shall be submitted to the Compliance Authority and the Bureau of Air Regulation only for the first four initial quarters of operation. [Rule 62-4.070(3), F.A.C.]

SECTION IV. APPENDICES

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FINAL BACT DETERMINATION AND EMISSION STANDARDS

Project Description

The applicant proposes to install two General Electric PG7241(FA) simple cycle gas turbine generators with a nominal output of 165 MW each at the existing Polk Power Station. Each gas turbine will fire natural gas as the exclusive fuel and will have a maximum operation of 4380 hours per year. In accordance with Rule 62-212.400, F.A.C., the existing plant is a major facility for the Prevention of Significant Deterioration (PSD) of Air Quality. The proposed project is subject to PSD preconstruction review for NOx, PM/PM_{10}, and SO_2 emissions.

Air Pollution Control Equipment

Each gas turbine will be equipped with a dry low-NOx combustion system capable of achieving low CO and NOx emissions with the lean, pre-mixed combustion of natural gas. Each gas turbine will employ continuous emissions monitoring systems (CEMS) to continuously demonstrate compliance with the CO and NOx emissions standards. As the only authorized fuel for the project, natural gas contains little ash or sulfur, which will minimize emissions of particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). Also, natural gas is readily combusted by the large frame gas turbines and will result in negligible emissions of volatile organic compounds (VOC).

Final BACT Determinations

In accordance with Rule 62-212.400, F.A.C., the Department establishes the following standards that represent the Best Available Control Technology (BACT).

Pollutant	Emission Standard [e]	Averaging Time	Compliance Method	Basis
CO [a]	99.0 tons (Emissions Cap)	12-month rolling total Both Units Combined	CEMS	Avoid PSD
	9.0 ppmvd @ 15% O_2 36.0 lb/hour	3-hour test avg.	Initial Only EPA Method 10 Test	
NO_X [b]	9.0 ppmvd @ 15% O_2	24-hour block, CEMS	CEMS	BACT
	60.9 lb/hour	3-hour test avg.	EPA Method 7E Test	
PM/PM_{10} [c]	10 % Opacity	6-minute block	EPA Method 9 Test	BACT
	2 grains S/100 SCF of gas	N/A	Record Keeping	
SO_2 [d]	2 grains S/100 SCF of gas	N/A	Record Keeping	BACT

a. The permittee shall conduct an initial test to demonstrate compliance with the short-term (ppmvd @ 15% O_2 and lb/hour) CO emissions limits for the unit as constructed. Thereafter, continuous compliance shall be demonstrated with the CO emissions cap by data collected from the required continuous emissions monitoring system (CEMS).

b. The permittee shall conduct an initial test to demonstrate compliance with the short-term (ppmvd @ 15% O_2 and lb/hour) NOx emissions limits. Thereafter, continuous compliance shall be demonstrated with the 24-hour block NOx emissions limit by data collected from the required continuous emissions monitoring system (CEMS).

c. The fuel sulfur specifications combined with the efficient combustion design and operation of the gas turbine represents BACT for particulate matter (PM/PM_{10}) emissions. No stack tests are required. Compliance with the CO and visible emissions standards shall serve as indicators of good combustion. *{Permitting Note: Maximum expected PM/PM_{10} emissions from each gas turbine are approximately 18 lb/hour.}*

d. The fuel sulfur specifications effectively limit the potential emissions of sulfur dioxide (SO_2) from each gas turbine and represent BACT for SO_2 emissions. No stack tests are required. *{Permitting Note: Maximum expected SO_2 emissions from each gas turbine are approximately 9.5 lb/hour.}*

e. The mass emission rate standards are based on a turbine inlet condition of 59° F and the higher heating value of natural gas. Mass emission rates may be adjusted from actual test conditions in accordance with the performance curves and/or

equations on file with the Department.

{Permitting Note: In combination with the annual restriction on hours of operation, the above emissions standards effectively limit annual potential emissions from both gas turbines to: 99 tons/year of CO, 267 tons/year of NOx, 79 tons/year of PM/PM_{10}, 42 tons/year of SO_2, 5 tons/year of SAM, and 12 tons/year of VOC.}

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

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 project. The final BACT determinations also consider comments received during public notice period as summarized in the Final Determination issued concurrently with the Final Permit.

COMMON STATE RULES

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the facility.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. 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.]
3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]
4. 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. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permitee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]
9. 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.]

GENERAL COMPLIANCE TESTING REQUIREMENTS

The focal point of a compliance test is the stack or duct which vents process and/or combustion gases and air pollutants from an emissions unit into the ambient air. [Rule 62-297.310, F.A.C.]

10. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

11. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate 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 purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. [Rule 62-297.310(2), F.A.C.]

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

13. Applicable Test Procedures [Rule 62-297.310(4), F.A.C.]

    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.

        (2) Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

            (a) For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

            (b) The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

            (c) The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

    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.

    c. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

    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.

    e. *Allowed Modification to EPA Method 5.* When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

14. Determination of Process Variables [Rule 62-297.310(5), F.A.C.]

    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.

    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.

15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must also comply with all applicable Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E. [Rule 62-297.310(6), F.A.C.]

a. *Permanent Test Facilities*. The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

b. *Temporary Test Facilities*. The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

c. *Sampling Ports*.

(1) All sampling ports shall have a minimum inside diameter of 3 inches.

(2) The ports shall be capable of being sealed when not in use.

(3) The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

(4) For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

(5) On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

d. *Work Platforms*.

(1) Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

(2) On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

(3) On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

(4) All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toe board, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

e. *Access to Work Platform*.

(1) Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

(2) Walkways over free-fall areas shall be equipped with safety rails and toe boards.

f. *Electrical Power*.

(1) A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

(2) If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

g. *Sampling Equipment Support.*

(1) A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

(a) The bracket shall be a standard 3 inch × 3 inch × one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

(b) A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

(c) The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

(2) A complete monorail or dualrail arrangement may be substituted for the eyebolt and bracket.

(3) When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

16. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required. [Rule 62-297.310(7), F.A.C.]

a. *General Compliance Testing.*

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to sub-subparagraph 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

(a) Did not operate; or

(b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours,

4. During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

(a) a. Visible emissions, if there is an applicable standard;

(b) b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

(c) c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
6. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.
7. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.
8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.
10. An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., F.A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.

b. *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.

c. *Waiver of Compliance Test Requirements*. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of paragraph 62-297.310(7)(b), F.A.C., shall apply.

RECORDS AND REPORTS

17. Test Reports [Rule 62-297.310(8), F.A.C.]

a. The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

b. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.

c. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information.

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.

6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

RECORDS AND REPORTS

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

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

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.

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, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

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.

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.

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.

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.

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.

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.

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 extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

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.

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.

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

13. This permit also constitutes:

    a. Determination of Best Available Control Technology;
    b. Determination of Prevention of Significant Deterioration; and
    c. Compliance with New Source Performance Standards.

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:

        a. The date, exact place, and time of sampling or measurements;
        b. The person responsible for performing the sampling or measurements;
        c. The dates analyses were performed;
        d. The person responsible for performing the analyses;
        e. The analytical techniques or methods used; and
        f. The results of such analyses.

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.

NSPS SUBPART GG – REQUIREMENTS FOR GAS TURBINES

Simple cycle gas turbine Units 4 and 5 (Emissions Units 011 and 012) are subject to the following applicable federal New Source Performance Standards (NSPS) in 40 CFR 60.

SUBPART A - GENERAL PROVISIONS

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

SUBPART GG – STATIONARY GAS TURBINES

60.330 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

(b) (b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of §60.332.

[44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987; 65 FR 61759, Oct. 17, 2000]

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.

(c) Regenerative cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

(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.

(e) Emergency gas turbine means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(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.

(k) Fire-fighting turbine means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) Turbines employed in oil/gas production or oil/gas transportation means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m) A Metropolitan Statistical Area or MSA as defined by the Department of Commerce.

(n) Offshore platform gas turbines means any stationary gas turbine located on a platform in an ocean.

(o) Garrison facility means any permanent military installation.

(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.

(r) Emergency fuel is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.

(s) Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

(t) Excess emissions means a specified averaging period over which either:

(1) The NOX emissions are higher than the applicable emission limit in §60.332;

(2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.333; or

(3) The recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

(u) Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

(v) Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

(w) Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(y) Unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by §60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) 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 ISO corrected (if required as given in §60.335(b)(1)) NOX emission concentration (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, and

F = NOX emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(2) 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:

$$STD = 0.0150\frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NOX emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated peak 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, and

F = NOX emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this section is optional. That is, the owner or operator may choose to apply a NOX allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

(4) If the owner or operator elects to apply a NOX emission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under §60.8 as follows:

Fuel-bound nitrogen (percent by weight)	F (NOX percent by volume)
N [le] 0.015	0
0.015 < N[le] 0.1	0.04(N)
0.1 < N [le] 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).

or:

Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by §60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the Federal Register.

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

(d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in §60.332(b) shall comply with paragraph (a)(2) of this section.

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) 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.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

(j) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour that commenced construction, modification, or reconstruction between the dates of October 3, 1977, and January 27, 1982, and were required in the September 10, 1979, Federal Register (44 FR 52792) to comply with paragraph (a)(1) of this section, except electric utility stationary gas turbines, are exempt from paragraph (a) of this section.

(k) Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from paragraph (a)(2) of this section when being fired with an emergency fuel.

(l) Regenerative cycle gas turbines with a heat input less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) are exempt from paragraph (a) of this section.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

60.333 Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by §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:

(a) 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 sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

[44 FR 52798, Sept. 10, 1979, as amended at 69 FR 41360, July 8, 2004]

60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NOX emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NOX emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NOX and O2 monitors. As an alternative, a CO2 monitor may be used to adjust the measured NOX concentrations to 15 percent O2 by either converting the CO2 hourly averages to equivalent O2 concentrations using Equation F–14a or F–14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O2, or by using the CO2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NOX and diluent monitors may be performed individually or on a combined basis, i.e., the relative accuracy tests of the CEMS may be performed either:

  (i) On a ppm basis (for NOX) and a percent O2 basis for oxygen; or

  (ii) On a ppm at 15 percent O2 basis; or

  (iii) On a ppm basis (for NOX) and a percent CO2 basis (for a CO2 monitor that uses the procedures in Method 20 to correct the NOX data to 15 percent O2).

(2) As specified in §60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in §60.13(h).

  (i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both NOX and diluent, the data acquisition and handling system must calculate and record the hourly NOX emissions in the units of the applicable NOX emission standard under §60.332(a), i.e., percent NOX by volume, dry basis, corrected to 15 percent O2 and International Organization for Standardization (ISO) standard conditions (if required as given in §60.335(b)(1)). For any hour in which the hourly average O2 concentration exceeds 19.0 percent O2, a diluent cap value of 19.0 percent O2 may be used in the emission calculations.

  (ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (Ta), and minimum combustor inlet absolute pressure (Po) into the ISO correction equation.

  (iii) If the owner or operator has installed a NOX CEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in §60.7(c).

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NOX emissions, the owner or operator may, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA or local permitting authority approval of a petition for an alternative procedure of continuously monitoring compliance with the applicable NOX emission limit under §60.332, that approved procedure may continue to be used, even if it deviates from paragraph (a) of this section.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control NOX emissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NOX CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NOX emissions may elect to use a NOX CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. An acceptable alternative to installing a CEMS is described in paragraph (f) of this section.

(f) The owner or operator of a new turbine who elects not to install a CEMS under paragraph (e) of this section, may instead perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NOX formation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in the lean premixed (low-NOX) combustion mode.

(3) For any turbine that uses SCR to reduce NOX emissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor NOX emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in §75.19(c)(1)(iv)(H) of this chapter.

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under §60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NOX emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in §75.19 of this chapter or the NOX emission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in §75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084–82, 94, D5504–01, D6228–98, or Gas Processors Association Standard 2377–86 (all of which are incorporated by reference-see §60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (i.e., if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in §60.332). The nitrogen content of the fuel shall be determined using methods described in §60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) *Gaseous fuel.* Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) *Custom schedules.* Notwithstanding the requirements of paragraph (i)(2) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (i)(3)(i) and (i)(3)(ii) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), subsequent sulfur content monitoring may be performed at 12 month intervals. If any of the samples taken at 12-month intervals has a total sulfur content between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(1) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(2) of this section.

(2) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(3) of this section.

(3) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (i.e., the maximum total sulfur content of natural gas as defined in §60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

(i) For turbines using water or steam to fuel ratio monitoring:

(A) An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.332, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

(B) A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in §60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using NOX and diluent CEMS:

(A) (A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NOX concentration exceeds the applicable emission limit in §60.332(a)(1) or (2). For the purposes of this subpart, a "4-hour rolling average NOX concentration" is the arithmetic average of the average NOX concentration measured by the CEMS for a given hour (corrected to 15 percent O2 and, if required under §60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NOX concentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NOX concentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(iv) For turbines required under paragraph (f) of this section to monitor combustion parameters or parameters that document proper operation of the NOX emission controls:

(A) An excess emission shall be a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(B) A period of monitor downtime shall be a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(3) Ice fog. Each period during which an exemption provided in §60.332(f) 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.

(4) Emergency fuel. Each period during which an exemption provided in §60.332(k) is in effect shall be included in the report required in §60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

(5) All reports required under §60.7(c) shall be postmarked by the 30th day following the end of each calendar quarter.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41360, July 8, 2004]

60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in §60.8, using either

(1) EPA Method 20,

(2) ASTM D6522–00 (incorporated by reference, see §60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine NOX and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for NOX and diluent pursuant to

(A) [Reserved]

(B) (B) The procedures specified in section 6.5.6.1(a) through (e) appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NOX concentrations, normalized to 15 percent O2, is within ±10 percent of the mean normalized concentration for all traverse points, then you may use 3 points (located either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The 3 points shall be located along the measurement line that exhibited the highest average normalized NOX concentration during the stratification test; or

(B) If each of the individual traverse point NOX concentrations, normalized to 15 percent O2, is within ±5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in §60.332 and shall meet the performance test requirements of §60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NOXo) corrected to 15 percent O2 shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

NOX=(NOXo)(Pr/Po)0.5 e19 (Ho−0.00633) (288°K/Ta)1.53

Where:

NOX = emission concentration of NOX at 15 percent O2 and ISO standard ambient conditions, ppm by volume, dry basis,

NOXo = mean observed NOX concentration, ppm by volume, dry basis, at 15 percent O2.

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

Po = observed combustor inlet absolute pressure at test, mm Hg,

Ho = observed humidity of ambient air, g H2O/g air,

e = transcendental constant, 2.718, and

Ta = ambient temperature, °K.

(2) The 3-run performance test required by §60.8 must be performed within ±5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these requirements, performance testing is not required for any emergency fuel (as defined in §60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NOX emissions after the duct burner rather than directly after the turbine. If the owner or

operator elects to use this alternative sampling location, the applicable NOX emission limit in §60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control NOX with no additional post-combustion NOX control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with §60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522–00 (incorporated by reference, see §60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.332 NOX emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in §60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in §60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NOX CEMS under §60.334(e), then the initial performance test required under §60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable NOX emission limit under §60.332 and to provide the required reference method data for the RATA of the CEMS described under §60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator is required under §60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NOX emission controls, the appropriate parameters shall be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597–94 (Reapproved 1999), D6366–99, D4629–02, D5762–02 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under §60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129–00, D2622–98, D4294–02, D1266–98, D5453–00 or D1552–01 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072–80, 90 (Reapproved 1994); D3246–81, 92, 96; D4468–85 (Reapproved 2000); or D6667–01 (all of which are incorporated by reference, see §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 prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section 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.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in §60.8 to ISO standard day conditions.

[69 FR 41363, July 8, 2004]

P.E. CERTIFICATION STATEMENT

APPLICANT

Tampa Electric Company
PO Box 111
Tampa, Florida 33601-0111

Permit No. PSD-FL-363
Project No. 1050233-018-AC
TECO Polk Power Station
Simple Cycle Units 4 and 5
Polk County, Florida

PROJECT DESCRIPTION

The applicant proposes to install two General Electric PG7241(FA) simple cycle gas turbine generators with a nominal output of 165 MW each at the existing power plant. Each gas turbine will fire natural gas as the exclusive fuel and will have a maximum operation of 4380 hours per year. In accordance with Rule 62-212.400, F.A.C., the existing plant is a major facility for the Prevention of Significant Deterioration (PSD) of Air Quality. The proposed project is subject to PSD preconstruction review for NOx, PM/PM_{10}, and SO_2 emissions. The Department made the following draft determinations of the Best Available Control Technology (BACT).

- NOx $\leq$ 9.0 ppmvd @ 15% O_2 (24-hour daily CEMS average) based on the efficient dry low-NOx combustion design of the General Electric gas turbines and the exclusive firing of natural gas;
- PM/PM_{10} emissions will be minimized by the efficient combustion design and the exclusive firing of natural gas containing no more than 2 grains per 100 scf of gas; and
- SO_2 emissions will be minimized exclusive firing of natural gas containing no more than 2 grains per 100 scf of gas.

In addition, annual CO emissions from both gas turbines combined will be restricted to 99.0 tons during any consecutive 12 months rolling total. Each gas turbine will employ continuous emissions monitoring systems (CEMS) to continuously demonstrate compliance with the CO and NOx emissions limits.

***I HEREBY CERTIFY** that the air pollution control 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, geological, and meteorological features).*

Jeffery J. Koerner 3-6-06

Jeffery F. Koerner, P.E.
Registration No. 49441

(Date)

P.E. CERTIFICATION STATEMENT

APPLICANT

Tampa Electric Company
PO Box 111
Tampa, Florida 33601-0111

Permit No. PSD-FL-363
Project No. 1050233-018-AC
TECO Polk Power Station
Simple Cycle Units 4 and 5
Polk County, Florida

PROJECT DESCRIPTION

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- PM/PM_{10} emissions will be minimized by the efficient combustion design and the exclusive firing of natural gas containing no more than 2 grains per 100 scf of gas; and
- SO_2 emissions will be minimized exclusive firing of natural gas containing no more than 2 grains per 100 scf of gas.

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Jeffery J. Koerner

Jeffery F. Koerner, P.E.
Registration No. 49441

3-6-06
(Date)

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

TAMPA ELECTRIC COMPANY,
Big Bend Station,

Petitioner,

v. **OGC #05-2789**
DEP Permit 0570039-18-AC

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 upon receipt of a request made by Petitioner, Tampa Electric Company, to grant an extension of time to file a petition for an administrative hearing to allow time to discuss with FDEP several specific permit conditions for its facility in Hillsborough County, Florida. Because the request shows good cause for the extension of time,

IT IS ORDERED:

The request for an extension of time to file a petition for administrative proceeding is granted. Petitioner shall have until **January 23, 2006**, to file a petition in this matter. Filing shall be complete on receipt by the Office of General Counsel, Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000.

DONE AND ORDERED on this 14th day of December, 2005, in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Jack Chis

JACK CHISOLM, Deputy General Counsel
3900 Commonwealth Boulevard. M.S. 35
Tallahassee, Florida 32399-3000
850-245-2242 facsimile 850-245-2302

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via __ U. S. Mail ✓ facsimile ✓ **only**, this 14th day of December, 2005, to:

Byron T. Burrows, P.E.
Manager, Air Programs
Environmental, Health & Safety
Post Office Box 111
Tampa, FL 33601-0111

facsimile: 813-228-1308

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

JACK CHISOLM, Deputy General Counsel
3900 Commonwealth Boulevard. M.S. 35
Tallahassee, Florida 32399-3000
850-245-2242 facsimile 850-245-2302

with a courtesy copy to:

Trina L. Vielhauer
Chief
Bureau of Air Regulation

facsimile: 850-921-9533

Karen Sheffield
General Manager
Tampa Electric Co.
Big Bend Station

facsimile: 813-228-1308

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

November 17, 2005

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Mark J. Hornick, General Manager
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33604-5927

Re: **Request for Additional Information**
Project No. 1050233-018- AC, PSD-FL-363
Request for 2 New Simple-Cycle Combustion Turbines at Polk Power Station

Dear Mr. Hornick:

On October 18, 2005, the Department received your application for a PSD permit to construct two new simple cycle combustion turbines at the Polk Power Station. The application is deemed to be incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. The proposed carbon monoxide (CO) emissions limits of 9.0 ppm on gas and 20.0 ppm on oil are higher than currently issued BACT determinations of 4.1 ppm on gas and 8.0 ppm on oil for similar units. It is the Department's intention to continue to issue all new BACT determinations with emissions limits at least as stringent as those being currently and routinely demonstrated by similar existing sources. Please provide a copy of the manufacturer's guaranteed CO emissions rates for these units and any comments you may have regarding why these units should not be held to currently achievable CO emissions rates.
2. The proposed nitrogen oxide (NO_X) emissions limit of 10.5 ppm on gas is higher than currently issued BACT determinations of 9.0 ppm for similar units. Please provide a copy of the manufacturer's guaranteed NO_X emissions rate for these units while firing gas. Also include the manufacturer's guarantee for firing oil and any comments you may have regarding why these units should not be held to currently achievable NO_X emissions rates.
3. Please provide an anticipated schedule for operation of these simple cycle units. Include the projected number of start ups and shut downs for a given year and quantify the emissions for each start up and each shut down. Are multiple start ups and shut down cycles anticipated during any single day? Does the plant currently have a gas contract that will provide sufficient gas for these units to operate for the 4,380 hours of operation that have been requested? Considering the gas contract, how often is it anticipated that fuel switching will be required?
4. The application contains a statement that the nameplate generation capacity for these units is 175.8 MW. However, the requested allowable capacity is 165 MW. Please explain the reason for this difference.
5. It is our understanding that these units may have been previously permitted, but never operated. Please provide information on the age and origin of these units, including information regarding the original permittee.

6. Please provide a more detailed plot plan. The Department is requesting both an electronic version (preferably a .dwg file or file compatible with AutoCAD2006) and an updated paper plan (preferably 2 x 3 feet). Please grid the plot plan in UTM coordinates and highlight the buildings, structures and stacks.

7. Since the previous permit application for TECO Polk Power Station (Combustion Turbines 2 and 3) was processed, the standard for the fence line receptor grid has become more refined within the Department, with at least 100 meter spacing along the boundary required. Please update the Class II modeling to reflect the 100 meter spacing requirement.

8. In Section 10.10, page 10-6, the modeled emissions sources for the Class I impact modeling were based on Case 4 instead of Cases 1, 2 or 9, which were the worst cases in the Class II modeling. Please explain.

9. On page 10-1 and Table 10-8, the maximum change in light extinction coefficient (B_{ext}) at the Chassahowitzka NWR is stated to be 9.33 percent. However, on page 10-8, the maximum change is stated to be 11.01 percent. Please explain this discrepancy.

10. Please explain why three different 1996 CALPUFF modeling runs were performed (January, February to July, and August to December).

11. Please discuss strategies for reducing SO_2, NO_X and PM_{10} emissions sufficiently to lower the predicted B_{ext} in the Chassahowitzka NWR to less than 5.0 percent.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department construction permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. For any material changes to the application, please include a new certification statement by the authorized representative or responsible official. You are reminded that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days or provide a written request for an additional period of time to submit the information.

If you have any questions regarding this matter, please call me at 850/921-9531.

Sincerely,

Jonathan Holtom

Jonathan Holtom, P.E.
North Permitting Section

/jh

EC: Raisa Calderon, TECO (rcalderon@tecoenergy.com)
Byron Burrows, P.E., TECO (btburrows@tecoenergy.com)

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:

Facility ID #: 1050233
Mr. Mark J. Hornick, General Manager
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33~~604-5927~~

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X ☐ Agent ☐ Addressee

B. Received by (Printed Name)

C. Date of Delivery

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

DOWNTOWN NOV 28 2005 TAMPA FL 33601

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 *(Transfer from service label)* 7003 1680 0002 4617 3974

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1540

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Restricted Delivery Fee (Endorsement Required)		
Total		

Facility ID #: 1050233
Sent T Mr. Mark J. Hornick, General Manager
Street, or PO Tampa Electric Company
P.O. Box 111
City, S Tampa, Florida 33604-5927

PS Form 3800, June 2002 See Reverse for Instructions

Department of
Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

October 27, 2005

Mr. Gregg M. Worley, Chief
Air Permits Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303-8960

RE: Tampa Electric Company
Polk Power Station Units 4 and 5
1050233-018-AC, PSD-FL-363

Dear Mr. Worley:

Enclosed for your review and comment is a PSD application submitted by Tampa Electric Company to construct two additional combustion turbines at the Polk Power Station in Mulberry, Polk County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/921-9533. If you have any questions, please contact Jonathan Holtom, review engineer, at 850/921-9531.

Sincerely,

Patty Adams

for Jeffrey F. Koerner, P.E., Administrator
North Permitting Section

JFK/pa

Enclosure

cc: J. Holtom

EXP+

Parcels: 1/1

From: DEP AIR RESOURCE MGMT
P. Adams
DIRECTOR OFFICE STE 23
111 S MAGNOLIA DR
TALLAHASSEE, FL 32301
UNITED STATES Tel:850-921-9505

Origin: TLH

Sender's ref: 37550201000 A7 AP255

To: U.S. EPA Region 4
Mr. Gregg M. Worley
61 Forsyth Street
Air Permits Section
Atlanta, GA 30303
UNITED STATES

POSTCODE: 30303

Tel: 404-562-9141

Time 10:30

Description: PSD-FL-363 application

Weight: 4 lbs for 1 pcs
Date: 2005-10-27

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(2L)US30303

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SENDER'S RECEIPT
Waybill #: 28425325854

To(Company):
U.S. EPA Region 4
Air Permits Section
61 Forsyth Street

Atlanta, GA 30303
UNITED STATES

Attention To: Mr. Gregg M. Worley
Phone#: 404-562-9141

Sent By: P. Adams
Phone#: 850-921-9505

Rate Estimate: 6.1
Protection: Not Required
Description: PSD-FL-363 application

Weight (lbs.): 4
Dimensions: 0 x 0 x 0

Ship Ref: 37550201000 A7 AP255
Service Level: Next Day 10:30 (Next business day by 10:30 A.M.)

Special Svc:

Date Printed: 10/27/2005
Bill Shipment To: Sender
Bill To Acct: 778941286

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DHL EXPRESS

From: DEP AIR RESOURCE MGMT
P. Adams
DIRECTOR OFFICE STE 23
111 S MAGNOLIA DR
TALLAHASSEE, FL 32301
UNITED STATES Tel:850-921-9505

To: National Park Service
Mr. John Bunyak
12795 W. Alameda Parkway
Air Division
Lakewood, CO 80228
UNITED STATES

Tel: 303-966-2818

EXP+

Parcels: **1/1**

ORIGIN: **TLH**

Sender's ref
37550201000 A7 AP255

POSTCODE:
80228

Time
10:30

Description: PSD-FL-363 application

Weight: 4 lbs for 1 pcs
Date: 2005-10-27

DHL standard terms and conditions apply.

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(2L)US80228

WAYBILL: 28425385855

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SENDER'S RECEIPT
Waybill #: 28425385855

To(Company):
National Park Service
Air Division
12795 W. Alameda Parkway

Lakewood, CO 80228
UNITED STATES

Attention To: Mr. John Bunyak
Phone#: 303-966-2818

Sent By: P. Adams
Phone#: 850-921-9505

Rate Estimate: 15.96
Protection: Not Required
Description: PSD-FL-363 application

Weight (lbs.): 4
Dimensions: 0 x 0 x 0

Ship Ref: 37550201000 A7 AP255
Service Level: Next Day 10:30 (Next business day by 10:30 A.M.)

Special Svc:

Date Printed: 10/27/2005
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BUREAU OF AIR REGULATION

October 21, 2005

Mr. Jeff Koerner
Florida Department of Environmental Protection
Division of Air Resource Management
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Via FedEx
Airbill No. 7906 8698 8068

Mr. Hamilton S. Oven, Administrator
Siting Coordination Office
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Via Fed Ex
Airbill No. 7906 8699 0995

Re: Tampa Electric Company
Polk Power Station
Polk Unit 4 & 5
Construction Permit Application & Request of Modification – Draft Permit
PPSA No. PA 92-32

Dear Mr. Koerner and Oven:

As a follow up to the telephone conversation on October 18, 2005 with Mr. Jeff Koerner, Tampa Electric Company (TEC) is providing copies of APPENDIX D: PROPOSED AIR CONSTRUCTION PERMIT, which was not included in the air construction permit application for the two new GE 7F simple cycle combustion turbines, Polk Units 4 and 5. On October 17, 2005, TEC submitted to Mr. Koerner four (4) signed and sealed copies of TEC's permit application, as well as the Electronic Submission of Application (ELSA), for the construction of these two new simple-cycle combustion turbines at the Polk Power Station. One (1) signed and sealed copy of TEC's permit application and the ELSA was also sent to Mr. Oven, along with a check made payable to the Florida Department of Environmental Protection Agency in the amount of $10,000 dollars to cover the modification fee per 62-17.293(c), F.A.C.

Enclosed with this letter to Mr. Koerner are four (4) copies of the addendum and one (1) copy to Mr. Oven. The addendum is a proposed air construction permit for Units 4 and 5. The Prevention of Significant Deterioration of Air Quality (PSD Permit) of Polk Units 2 and 3, PSD-FL-263 (PA92-32), was used as basis of the proposed air construction permit for Polk Units 4 and 5 because of their similarities. All four units are dual fuel fired GE 7F turbines operated in simple cycle mode.

TEC appreciates the Departments approval to submit the addendum enclosed as part of the air construction permit application previously submitted. If you should have any questions, please feel free to call Raiza Calderon or me at (813) 228-4369.

Sincerely,

for

Byron T. Burrows, P.E.
Manager - Air Programs
Environmental, Health & Safety

EA/rlk/RC207

Enclosures

APPENDIX D

PROPOSED AIR CONSTRUCTION PERMIT

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE:

Tampa Electric Company (TEC)
6944 U.S. Highway 41 North
Apollo Beach, Florida 33572-9200

Authorized Representative.

Gregory M. Nelson, Manager, ~~Environmental Planning~~ Environmental, Health, Safety

PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of: two dual-fuel nominal 165 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators and two 114-foot stacks. The units will operate in simple cycle mode and intermittent duty. The units will be equipped with Dry Low NO_X (DLN-2.6) combustors and wet injection capability. They are designated by TEC as CTGs Nos. ~~2~~ 4 and ~~3~~ 5 and by the Department as ARMS Emissions Unit ~~009~~ 011 and ~~010~~ 012.

The project will be located at the existing Polk Power Station, 9995 State Route 37 South, Mulberry, Polk County. UTM coordinates are: Zone 17; 402.45 km E; 3067.35 km N.

STATEMENT OF BASIS:

This PSD permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62.-297 of the Florida Administrative Code (F.A.C.) and 40CFR52.21. The above named 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 of Environmental Protection (Department).

Attached Appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L Rhodes

Howard If Rhodes, Director
Division of Air Resources Management

FACILITY DESCRIPTION

This facility presently generates electric power from a 260 megawatt (MW) integrated coal gasification and combined cycle turbine unit. The primary mover is a General Electric MS 7001F combustion turbine capable of firing syngas or No.2 fuel oil. Associated support facilities include: a solid fuel gasification system; a hydrogen sulfide to sulfur dioxide converter; a sulfuric acid plant; solid fuel handling and storage; and fuel oil handling and storage.

This permitting action is to install two dual-fuel nominal 165 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with two 114-foot stacks. The project will utilize existing infrastructure including oil storage and auxiliary equipment.

Emissions from the new units will be controlled by Dry Low NO_x (DLN-2.6) combustors when operating on natural gas and wet injection when firing fuel oil. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

ARMS EMISSIONS UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
~~009~~ 011 (CTG-~~2~~4)	Power Generation	One nominal 165 Megawatt ~~Gas~~ Simple Cycle Gas Combustion Turbine-Electrical Generator
~~010~~ 012 (CTG-~~3~~5)	Power Generation	One nominal 165 Megawatt Simple Cycle Gas Combustion Turbine-Electrical Generator

REGULATORY CLASSIFICATION

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

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, modifications at this facility resulting in emissions increases greater than any of the following values require review per the PSD rules as well as a determination of Best Available Control Technology (BACT): 40 TPY of NO_X, SO_2, or VOC; 25/15 TPY of PM/PM_{10}; 100 TPY of CO; or 7 TPY of sulfuric acid mist (SAM).

This project is subject to certain requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting, including a modification of the Conditions of Certification (reference Site Certification P A92-32).

This facility and the project are also subject to applicable provisions of Title IV, Acid Rain, of the Clean Air Act.

PERMIT SCHEDULE

- xx/xx/99 Modification of Conditions of Certification Approved.
- 07/10/99 Notice of Intent to Issue PSD Permit published in the Lakeland Ledger.
- 06/30/99 Distributed Intent to Issue Permit.
- 06/10/99 Application deemed complete for PSD review.
- 02/08/99 Received revised PSD Application.

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

- Application received on February 8, 1999
- Department/ Siting Coordination Office incompleteness letter dated February 11, 1999.
- Department/BAR memo to Siting Coordination Office dated March 9, 1999
- Comments and letter from the U. S. Fish and Wildlife Service dated March 19, 1999
- Site Certification and Revised PSD Application received May 10, 1999
- Department/BAR comments on Modeling dated May 20, 1999
- Comments from Hillsborough County EPC dated June 7, 1999
- Response from TEC/ECT received June 10, 1999
- Department's Intent to Issue PSD Permit and Public Notice Package dated June 30, 1999
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.
- Comments from TEC dated August 9, September 10, and 14, 1999.

GENERAL AND ADMINSTRATIVE REQUIREMENTS

1. Regulating Agencies: 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 (FDEP), at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Southwest District, 3804 Coconut Palm Drive, Tampa, Fl 33619-8218 and phone number 813/744-6100.

2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

4. Forms and Application Procedures: 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. [Rule 62210.900, F.A.C.]

5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]

6. 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. BACT Determination: In conjunction with extension of the 18 month periods to commence or continue construction, or extension of the December 31, 2002 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. In accordance with paragraph (4) of 40 CFR 52.210) the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction project, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate

the adequacy of any previous determination of best available control technology for the source." [40 CFR 52.210)(4), Rule 62-4.070 F.A.C.]

8. Permit Extension: The permittee, for good cause, may request that this PSD permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.080, F.A.C.).

9. Application for Title IV Permit: An application for a Title IV Acid Rain Permit, must be submitted to the U.S. Environmental Protection Agency Region IV office in Atlanta, Georgia and a copy to the DEP's Bureau of Air Regulation in Tallahassee 24 months before the date on which a new unit begins serving an electrical generator greater than 25 MW. [40 CFR 72]

10. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department's Southwest District. [Chapter 62-213, F.A.C.]

11. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., 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.]

12. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Southwest District by March 1st of each year.

13. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

14. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1998 version), shall be submitted to the DEP's Southwest District.

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 52, 60, 72, 73, and 75.
2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]
3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

   40CFR60.7, Notification and Recordkeeping
   40CFR60.8, Performance Tests
   40CFR60.11, Compliance with Standards and Maintenance Requirements
   40CFR60.12, Circumvention
   40CFR60.13, Monitoring Requirements
   40CFR60.19, General Notification and Reporting requirements
4. ARMS Emissions Unit ~~009~~ 011. Direct Power Generation, consisting of a nominal 165 megawatt simple cycle combustion turbine-electrical generator, shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s).
5. ARMS Emissions Unit ~~010~~ 012. Direct Power Generation, consisting of a nominal 165 megawatt simple cycle combustion turbine-electrical generator, shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s).
6. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Southwest District.

GENERAL OPERATION REQUIREMENTS

7. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No.2 or superior grade of distillate fuel oil shall be fired in this unit. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)] {Note: The limitation of this specific condition is more stringent than the NSPS sulfur dioxide limitation and thus assures compliance with 40 CFR 60.333 and 60.334}

8. Combustion Turbine Capacity: The maximum heat input rates, based on the ~~lower~~ higher heating value (~~LHV~~ HHV) of each fuel to each unit at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed ~~1,600~~ 1,834 million Btu per hour (mmBtu/hr) when firing natural gas, nor ~~1,800~~ 2,015 mmBtu/hr when firing No.2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. 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.

10. 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 DEP Southwest District as soon as possible, but at least within (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.]

11. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

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

13. Maximum allowable hours of operation for each unit are equivalent to 4,380 hours per year at the maximum firing rate for a compressor inlet air temperature of 59° on natural gas and equivalent to 750 hours per year at the maximum firing rate for a compressor inlet air temperature of 59° on fuel oil. [Rule 62-210.200, F.A.C., (Definitions - Potential Emissions), 62-212.400, F.A.C., (BACT Determination)]

CONTROL TECHNOLOGY

14. Dry Low NO_x (DLN) combustors shall be installed on the stationary combustion turbine to comply with the NO_x emissions limits while firing natural gas. [Design, Rules 62-4.070 and 62-212.400, F.A.C. (BACT Determination)]

15. A water injection system shall be installed for use when firing No.2 or superior grade distillate fuel oil for control of NO_x emissions. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

16. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions No. 19 through 24. [Rule 62-4.070, Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)]

17. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems prior to their installation. DLN systems shall each be tuned upon initial operation to optimize emissions reductions consistent with normal operation and maintenance practices and shall be maintained to minimize NO_x emissions and CO emissions, consistent with normal operation and maintenance practices. Operation ofthe DLN systems in the diffusion-firing mode shall be minimized when firing natural gas. [Rule 62- 4.070, and 62-210.650, F.A.C.]

EMISSION LIMITS AND STANDARDS

18. Following is a summary of the emission limits and required technology. Values for NO_x are corrected to 15 % O_2 on a dry basis. These limits or their equivalent in terms of lb/hr or NSPS units, as well as the applicable averaging times, are followed by the applicable specific conditions [Rules 62-212.400, 62-204.800(7)(b) (Subpart GO), 62-210.200 (Definitions-Potential Emissions) F.A.C.]

POLLUTANT	CONTROL TECHNOLOGY	EMISSION LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity (gas or oil)
~~VOC~~	~~As Above~~	~~1.4 ppmvw (Gas)~~ ~~3.5 ppmvw (FO)~~
CO	Pipeline Natural Gas~~As Above~~ Good Combustion	~~12~~ 9 ppmvd (Gas) 20 ppmvd (FO)
SO_2 and Sulfuric Acid Mist	Pipeline Natural Gas Low Sulfur Oil	2 gr S/100 ft^3 0.05% S Fuel Oil
NO_x	DLN, WI for F.O., limited fuel oil usage	10.5 ppmvd (DLN) 42 ppmvd (FO)

19. Nitrogen Oxides (NO_X) Emissions:

- While firing Natural Gas: The emission rate of NO_X in the exhaust gas shall not exceed 10.5 ppm @15% O_2 on a 24 hr block average as measured by the continuous emission monitoring system (CEMS). In addition, NO_x emissions calculated as NO_2 shall not exceed ~~59~~ 68.8 pounds per hour (at ISO conditions)~~ and 9 ppmvd @15% O2 to be demonstrated by the initial "new and clean" GE performance stack test~~ and 10.5 ppmvd @15% O_2 to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

  ~~Notwithstanding the applicable NOx limit during normal operation, reasonable measures shall be implemented to maintain the concentration of NOx in the exhaust gas at 9 ppmvd at 15% O2 or lower. Any tuning of the combustors for Dry Low NOx operation while firing gas shall result in initial subsequent NOx concentrations of 9 ppmvd @15% O2 or lower.~~ [Rules 62-212.400 and 62-4.070, F.A.C.]

- While firing Fuel oil: The concentration of NO_x in the exhaust gas shall not exceed 42 ppmvd at 15% O_2 on the basis of a ~~3-hr~~ 24-hr block average as measured by the continuous emission monitoring system (CEMS). In addition, NO_x emissions calculated as NO_2 shall not exceed 319 lb/hr (at ISO conditions) and 42 ppmvd @15% O_2 to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

  The permittee shall develop a NO_x reduction plan when the hours of oil firing reach the allowable limit of 750 equivalent hours per year. This plan shall include a testing protocol designed to establish the maximum water injection rate and the lowest NO_x 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 NO_x emissions for each rate and noting any problems with performance. Based on the test results, the plan shall recommend a new NO_x 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 NO_x emissions standard is warranted for oil firing, this permit shall be revised. (BACT Determination].

20. Carbon Monoxide (CO) Emissions: During the first 12 months after initial start up, the concentration of CO in the stack exhaust gas shall exceed neither 15 ppmvd nor 48lb/hr (at ISO conditions) while firing gas and neither 33 ppmvd nor 106lb/hr (at ISO conditions) while firing oil based on stack test. Thereafter, these limits will be revised and lowered to ~~12~~ 9 ppmvd and ~~38~~ 36 lb/hr (at ISO conditions) while firing gas and 20 ppmvd and ~~65~~ 92.2 lb/hr (at ISO conditions). The permittee shall demonstrate compliance with these limits by stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]

21. ~~Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the stack exhaust gas with the combustion turbine operating on natural gas shall exceed neither 1.4 ppmvw nor 2.8 lb/hr (ISO conditions) and neither 3.5 ppmvw nor 7lb/hr (ISO conditions) while operating on oil to be demonstrated by initial stack test using EP A Method 18, 25 or 25A. [Applicant Request]~~

22. Sulfur Dioxide (SO_2) emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content less than 2 grains per 100 standard cubic foot) or by firing No.2 or superior grade distillate fuel oil with a maximum 0.05 percent sulfur for 750 equivalent hours per year per unit. Emissions of $S0_2$ (at ISO conditions) shall not exceed 9.21b/hr (natural gas) and 98.11b/hr (fuel oil) as measured by applicable compliance methods described below. [40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C]

23. Visible Emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions and shall not exceed 10 opacity. Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

24. ~~Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions~~

~~shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour~~

Excess emissions resulting from startup, shutdown and malfunction of any emissions unit shall be permitted providing: (1) best operational practices to minimize emissions are adhered to, and (2) the duration of excess emissions shall be minimized but in no case exceed 120 minutes in any 24 hour period with one unit cycle and 60 minutes for each additional startup within the same 24 hour period.

In other words, excess emissions shall be limited to 120 minutes in any 24 hour period in which the unit cycles once, 180 minutes in which the unit cycles twice, and 240 minutes in any 24 hour period in which the unit cycles three times. The duration of excess emissions shall be minimized but in no case exceed these durations unless specifically authorized by the Department. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.

~~period for other reasons unless specifically authorized by DEP for longer duration. Operation below 50% output shall be limited to 2 hours per unit cycle (breaker closed to breaker open).~~

25. Excess emissions which are 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 pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 24-hr average for NO_x.

26. Excess Emissions Report: If excess emissions occur due to malfunction (for greater than 2 hours in a 24-hr period), the owner or operator shall notify DEP's Southwest District 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 permitted standards listed in Specific Condition No. 18 and 19. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

COMPLIANCE DETERMINATION

27. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.

28. Initial (I) performance tests (for both fuels) shall be performed on each unit while firing natural gas as well as while firing oil. ~~Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment such as change or tuning of combustors.~~ Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F .A.C., on each unit as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG and (I, A) short-term NO_x BACT limits (EPA reference Method 7E, "Determination of Nitrogen Oxides Emission from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirements).

- ~~EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.~~

29. Continuous compliance with the NO_x emission limits: Continuous compliance with the NO_x emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average ~~(DLN)~~. Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day. A valid hourly emission rate shall be calculated for each hour in which at least two NO_x concentrations are obtained 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. These excess emissions periods shall be reported as required in Conditions 25 and 26. [Rules 62-4.070 F .A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

   - All continuous monitoring systems (CEMS) shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. These CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. [40CFR60.13]

30. Compliance with the SO_2 and PM/PM_{10} emission limits: Not withstanding the requirements of Rule 62-297.340, F .A.C., the use of pipeline natural gas, is the method for determining compliance for SO_2 and PM_{10} For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. 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) (1998 version).

31. Compliance with CO emission limit: An initial test for CO shall be conducted concurrently with the initial NO_x test, as required. The initial NO_x and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the annual RATA testing for the NO_x CEMS required pursuant to 40 CFR 75

~~32. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit and periodic tuning data will be employed as surrogate and no annual testing is required.~~

33. Testing procedures: 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. In this case, 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. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

34. Test Notification: The DEP's Southwest District shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance testes).

35. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

36. Test Results: Compliance test results shall be submitted to the DEP's Southwest District no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.].

NOTIFICATION, REPORTING, AND RECORDKEEPING

37. Records: All measurements, records, and other data required to be maintained by TEC shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

38. Compliance Test Reports: A test report indicating the results of the required compliance tests shall be filed as per Condition No.36 above. 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), F .A.C.

MONITORING REQUIREMENTS

39. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from these units. Upon request from EPA or DEP, the CEMS emission rates for NO_x on these Units shall be corrected to ISO conditions to demonstrate compliance with the NO_x standard established in 40 CFR 60.332. [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C, 40 CFR 75and 40 CFR 60.7 (1998 version)].

40. CEMS for reporting excess emissions: Excess Emissions and Monitoring System Performance Reports shall be submitted as specified in 40 CFR 60.7(c). CEM monitor downtime shall be

calculated and reported according to the requirements of 40 CFR 60.7(c)(3) and 40CFR 60.7(d)(2). Periods when NO_x emissions (ppmvd @ 15% oxygen) are above the BACT standards, listed in Specific Conditions No 18 and 19, shall be reported to the DEP Southwest District within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternatively by facsimile within one working day).

41. CEMS in lieu of Water to Fuel Ratio: The NO_x CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998 version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1998 version) will be replaced by the 40 CFR 75 certification tests of the NO_x CEMS.

42. Continuous Monitoring Certification and Quality Assurance Requirements: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix For 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Emissions Monitoring Section Administrator and EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

43. Natural Gas Monitoring Schedule: 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 requirements are met:

   - The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.
   - The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.1 1 (d)(2)).
   - 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, $S0_2$ emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

44. Fuel Oil Monitoring Schedule: One or more of ~~T~~the following monitoring schedules for No.2 or superior grade fuel oil shall be followed~~:~~ ~~F~~for all bulk shipments of No. 2 fuel oil received at this facility:

   (1) A~~a~~n analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

(2) A monthly fuel oil composite sample shall be prepared from daily fuel oil samples obtained in the storage tank, when the unit(s) is firing oil. Compliance shall be demonstrated through an analysis which reports the sulfur content of the monthly fuel oil composite sample. Testing for fuel oil heating value shall also be conducted on the same schedule. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

(3) The NO_x CEMS shall be used in lieu of testing the nitrogen content of the fuel. See specific condition 41.

45. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh 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), F.A.C]

PSD-FL-363
1050233-018-AC

TECO
TAMPA ELECTRIC

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OCT 18 2005
BUREAU OF AIR REGULATION

October 17, 2005

Mr. Jeff Koerner
Florida Department of Environmental Protection
Division of Air Resource Management
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Via FedEx
Airbill No. 7917 5786 3925

Mr. Hamilton S. Oven, Administrator
Siting Coordination Office
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Via Fed Ex
Airbill No. 7924 1316 5803

Re: Tampa Electric Company
Polk Power Station
Polk Unit 4 & 5
Construction Permit Application & Request of Modification
PPSA No. PA 92-32

Dear Mr. Koerner and Oven:

Tampa Electric Company (TEC) intends to construct and operate two General Electric (GE) 7F combustion turbines at its Polk Power Station facility and hereby requests a construction permit and a modification of the Site Certification for the Polk Power Station (PA 92-32), pursuant to Section 403.516(1)(b), Florida Statutes. The Siting Board issued the certification for this facility in January 1994, authorizing the construction and operation of the first phase of an 1150 MW capacity facility, which was Polk Unit 1, a gasification unit. The second phase involved the addition of two dual fuel fired GE 7F turbines operated in simple cycle mode, Polk Units 2 and 3. Phase three will include two new GE 7F combustion turbines, which will also be operated in simple cycle mode, Polk Units 4 and 5. TEC has identified the need to obtain an air construction permit and the modification of the existing Conditions of Certification (COC) to incorporate this change.

It is intended that the modifications related to Polk Unit 4 and 5 will be resolved by incorporating the conditions of the separately issued Prevention of Significant Deterioration (PSD) permit that is needed to construct these units. Once the conditions in the new PSD permit are agreed on, TEC will supplement this request to include the new PSD condition language into a new section of the current COC addressing the third phase of the build-out of this site.

Hard copy only

Enclosed with this letter to Mr. Koerner are four (4) signed and sealed copies of TEC's permit application, ~~as well as the Electronic Submission of Application (ELSA)~~, for the construction of these two new simple-cycle combustion turbines at the Polk Power Station. One (1) signed and sealed copy of TEC's permit application and the ELSA is also being sent to Mr. Oven. A check made payable to the Florida Department of Environmental Protection in the amount of $10,000 dollars is enclosed to cover the modification fee per 62-17.293(c), F.A.C. Copies of the attached permit application (with the exception of the associated electronic files) and the modification request are being distributed to all "Parties to the Proceedings" concurrent with this submittal.

TEC appreciates the Departments timely review and processing of the air construction permit application and this modification. If you should have any questions, please feel free to call Raiza Calderon or me at (813) 228-4369.

Sincerely,

Byron T. Burrows, P.E.
Manager - Air Programs
Environmental, Health & Safety

EA/rlk/RC206

Enclosures

c/enc: Joel Smolen, FDEP SW
Bob Soich, FDEP SW
All parties of record (list attached)

TECO

TAMPA ELECTRIC

October 17, 2005

Mr. Jeff Koerner
Florida Department of Environmental Protection
Division of Air Resource Management
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Via Email Notification
Jeff.Koerner@dep.state.fl.us

Re: Tampa Electric Company
Polk Power Station
Polk Unit 4 & 5 Construction Permit Application RAI Comments
Project No. 1050233-018- AC, PSD-FL-363

Dear Mr. Koerner:

The purpose of this letter is to provide you with information discussed on the November 21, 2006 conversations regarding permit limits and conditions to be included in the draft Air Construction Permit for Polk Power Station Unit 4 and 5. This correspondence is intended to provide the responses to each item raised by the Florida Department of Environmental Protection (FDEP).

1. **NO_x emissions limit** – TEC accepts a NO_x limit of 9.0 ppmvd @ 15% O_2. In addition TEC requests language be included on the draft permit referring to allowable tuning through out the year.

2. **CO emissions limit** – TEC accepts an annual CO tons cap of 99 tons.

3. **Hours of Operation** – TEC accepts a 4,380 hr/yr/CT annual operating hour limit

4. **Excess Emissions** – TEC accepts up to 30-minutes of data exclusion allowed per startup event with no limits on the number of startup events. Similarly, up to 20-minutes of data exclusion would be allowed per shutdown events with no limits on the number of shutdown events. For malfunctions, up to 120 minutes of excess emissions would be allowed in any 24 hr period.

5. **Heat Input Margin** – TEC recognizes Mr. Koerner's concern of the footnote in the AC application regarding the use of a 3.5% margin for heat input rates to allow for future CT heat rate degradation. The pollutant mass emission rate estimates were not calculated using the heat input rate with the 3.5% margin. TEC will submit the corrected pollutant mass emission rate estimates by March 3, 2006.

TEC appreciates the Departments timely review and processing of the air construction permit application and this modification. If you should have any questions, please feel free to call Raiza Calderon or me at (813) 228-4369.

Sincerely,

(No Electronic Signature Available)

Raiza Calderon for
Byron Burrows, P.E. BCEE
Manager - Air Programs
Environmental, Health, and Safety

EA/rlk/RC/RC211

ECOtek

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE	BASE	BASE	BASE
Ambient Temp.	Deg F.	45.	50.	59.	75.	95.
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	80	80	80	80	80
Liquid Fuel H/C Ratio		1.8	1.8	1.8	1.8	1.8
Output	kW	185,500.	183,800.	180,300.	172,500.	158,600.
Heat Rate (LHV)	Btu/kWh	10,010.	10,020.	10,030.	10,090.	10,260.
Heat Cons. (LHV) X 10^6	Btu/h	1,856.9	1,841.7	1,808.4	1,740.5	1,627.2
Exhaust Flow X 10^3	lb/h	3794.	3758.	3690.	3559.	3372.
Exhaust Temp.	Deg F.	1084.	1089.	1097.	1113.	1132.
Exhaust Heat (LHV) X 10^6	Btu/h	1026.8	1019.5	1002.5	972.0	927.7
Water Flow	lb/h	126,840.	125,150.	121,590.	112,780.	95,100.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.	42.	42.
NOx AS NO2	lb/h	330.	327.	321.	309.	289.
CO	ppmvd	20.	20.	20.	20.	20.
CO	lb/h	67.	66.	65.	62.	59.
UHC	ppmvw	7.	7.	7.	7.	7.
UHC	lb/h	15.	15.	15.	14.	13.
SO2	ppmvw	115.0	115.0	115.0	115.0	113.0
SO2	lb/h	964.0	956.0	939.0	904.0	845.0
SO3	ppmvw	6.0	6.0	6.0	6.0	6.0
SO3	lb/h	63.0	63.0	62.0	59.0	55.0
Sulfur Mist	lb/h	101.0	101.0	99.0	95.0	89.0
Particulates	lb/h	17.0	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.86	0.84	0.85	0.84
Nitrogen	71.54	71.46	71.31	70.94	70.26
Oxygen	11.10	11.08	11.04	10.98	10.93
Carbon Dioxide	5.61	5.61	5.61	5.58	5.49
Water	10.90	11.00	11.20	11.66	12.48

SITE CONDITIONS

Elevation	ft.	0.0
Site Pressure	psia	14.7
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-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 0.5 WT% Sulfur Content in the Fuel.

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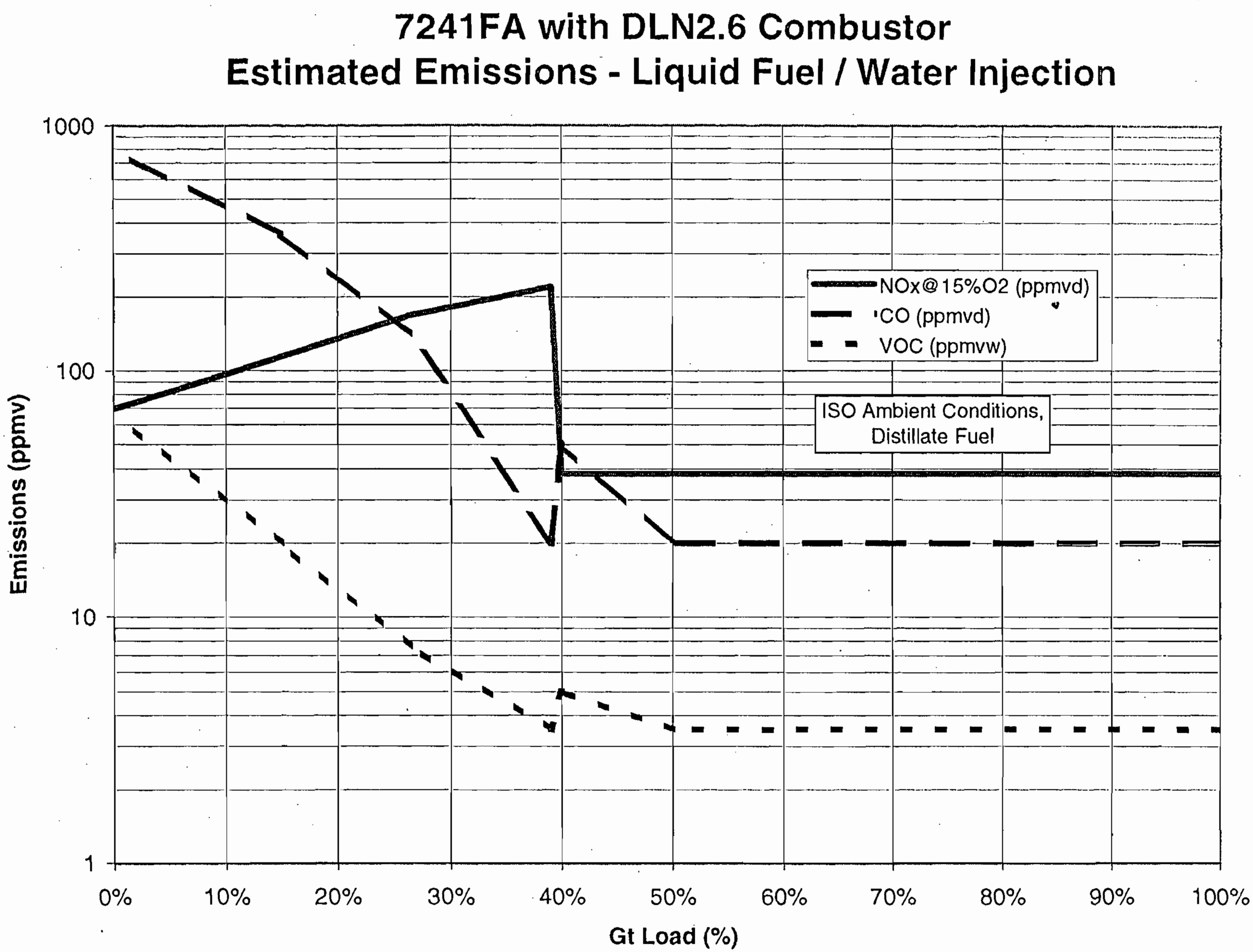

Prepared by GE Power Systems 5/3/99

Lake Worth Generation, LLC 4 Mar 99

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%	25%
Ambient Temp.	Deg F.	55.	55.	55.	55.
Fuel Type		Methane	Methane	Methane	Methane
Fuel LHV	Btu/lb	21,515	21,515	21,515	21,515
Fuel Temperature	Deg F	80	80	80	80
Output	kW	171,400.	128,500.	85,700.	42,800.
Heat Rate (LHV)	Btu/kWh	9,410.	10,240.	12,330.	17,070.
Heat Cons. (LHV) X 10^6	Btu/h	1,612.9	1,315.8	1,056.7	730.6
Exhaust Flow X 10^3	lb/h	3556.	2895.	2398.	2154.
Exhaust Temp.	Deg F.	1118.	1155.	1200.	1041.
Exhaust Heat (LHV) X 10^6	Btu/h	969.2	829.0	724.4	555.0

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	81.
NOx AS NO2	lb/h	60.	48.	38.	236.
CO	ppmvd	9.	9.	9.	47.
CO	lb/h	29.	24.	20.	92.
UHC	ppmvw	7.	7.	7.	21.
UHC	lb/h	14.	11.	9.	26.
Particulates	lb/h	9.0	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.90	0.89	0.89	0.90
Nitrogen	74.35	74.37	74.48	75.14
Oxygen	12.32	12.38	12.72	14.59
Carbon Dioxide	3.84	3.81	3.66	2.81
Water	8.60	8.55	8.25	6.56

SITE CONDITIONS

Elevation	ft.	50.0
Site Pressure	psia	14.67
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	12.0
Relative Humidity	%	70
Application		
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.

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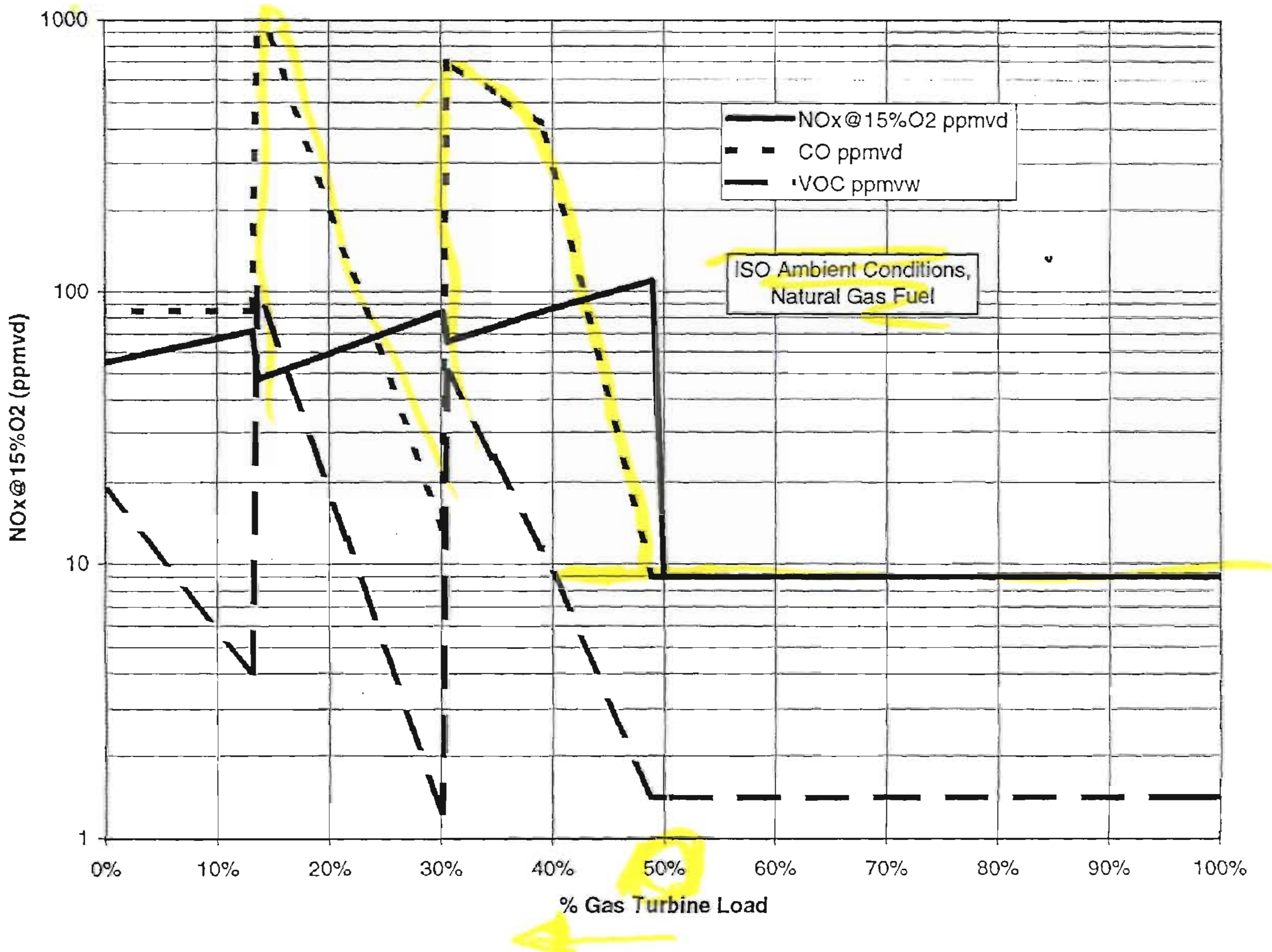
PG7241FA with DLN2.6 Combustor
Estimated Emissions vs Gas Turbine Load



prepared by GEPS, 5/3/99

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Construction Permit Application & Request of Modification
PPSA No. PA 92-32

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Sincerely,

Byron T. Burrows, P.E.
Manager - Air Programs
Environmental, Health & Safety

EA/rlk/RC206

Enclosures

c/enc: Joel Smolen, FDEP SW
Bob Soich, FDEP SW
All parties of record (list attached)

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Environmental Protection Commission Of Hillsborough County
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LIST OF FIGURES

1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Tampa Electric Company (TEC) plans to install two additional simple-cycle combustion turbine (SCCT) generators at its existing Polk Power Station (PPS) located in Polk County, Florida. The PPS is situated approximately 17 miles south of the city of Lakeland, approximately 11 miles south of the city of Mulberry, and approximately 13 miles southwest of the city of Bartow in southwest Polk County.

The existing PPS coal gasification facility consists of solid fuel handling facilities, a solid fuel gasification system, one nominal 260-megawatt (MW) combined-cycle combustion turbine (designated as Unit 1) fired with syngas or distillate fuel oil, an auxiliary boiler, a sulfuric acid (H_2SO_4) plant, slag handling systems, two nominal 165-MW simple-cycle combustion turbine generators (CTGs) (designated as Units 2 and 3), and ancillary support equipment. Operation of the existing PPS coal gasification facility emission sources is currently authorized by Title V Final Permit Revision No. 1050233-016-AV, which was issued with an effective date of January 1, 2005, and expires on December 31, 2009.

TEC is planning to construct and operate two additional simple-cycle CTGs at the PPS. The PPS simple-cycle CTG project will consist of two, nominal 165-MW CTGs (designated as Units 4 and 5) fired primarily with pipeline-quality natural gas. Low-sulfur distillate fuel oil will serve as a back-up fuel source. The new simple-cycle CTGs will operate at annual capacity factors up to 50 (equivalent to 4,380 hours per year [hr/yr] at baseload) and 8.6 (equivalent to 750 hr/yr at baseload) percent for natural gas and oil firing, respectively.

Operation of the proposed project will result in airborne emissions. Therefore, a permit is required prior to the beginning of facility construction, per Rule 62-212.300(1)(a), Florida Administrative Code (F.A.C.). This report, including the required permit application forms and supporting documentation included in the attachments, constitutes TEC's application for authorization to commence construction in accordance with the Florida Department of Environmental Protection (FDEP) permitting rules contained in Chapter 62-212, *et. seq.*, F.A.C.

Units 4 and 5 will be located in an attainment area and will have nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM), particulate matter equal to or less than 10 micrometers (PM_{10}), sulfur dioxide (SO_2), and H_2SO_4 mist emissions increases in excess of 40, 100, 25, 15, 40, and 7 tons per year (tpy), respectively. Consequently, Units 4 and 5 qualify as a major modification to an existing major facility and are subject to the PSD new source review (NSR) requirements of Rule 62-212.400, F.A.C., for NO_x, CO, PM, PM_{10}, SO_2, and H_2SO_4 mist. Therefore, this report and application is also submitted to satisfy the permitting requirements contained in the FDEP Prevention of Significant Deterioration (PSD) rules and regulations.

This report is organized as follows:

- Section 1.2 provides an overview and summary of the key regulatory determinations.
- Section 2.0 describes the proposed facility and associated air emissions.
- Section 3.0 describes national and state air quality standards and discusses applicability of NSR procedures to the proposed project.
- Section 4.0 describes the PSD NSR review procedures.
- Section 5.0 provides an analysis of best available control technology (BACT).
- Sections 6.0 (Dispersion Modeling Methodology) and 7.0 (Dispersion Modeling Results) address ambient air quality impacts.
- Section 8.0 discusses current ambient air quality in the vicinity of the project and preconstruction ambient air quality monitoring.
- Section 9.0 addresses other potential air quality impact analyses.
- Section 10.0 provides an assessment of impacts on the Chassahowitzka National Wildlife Refuge (NWR) Class I area.
- Section 11.0 lists the references used in preparing this report.

Appendices A and B provide the FDEP Application for Air Permit—Long Form and emission rate calculations, respectively. All dispersion modeling input and output files for the ambient impact analyses are provided in Appendix C. A proposed air construction permit for Units 4 and 5 is provided in Appendix D.

1.2 SUMMARY

The PPS simple-cycle CTG project will consist of two nominal 165-MW General Electric (GE) PG7241 (FA) CTGs. The CTGs will be fired with pipeline-quality natural gas containing no more than 2.0 grains of total sulfur per one hundred standard cubic feet (gr S/100 scf). Low sulfur (containing no more than 0.05 weight percent sulfur [wt%S]) will serve as a back-up fuel source.

The planned construction start date for Units 4 and 5 is April 2006. The planned initial date of commencement of operation is May 2007.

Based on an evaluation of anticipated worst-case annual operating scenarios, Units 4 and 5 will have the potential to emit 540.7 tpy of NO_x, 226.8 tpy of CO, 104.3 tpy of PM/PM_{10}, 117.9 tpy of SO_2, and 17.7 tpy of volatile organic compounds (VOCs). Regarding noncriteria pollutants, Units 4 and 5 will potentially emit 13.5 tpy of H_2SO_4 mist and trace amounts of heavy metals and organic compounds associated with distillate fuel oil combustion. Based on these annual emission rate potentials, NO_x, CO, PM/PM_{10}, SO_2, and H_2SO_4 mist emissions are subject to PSD review.

As presented in this report, the analyses required for this permit application resulted in the following conclusions:

- The use of good combustion practices and clean fuels is considered to be BACT for PM/PM_{10}. Units 4 and 5 will utilize dry low-NO_x (DLN) burner technology to maximize combustion efficiency and minimize PM/PM_{10} emission rates and will be fired with pipeline-quality natural gas and low-sulfur, low-ash distillate fuel oil.
- Advanced burner design and good operating practices to minimize incomplete combustion are proposed as CO BACT for Units 4 and 5. At baseload

operation during natural gas and distillate fuel oil firing, Units 4 and 5 CO exhaust concentrations are projected to be 9.0 and 20.0 parts per million by volume dry (ppmvd), respectively. These concentrations are consistent with prior FDEP BACT determinations for simple-cycle CTGs. Cost effectiveness of a CO oxidation catalyst control system was determined to be \$6,203 per ton of CO using the FDEP recommended economic cost factors. Use of current fuel and electric generation costs results in a cost effectiveness of \$8,990 per ton of CO controlled. Because these costs exceed values previously determined by FDEP to be cost effective, installation of a CO oxidation catalyst control system is considered to be economically unreasonable.

- BACT for SO_2 and H_2SO_4 mist will be achieved through the use of low-sulfur, pipeline-quality natural gas containing no more than 2.0 gr S/100 scf and distillate fuel oil containing no more than 0.05 wt%S.
- Dry low-NO_x burner technology is proposed as BACT for NO_x for Units 4 and 5 during natural gas firing. For all normal operating loads, the NO_x exhaust concentration will not exceed 10.5 ppmvd, corrected to 15-percent oxygen. This concentration is consistent with prior FDEP BACT determinations for simple-cycle CTGs. Cost effectiveness of a selective catalytic reduction (SCR) control system was determined to be \$10,807 per ton of NO_x using the FDEP-recommended economic cost factors. Use of current fuel and electric generation costs results in a cost effectiveness of \$15,760 per ton of NO_x controlled. Because these costs exceed values previously determined by FDEP to be cost effective, installation of an SCR control system is considered to be economically unreasonable. During distillate fuel oil firing, wet injection will be employed to reduce the NO_x exhaust concentration to 42 ppmvd, corrected to 15-percent oxygen.
- Units 4 and 5 are projected to emit NO_x, CO, PM/PM_{10}, SO_2, and H_2SO_4 mist in greater than significant amounts. The ambient impact analysis demonstrates that project impacts will be below the PSD *de minimis* monitoring significance levels for these pollutants. Accordingly, the Unit 4 and 5 project qualifies for the Section 62-212.400, Table 212.400-3, F.A.C., exemp-

tion from PSD preconstruction ambient air quality monitoring requirements for all PSD pollutants.

- The ambient impact analysis demonstrates that project impacts for the pollutants emitted in significant amounts will be below the PSD significant impact levels defined in Rule 62-210.200(260), F.A.C. Accordingly, a multi-source interactive assessment of national ambient air quality standards (NAAQS) attainment and PSD Class I and II increment consumption was not required.
- Based on refined dispersion modeling, Units 4 and 5 will not cause nor contribute to a violation of any NAAQS, Florida ambient air quality standards (AAQS), or PSD increment for Class I or Class II areas.
- The ambient impact analysis also demonstrates that project impacts will be well below levels that are detrimental to soils and vegetation and will not impair visibility.
- The PPS is presently not a major source of hazardous air pollutants (HAPs). The addition of Units 4 and 5 will not change the status of the PPS as a non-major HAP source. Accordingly, Units 4 and 5 will not be subject to any maximum achievable control technology (MACT) requirements.
- The nearest PSD Class I area (Chassahowitzka NWR) is located approximately 120 kilometers (km) northwest of the project site. Air quality and visibility impacts on this Class I area will be negligible.

2.0 DESCRIPTION OF THE PROPOSED FACILITY

2.1 PROJECT DESCRIPTION, AREA MAP, AND PLOT PLAN

Proposed Units 4 and 5 will be located at the existing TEC PPS. The PPS is situated approximately 17 miles south of the city of Lakeland, approximately 11 miles south of the city of Mulberry, and approximately 13 miles southwest of the city of Bartow in southwest Polk County, Florida. Figure 2-1 provides portions of a U.S. Geological Survey (USGS) topographical map showing the PPS site location and nearby prominent geographical features

The proposed project consists of two, simple-cycle GE PG7241 (FA) CTGs. Each of the two CTGs will be capable of producing a nominal 165 MW of electricity for an overall total nominal generation capacity of 330 MW. The CTGs will be fired primarily with pipeline-quality natural gas. Low-sulfur distillate fuel oil will serve as a back-up fuel source.

Units 4 and 5 will operate at annual capacity factors up to 50 and 8.6 percent for natural gas and oil firing, respectively. At baseload operation, these annual capacity factors are equivalent to 4,380 and 750 hr/yr for natural gas and oil firing, respectively. Annual CTG operating hours will increase with lower load operations.

Combustion of natural gas and distillate fuel oil in the CTGs will result in emissions of PM/PM_{10}, SO_2, NO_x, CO, VOCs, and H_2SO_4 mist. Emission control systems proposed for the simple-cycle CTGs include the use of DLN combustors (natural gas firing) and water injection (distillate fuel oil firing) for control of NO_x; good combustion practices for abatement of CO and VOCs; and use of clean, low-sulfur, low-ash natural gas and distillate fuel oil to minimize PM/PM_{10}, SO_2, and H_2SO_4 mist emissions.

Figure 2-2 provides a plot plan showing the PPS major process equipment and structures, and the new CTG emission points. Primary access to the PPS plant is from State Road 37 on the west side of the site. The PPS entrance has security to control site access.

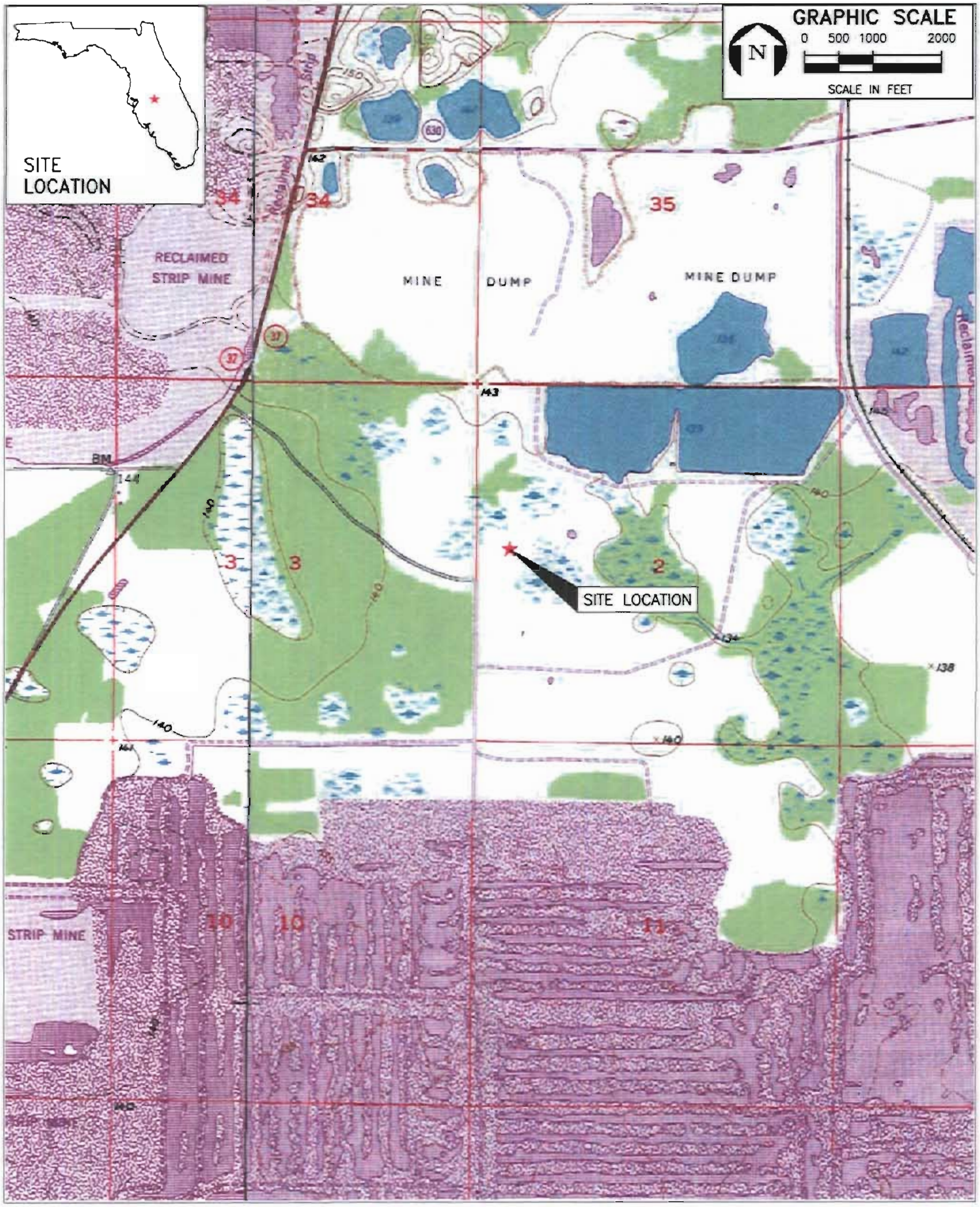

FIGURE 2-1.

AREA MAP

Sources: USGS Quads: Duette NE, FL, 1987; Baird, Fl, 1987; ECT, 2005.

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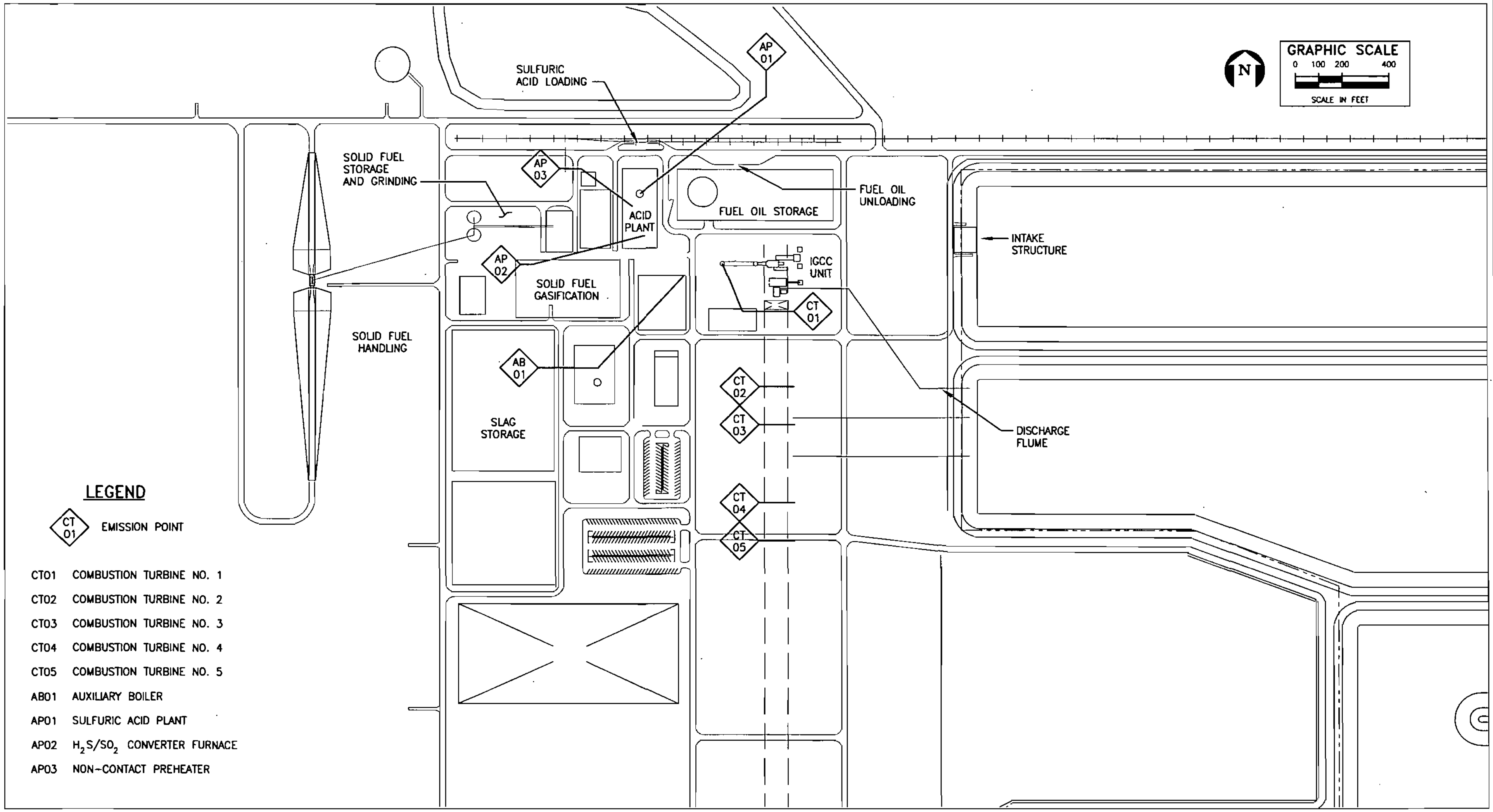

FIGURE 2-2.

POLK POWER STATION PLOT PLAN

Source: Black and Veatch, 2005; ECT, 2005.

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2.2 PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

Proposed Units 4 and 5 will consist of two nominal 165-MW simple-cycle CTGs. Figure 2-3 presents a process flow diagram of the two simple-cycle CTGS.

CTGs are heat engines that convert latent fuel energy into work using compressed hot gas as the working medium. CTGs deliver mechanical output by means of a rotating shaft used to drive an electrical generator, thereby converting a portion of the engine's mechanical output to electrical energy. Ambient air is first filtered and then compressed by the CTG compressor. The CTG compressor increases the pressure of the combustion air stream and also raises its temperature. The compressed combustion air is then combined with natural gas fuel or distillate fuel oil and burned in the CTG's high-pressure combustor to produce hot exhaust gases. These high-pressure, hot gases next expand and turn the CTG's turbine to produce rotary shaft power, which is used to drive an electric generator as well as the CTG combustion air compressor.

During normal gas-firing operations, CO and NO_x exhaust concentrations are expected to remain essentially constant. However, it is possible that CO and NO_x exhaust concentrations will also remain essentially unchanged at lower loads. For this reason, TEC requests the same permit condition authorizing lower load operations for PPS Units 4 and 5 as specified in Section III, Condition 17.b. of Department Air Permit No. PSD-FL-301A, Project No. 0570040-019-AC issued for H.L. Culbreath Bayside Power Station Units 3A and 3B. As noted previously, the simple-cycle CTGs may operate at annual capacity factors up to 50 and 8.6 percent for natural gas and oil firing, respectively.

Vendor information indicates that Units 4 and 5 will have a heat input of 1,894 and 2,067 million British thermal Units power hour (MMBtu/hr), higher heating value (HHV) at stable baseload and 20°F ambient temperature for natural gas and distillate fuel oil firing, respectively. However, CT vendors typically include a margin in guaranteed heat rates and therefore actual heat inputs could be somewhat higher than provided on the vendor expected performance data sheets. In addition, CTG heat rates will gradually increase over time due to routine CTG operation and degradation. TEC has therefore estimated heat input rates based on a 3.5-percent margin to allow for heat rate degradation

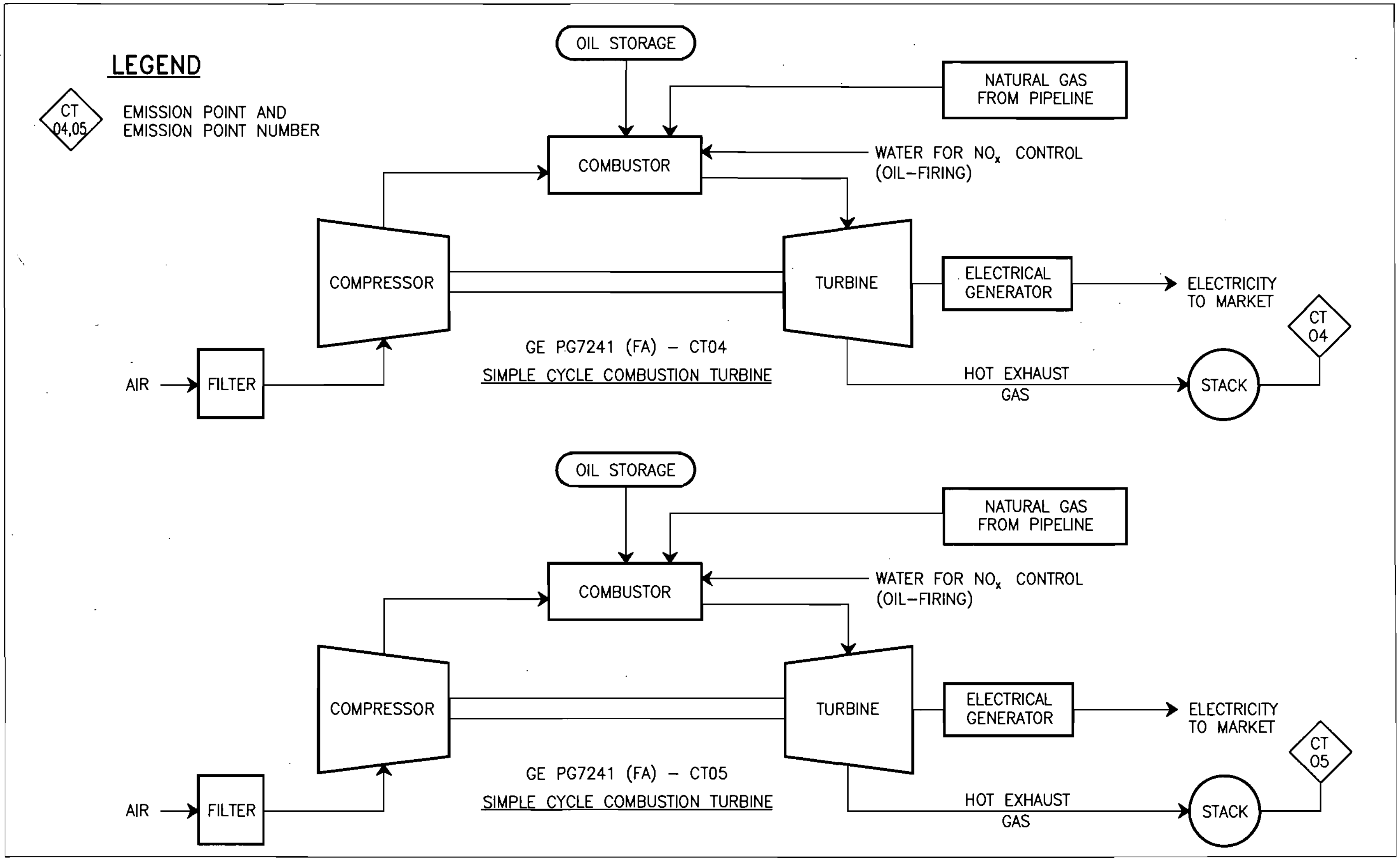

FIGURE 2-3.
SIMPLE CYCLE COMBUSTION TURBINE: PROCESS FLOW DIAGRAM

Source: ECT, 2005.

TECO
TAMPA ELECTRIC

over time consistent with the approach taken for the H.L. Culbreath Bayside Power Station CTGs.

The CTGs will utilize DLN combustion technology and water injection to control NO_x air emissions. The use of low-sulfur natural gas and distillate fuel oil in the CTGs will minimize PM/PM_{10}, SO_2, and H_2SO_4 mist air emissions. High efficiency combustion practices will be employed to control CO and VOC emissions.

2.3 EMISSION AND STACK PARAMETERS

Tables 2-1 and 2-2 provide maximum hourly criteria pollutant CTG emission rates for natural gas and distillate fuel oil firing, respectively. Maximum hourly H_2SO_4 emission rates for natural gas and distillate fuel oil firing are summarized in Tables 2-3. Maximum HAP emission rates for natural gas and distillate fuel oil firing are provided in Tables 2-4 and 2-5, respectively. The highest hourly emission rates for each pollutant are prescribed, taking into account load and ambient temperature to develop maximum hourly emission estimates for each CTG. HAP emissions consist primarily of trace amounts of organic and inorganic compounds associated with the combustion of distillate fuel oil.

Maximum hourly emission rates for all pollutants, in Units of pounds per hour (lb/hr), are projected to occur for CTG operations at low ambient temperature (i.e., 20 degrees Fahrenheit [°F]), baseload, and fuel oil firing. The bases for these emission rates are provided in Appendix C.

Table 2-6 presents projected maximum annualized criteria and HAP emissions for the project. The maximum annualized rates were conservatively estimated assuming baseload operation for 4,380 hr/yr (natural gas firing), baseload operation for 750 hr/yr (fuel oil firing) for each CTG, and an ambient temperature of 59°F.

Stack parameters for Units 4 and 5 are provided in Tables 2-7 and 2-8 for natural gas and distillate fuel oil firing, respectively.

Table 2-1. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures (per SCCT)—Natural Gas

Steady-State Unit Load (%)	Ambient Temperature (°F)	PM/PM_{10}		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	18.0	2.27	10.2	1.28	73.5	9.26	30.3	3.82	3.0	0.38	Neg.	Neg.
	59	18.0	2.27	9.5	1.20	68.8	8.67	28.8	3.63	2.8	0.35	Neg.	Neg.
	90	18.0	2.27	8.8	1.10	63.0	7.94	25.7	3.23	2.6	0.33	Neg.	Neg.
75	20	18.0	2.27	8.2	1.03	58.3	7.35	23.9	3.01	2.1	0.26	Neg.	Neg.
	59	18.0	2.27	7.7	0.97	54.8	6.91	23.0	2.90	1.9	0.24	Neg.	Neg.
	90	18.0	2.27	7.2	0.91	51.3	6.47	21.7	2.74	2.1	0.26	Neg.	Neg.
50	20	18.0	2.27	6.5	0.82	45.5	5.73	19.9	2.50	1.9	0.23	Neg.	Neg.
	59	18.0	2.27	6.2	0.78	43.2	5.44	19.0	2.39	1.7	0.21	Neg.	Neg.
	90	18.0	2.27	5.8	0.73	40.8	5.15	18.4	2.30	1.7	0.21	Neg.	Neg.

Note: g/s = gram per second.
lb/hr = pound per hour.
Neg. = negligible

*Excludes H_2SO_4 mist.

Sources: GE, 1998.
ECT, 2003.

Table 2-2. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures (per SCCT)—Distillate Fuel Oil

Steady-State Unit Load (%)	Ambient Temperature (°F)	PM/PM_{10}		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	34.0	4.28	107.8	13.58	338.0	42.59	97.7	12.31	7.6	0.96	0.104	0.013
	59	34.0	4.28	101.5	12.79	319.0	40.19	92.2	11.62	7.2	0.91	0.098	0.012
	90	34.0	4.28	92.3	11.63	290.0	36.54	84.3	10.62	6.5	0.82	0.093	0.012
75	20	34.0	4.28	87.4	11.02	272.0	34.27	78.5	9.89	5.8	0.73	0.084	0.011
	59	34.0	4.28	82.5	10.40	257.0	32.38	74.0	9.32	5.7	0.72	0.079	0.010
	90	34.0	4.28	75.6	9.53	235.0	29.61	67.8	8.55	5.6	0.71	0.073	0.009
50	20	34.0	4.28	68.2	8.59	210.0	26.46	60.7	7.65	5.1	0.64	0.067	0.008
	59	34.0	4.28	64.9	8.18	200.0	25.20	57.9	7.29	4.6	0.58	0.063	0.008
	90	34.0	4.28	59.8	7.54	184.0	23.18	53.2	6.70	4.5	0.57	0.058	0.007

Note: Neg. = negligible

*Excludes H_2SO_4 mist.

Sources: GE, 1998.
ECT, 2005.

Table 2-3. Maximum H_2SO_4 Pollutant Emission Rates for Three Loads and Three Ambient Temperatures (per SCCT)

Unit Load (%)	Ambient Temperature (°F)	Natural Gas H_2SO_4		Distillate Fuel Oil H_2SO_4	
		lb/hr	g/s	lb/hr	g/s
100	20	1.2	0.15	12.4	1.56
	59	1.1	0.13	11.7	1.47
	90	1.0	0.12	10.6	1.34
75	20	0.9	0.12	10.0	1.27
	59	0.9	0.11	9.5	1.19
	90	0.8	0.10	8.7	1.09
50	20	0.7	0.09	7.8	0.99
	59	0.7	0.09	7.5	0.94
	90	0.7	0.08	6.9	0.87

Sources: GE, 1998.
ECT, 2005.

Table 2-4. Maximum HAP Emission Rates for 100-Percent Load and Three Temperatures (per SCCT)—Natural Gas

Steady-State Unit Load (%)	Ambient Temperature (°F)	1,3-Butadiene		Acetaldehyde		Acrolein		Benzene		Ethylbenzene		Formaldehyde	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	8.43E-05	1.06E-05	7.84E-03	9.88E-04	1.25E-03	1.58E-04	2.35E-03	2.96E-04	6.27E-03	7.90E-04	4.29E-01	5.40E-02
	59	7.89E-05	9.94E-06	7.34E-03	9.24E-04	1.17E-03	1.48E-04	2.20E-03	2.77E-04	5.87E-03	7.39E-04	4.01E-01	5.05E-02
	90	7.26E-05	9.15E-06	6.75E-03	8.51E-04	1.08E-03	1.36E-04	2.03E-03	2.55E-04	5.40E-03	6.81E-04	3.69E-01	4.65E-02

		Naphthalene		Polycyclic Aromatic Hydrocarbons		Propylene Oxide		Toluene		Xylene	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	2.55E-04	3.21E-05	4.31E-04	5.43E-05	5.68E-03	7.16E-04	2.55E-02	3.21E-03	1.25E-02	1.58E-03
	59	2.38E-04	3.00E-05	4.03E-04	5.08E-05	5.32E-03	6.70E-04	2.38E-02	3.00E-03	1.17E-02	1.48E-03
	90	2.19E-04	2.77E-05	3.71E-04	4.68E-05	4.90E-03	6.17E-04	2.19E-02	2.77E-03	1.08E-02	1.36E-03

Note: g/s = gram per second.
lb/hr = pound per hour.

Source: ECT, 2005.

Table 2-5. Maximum HAP Emission Rates for 100-Percent Load and Three Temperatures (per SCCT)—Distillate Fuel Oil

Steady-State Unit Load (%)	Ambient Temperature (°F)	1,3-Butadiene		Arsenic		Benzene		Beryllium		Cadmium		Chromium	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	3.42E-02	4.31E-03	2.35E-02	2.96E-03	1.18E-01	1.48E-02	6.63E-04	8.35E-05	1.03E-02	1.29E-03	2.35E-02	2.96E-03
	59	3.22E-02	4.06E-03	2.22E-02	2.79E-03	1.11E-01	1.40E-02	6.25E-04	7.87E-05	9.67E-03	1.22E-03	2.22E-02	2.79E-03
	90	2.93E-02	3.69E-03	2.02E-02	2.54E-03	1.01E-01	1.27E-02	5.68E-04	7.16E-05	8.80E-03	1.11E-03	2.02E-02	2.54E-03

		Formaldehyde		Lead		Manganese		Mercury		Naphthalene		Nickel	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	4.94E-01	6.22E-02	2.99E-02	3.77E-03	1.69E-00	2.13E-01	2.57E-03	3.23E-04	7.49E-02	9.43E-03	9.84E-03	1.24E-03
	59	4.65E-01	5.86E-02	2.82E-02	3.55E-03	1.59E-00	2.01E-01	2.42E-03	3.05E-04	7.05E-02	8.89E-03	9.27E-03	1.17E-03
	90	4.23E-01	5.33E-02	2.57E-02	3.23E-03	1.45E-00	1.82E-01	2.20E-03	2.77E-04	6.41E-02	8.08E-03	8.43E-03	1.06E-03

		PAH		Selenium	
		lb/hr	g/s	lb/hr	g/s
100	20	8.55E-02	1.08E-02	5.35E-02	6.74E-03
	59	8.06E-02	1.02E-02	5.04E-02	6.35E-03
	90	7.33E-02	8.24E-03	4.58E-02	5.77E-03

Note: Neg. = negligible

Source: ECT, 2005

Table 2-6. Maximum Annualized Emission Rates for Units 4 and 5

Pollutant	Annualized Emission Rates Units 4 and 5 (tpy)		
	Natural Gas	Distillate Fuel Oil	Total Facility
NO_x	301.5	239.2	540.7
CO	157.6	69.2	226.8
PM/PM_{10}*	78.7	25.6	104.3
SO_2	41.7	76.2	117.9
VOC	12.3	5.4	17.7
H_2SO_4	4.7	8.8	13.5
HAPs			
1,3 Butadiene	3.45E-04	2.42E-02	2.45E-02
Acetaldehyde	3.21E-02		3.21E-02
Acrolein	5.14E-03		5.14E-03
Arsenic		1.66E-02	1.66E-02
Benzene	9.64E-03	8.31E-02	9.28E-02
Beryllium		4.68E-04	4.68E-04
Cadmium		7.25E-03	7.25E-03
Chromium		1.66E-02	1.66E-02
Ethylbenzene	2.57E-02		2.57E-02
Formaldehyde	1.76E-00	3.94E-01	2.11E+00
Lead		2.12E-02	2.12E-02
Manganese		1.19E+00	1.19E+00
Mercury		1.81E-03	1.81E-03
Naphthalene	1.04E-03	5.29E-02	5.39E-02
Nickel		6.95E-03	6.95E-03
PAH	1.77E-03	6.04E-02	6.22E-02
Propylene oxide	2.33E-02		2.33E-02
Selenium		3.78E-02	3.78E-02
Toluene	1.04E-01		1.04E-01
Xylenes	5.14E-02		5.14E-02
Total HAPs	2.01	1.87	3.88

*Excludes H_2SO_4 mist.

Sourcs: TEC, 2005.
GE, 1998.
ECT, 2005.

Table 2-7. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—Natural Gas

Steady-State Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meters	°F	K	ft/sec	m/sec	ft	meters
100	20	114.0	34.7	1,081	856	163.8	49.9	18.0	5.49
	59	114.0	34.7	1,117	876	156.8	47.8	18.0	5.49
	90	114.0	34.7	1,141	889	149.3	45.5	18.0	5.49
75	20	114.0	34.7	1,111	873	133.1	40.6	18.0	5.49
	59	114.0	34.7	1,139	888	129.8	39.6	18.0	5.49
	90	114.0	34.7	1,166	903	125.2	38.2	18.0	5.49
50	20	114.0	34.7	1,160	900	112.7	34.4	18.0	5.49
	59	114.0	34.7	1,184	913	110.6	33.7	18.0	5.49
	90	114.0	34.7	1,200	922	107.2	32.7	18.0	5.49

Note: K = Kelvin.
ft/sec = foot per second.
m/sec = meter per second.

Sources: GE, 1998.
ECT, 2005.

Table 2-8. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—Distillate Fuel Oil

Steady-State Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meters	°F	K	ft/sec	m/sec	ft	meters
100	20	114.0	34.7	1,067	848	168.0	51.2	18.0	5.49
	59	114.0	34.7	1,098	865	161.7	49.3	18.0	5.49
	90	114.0	34.7	1,130	883	153.1	46.7	18.0	5.49
75	20	114.0	34.7	1,184	913	135.4	41.3	18.0	5.49
	59	114.0	34.7	1,195	919	131.8	40.2	18.0	5.49
	90	114.0	34.7	1,200	922	127.4	38.8	18.0	5.49
50	20	114.0	34.7	1,200	922	113.6	34.6	18.0	5.49
	59	114.0	34.7	1,200	922	112.1	34.2	18.0	5.49
	90	114.0	34.7	1,200	922	109.2	33.3	18.0	5.49

Note: K = Kelvin.
ft/sec = foot per second.
m/sec = meter per second.

Sources: GE, 1998.
ECT, 2005.

3.0 AIR QUALITY STANDARDS AND

3.1 NATIONAL AND STATE AAQS

As a result of the 1977 Clean Air Act (CAA) Amendments, the U.S. Environmental Protection Agency (EPA) has enacted primary and secondary NAAQS for six air pollutants (Chapter 40, Part 50, Code of Federal Regulations [CFR]). Primary NAAQS are intended to protect the public health, and secondary NAAQS are intended to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Florida has also adopted AAQS (reference Section 62-204.240, F.A.C.). Table 3-1 presents the current national and Florida AAQS.

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. The PPS is located in southwestern Polk County approximately 17 miles south of the city of Lakeland. Polk County is presently designated in 40 CFR 81.310 as better than national standards (for SO_2 and nitrogen dioxide [NO_2]), unclassifiable/attainment (for CO, 1- and 8-hour ozone, and particulate matter less than or equal to 2.5 micrometers [$PM_{2.5}$]), cannot be classified (for total suspended particulates [TSPs]), and not designated (for lead). Polk County is designated attainment (for ozone, SO_2, CO, and NO_2) and unclassifiable (for PM_{10} and lead) by Section 62-204.340, F.A.C.

3.2 NONATTAINMENT NSR APPLICABILITY

The PPS is located in Polk County. As noted previously, Polk County is presently designated as either better than national standards or unclassifiable/attainment for all criteria pollutants. Accordingly, the Units 4 and 5 project is not subject to the nonattainment NSR requirements of Section 62-212.500, F.A.C.

3.3 PSD NSR APPLICABILITY

The existing PPS is classified as a *major facility.* A modification to a major facility which has potential net emissions equal to or exceeding the significant emission rates indicated in Section 62-212.400, Table 212.400-2, F.A.C., is subject to PSD NSR.

Table 3-1. National and Florida Quality Standards (micrograms per cubic meter [$\mu g/m^3$] unless otherwise stated)

Pollutant (units)	Averaging Periods	National Standards Primary	National Standards Secondary	Florida Standards
SO_2	3-hour[1]		1,300	1,300
	24-hour[1]	365		260
	Annual[2]	80		60
PM_{10}	24-hour[3]	150	150	150
	Annual[4]	50	50	50
$PM_{2.5}$	24-hour[5]	65	65	
	Annual[6]	15	15	
CO	1-hour[1]	40,000		40,000
	8-hour[1]	10,000		10,000
Ozone (ppmv)	1-hour[7]			0.12[9]
	8-hour[8]	0.08	0.08	
NO_2	Annual[2]	100	100	100
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5

Note: ppmv = part per million by volume.

[1]Not to be exceeded more than once per calendar year.
[2]Arithmetic mean.
[3]The standards are attained when the expected number of days per calendar year with a 24-hour average concentration above 150 $\mu g/m^3$, as determined in accordance with 40 CFR 50, Appendix K, is equal to or less than one.
[4]The standards are attained when the expected annual arithmetic mean concentration, as determined in accordance with 40 CFR 50, Appendix K, is less than or equal to 50 $\mu g/m^3$.
[5]98th percentile concentration, as determined in accordance with 40 CFR 50, Appendix N.
[6]Arithmetic mean concentration, as determined in accordance with 40 CFR 50, Appendix N.
[7]Standard attained when the expected number of calendar days per calendar year with maximum hourly average concentrations above the standard is equal to or less than 1, as determined by 40 CFR 50, Appendix H. The 1-hour ozone standard was revoked on June 15, 2005, one year following the effective date of the 8-hour ozone standard designations.
[8]Standard attained when the average of the annual 4th highest daily maximum 8-hour average concentration is less than or equal to the standard, as determined by 40 CFR 50, Appendix I.
[9]Applies only in Jacksonville, Miami-Fort Lauderdale-West Palm Beach, and Tampa-St.Petersburg-Clearwater.

Sources: 40 CFR 50.
Section 62-204.240, F.A.C.

The proposed two, new simple-cycle CTGs will have potential emissions in excess of the significant emission rate thresholds. Therefore, the project qualifies as a major modification to a major facility and is subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for those pollutants that are emitted at or above the specified PSD significant emission rate levels. Comparisons of estimated potential annual emission rates for the project and the PSD significant emission rate thresholds are provided in Table 3-2. As shown in this table, potential emissions of NO_x, CO, PM, PM_{10}, SO_2, and H_2SO_4 mist are each projected to exceed the applicable PSD significant emission rate level. These pollutants are, therefore, subject to the PSD NSR requirements of Section 62-212.400, F.A.C. Appendix C provides detailed emission rate estimates for Units 4 and 5.

Table 3-2. Projected Emissions Compared to PSD Significant Emission Rates

Pollutant	Projected Maximum Annual Emissions (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO_x	540.7	40	Yes
CO	226.8	100	Yes
PM	104.3	25	Yes
PM_{10}	104.3	15	Yes
SO_2	117.9	40	Yes
Ozone/VOC	17.7	40	No
Lead	0.2	0.6	No
Mercury	0.0018	0.1	No
Total fluorides	Neg.	3	No
H_2SO_4 mist	13.5	7	Yes
Total reduced sulfur (including hydrogen sulfide)	Not present	10	No
Reduced sulfur compounds (including hydrogen sulfide)	Not present	10	No
Municipal waste combustor acid gases (measured as SO_2 and hydrogen chloride)	Not present	40	No
Municipal waste combustor metals (measured as PM)	Not present	15	No
Municipal waste combustor organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	Not present	3.5×10^{-6}	No

Note: Neg. = negligible.

Sources: Section 62-212.400, Table 212.400-2, F.A.C.
ECT, 2005.

4.0 PSD NSR REQUIREMENTS

4.1 CONTROL TECHNOLOGY REVIEW

Pursuant to Rule 62-212.400(5)(c), F.A.C., an analysis of BACT is required for each pollutant emitted by Units 4 and 5 in amounts equal to or greater than the PSD significant emission rate levels. As defined by Rule 62-210.200(38), F.A.C., BACT is "an emission 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 each such pollutant."

BACT determinations are made on a case-by-case basis as part of the FDEP NSR process and apply to each pollutant that exceeds the PSD significant emission rate thresholds shown in Table 3-2. All emission units, which emit or increase emissions of the applicable pollutants, involved in a major modification or a new major source must undergo BACT analysis. Because each applicable pollutant must be analyzed, particular emission Units may undergo BACT analysis for more than one pollutant.

BACT is defined in terms of a numerical emissions limit. This numerical emissions limit can be based on the application of air pollution control equipment; specific production processes, methods, systems, or techniques; fuel cleaning; or combustion techniques. BACT limitations may not exceed any applicable federal new source performance standard (NSPS), national emission standard for hazardous air pollutants (NESHAPs), or any other emission limitation established by state regulations.

BACT analyses must be conducted using the *top-down* analysis approach, which was outlined in a December 1, 1987, memorandum from Craig Potter, EPA Assistant Administrator, to EPA Regional Administrators on the subject of "Improving New Source Review Implementation." Using the top-down methodology, available control technology alternatives are identified based on knowledge of the particular industry of the applicant and previous control technology permitting decisions for other identical or similar sources. These alternatives are rank-ordered by stringency into a control technology hierarchy. The hierarchy is evaluated starting with the *top*, or most stringent alternative, to determine economic, environmental, and energy impacts and to assess the feasibility or appropriateness of each alternative as BACT based on site-specific factors. If the top control alternative is not applicable or is technically or economically infeasible, it is rejected as BACT, and the next most stringent alternative is then considered. This evaluation process continues until an applicable control alternative is determined to be both technologically and economically feasible, thereby defining the emission level corresponding to BACT for the pollutant in question emitted from the particular facility under consideration.

4.2 AMBIENT AIR QUALITY MONITORING

In accordance with the PSD requirements of Rule 62-212.400(5)(f), F.A.C., any application for a PSD permit must contain, for each pollutant subject to review, an analysis of ambient air quality data in the area affected by the proposed major stationary source or major modification. The affected pollutants are those which the source would potentially emit in significant amounts (i.e., those which exceed the PSD significant emission rate thresholds shown in Table 3-2).

Preconstruction ambient air monitoring for a period of up to 1 year generally is appropriate to complete the PSD requirements. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance (QA) requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided by EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (1987a).

Rule 62-212.400(3)(e), F.A.C., provides an exemption that excludes or limits the pollutants for which an air quality monitoring analysis is conducted. This exemption states that a proposed facility will be exempt from the monitoring requirements of Rule 62-212.400(5)(f) and (g), F.A.C., with respect to a particular pollutant if the emissions increase of the pollution from the source or modification would cause, in any area, air quality impacts less than the PSD *de minimis* ambient impact levels presented in

Rule 62-212.400, Table 212.400-3, F.A.C. (see Table 4-1). In addition, an exemption may be granted if the air quality impacts due to existing sources in the area of concern are less than the PSD *de minimis* ambient impact levels.

Applicability of the PSD preconstruction ambient monitoring requirements to the proposed project is discussed in Section 8.0.

4.3 AMBIENT IMPACT ANALYSIS

An air quality or 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 rates (see Table 3-2). FDEP rules specifically require the use of applicable EPA atmospheric dispersion models in determining estimates of ambient concentrations (refer to Rule 62-204.220[4], F.A.C.). Guidance for the use and application of dispersion models is presented in the EPA *Guideline on Air Quality Models* as published in Appendix W to 40 CFR 51. Criteria pollutants may be exempt from the full source impact analysis if the net increase in impacts due to the new source or modification is below the appropriate Rule 62-210.200(231), F.A.C., significant impact level, as presented in Table 4-2.

Ozone is one pollutant for which a source impact analysis is not normally required. Ozone is formed in the atmosphere as a result of complex photochemical reactions. Models for ozone generally are applied to entire urban areas.

Various lengths of record for meteorological data can be used for impact analyses. A 5-year period can be used with corresponding evaluation of the highest of the 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 PSD increments specify the standard should not be exceeded at any location more than once per year. If less than 5 years of meteorological data are used, the highest concentration at each receptor must be used.

Table 4-1. PSD *De Minimis* Ambient Impact Levels

Averaging Time	Pollutant	Significance Level ($\mu g/m^3$)
Annual	NO_2	14
Quarterly	Lead	0.1
24-Hour	PM_{10}	10
	SO_2	13
	Mercury	0.25
	Fluorides	0.25
8-Hour	CO	575
1-Hour	Hydrogen sulfide	0.2
NA	Ozone	100 tpy of VOC emissions

Source: Section 62-212.400, Table 212.400-3, F.A.C.

Table 4-2. Significant Impact Levels

Pollutant	Averaging Period	Concentration ($\mu g/m^3$)
SO_2	Annual	1
	24-Hour	5
	3-Hour	25
PM_{10}	Annual	1
	24-Hour	5
NO_2	Annual	1
CO	8-Hour	500
	1-Hour	2,000
Lead	Quarterly	0.03

Source: Rule 62-210.200(231), F.A.C.

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality *baseline concentration* level for SO_2 and TSP would constitute significant deterioration. The magnitude of the increment that cannot be exceeded depends on the classification of the area in which a new source (or modification) will 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 2,024 hectares [ha] [5,000 acres], and national parks larger than 2,428 ha [6,000 acres]) or Class II (all other areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. However, the states were given the authority to redesignate any Class II area to Class III status, provided certain requirements were met. EPA then promulgated, as regulations, the requirements for classifications and area designations.

On October 17, 1988, EPA promulgated PSD increments for NO_2; the effective date of the new regulation was October 17, 1989. However, the baseline date for NO_2 increment consumption was set at February 8, 1988; new major sources or modifications constructed after this date will consume NO_2 increment.

On June 3, 1993, EPA promulgated PSD increments for PM_{10}; the effective date of the new regulation was June 3, 1994. The increments for PM_{10} replace the original PM increments which were based on TSP. Baseline dates and areas that were previously established for the original TSP increments remain in effect for the new PM_{10} increments. Revised NAAQS for PM, which include revised NAAQS for PM_{10} and new NAAQS for $PM_{2.5}$, became effective on September 16, 1997. Due to the significant technical difficulties that exist with respect to $PM_{2.5}$ monitoring, emissions estimation, and modeling, EPA has determined that implementation of PSD permitting for $PM_{2.5}$ is administratively impracticable at this time for state permitting authorities. Accordingly, EPA has advised that PM_{10} may be used as a surrogate for $PM_{2.5}$ in meeting NSR requirements until these difficulties are resolved.

Current Florida PSD allowable increments are specified in Section 62-204.260, F.A.C., and shown on Table 4-3.

The term *baseline concentration* evolved from federal and state PSD regulations and denotes a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition in the PSD regulations, as amended, *baseline concentration* means the ambient concentration level that exists in the baseline area at the time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established based on:

- The actual emissions representative of sources in existence on the applicable minor source baseline date.
- The allowable emissions of major stationary sources that commenced construction before the major source baseline date but were not in operation by the applicable minor source baseline date.

The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s) (i.e., allowed increment consumption):

- Actual emissions from any major stationary source on which construction commenced after the major source baseline date.
- Actual emissions increases and decreases at any stationary source occurring after the minor source baseline date.

It is not necessary to make a determination of the baseline concentration to determine the amount of PSD increment consumed. Instead, increment consumption calculations need only reflect the ambient pollutant concentration *change* attributable to emission sources that affect increment. *Major source baseline date* means January 6, 1975, for PM (TSP/PM_{10}) and SO_2 and February 8, 1988, for NO_2. *Minor source baseline date* means the earliest date after the trigger date on which the first complete application was submitted by a major stationary source or major modification subject to the requirements of 40 CFR 52.21 or Section 62-212.400, F.A.C. The trigger dates are August 7, 1977, for PM (TSP/PM_{10}) and SO_2 and February 8, 1988, for NO_2.

Table 4-3. PSD Allowable Increments ($\mu g/m^3$)

Pollutant	Averaging Time	Class I	Class II	Class III
PM_{10}	Annual arithmetic mean	4	17	34
	24-Hour maximum*	8	30	60
SO_2	Annual arithmetic mean	2	20	40
	24-Hour maximum*	5	91	182
	3-Hour maximum*	25	512	700
NO_2	Annual arithmetic mean	2.5	25	50

*Maximum concentration not to be exceeded more than once per year at any one location.

Source: Section 62-204.260, F.A.C.

The ambient impact analysis for Units 4 and 5 is provided in Sections 6.0 (Methodology) and 7.0 (Results).

4.4 ADDITIONAL IMPACT ANALYSES

Rule 62-212.400(5)(e), F.A.C., requires additional impact analyses for three areas: associated growth, soils and vegetation impact, and visibility impairment. The level of analysis for each area should be commensurate with the scope of the project. A more extensive analysis would be conducted for projects having large emission increases than those that will cause a small increase in emissions.

The growth analysis generally includes:

- A projection of the associated industrial, commercial, and residential growth that will occur in the area.
- An estimate of the air pollution emissions generated by the permanent associated growth.
- An air quality analysis based on the associated growth emission estimates and the emissions expected to be generated directly by the new source or modification.

The soils and vegetation analysis is typically conducted by comparing projected ambient concentrations for the pollutants of concern with applicable susceptibility data from the air pollution literature. For most types of soils and vegetation, ambient air concentrations of criteria pollutants below the NAAQS will not result in harmful effects. Sensitive vegetation and emissions of toxic air pollutants could necessitate a more extensive assessment of potential adverse effects on soils and vegetation.

The visibility impairment analysis pertains particularly to Class I area impacts and other areas where good visibility is of special concern. A quantitative estimate of visibility impairment is conducted, if warranted by the scope of the project. Section 9.0 provides the additional impact analyses for Units 4 and 5.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

5.1 METHODOLOGY

BACT analyses were performed in accordance with the EPA top-down method as previously described in Section 4.1. The first step in the top-down BACT procedure is the identification of all available control technologies. Alternatives considered included process designs and operating practices that reduce the formation of emissions, postprocess stack controls that reduce emissions after they are formed, and combinations of these two control categories. Sources of information used to identify control alternatives included:

- EPA reasonably available control technology (RACT)/BACT/lowest achievable emission rate (LAER) Clearinghouse (RBLC) via the RBLC Information System database.
- EPA NSR Web site.
- EPA Control Technology Center (CTC) Web site.
- Recent FDEP BACT determinations for similar facilities.
- Vendor information.
- Environmental Consulting & Technology, Inc. (ECT), experience for similar projects.

Following the identification of available control technologies, the next step in the analysis is to determine which technologies may be technically infeasible. Technical feasibility was evaluated using the criteria contained in Chapter B of the EPA NSR Workshop Manual (EPA, 1990a). The third step in the top-down BACT process is the ranking of the remaining technically feasible control technologies from high to low in order of control effectiveness.

An assessment of energy, environmental, and economic impacts is then performed. The economic analysis employed the procedures found in the Office of Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual, 6th Edition (EPA, 2002). An assessment of energy, environmental, and economic impacts is then performed. Table 5-1 summarizes specific factors used in estimating capital and annual operating costs.

The fifth and final step is the selection of a BACT emission limitation corresponding to the most stringent, technically feasible control technology that was not eliminated based on adverse energy, environmental, or economic grounds.

As indicated in Section 3.3, Table 3-2, projected annual emission rates of NO_x, CO, PM/PM_{10}, SO_2, and H_2SO_4 mist for Units 4 and 5 exceed the PSD significance rates and, therefore, are subject to BACT analysis. Control technology analyses using the five-step top-down BACT method are provided in Sections 5.3, 5.4, and 5.5 for combustion products (PM/PM_{10}), products of incomplete combustion (CO), and acid gases (NO_x, SO_2, and H_2SO_4 mist), respectively.

5.2 FEDERAL AND FLORIDA EMISSION STANDARDS

Pursuant to Rule 62-212.400(5)(b), F.A.C., BACT emission limitations must be no less stringent than any applicable NSPS (40 CFR 60), NESHAPs (40 CFR 61 and 63), and FDEP emission standards (Chapter 62-296, Stationary Sources—Emission Standards, F.A.C.).

On the federal level, emissions from gas turbines are regulated by NSPS Subpart GG. Subpart GG establishes emission limits for gas turbines that were constructed after October 3, 1977, and that meet any of the following criteria:

- Electric utility stationary gas turbines with a heat input at peak load of greater than 100 MMBtu/hr based on the lower heating value (LHV) of the fuel.
- Stationary gas turbines with a heat input at peak load between 10 and 100 MMBtu/hr based on the fuel LHV.
- Stationary gas turbines with a manufacturer's rated baseload at International Standards Organization (ISO) standard day conditions of 30 MW or less.

Table 5-1. Capital and Annual Operating Cost Factors

Cost Item	Factor
Direct Capital Costs	
Instrumentation	0.10 × equipment cost
Sales Tax	0.06 × equipment cost
Freight	0.05 × equipment cost
Foundations and supports	0.08 × purchased equipment cost
Handling and erection	0.14 × purchased equipment cost
Electrical	0.04 × purchased equipment cost
Piping	0.02 × purchased equipment cost
Insulation	0.01 × purchased equipment cost
Painting	0.01 × purchased equipment cost
Indirect Capital Costs	
Engineering	0.10 × purchased equipment cost
Construction and field expenses	0.05 × purchased equipment cost
Contractor fees	0.10 × purchased equipment cost
Start-up	0.02 × purchased equipment cost
Performance testing	0.01 × purchased equipment cost
Contingencies	0.03 × purchased equipment cost
Direct Annual Operating Costs	
Supervisor labor	0.15 × total operator labor cost
Maintenance materials	1.00 × total maintenance labor cost
Emission Fee Credit	$25 per ton
Indirect Annual Operating Costs	
Overhead	0.60 × total of operating, supervisory, and maintenance labor and maintenance materials
Administrative charges	0.02 × total capital investment
Property taxes	0.01 × total capital investment
Insurance	0.01 × total capital investment

Source: EPA, 2002.

The electric utility stationary gas turbine NSPS applicability criterion applies to stationary gas turbines that sell more than one-third of their potential electric output to any utility power distribution system. Units 4 and 5 qualify as electric utility stationary gas turbines and, therefore, are subject to the NO_x and SO_2 emission limitations of NSPS 40 CFR 60, Subpart GG, 60.332(a)(1) and 60.333, respectively.

On February 18, 2005, EPA issued a proposed NSPS Subpart KKKK that will apply to new CTs that commence construction after February 18, 2005. The proposed rule establishes NO_x output-based standards of 1.0 and 1.9 pounds per megawatt-hour (lb/MWhr) of NO_x for CTs greater than 30 MW for gas- and oil-firing, respectively. For SO_2, proposed NSPS Subpart KKKK sets an output-based limit of 0.58 lb/MWhr based on the use of fuels containing no more than 0.05 wt%S. Once NSPS Subpart KKKK is finalized, new CTs constructed after February 18, 2005, will be subject to NSPS Subpart KKKK instead of NSPS Subpart GG. Since Units 4 and 5 will commence construction after February 18, 2005, they will be subject to NSPS Subpart KKKK when finalized.

The proposed Units 4 and 5 have no applicable NESHAP/MACT requirements.

FDEP emission standards for stationary sources are contained in Chapters 62-296, Stationary Sources—Emission Standards, F.A.C. If deemed necessary by FDEP, vapor emission control devices or systems must be employed during the handling of any VOC as required by Rule 62-296.320(1)(a), F.A.C. Visible emissions are limited to a maximum of 20-percent opacity pursuant to Rule 62-296.320(4)(b), F.A.C. Sections 62-296.401 through 62-296.417, F.A.C., specify emission standards for 17 categories of sources; none of these categories are applicable to SCCTs. Finally, Section 62-204.800, F.A.C., adopts federal NSPS and NESHAP, respectively, by reference. As noted previously, NSPS Subpart GG, Stationary Gas Turbines, is applicable to Units 4 and 5. There are no applicable NESHAP requirements.

Tables 5-2 and 5-3 summarize applicable federal and state emission standards, respectively. Detailed calculations of NSPS Subpart GG NO_x limitations are provided in Attachment B.

Table 5-2. Federal Emission Limitations

NSPS Subpart GG, Stationary Gas Turbines

Pollutant	Emission Limitation
NO_x	STD = 0.0075 × (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 in kilojoules per watt hour at manufacturer's rated load, or actual measured heat rate based on LHV of fuel as measured at actual peak load. Y cannot exceed 14.4 kilojoules per watt hour.
- F = NO_x emission allowance for fuel-bound nitrogen per:
- FBN = fuel bound nitrogen.

FBN (weight percent)	F (NO_x - volume percent)
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 = nitrogen content of fuel; percent by weight.
- SO_2 = .0.015 percent by volume at 15-percent oxygen and on a dry basis; or fuel sulfur content. 0.8 wt%S.

Source: 40 CFR 60, Subpart GG.

Table 5-3. Florida Emission Limitations

Pollutant	Emission Limitation
General Visible Emissions Standard Rule 62-296.320(4)(b)1., F.A.C.	
• Visible emissions	<20-percent opacity (averaged over a 6-minute period
General VOCs or Organic Solvents Standard Rule 62-296.320(1)(a), F.A.C.	
• VOC	No person shall store, pump, handle, process, load, unload, or use in any process or installation VOCs or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.

Source: Chapter 62-296, F.A.C.

BACT emission limitations proposed for Units 4 and 5 are all more stringent than the applicable federal and state standards cited in these tables.

5.3 BACT ANALYSIS FOR PM/PM_{10}

PM/PM_{10} emissions resulting from the combustion of natural gas and distillate fuel oil are due to the oxidation of ash and sulfur contained in these fuels. Due to their low ash and sulfur contents, natural gas and distillate fuel oil combustion generate inherently low PM/PM_{10} emissions.

5.3.1 POTENTIAL CONTROL TECHNOLOGIES

Available technologies used for controlling PM/PM_{10} include the following:

- Centrifugal collectors.
- Electrostatic precipitators (ESPs).
- Fabric filters or baghouses.
- Wet scrubbers.

Centrifugal (cyclone) separators are primarily used to recover material from an exhaust stream before the stream is ducted to the principal control device since cyclones are effective in removing only large sized (greater than 10 microns) particles. Particles generated from natural gas combustion are typically less than 1.0 micron in size.

ESPs remove particles from a gas stream through the use of electrical forces. Discharge electrodes apply a negative charge to particles passing through a strong electrical field. These charged particles then migrate to a collecting electrode having an opposite, or positive, charge. Collected particles are removed from the collecting electrodes by periodic mechanical rapping of the electrodes. Collection efficiencies are typically 95 percent for particles smaller than 2.5 microns in size.

A fabric filter system consists of a number of filtering elements, bag cleaning system, main shell structure, dust removal system, and fan. PM is filtered from the gas stream by various mechanisms (inertial impaction, impingement, accumulated dust cake sieving, etc.) as the gas passes through the fabric filter. Accumulated dust on the bags is periodically removed using mechanical or pneumatic means. In pulse jet pneumatic cleaning, a sudden pulse of compressed air is injected into the top of the bag. This pulse creates a traveling wave in the fabric that separates the cake from the surface of the fabric. The cleaning normally proceeds by row, all bags in the row being cleaned simultaneously. Typical air-to-cloth ratios range from 2 to 8 cubic feet per minute-square foot (cfm-ft^2). Collection efficiencies are on the order of 99 percent for particles smaller than 2.5 microns in size.

Wet scrubbers remove PM from gas streams principally by inertial impaction of the particulate onto a water droplet. Particles can be wetted by impingement, diffusion, or condensation mechanisms. To be wetted, PM must either make contact with a spray droplet or impinge upon a wet surface. In a venturi scrubber, the gas stream is constricted in a throat section. The large volume of gas passing through a small constriction gives a high gas velocity and a high-pressure drop across the system. As water is introduced into the throat, the gas is forced to move at a higher velocity causing the water to shear into droplets. Particles in the gas stream then impact onto the water droplets produced. The entrained water droplets are subsequently removed from the gas stream by a cyclone separator. Venturi scrubber collection efficiency increases with increasing pressure drops for a given particle size. Collection efficiency will also increase with increasing liquid-to-gas ratios up to the point where flooding of the system occurs. Packed-bed and venturi scrubber collection efficiencies are typically 90 percent for particles smaller than 2.5 microns in size.

While all of these postprocess technologies would be technically feasible for controlling PM/PM_{10} emissions from SCCTs, none of the previously described control equipment have been applied to SCCTs because exhaust gas PM concentrations are inherently low. SCCTs operate with a significant amount of excess air, which generates large exhaust gas flow rates. Units 4 and 5 will be fired with natural gas as the primary fuel and distillate fuel oil as the back-up fuel source. Combustion of natural gas and distillate fuel oil will generate low PM emissions in comparison to other fuels due to their low ash and sulfur contents. The minor PM emissions coupled with a large volume of exhaust gas produces extremely low exhaust stream PM concentrations. The estimated PM/PM_{10} exhaust concentrations for Units 4 and 5 at baseload and 59°F are approximately 0.003 and 0.005 grain per dry standard cubic foot (gr/dscf) while firing natural gas and distillate fuel oil, respectively. Exhaust stream PM concentrations of such low magnitude are not amenable to control using available technologies because removal efficiencies would be unreasonably low and costs excessive.

5.3.2 PROPOSED BACT EMISSION LIMITATIONS

Recent Florida BACT determinations for natural gas- and distillate fuel oil-fired SCCTs are based on the use of clean fuels and good combustion practice.

Because postprocess stack controls for PM/PM_{10} are not appropriate for SCCTs, the use of good combustion practices and clean fuels is considered to be BACT. Units 4 and 5 will use DLN combustor technology to maximize combustion efficiency and minimize PM/PM_{10} emission rates. Combustion efficiency, defined as the percentage of fuel completely oxidized in the combustion process, is projected to be greater than 99 percent. Units 4 and 5 will be fired primarily with pipeline-quality natural gas. Low-sulfur, low-ash distillate fuel oil will serve as a back-up fuel source. Due to the difficulties associated with stack testing exhaust streams containing very low PM/PM_{10} concentrations and consistent with recent FDEP BACT determinations for SCCTs, a visible emissions limit of 10-percent opacity is proposed as a surrogate BACT limit for PM/PM_{10}. Table 5-4 summarizes PM/PM_{10} BACT emission limits proposed for Units 4 and 5.

5.4 BACT ANALYSIS FOR CO

There are two available technologies for controlling CO from SCCTs: combustion process design and oxidation catalysts.

Combustion Process Design

Combustion process controls involve combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. Due to the high combustion efficiency of SCCTs, approximately 99 percent, CO emissions are inherently low.

Table 5-4. Proposed PM/PM_{10} BACT

Emission Source	Proposed PM/PM_{10} BACT
GE PG7241 (FA) (per SCCT unit)	Exclusive use of clean fuels (i.e., natural gas and distillate fuel oil) Efficient combustion design and operation 10.0-percent opacity (indicator of efficient combustion design and operation)

Sources: TEC, 2005.
ECT, 2005.

Oxidation Catalysts

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of CO to carbon dioxide (CO_2) at temperatures lower than would be necessary for oxidation without a catalyst. The operating temperature range for conventional oxidation catalysts is between 650 and 1,150°F. Recently, high temperature oxidation catalysts have been developed which can tolerate higher temperatures (i.e., greater than 1,200°F). Typically, the oxidation catalyst is located within a heat recovery steam generator (HRSG) where temperatures range from 450 to 1,100°F.

Efficiency of CO oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature up to a temperature of approximately 1,100°F; further temperature increases will have little effect on control efficiency. Significant CO oxidation will occur at any temperature above roughly 500°F. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst that will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time that is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an increase in pressure drop across the catalyst bed. For combustion turbine applications, oxidation catalyst systems are typically designed to achieve a control efficiency of 80 to 90 percent for CO.

Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica will all act as catalyst poisons causing a reduction in catalyst activity and pollutant removal efficiencies.

Oxidation catalysts are nonselective and will oxidize other compounds in addition to CO. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. The catalyst will further oxidize sulfur compounds that have been oxidized to SO_2 in the combustion process to sulfur trioxide (SO_3). SO_3 will, in turn, combine with moisture in the gas stream to form H_2SO_4 mist. Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalysts are not considered to be an appropriate control technology for combustion devices that are fired with fuels containing significant amounts of sulfur.

Technical Feasibility

Both SCCT combustor design and oxidation catalyst control systems are considered to be technically feasible for Units 4 and 5. Information regarding energy, environmental, and economic impacts and proposed BACT limits for CO are provided in the following sections.

5.4.1 ENERGY AND ENVIRONMENTAL IMPACTS

There are no significant adverse energy or environmental impacts associated with the use of good combustor designs and operating practices to minimize CO emissions.

The use of oxidation catalysts will, as previously noted, result in excessive H_2SO_4 mist emissions if applied to combustion devices fired with fuels containing high sulfur contents. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from SCCTs fired with natural gas and distillate fuel oil.

Because CO emission rates from SCCTs are inherently low, further reductions through the use of oxidation catalysts will result in minimal air quality improvements (i.e., below the defined PSD significant impact levels for CO). The location of Units 4 and 5 (rural Polk County) is classified attainment for all criteria pollutants, including CO. As noted in FDEP's 2003 Air Monitoring Report, there have been no exceedances of the CO AAQSs in Florida since 1988. Maximum CO concentrations for all Florida monitoring sites during 2003 were less than 25 percent of the 35-part-per-million (ppm) 1-hour AAQS, and less than 45 percent of the 9-ppm 8-hour AAQS. From an air quality perspective, the only potential benefit of CO oxidation catalyst is to prevent the possible formation of a localized area with elevated concentrations of CO. The catalyst does not remove CO but rather simply accelerates the natural atmospheric oxidation of CO to CO_2. Dispersion modeling of Units 4 and 5 CO emissions indicated that maximum CO impacts, without oxidation catalyst, will be insignificant. The highest 1- and 8-hour average CO impacts were projected to be only 0.13 and 0.20 percent of the Florida and Federal CO AAQS.

The application of oxidation catalyst technology to a gas turbine will result in an increase in backpressure due to a pressure drop across the catalyst bed. The increased backpressure will, in turn, constrain turbine output power thereby increasing the unit's heat rate. An oxidation catalyst system for Units 4 and 5 is projected to have a pressure drop across the catalyst bed of approximately 1.4 inch of water (H_2O). This pressure drop will result in a 0.28-percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 4,740,120 kilowatt-hours (kWh) (16,174 million British thermal units [MMBtu] per year at baseload (165 MW) operation and 50-percent capacity factor for both SCCTs. This energy penalty is equivalent to the use of 15.4 million cubic feet (ft^3) of natural gas annually based on a natural gas heating value of 1,050 British thermal Units per cubic foot (Btu/ft^3) for both SCCTs. The lost power generation energy penalty, based on a power cost of $0.030/kWh, is $42,204 per year for both SCCTs. Actual generation cost based on current fuel prices is $0.150/kWh resulting in an energy penalty of $11,018.

5.4.2 ECONOMIC IMPACTS

An economic evaluation of an oxidation catalyst system was performed using OAQPS factors and the project-specific economic factors provided in Table 5-5. Specific capital and annual operating costs for the oxidation catalyst control system are summarized in Tables 5-6 and 5-7, respectively.

The base case Units 4 and 5 annual CO emission rate (i.e., for both SCCTs) is 226.8 tpy based on SCCT baseload operation at 59°F for 4,380 hr/yr operation gas-firing and 750 hr/yr oil-firing. The controlled annual CO emission rate, based on 90-percent control efficiency, is 22.7 tpy. The cost effectiveness of oxidation catalyst for CO emissions was determined to be $6,203 per ton of CO removed using the FDEP-recommended economic cost factors. Use of current fuel and electric generation costs results in a cost effectiveness of $8,990 per ton of CO controlled. Based on these high control costs, use of oxidation catalyst technology to control CO emissions is not considered to be economically feasible. The economic analysis is considered to be conservative (i.e., under-estimate the actual cost effectiveness) since actual SCCT exhaust CO concentrations are expected to

Table 5-5. Economic Cost Factors

Factor	Units	Value
Interest rate	Percent	7.0*
Control system life	Years	15
Oxidation catalyst life	Years	5
SCR catalyst life	Years	3
Oxidation catalyst control efficiency	Percent	90.0*
SCR catalyst control efficiency (gas)	Percent	67.0
SCR catalyst control efficiency (oil)	Percent	76.0
Electricity cost	$/kWh	0.030*
Electricity cost (current)	$/kWh	0.150
Labor costs (base rates)	$/hour	
Operator		22.00
Maintenance	22.00	

* Per FDEP recommendation.

Sources: TEC, 2005.
ECT, 2005.

Table 5-6. Capital Costs for Oxidation Catalyst Systems, Units 4 and 5

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	3,215,000	A
Sales tax	192,900	0.06 × A
Instrumentation	321,500	0.10 × A
Freight	105,300	0.05 × A
Subtotal Purchased Equipment	**3,890,150**	**B**
Installation		
Foundations and supports	311,212	0.08 × B
Handling and erection	544,621	0.14 × B
Electrical	155,606	0.04 × B
Piping	77,803	0.02 × B
Insulation for ductwork	38,902	0.01 × B
Painting	38,902	0.01 × B
Subtotal Installation Cost	**1,167,045**	
Total Direct Costs (TDC)	**5,057,195**	
Indirect Costs		
Engineering	389,015	0.10 × B
Construction and field expenses	194,508	0.05 × B
Contractor fees	389,015	0.10 × B
Startup	77,803	0.02 × B
Performance test	38,902	0.01 × B
Contingency	116,705	0.03 × B
Total Indirect Costs (TIC)	**1,205,947**	
TOTAL CAPITAL INVESTMENT (TCI)	**6,263,142**	TDC + TIC

Source: ECT, 2005.

Table 5-7. Annual Operating Costs for Oxidation Catalyst Systems, Units 4 and 5

Item	Dollars	OAQPS Factor
Direct Costs		
Catalyst costs		
Replacement (materials and labor)	1,889,112	5-year replacement
Credit for Recycled Catalyst	(255,000)	15%
Annualized Catalyst Costs	**398,545**	
Energy Penalties		
Turbine backpressure	142,204	0.28% penalty
Total Direct Costs (TDC)	**540,748**	
Indirect Costs		
Administrative charges	125,263	0.02 × TCI
Property taxes	62,631	0.01 × TCI
Insurance	62,631	0.01 × TCI
Capital recovery	480,245	15 years @ 7.0%
Total Indirect Costs (TIC)	**730,771**	
Permit Fee Credit	(5,104)	$25/ton
TOTAL ANNUAL COST (TAC)	**1,266,415**	TDC + TIC

Sources: ECT, 2005.

be well below the GE guarantees. Results of the oxidation catalyst economic analysis are summarized in Table 5-8.

5.4.3 PROPOSED BACT EMISSION LIMITATIONS

The use of oxidation catalyst to control CO from SCCTs is typically required only for facilities located in CO or ozone nonattainment areas.

The use of oxidation catalysts will, as previously noted, result in excessive H_2SO_4 mist emissions if applied to combustion devices fired with fuels containing appreciable amounts of sulfur. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from SCCTs fired with natural gas and low sulfur distillate fuel oil. Because CO emission rates from SCCTs are inherently low, further reductions through the use of oxidation catalysts will result in only minor improvement in air quality (i.e., well below the defined PSD significant impact levels for CO).

Use of state-of-the-art combustor design and good operating practices to minimize incomplete combustion is proposed as BACT for CO. These control techniques have been considered by FDEP to represent BACT for CO for recent SCCT projects

CO exhaust concentrations from Units 4 and 5 will be less than or equal to 9.0 and 20.0 ppmvd for natural gas and distillate fuel oil firing, respectively, at baseload. These CO exhaust concentrations are consistent with recent FDEP CO BACT determinations for SCCT units.

CO BACT emission limits proposed for Units 4 and 5 are provided in Table 5-9. The CO BACT limits shown in Table 5-9 are consistent with the limits recently approved by FDEP for the Bayside Unit 3 SCCTs.

5.5 <u>BACT ANALYSIS FOR NO_X</u>

NO_x emissions from combustion sources consist of two components: oxidation of combustion air atmospheric nitrogen (thermal NO_x and prompt NO_x) and conversion of chemically bound fuel nitrogen (fuel NO_x). Essentially all SCCT NO_x emissions originate

Table 5-8. Summary of CO BACT Analysis

	Emission Impacts			Economic Impacts			Energy Impacts	Environmental Impacts	
	Emission Rates		Emission Reduction	Installed Capital Cost	Total Annualized Cost	Cost Effectiveness Over Baseline	Increase Over Baseline	Toxic Impact	Adverse Environmental Impact
Control Option	lb/hr	tpy	(tpy)	($)	($/yr)	($/ton)	(MMBtu/yr)	(Y/N)	(Y/N)
Oxidation catalyst	8.9	22.7	204.1	6,263,142	1,266,415	6,203	16,174	Y	Y
Baseline	88.4	226.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Two GE PG7241 (FA) SCCTs, 100-percent load, 59°F ambient temperature, 4,380 hr/yr gas-fired, 750 hr/yr oil-fired, FDEP economic factors.

Sources: GE, 1998.
ECT, 2005.

Table 5-9. Proposed CO BACT Emission Limits

Emission Source	Proposed CO BACT Emission Limits	
	ppmvd*	lb/hr†
GE PG7241 (FA) SCCT (per SCCT)		
CO (natural gas)	9.0	36.0
CO (distillate fuel oil)	20.0	92.2

*Corrected to 15-percent oxygen, 24-hour block average.
†CT compressor inlet air temperature of 59°F, baseload.

Sources: TEC, 2005.
ECT, 2005.

as nitric oxide (NO). NO generated by the SCCT combustion process is subsequently further oxidized in the SCCT exhaust system or in the atmosphere to the more stable NO_2 molecule.

Thermal NO_x results from the oxidation of atmospheric nitrogen under high temperature combustion conditions. The amount of thermal NO_x formed is primarily a function of combustion temperature and residence time, air/fuel ratio, and, to a lesser extent, combustion pressure. Thermal NO_x increases exponentially with increases in temperature and linearly with increases in residence time as described by the Zeldovich mechanism. Prompt NO_x is formed near the combustion flame front from the oxidation of intermediate combustion products such as hydrogen cyanide (HCN), nitrogen (N), and NH. Prompt NO_x comprises a small portion of total NO_x in conventional near-stoichiometric CTG combustors but increases under fuel-lean conditions. Prompt NO_x, therefore, is an important consideration with respect to DLN combustors that use lean fuel mixtures. Fuel NO_x arises from the oxidation of nonelemental nitrogen contained in the fuel. The conversion of fuel-bound nitrogen (FBN) to NO_x depends on the bound nitrogen content of the fuel. In contrast to thermal NO_x, fuel NO_x formation does not vary appreciably with combustion variables such as temperature or residence time. Presently, there are no combustion processes or fuel treatment technologies available to control fuel NO_x emissions. For this reason, the gas turbine NSPS (Subpart GG) contains an allowance for FBN (see Table 5-2). NO_x emissions from combustion sources fired with fuel oil are higher than those fired with natural gas due to higher combustion flame temperatures and FBN contents. Natural gas may contain molecular nitrogen (N_2); however, the N_2 found in natural gas does not contribute significantly to fuel NO_x formation. Typically, natural gas contains a negligible amount of FBN.

5.5.1 POTENTIAL CONTROL TECHNOLOGIES

Available technologies for controlling NO_x emissions from SCCTs include combustion process modifications and postcombustion exhaust gas treatment systems. A listing of available technologies for each of these categories follows:

Combustion Process Modifications:

- Water or steam injection, with advanced combustors.
- DLN combustor design.
- XONON™.

Postcombustion Exhaust Gas Treatment Systems:

- Selective non-catalytic reduction (SNCR).
- Non-selective catalytic reduction (NSCR).
- SCR.
- EMx™ (formerly SCONOx™).

A description of each of the listed control technologies is provided in the following sections.

Water or Steam Injection

Injection of water or steam into the primary combustion zone of advanced combustors of a CT reduces the formation of thermal NO_x by decreasing the peak combustion temperature. Water injection decreases the peak flame temperature by diluting the combustion gas stream and acting as a heat sink by absorbing heat necessary to: (a) vaporize the water (latent heat of vaporization), and (b) raise the vaporized water temperature to the combustion temperature. High purity water must be employed to prevent turbine corrosion and deposition of solids on the turbine blades. Steam injection employs the same mechanisms to reduce the peak flame temperature with the exclusion of heat absorbed due to vaporization since the heat of vaporization has been added to the steam prior to injection. Accordingly, a greater amount of steam, on a mass basis, is required to achieve a specified level of NO_x reduction in comparison to water injection. Typical injection rates range from 0.3 to 1.0 and 0.5 to 2.0 pounds of water and steam, respectively, per pound of fuel. Water or steam injection will not reduce the formation of fuel NO_x.

The maximum amount of steam or water that can be injected depends on the SCCT combustor design. Excessive rates of injection will cause flame instability, combustor dynamic pressure oscillations, thermal stress (cold-spots), and increased emissions of CO and VOCs due to combustion inefficiency. Accordingly, the efficiency of steam or water injection to reduce NO_x emissions also depends on turbine combustor design.

The use of water or steam injection in advanced combustors can typically achieve NO_x exhaust concentrations of 25 and 42 ppmvd for gas and oil firing, respectively.

Dry Low-NO_x Combustor Design

A number of turbine vendors have developed DLN combustors that premix turbine fuel and air prior to combustion in the primary zone. Use of a premix burner results in a homogeneous air/fuel mixture without an identifiable flame front. For this reason, the peak and average flame temperatures are the same, causing a decrease in thermal NO_x emissions in comparison to a conventional diffusion burner. A typical DLN combustor incorporates fuel staging using several operating modes as follows:

- Primary Mode—Fuel supplied to first stage only at turbine loads from 0 to 35 percent. Combustor burns with a diffusion flame with quiet, stable operation. This mode is used for ignition, warm-up, acceleration, and low-load operation.
- Lean-Lean Mode—Fuel supplied to both stages with flame in both stages at turbine loads from 35 to 50 percent. Most of the secondary fuel is premixed with air. Turbine loading continues with a flame present in both fuel stages. As load is increased, CO emissions will decrease, and NO_x levels will increase. Lean-lean operation will be maintained with increasing turbine load until a preset combustor fuel-to-air ratio is reached when transfer to premix operation occurs.
- Secondary Mode (Transfer to Premix)—At 70-percent load, all fuel is supplied to second stage.
- Premix Mode—Fuel is provided to both stages with approximately 80 percent furnished to the first stage at turbine loads from 70 to 100 percent. Flame is present in the second stage only.

Currently, premix burners are limited in application to natural gas and loads above approximately 35 to 50 percent of baseline due to flame stability considerations. For SCCTs capable of oil firing, wet injection is employed to control NO_x emissions.

In addition to lean premixed combustion, SCCT DLN combustors typically incorporate lean combustion and reduced combustor residence time to reduce the rate of NO_x formation. All SCCTs cool the high-temperature SCCT exhaust gas stream with dilution air to lower the exhaust gas to an acceptable temperature prior to entering the SCCT turbine. By adding additional dilution air, the hot SCCT exhaust gases are rapidly cooled to temperatures below those needed for NO_x formation. Reduced residence time combustors add the dilution air sooner than do standard combustors. The amount of thermal NO_x is reduced because the SCCT combustion gases are at a higher temperature for a shorter period of time.

Current DLN combustor technology can typically achieve a NO_x exhaust concentration of 15 ppmvd or less using natural gas fuel.

XONON™

The XONON™ Cool Combustion technology, being developed for CTs by Catalytica Energy Systems, Inc. (CESI), employs a catalyst integral to the CT combustor to reduce the formation of NO_x. In a conventional CT combustor, fuel and air are oxidized in the presence of a flame to produce the hot exhaust gases required for power generation. The XONON™ Cool Combustion technology replaces this conventional combustion process with a two-step approach. First, a portion of the CT fuel is mixed with air and burned in a low-temperature pre-combustor. The main CT fuel is then added and oxidation of the total fuel/air mixture stream is completed by means of flameless, catalytic combustion. The catalyst module is located within the CT combustor. NO_x formation is reduced due to the relatively low oxidation temperatures occurring within the pre-combustor and the flameless combustor catalyst module. Information provided by CESI indicates that the XONON™ Cool Combustion technology is capable of achieving CT NO_x exhaust concentrations of 2.5 ppmvd at 15-percent oxygen.

Commercial operation of the XONON™ Cool Combustion technology is limited to one small (1.5 MW) baseload, natural gas-fired Kawasaki CT operated by the Silicon Valley Power municipal utility. This CT is located in Santa Clara, California. Performance of the XONON™ Cool Combustion technology on larger CTs has not been demonstrated to date.

Availability of the XONON™ Cool Combustion technology is limited to specific gas turbine manufacturers which have agreements with CESI to adapt the proprietary XONON™ combustion system to gas turbines in their product lines. CESI literature indicates that General Electric Power Systems is engaged in development work to adapt the XONON™ Cool Combustion technology to their E- and F-Class CTs. Other CT vendors having agreements with CESI include Pratt & Whitney Canada (for their ST-18 and ST-30 CTs), Rolls Royce Allison, and Solar Turbines.

Proposed Unit 4 and 5 are GE 7FA units. The XONON™ Cool Combustion technology is not yet commercially available for this unit. In addition, XONON™ Cool Combustion technology has not been demonstrated on large, heavy-duty CTs. Accordingly, the XONON™ Cool Combustion technology is not considered to be an available control technology for Units 4 and 5.

Selective Non-Catalytic Reduction

The SNCR process involves the gas phase reaction, in the absence of a catalyst, of NO_x in the exhaust gas stream with injected ammonia (NH_3) or urea to yield nitrogen and water vapor. The two commercial applications of SNCR include the Electric Power Research Institute's NO_xOUT and Exxon's Thermal DeNO_x processes. The two processes are similar in that either NH_3 (Thermal DeNO_x) or urea (NO_xOUT) is injected into a hot exhaust gas stream at a location specifically chosen to achieve the optimum reaction temperature and residence time. Simplified chemical reactions for the Thermal DeNO_x process are as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6\,H_2O \qquad (1)$$

$$4\,NH_3 + 5\,O_2 \rightarrow 4NO + 6\,H_2O \qquad (2)$$

The NO_xOUT process is similar with the exception that urea is used in place of NH_3. The critical design parameter for both SNCR processes is the reaction temperature. At temperatures below 1,600°F, rates for both reactions decrease allowing unreacted NH_3 to exit with the exhaust stream. Temperatures between 1,600 and 2,000°F will favor Reaction (1) resulting in a reduction in NO_x emissions. Reaction (2) will dominate at temperatures above approximately 2,000°F, causing an increase in NO_x emissions. Due to reaction temperature considerations, the SNCR injection system must be located at a point in the exhaust duct where temperatures are consistently between 1,600 and 2,000°F.

Non-Selective Catalytic Reduction

The NSCR process utilizes a platinum/rhodium catalyst to reduce NO_x to nitrogen and water vapor under fuel-rich (less than 3-percent oxygen) conditions. NSCR technology has been applied to automobiles and stationary reciprocating engines.

Selective Catalytic Reduction

In contrast to SNCR, SCR reduces NO_x emissions by reacting NH_3 with exhaust gas NO_x to yield nitrogen and water vapor in the presence of a catalyst. NH_3 is injected upstream of the catalyst bed where the following primary reactions take place:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \quad (3)$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O \quad (4)$$

The catalyst serves to lower the activation energy of these reactions, which allows the NO_x conversions to take place at a lower temperature (i.e., in the range of 600 to 750°F). Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the volume of the catalyst bed), NH_3/NO_x molar ratio, and catalyst bed temperature. Space velocity is a function of catalyst bed depth. Decreasing the space velocity (increasing catalyst bed depth) will improve NO_x removal efficiency by increasing residence time but will also cause an increase in catalyst bed pressure drop. The reaction of NO_x with NH_3 theoretically requires a 1:1 molar ratio. NH_3/NO_x molar ratios greater than

1:1 are necessary to achieve high-NO_x removal efficiencies due to imperfect mixing and other reaction limitations. However, NH_3/NO_x molar ratios are typically maintained at 1:1 or lower to prevent excessive unreacted NH_3 (ammonia slip) emissions.

As was the case for SNCR, reaction temperature is critical for proper SCR operation. The optimum temperature range for conventional SCR operation is 600 to 750°F. Below this temperature range, reduction Reactions (3) and (4) will not proceed. At temperatures exceeding the optimal range, oxidation of NH_3 will take place resulting in an increase in NO_x emissions. Specially formulated, high-temperature zeolite catalysts have recently been developed that function at exhaust stream temperatures up to a maximum of approximately 1,050°F. NO_x removal efficiencies for SCR systems typically range from 60 to 90 percent.

SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include arsenic, sulfur, potassium, sodium, and calcium. Due to the potential for chemical poisoning with fuels other than natural gas, application of SCR to CTs has been primarily limited to natural gas-fired units.

EMx™ (SCONO$_x$™)

EMx™ (formerly referred to as SCONO$_x$™) is a multi-pollutant reduction catalytic control system offered by EmeraChem. EMx™ is a complex technology that is designed to simultaneously reduce NO_x, VOC, and CO through a series of oxidation/absorption catalytic reactions.

The EMx™ system employs a single catalyst to simultaneously oxidize CO to CO_2 and NO to NO_2. NO_2 formed by the oxidation of NO is subsequently absorbed onto the catalyst surface through the use of a potassium carbonate absorber coating. The EMx™ oxidation/absorption cycle reactions are:

$$CO + \frac{1}{2} O_2 \rightarrow CO_2 \quad (5)$$

$$NO + \frac{1}{2} O_2 \rightarrow NO_2 \quad (6)$$

$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3 \quad (7)$$

CO_2 produced by Reactions (5) and (7) is released to the atmosphere as part of the CT/HRSG exhaust stream.

As shown in Reaction (7), the potassium carbonate catalyst coating reacts with NO_2 to form potassium nitrites and nitrates. Prior to saturation of the potassium carbonate coating, the catalyst must be regenerated. This regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of O_2. Hydrogen in the reducing gas reacts with the nitrites and nitrates to form water and elemental nitrogen. CO_2 in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate; this compound is the catalyst absorber coating present on the surface of the catalyst at the start of the oxidation/absorption cycle. The EMx™ regeneration cycle reaction is:

$$KNO_2 + KNO_3 + 4 H_2 + CO_2 \rightarrow K_2CO_3 + 4 H_2O_{(g)} + N_2 \quad (8)$$

Water vapor and elemental nitrogen are released to the atmosphere as part of the CT/HRSG exhaust stream. Following regeneration, the EMx™ catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again. There is no net gain or loss of potassium carbonate after both the oxidation/absorption and regeneration cycles have been completed.

Since the regeneration cycle must take place in an oxygen-free environment, the section of catalyst undergoing regeneration is isolated from the exhaust gas stream using a set of louvers. Each catalyst section is equipped with a set of upstream and downstream louvers. During the regeneration cycle, these louvers close and valves open allowing fresh regeneration gas to enter and spent regeneration gas to exit the catalyst section being regenerated. At any given time, 80 percent of the catalyst sections will be in the oxidation/absorption cycle, while 20 percent will be in regeneration mode. A regeneration cycle is typically set to last for 3 to 8 minutes.

The EMx™ operates at a temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG. For installations below 450°F, the EMx™ system uses an inert gas generator for the production of hydrogen and CO_2. The regeneration gas is diluted to under 4 percent hydrogen using steam as a carrier gas; the typical system is designed for 2 percent hydrogen. The regeneration gas reaction is:

$$CH_4 + \tfrac{1}{2} O_2 + H_2O \rightarrow CO_2 + 3 H_2 \qquad (9)$$

For installations above 450°F, the EMx™ catalyst is regenerated by introducing a small quantity of natural gas with a carrier gas, such as steam, over a steam reforming catalyst and then to the EMx™ catalyst. The reforming catalyst initiates the conversion of methane to hydrogen, and the conversion is completed over the EMx™ catalyst. The reformer catalyst works to partially reform the methane gas to hydrogen (2 percent by volume) to be used in the regeneration of the EMx™ catalysts. The reformer converts methane to hydrogen by the steam reforming reaction as shown by the following equation:

$$CH_4 + 2 H_2O \rightarrow CO_2 + 4 H_2 \qquad (10)$$

The reformer catalyst is placed upstream of the EMx™ catalyst in a steam reformer reactor. The reformer catalyst is designed for a minimum 50-percent conversion of methane to hydrogen.

A gradual decrease in catalyst temperature is indicative of sulfur masking. EmerChem recommends the installation of a sulfur filter to reduce the rate of catalyst masking. The sulfur filter is placed in the inlet natural gas feed prior to the regeneration production skid. The sulfur filter consists of impregnated granular activated carbon that is housed in a stainless steel vessel. Spent media is discarded as a nonhazardous waste.

The EMx™ system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. As necessary, an additional catalytic oxidation/absorption system to remove sulfur compounds is installed upstream of the EMx™ catalyst. The sulfur removal catalyst utilizes the same oxidation/absorption cycle and a regeneration cycle as the EMx™ system. During regeneration of the catalyst, either H_2SO_4 mist or SO_2 is released to the atmosphere as part of the CT/HRSG exhaust gas stream. The absorption portion of the process is proprietary. Oxidation/absorption and regeneration reactions are:

$$CO + \tfrac{1}{2} O_2 \rightarrow CO_2 \quad (11)$$

$$SO_2 + \tfrac{1}{2} O_2 \rightarrow SO_3 \quad (12)$$

$$SO_3 + SORBER \rightarrow [SO_3 + SORBER] \quad (13)$$

$$[SO_3 + SORBER] + 4\,H_2 \rightarrow H_2S + 3\,H_2O + [SORBER] \quad (14)$$

(below 500°F)

$$[SO_3 + SORBER] + H_2 \rightarrow SO_2 + H_2O + [SORBER] \quad (15)$$

(above 500°F)

A programmable logic controller (PLC) controls the EMx™ system. The controller is programmed to control all essential EMx™ functions including the opening and closing of louver doors and regeneration gas inlet and outlet valves, and the maintaining of regeneration gas flow to achieve positive pressure in each section during the regeneration cycle.

Utility materials needed for the operation of the EMx™ control system include ambient air, natural gas, water, steam, and electricity. The primary utility material is natural gas used for regeneration gas production. Steam is used as the carrier/dilution gas for the regeneration gas. Electricity is required to operate the computer control system, control valves, and louver actuators.

Commercial experience to date with the EMx™ control system is limited to several small CC power plants located in California. Representative of these small power plants is a GE LM2500 turbine, owned by Sunlaw Energy Corporation, equipped with water injection to control NO_x emissions to approximately 25 ppmvd. The low temperature SCONO$_x$™ control system (i.e., located downstream of the HRSG at a temperature between 300 and 400°F) was retrofitted to the Sunlaw Energy facility in December 1996 and has achieved a NO_x exhaust concentration of 3.5 parts per million by volume (ppmv) resulting in an approximate 85-percent NO_x removal efficiency. A high temperature application of SCONO$_x$™ (i.e., control system located within the HRSG at a temperature between 600 and 700°F) has been in service since June 1999 on a small, 5-MW solar CT located at the Genetics Institute in Massachusetts. Although considered commercially available for large natural gas-fired CTs, there are currently no CTs larger than 32 MW that have demonstrated successful application of the EMx™ control technology.

<u>Technical Feasibility</u>

Two of the combustion process modification technologies mentioned (i.e., water or steam injection with advanced combustor design and DLN combustor design) would be feasible for Units 4 and 5. As previously noted, the XONON™ control technology is not currently available for GE 7FA CTs. Of the postcombustion stack gas treatment technologies, SNCR is not feasible because the temperature required for this technology (between 1,600 and 2,000°F) exceeds that found in the Units 4 and 5 exhaust gas streams (approximately 1,100°F). NSCR was also determined to be technically infeasible because the process must take place in a fuel-rich (less than 3-percent oxygen) environment. Due to high excess air rates, the oxygen content of the Units 4 and 5 exhausts is approximately 13 percent. The EMx™ control technology is not technically feasible because the temperature required for this technology (between 300 to 700°F) is well below the 1,100°F Units 4 and 5 exhaust gas streams. In addition, EMx™ control technology has not been commercially demonstrated on a large CT. Units 4 and 5, GE PG7241 (7FA) units, each has a nominal generation capacity of 165 MW. Accordingly, Units 4 and 5 are each 6.6 times larger than the nominal 25-MW GE LM2500 used at the Sunlaw Energy Corporation Los Angeles facility. Technical problems associated with scale-up of the EMx™ technology are unknown. Additional concerns with EMx™ control technology include process complexity (multiple catalytic oxidation/absorption/regeneration systems), reliance on only one supplier, and the relatively brief operating history of the technology.

For natural gas firing, use of advanced DLN combustor technology will achieve NO_x emission rates comparable to or less than wet injection based on GE SCCT vendor data. Accordingly, the BACT analysis for NO_x for Units 4 and 5 was confined to advanced

DLN combustors (for gas-firing), wet injection (for oil-firing), and the application of postcombustion SCR control technology. SCR is considered potentially feasible. However, this technology has primarily been installed on smaller, aeroderivative SCCTs that do not require exhaust gas cooling prior to treatment. The following sections provide information regarding energy, environmental, and economic impacts and proposed BACT limits for NO_x.

5.5.2 ENERGY AND ENVIRONMENTAL IMPACTS

The use of advanced DLN combustor technology will not have a significant adverse impact on SCCT heat rate.

The installation of SCR technology will cause an increase in back pressure on Units 4 and 5 due to the pressure drop across the catalyst bed. Additional energy would be needed for the pumping of aqueous NH_3 from storage to the injection nozzles and generation of steam for NH_3 vaporization. A SCR control system for Units 4 and 5 is projected to have a pressure drop across the catalyst bed of approximately 4.5 inches of water. This pressure drop will result in a 0.9-percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 15,236,100 kwh (51,988 MMBtu) per year at baseload (165-MW) operation and 50 percent capacity factor for both SCCTs. This energy penalty is equivalent to the use of 49.51 million ft^3 of natural gas annually based on a natural gas heating value of 1,050 Btu/ft^3 for both SCCTs. The lost power generation energy penalty, based on a power cost of $0.030/kwh, is $457,100 per year for both SCCTs. Actual generation cost based on current fuel prices is $0.150/kW resulting in an energy penalty of $2,285,400.

There are no significant adverse environmental effects due to the use of advanced DLN combustor technology. In contrast, application of SCR technology would result in the following adverse environmental impacts:

- NH_3 emissions due to *ammonia slip*; NH_3 emissions are estimated to total 100.8 tpy (at baseload and 59°F ambient temperature) for a SCR design NH_3 slip rate of 5 ppmvd. However, NH_3 slip can increase significantly during start-ups, upsets, or failures of the NH_3 injection system, or due to catalyst degradation. In instances where such events have occurred, NH_3 exhaust concentrations of 50 ppmv or greater have been measured. Since the odor threshold of NH_3 is 20 ppmv, releases of NH_3 during upsets or malfunctions have the potential to cause ambient odor problems. NH_3 also acts as an irritant to human tissue. Depending on the concentration and duration of exposure, NH_3 can cause eye, skin, and mucous membrane irritation. These effects can vary from minor irritation to severe damage. Contact of the skin or mucosa with liquid NH_3 or a high vapor concentration can result in burns or obstructed breathing.

- Ammonium bisulfate and ammonium sulfate particulate emissions due to the reaction of NH_3 with SO_3 present in the exhaust gases.
- A public risk due to potential leaks from the storage of large quantities of NH_3; NH_3 has been designated an Extremely Hazardous Substance under the federal Superfund Amendment and Reauthorization Act Title III regulations.
- Disposal of spent catalyst that may be considered hazardous due to heavy metal contamination; vanadium pentoxide is an active component of a typical SCR catalyst and is listed as a hazardous chemical waste under Resource Conservation and Recovery Act Regulations 40 CFR 261.30. As a potential hazardous waste, spent catalyst may have to be transported and disposed in a hazardous waste landfill. In addition, facility workers could be exposed to high levels of vanadium pentoxide particulates during catalyst handling.

5.5.3 ECONOMIC IMPACTS

An assessment of economic impacts was performed by comparing control costs between a baseline case of advanced DLN combustor/wet injection technology and baseline technology with the addition of SCR controls. Baseline technology is expected to achieve NO_x exhaust concentrations of 10.5 and 42.0 ppmvd at 15-percent oxygen for gas and oil firing, respectively. SCR technology was premised to achieve NO_x concentrations of 3.5 and 10.0 ppmvd at 15-percent oxygen for gas and oil firing, respectively. The NO_x concentration of 3.5 ppmvd is representative of recent LAER determinations made in California for natural gas-fired aeroderivative SCCTs equipped with SCR controls.

The cost impact analysis was conducted using the OAQPS factors previously summarized in Tables 5-1 and 5-2 and project-specific economic factors previously provided in Table 5-4. Emission reductions were calculated assuming baseload operation for 4,380 and 750 hr/yr for gas- and oil-firing, respectively, at an annual average ambient temperature of 59°F. Tables 5-10 and 5-11 summarize specific capital and annual operating costs for the SCR control system, respectively.

Cost effectiveness for the application of SCR technology to Units 4 and 5 was determined to be $10,807 per ton of NO_x removed using the FDEP-recommended economic cost factors. Use of current fuel and electric generation costs results in a cost effectiveness of $15,760 per ton of CO controlled. These control costs are considered economically unreasonable. Table 5-12 summarizes results of the NO_x BACT analysis.

5.5.4 PROPOSED BACT EMISSION LIMITATIONS

At baseload operation, maximum NO_x exhaust concentrations from Units 4 and 5 will be 10.5 and 42.0 ppmvd for gas- and oil-firing, respectively, based on the application of DLN combustors (for gas firing) and water injection (for oil firing). NO_x emission rates proposed as BACT for Units 4 and 5 are consistent with prior recent FDEP BACT determinations for SCCTs (e.g., Bayside Unit 3).

Table 5-13 summarizes the NO_x BACT emission limits proposed for Units 4 and 5.

5.6 BACT ANALYSIS FOR SO_2 AND H_2SO_4 MIST

5.6.1 POTENTIAL CONTROL TECHNOLOGIES

Technologies employed to control SO_2 and H_2SO_4 mist emissions from combustion sources consist of fuel treatment and postcombustion add-on controls (i.e., flue gas desulfurization (FGD) systems).

Fuel Treatment

Fuel treatment technologies are applied to gaseous, liquid, and solid fuels to reduce their sulfur contents prior to delivery to end fuel users. For wellhead natural gas and fuel oils containing sulfur compounds (e.g., H_2SO_4), a variety of technologies are available to

Table 5-10. Capital Costs for SCR Systems, Units 4 and 5

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	8,070,000	A
Sales tax	484,200	0.06 × A
Instrumentation	807,000	0.10 × A
Freight	403,500	0.05 × A
Subtotal Purchased Equipment	**9,764,700**	**B**
Installation		
Foundations and supports	781,200	0.08 × B
Handling and erection	1,367,100	0.14 × B
Electrical	390,600	0.04 × B
Piping	195,300	0.02 × B
Insulation for ductwork	97,600	0.01 × B
Painting	97,600	0.01 × B
Subtotal Installation Cost	**2,929,400**	
Total Direct Costs (TDC)	**12,694,100**	
Indirect Costs		
Engineering	976,500	0.10 × B
Construction and field expenses	488,200	0.05 × B
Contractor fees	976,500	0.10 × B
Startup	195,300	0.02 × B
Performance test	97,600	0.01 × B
Contingency	292,900	0.03 × B
Total Indirect Costs (TIC)	**3,027,000**	
TOTAL CAPITAL INVESTMENT (TCI)	**15,721,100**	TDC + TIC

Source: ECT, 2005.

Table 5-11. Annual Operating Costs for Oxidation Catalyst Systems, Units 4 and 5

Item	Dollars	OAQPS Factor
Direct Costs		
Labor and material costs		
Operator	14,100	A
Supervisor	2,100	0.15 × A
Maintenance		
Labor	14,100	B
Materials	2,100	1.0 × B
Subtotal Labor, Material, and Maintenance Costs	**44,400**	**C**
Catalyst costs		
Replacement (materials and labor)	4,294,100	3-year replacement
Annualized Catalyst Costs	**1,636,300**	
Electricity	17,500	
Aqueous Ammonia	53,600	
Energy Penalties		
Turbine backpressure	457,100	0.9% penalty
Total Direct Costs (TDC)	**2,208,900**	
Indirect Costs		
Overhead	26,600	0.60 × C
Administrative charges	314,400	0.02 × TCI
Property taxes	157,200	0.01 × TCI
Insurance	157,200	0.01 × TCI
Capital recovery	1,286,200	15 years @ 7.0%
Permit Fee Credit	(9,600)	$25/ton
Total Indirect Costs (TIC)	**1,932,000**	
TOTAL ANNUAL COST (TAC)	**4,140,900**	TDC + TIC

Sources: ECT, 2005.

Table 5-12. Summary of NO_x BACT Analysis

Control Option	Emission Impacts: Emission Rates lb/hr	Emission Impacts: Emission Rates tpy	Emission Impacts: Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Economic Impacts: Total Annualized Cost ($/yr)	Economic Impacts: Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Environmental Impacts: Adverse Environmental Impact (Y/N)
Oxidation catalyst	60.3	154.7	383.2	15,721,100	4,140,900	10,807	51,988	Y	Y
Baseline	210.8	540.6	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Two GE PG7241 (FA) SCCTs, 100-percent load, 59°F ambient temperature, 4,380 hr/yr gas-fired, 750 hr/yr oil-fired, FDEP economic factors.

Sources: GE, 1998.
ECT, 2005.

Table 5-13. Proposed NO_x BACT Emission Limits

Emission Source	Proposed NO_x BACT Emission Limits	
	ppmvd*	lb/hr†
GE PG 241 (FA) SCCT (Natural Gas firing, Per SCCT)	10.5	68.8
GE PG 241 (FA) SCCT (Distillate Fuel Oil firing, Per SCCT)	42.0	319.0

*Corrected to 15 percent oxygen, 24-hour block average.
†CT compressor inlet air temperature of 59°F, baseload.

Sources: TEC, 2005.
ECT, 2005.

remove these sulfur compounds to acceptable levels. Desulfurization of natural gas and fuel oils are performed by the fuel supplier prior to distribution by pipeline.

Flue Gas Desulfurization

FGD systems remove SO_2 from exhaust streams by using an alkaline reagent to form sulfite and sulfate salts. The reaction of SO_2 with the alkaline chemical can be performed using either a wet- or dry-contact system. FGD wet scrubbers typically employ sodium, calcium, or dual-alkali reagents using packed or spray towers. Wet FGD systems will generate wastewater and wet sludge streams requiring treatment and disposal. In a dry FGD system, an alkaline slurry is injected into the combustion process exhaust stream. The liquid sulfite/sulfate salts that form from the reaction of the alkaline slurry with SO_2 are dried by heat contained in the exhaust stream and subsequently removed by downstream PM control equipment.

Technical Feasibility

Treatment of natural gas and fuel oils to remove sulfur compounds is conducted by the fuel supplier, when necessary, prior to distribution. Accordingly, additional fuel treatment by end users is considered technically infeasible because the natural gas and distillate fuel oil sulfur contents have already been reduced to very low levels.

There have been no applications of FGD technology to SCCTs because low sulfur fuels are typically used. Units 4 and 5 will be fired with natural gas and distillate fuel oil. The sulfur content of natural gas, the primary fuel source, is more than 100 times lower than the fuels (e.g., coal) employed in boilers using FGD systems. In addition, SCCTs operate with a significant amount of excess air that generates high exhaust gas flow rates. Because FGD SO_2 removal efficiency decreases with decreasing inlet SO_2 concentration, application of an FGD system to a SCCT exhaust stream will result in unreasonably low SO_2 removal efficiencies. Due to low SO_2 exhaust stream concentrations, FGD technology is not considered to be technically feasible for SCCTs because removal efficiencies would be unreasonably low. Similarly, use of mist eliminators to control H_2SO_4 mist emissions is not technically feasible due to the very low SCCT H_2SO_4 mist exhaust concentrations.

Pipeline-quality natural gas contains a negligible amount of sulfur; typically less than 0.50 grains per standard cubic foot (equivalent to 0.0016 weight percent sulfur and 16 parts per million by weight). Ultra-low sulfur diesel fuel (ULSD) containing no more than 0.0015 weight percent sulfur (15 parts per million by weight) will become available at distribution terminals by July 15, 2006 as required by the *Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle standards and Highway Diesel Fuel Sulfur Control Requirements: Final Rule* promulgated by EPA on January 18, 2001. Since there are no feasible SO_2 control technologies applicable to Units 4 and 5 other than the use of commercially available low sulfur fuels and because there are no significant differences in the sulfur content of pipeline-quality natural gas, the BACT analysis for SO_2 was confined to the evaluation of the baseline distillate fuel oil containing no more than 0.05 weight percent sulfur (500 parts per million by weight) and ULSD. There are no significant energy and non-air related environmental impacts associated with the use of ULSD. The following sections provide information regarding economic impacts and proposed BACT limits for SO_2.

5.6.2 ECONOMIC IMPACTS

In May 2001, the Energy Information Agency (EIA) of the U.S. Department of Energy (DOE) assessed the additional costs associated with the use of ULSD in a report entitled The Transition to Ultra-Low Sulfur Diesel Fuel: Effects on Prices and Supply. This EIA report estimated an average price increase between current diesel fuel oil containing 500 ppm sulfur and ULSD of 6.8 cents per gallon for the 2007 to 2010 period and 5.4 cents per gallon for the 2011 to 2015 period. For the Units 4 and 5 economic analysis, an average price differential of 5.4 cents was used. Based on 750-hr/yr operation of distillate fuel oil firing per SCCT, annual distillate fuel oil consumption is 20,833,500 gallons per year for both SCCTs. The increase in distillate fuel oil costs in using ULSD, based on the EIA data, is $1,125,009 per year for both SCCTs. The reduction in SO_2 emissions is 73.8 tpy for Units 4 and 5 resulting in a cost effectiveness of $15,231 per ton of SO_2 reduced. Details of the SO_2 economic analysis are provided in Table 5-14.

Table 5-14. SO_2 Economic Analysis for ULSD

Data:

Number of Simple Cycle CTs:	2	
Hourly Fuel Oil Usage:	27,778	gal/hr for two SCCTs (Case 4, 100% load, 59°F)
	203,064	lb/hr for two SCCTs (Case 4, 100% load, 59°F)
Annual Fuel Oil Hours:	750	hr/yr per SCCT
Fuel Oil Cost Premium:	0.054	\$/gal (ULSD vs. 0.05 % S)

Calculations:

Annual Fuel Oil Usage:	20,833,500	gal/yr for two SCCTs (Case 4, 100% load, 59°F)
	152,298,000	lb/yr for two SCCTs (Case 4, 100% load, 59°F)
Cost Differential:	1,125,009	\$/yr for two SCCTs

Fuel Type	Sulfur (wt%)	SO_2 (ton/yr)	SO_2 (\$/ton)
Distillate Fuel Oil (base case)	0.05	76.1	-
Distillate Fuel Oil (ULSD)	0.0015	2.3	15,231

Sources: EIA/DOE, 2001.
GE, 1998.
TEC, 2005.
ECT, 2005.

5.6.3 PROPOSED BACT EMISSION LIMITATIONS

Because postcombustion SO_2 controls are not applicable, use of low sulfur fuel is considered to represent BACT Units 4 and 5. Natural gas utilized for Units 4 and 5 will be pipeline-quality. Distillate fuel oil used for Units 4 and 5 as a back-up fuel source will contain no more than 0.05 wt%S. Table 5-15 summarizes the SO_2 BACT emission limits proposed for Units 4 and 5.

5.7 SUMMARY OF PROPOSED BACT EMISSION LIMITS

Table 5-16 summarizes control technologies proposed as BACT for each pollutant subject to review. Table 5-17 summarizes specific proposed BACT emission limits for each pollutant.

Table 5-15. Proposed SO_2 BACT Emission Limit

Emission Source	Proposed SO_2 BACT Emission Limits
GE PG 7241 (FA) SCCT (natural gas firing)	Pipeline quality
GE PG 7241 (FA) SCCT (distillate fuel oil firing)	0.05 wt%S

Sources: TEC, 2005.
ECT, 2005.

Table 5-16. Summary of BACT Control Technologies

Pollutant	Control Technology
GE PG7241 (FA) SCCTs	
PM/PM_{10}	• Exclusive use of low-ash and low-sulfur natural gas and distillate fuel oil. • Efficient and complete combustion.
CO	• Efficient and complete combustion.
NO_x	• Use of advanced DLN burners (natural gas firing). • Use of wet injection (distillate fuel oil firing).
SO_2/H_2SO_4 mist	• Exclusive use of low-ash and low-sulfur natural gas and distillate fuel oil.

Source: TEC, 2005.
ECT, 2005.

Table 5-17. Summary of Proposed BACT Emission Limits

Emission Source/Pollutant	Proposed BACT Emission Limits ppmvd*	lb/hr†
GE PG7241 (FA) SCCT (natural gas firing, per SCCT)		
PM/PM_{10}	10-percent opacity	
CO	9.0	36.0
NO_x	10.5	68.8
SO_2/ H_2SO_4	(fuel ≤2.0 gr S/100 scf)	
GE PG7241 (FA) SCCT (distillate fuel firing, per SCCT)		
PM/PM_{10}	10-percent opacity	
CO	20.0	92.2
NO_x	42.0	319.0
SO_2/ H_2SO_4	(fuel ≤0.05 wt % S)	

*Corrected to 15-percent oxygen, 24-hour block average.
†CT compressor inlet air temperature of 59°F, baseload.

Sources: TEC, 2005.
ECT, 2005.

6.0 AMBIENT IMPACT ANALYSIS METHODOLOGY

6.1 GENERAL APPROACH

The approach used to analyze the potential impacts of the proposed facility, as described in detail in the following sections, was developed in accordance with accepted practice. Guidance contained in EPA manuals and user's guides was sought and followed.

6.2 POLLUTANTS EVALUATED

Based on an evaluation of anticipated worst-case annual operating scenarios, Units 4 and 5 will have the potential to emit 540.7 tpy of NO_x, 226.8 tpy of CO, 104.3 tpy of PM/PM_{10}, 117.9 tpy of SO_2, 17.7 tpy of VOCs, and 13.5 tpy of H_2SO_4 mist. Table 3-2 previously provided estimated potential annual emission rates for Units 4 and 5. As shown in that table, potential emission increases of all PSD regulated pollutants will be below the applicable PSD significant emission rate levels, with the exception of NO_x, CO, PM, PM_{10}, SO_2, and H_2SO_4 mist. There are no national or Florida AAQS or PSD increments promulgated for H_2SO_4 mist. Accordingly, Units 4 and 5 are subject to the PSD NSR air quality impact analysis requirements of Rule 62-212.400(5)(d), F.A.C. for NO_x, CO, PM, PM_{10}, and SO_2.

6.3 MODEL SELECTION AND USE

For this study, air quality modeling was applied at the refined level. Refined modeling requires more detailed and precise input data than screening modeling, but is presumed to have provided more accurate estimates of source impacts.

The most recent regulatory version of the Industrial Source Complex (ISC3) models (EPA, 2000) is recommended and was used in this analysis for refined modeling. The ISC3 models are steady-state Gaussian plume models that can be used to assess air quality impacts over simple terrain from a wide variety of sources. The ISC3 models are capable of calculating concentrations for averaging times ranging from 1 hour to annual. For this study, the ISC3 short-term (ISCST3) (Version 02035) model was used to calculate short-term ambient impacts with averaging times between 1 and 24 hours as well as long-term annual averages.

Procedures applicable to the ISCST3 dispersion model specified in EPA's Guideline for Air Quality Models (GAQM) were followed in conducting the refined dispersion modeling. The GAQM is codified in Appendix W of 40 CFR 51. In particular, the ISCST3 model control pathway MODELOPT keyword parameters DFAULT, CONC, RURAL, and NOCMPL were selected. Selection of the parameter DFAULT, which specifies use of the regulatory default options, is recommended by the GAQM. The CONC, RURAL, and NOCMPL parameters specify calculation of concentrations, use of rural dispersion, and suppression of complex terrain calculations, respectively. As previously mentioned, the ISCST3 model was also used to determine annual average impact predictions, in addition to short-term averages, by using the PERIOD parameter for the AVERTIME keyword. Conservatively, no consideration was given to pollutant exponential decay.

6.4 NO_2 AMBIENT IMPACT ANALYSIS

For annual NO_2 impacts, the tiered screening approach described in the GAQM, Section 6.2.3, was used. Tier 1 of this screening procedure assumes complete conversion of NO_x to NO_2. Tier 2 applies an empirically derived NO_2/NO_x ratio of 0.75 to the Tier 1 results.

6.5 DISPERSION OPTION SELECTION

Area characteristics in the vicinity of proposed emission sources are important in determining model selection and use. One important consideration is whether the area is rural or urban since dispersion rates differ between these two classifications. In general, urban areas cause greater rates of dispersion because of increased turbulent mixing and buoyancy-induced mixing. This is due to the combination of greater surface roughness caused by more buildings and structures and greater amount of heat released from concrete and similar surfaces. EPA guidance provides two procedures to determine whether the character of an area is predominantly urban or rural. One procedure is based on land use typing, and the other is based on population density. The land use typing method uses the work of Auer (Auer, 1978) and is preferred by EPA and FDEP because it is meteorologically oriented. In other words, the land use factors employed in making a rural/urban designation are also factors that have a direct effect on atmospheric dispersion. These factors include building types, extent of vegetated surface area and water surface area, types of industry and commerce, etc. Auer recommends these land use factors be considered within 3 km of the source to be modeled to determine urban or rural classifications. The Auer land use typing method was used for the ambient impact analysis.

The Auer technique recognizes four primary land use types: industrial (I), commercial (C), residential (R), and agricultural (A). Practically all industrial and commercial areas come under the heading of urban, while the agricultural areas are considered rural. However, those portions of generally industrial and commercial areas that are heavily vegetated can be considered rural in character. In the case of residential areas, the delineation between urban and rural is not as clear. For residential areas, Auer subdivides this land use type into four groupings based on building structures and associated vegetation. Accurate classification of the residential areas into proper groupings is important to determine the most appropriate land use classification for the study area.

USGS 7.5-minute series topographic maps for the area were used to identify the land use types within a 3-km radius area of the proposed site. Based on this analysis, more than 50-percent of the land use surrounding the PPS was determined to be rural under the Auer land use classification technique. Therefore, rural dispersion coefficients and mixing heights were used for the ambient impact analysis.

6.6 TERRAIN CONSIDERATION

The GAQM defines flat terrain as terrain equal to the elevation of the stack base, simple terrain as terrain lower than the height of the stack top, and complex terrain as terrain above the height of the plume center line (for screening modeling, complex terrain is terrain above the height of the stack top). Terrain above the height of the stack top, but below the height of the plume center line, is defined as intermediate terrain.

USGS 7.5-minute series topographic maps were examined for terrain features in the vicinity of the PPS (i.e., within an approximate 10-km radius). Review of the USGS topographic maps indicates nearby terrain would be classified as simple terrain. Due to the minimal amount of terrain elevation differences in the vicinity, assignment of receptor terrain elevations was not conducted (i.e., all receptors were assumed to be at the same elevation as the Unit 4 and 5 stack bases for modeling purposes).

6.7 GOOD ENGINEERING PRACTICE STACK HEIGHT/BUILDING WAKE EFFECTS

According to EPA regulations (40 CFR 51), good engineering practice (GEP) stack height is defined as the highest of 65 meters or a height established by applying the formula:

$$Hg = H + 1.5\ L$$

where: Hg = GEP stack height.

H = height of the structure or nearby structure.

L = lesser dimension (height or projected width) of the nearby structure.

Nearby is defined as a distance up to five times the lesser of the height or width dimension of a structure or terrain feature, but not greater than 800 meters. While the GEP stack height regulations require that stack heights used in modeling for determining compliance with NAAQS and PSD increments not exceed GEP stack heights, the actual stack height may be greater. Guidelines for determining GEP stack height have been issued by EPA (1985).

The stack height proposed for Units 4 and 5 (114 feet [ft]) is less than the *de minimis* GEP height of 65 meters (213 ft), and, therefore, complies with the EPA promulgated final stack height regulations (40 CFR 51).

While the GEP stack height rules address the maximum stack height that can be employed in a dispersion model analysis, stacks having heights lower than GEP stack height can potentially result in higher downwind concentrations due to building downwash effects. The ISC3 dispersion models contain two algorithms that assess the effect of building downwash; these algorithms are referred to as the Huber-Snyder and Schulman-Scire methods. The following steps are employed in determining the effects of building downwash:

- A determination is made as to whether a particular stack is located in the area of influence of a building (i.e., within five times the lesser of the building's height or projected width). If the stack is not within this area, it will not be subject to downwash from that building.
- If a stack is within a building's area of influence, a determination is made as to whether it will be subject to downwash based on the heights of the stack and building. If the stack height to building height ratio is equal to or greater than 2.5, the stack will not be subject to downwash from that building.
- If both conditions in the previous two items are satisfied (i.e., a stack is within the area of influence of a building and has a stack height to building height ratio of less than 2.5), the stack will be subject to building downwash. The determination is then made as to whether the Huber-Snyder or Schulman-Scire downwash method applies. If the stack height is less than or equal to the building height plus one-half the lesser of the building height or width, the Schulman-Scire method is used. Conversely, if the stack height is greater than this criterion, the Huber-Snyder method is employed.
- The ISCST3 downwash input data consists of an array of 36 wind direction-specific building heights and projected widths for each stack. LB is defined as the lesser of the height and projected width of the building. For directionally dependent building downwash, wake effects are assumed to occur if a stack is situated within a rectangle composed of two lines perpendicular to the wind direction, one line at 5 LB downwind of the building and the other at 2 LB upwind of the building, and by two lines parallel to the wind, each at 0.5 LB away from the side of the building.

Table 6-1 provides dimensions of the building/structures evaluated for wake effects; the locations of these buildings/structures were previously provided on Figure 2-2.

6.8 RECEPTOR GRIDS

Receptors were placed at locations considered to be *ambient air*, which is defined as "that portion of the atmosphere, external to buildings, to which the general public has access."

Table 6-1. Building/Structure Dimensions

Building/Structure	Dimensions Width (meters)	Length (meters)	Height (meters)
Unit 1 7F HRSG	13.1	40.0	27.4
Gasifier structure	19.2	18.3	91.4
Syngas cooling wings (two)	7.6	46.3	27.4
Air separation Unit cold box	—	7.0*	50.3
Coal grinding structure	7.6	15.2	27.4
H_2SO_4 plant absorbers (two) and dryer (one)	—	2.4*	18.3
H_2SO_4 plant gas cooling tower	—	2.4*	21.3
Acid gas removal stripper	—	3.0*	30.5
Water wash column	—	3.0*	24.4
Acid gas removal absorber	—	3.0*	30.5
Coal storage silos (two)	—	18.0*	60.0
Hot gas cleanup unit	15.8	19.8	85.0
Oil storage tanks (three)	—	30.5	17.4

*Diameter.

Sources: Bechtel, 1994.
Texaco, 1992.
ECT, 2005.

The entire perimeter of the PPS is fenced. Therefore, the nearest locations of general public access are at the facility fence lines.

Consistent with GAQM recommendations, the ambient impact analysis used the following receptor grids:

- Fence line receptors—Receptors placed on the site fence line at 10-degree (°) spacing radials.
- Polar receptor rings (36 receptors at 10° spacing radials) at distances of 2,000, 2,500, 3,000, 3,500, 4,000, 5,000, 6,000, 7,000, 8,000, 9,000, 10,000, 12,500, 15,000, 17,500, 20,000, 22,500, 25,000, 27,500, 30,000, 32,500, 35,000, 40,000, 45,000, and 50,000 meters from the grid center.

This receptor grid is consistent with the grid employed in the modeling conducted for the original PPS project.

Figure 6-1 illustrates a graphical representation of the receptor grids (out to a distance of 5 km). A depiction of the receptor grids (from 5 to 50 km) is shown in Figure 6-2.

6.9 METEOROLOGICAL DATA

Detailed meteorological data are needed for modeling with the ISC3 dispersion models. The ISCST3 model requires a preprocessed data file compiled from hourly surface observations and concurrent twice-daily rawinsonde soundings (i.e., mixing height data).

Consistent with the GAQM and FDEP guidance, modeling should be conducted using the most recent, readily available, 5 years of meteorological data collected at a nearby observation station. In accordance with this guidance, the selected meteorological dataset consisted of St. Petersburg/Clearwater International Airport (SPG), Station ID 72211, surface data and Ruskin (RUS), Station ID 12842, upper air data. These data were obtained from the National Climatic Data Center (NCDC) for the 1992 through 1996 5-year period.

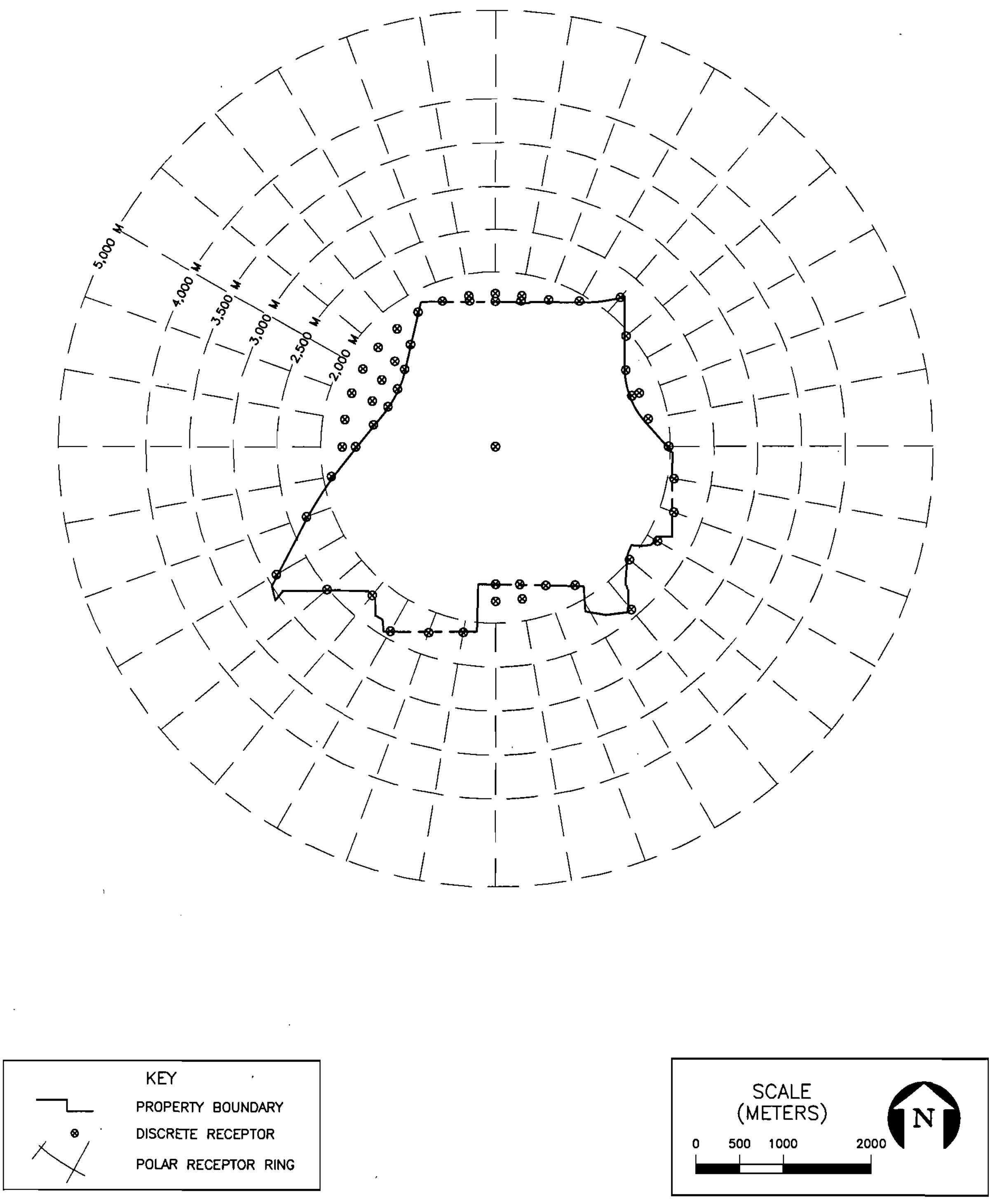

FIGURE 6-1.

LOCATIONS OF DISCRETE RECEPTORS AND CLOSE-IN RECEPTORS

Source: ECT, 2005.

TECO
TAMPA ELECTRIC

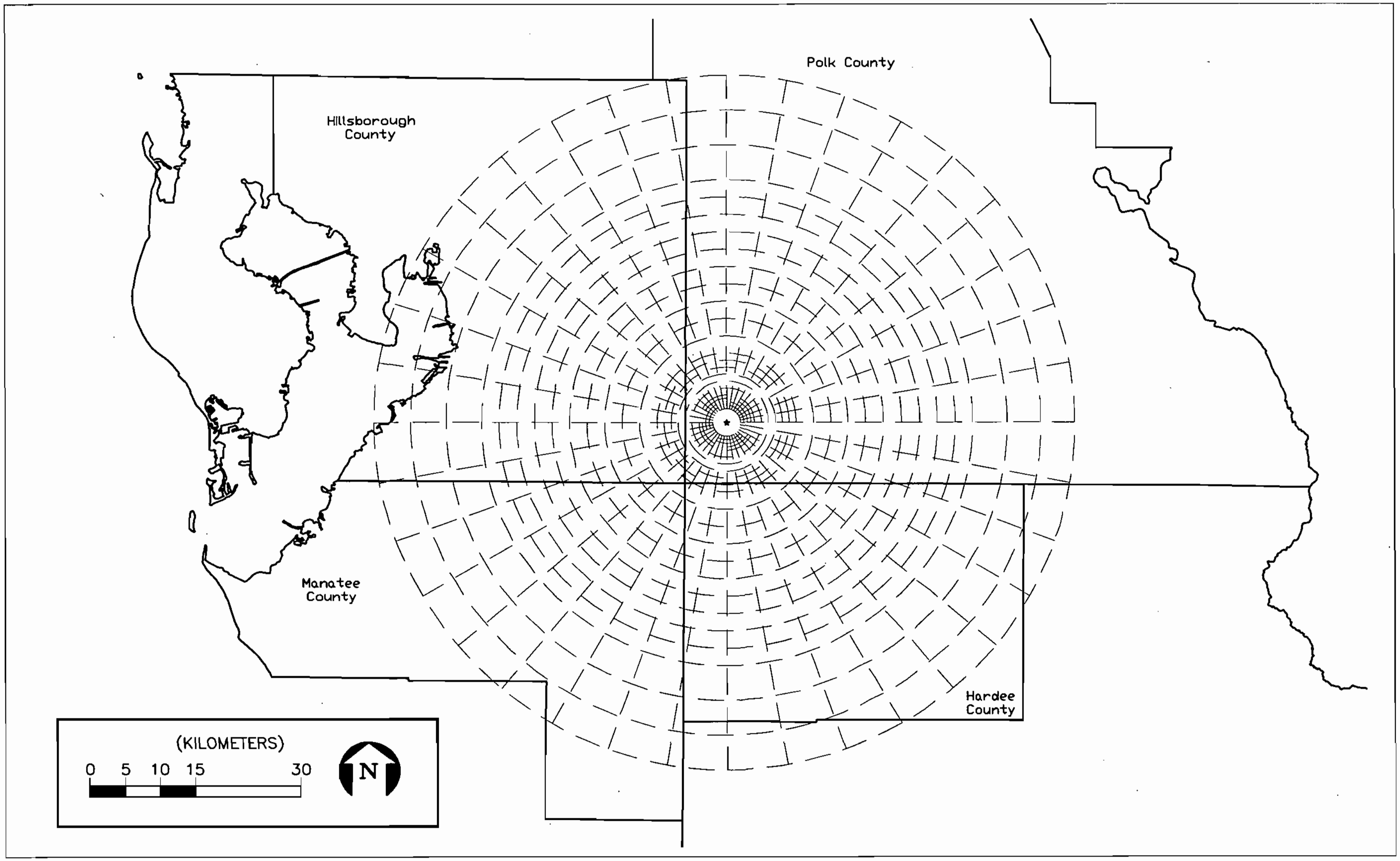

FIGURE 6-2.
POLAR RECEPTOR RINGS

Source: ECT, 2005.

TECO
TAMPA ELECTRIC

The surface and mixing height data for each of the 5 years were processed using EPA's PCRAMMET meteorological preprocessing program to generate the meteorological data files in the format required by the ISCST3 dispersion model.

6.10 MODELED EMISSION INVENTORY

Modeled on-property emission sources consisted of the two proposed Units 4 and 5. As will be discussed in Section 7.0, Ambient Impact Analysis Results, emissions from the two new CTGs resulted in air quality impacts below the significance impact levels (reference Table 4-2) for all pollutants and all averaging periods. Accordingly, additional, multisource interactive dispersion modeling was not required.

Emission rates and stack parameters for Units 4 and 5 were previously presented in Tables 2-1 through 2-8.

7.0 AMBIENT IMPACT ANALYSIS RESULTS

7.1 MAXIMUM FACILITY IMPACTS AND SIGNIFICANT IMPACT AREAS

The ISCST3 model was used to model each of the nine Unit 4 and 5 SCCT operating cases for both gas and oil firing. These operating scenarios included three SCCT loads (100, 75, and 50 percent) and three ambient temperatures (20, 59, and 90°F). Modeling was conducted for those project pollutants that exceed the PSD significant emission rate thresholds (i.e., NO_x, SO_2, CO, and PM/PM_{10}).

ISCST3 model results for each year of meteorology evaluated (1992 to 1996) are summarized on Table 7-1 for the Units 4 and 5 gas-firing operating cases. Model results for the oil-firing operating cases are provided on Table 7-2. These tables show the highest project impacts for each year and each operating scenario. For annual average impacts, the air quality analysis conservatively assumed continuous operation for each operating scenario. This approach will significantly over-estimate annual impacts for the full load operating cases since the SCCTs will operate at full load for no more than 4,800 hr/yr per SCCT during gas-firing and for no more than 750 hr/yr per SCCT during oil-firing.

The dispersion model results presented in Tables 7-1 and 7-2 demonstrate that Units 4 and 5 impacts, for all pollutants and averaging periods, will be below the PSD significant impact levels previously shown in Table 3-3. Table 7-3 provides a summary of maximum Units 4 and 5 impacts and the PSD Class II area significant impact levels.

The PPS is located in rural Polk County. With the exception of new power generation facilities, this area has not experienced significant general growth since August 7, 1977. The air quality impacts of any major industrial project in the area of the PPS would have been subject to a detailed regulatory agency assessment under the PSD permitting program.

7.2 CONCLUSIONS

Comprehensive dispersion modeling using the ISCST3 model demonstrates that Units 4 and 5 will result in ambient air quality impacts that are well below the PSD Class II significant impact levels for all pollutants and all averaging periods. Accordingly, a multisource interactive assessment of air quality impacts with respect to the AAQS and PSD Class II increments is not required.

Table 7-1. Air Quality Impact Analysis Summary, Units 4 and 5—Natural Gas Firing

	Case 1 (100% Load, 20°F Ambient)					Case 2 (75% Load, 20°F Ambient)					Case 3 (50% Load, 20°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts (Units 4 and 5):															
High, 1-Hour ($\mu g/m^3$)	2.06	1.86	1.95	1.99	2.06	2.10	2.25	2.37	2.43	2.43	2.82	2.76	2.87	2.67	2.86
High, 3-Hour ($\mu g/m^3$)	0.96	1.16	1.20	1.28	1.22	1.14	1.38	1.43	1.51	1.45	1.34	1.62	1.68	1.77	1.69
High, 8-Hour ($\mu g/m^3$)	0.59	0.81	0.59	0.80	0.63	0.70	0.95	0.71	0.95	0.74	0.82	1.10	0.84	1.11	0.86
High, 24-Hour ($\mu g/m^3$)	0.23	0.23	0.24	0.24	0.25	0.28	0.27	0.29	0.29	0.30	0.32	0.32	0.34	0.33	0.36
Annual ($\mu g/m^3$)	0.011	0.012	0.013	0.012	0.012	0.015	0.016	0.017	0.015	0.016	0.018	0.021	0.021	0.020	0.019
SO_2															
Emission Rate (g/s)	1.28	1.28	1.28	1.28	1.28	1.03	1.03	1.03	1.03	1.03	0.82	0.82	0.82	0.82	0.82
High, 3-Hour ($\mu g/m^3$)	0.12	0.15	0.15	0.16	0.16	0.12	0.14	0.15	0.16	0.15	0.11	0.13	0.14	0.15	0.14
High, 24-Hour ($\mu g/m^3$)	0.030	0.030	0.031	0.031	0.032	0.028	0.028	0.030	0.029	0.031	0.027	0.026	0.028	0.027	0.030
Annual ($\mu g/m^3$)	0.0015	0.0016	0.0017	0.0016	0.0016	0.0015	0.0017	0.0017	0.0016	0.0016	0.0015	0.0017	0.0017	0.0016	0.0016
NO_2															
Emission Rate (g/s)	9.26	9.26	9.26	9.26	9.26	7.35	7.35	7.35	7.35	7.35	5.73	5.73	5.73	5.73	5.73
Tier 2 Annual ($\mu g/m^3$)	0.0080	0.0085	0.0090	0.0086	0.0086	0.0080	0.0089	0.0093	0.0085	0.0085	0.0078	0.0088	0.0090	0.0086	0.0083
PM_{10}															
Emission Rate (g/s)	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27
High, 24-Hour ($\mu g/m^3$)	0.053	0.052	0.055	0.055	0.057	0.063	0.062	0.066	0.065	0.069	0.074	0.073	0.078	0.076	0.082
Annual ($\mu g/m^3$)	0.0026	0.0028	0.0029	0.0028	0.0028	0.0033	0.0037	0.0038	0.0035	0.0035	0.0041	0.0047	0.0048	0.0046	0.0044
CO															
Emission Rate (g/s)	3.82	3.82	3.82	3.82	3.82	3.02	3.02	3.02	3.02	3.02	2.50	2.50	2.50	2.50	2.50
High, 1-Hour ($\mu g/m^3$)	0.79	0.71	0.74	0.76	0.79	0.63	0.68	0.72	0.74	0.73	0.71	0.69	0.72	0.67	0.72
High, 8-Hour ($\mu g/m^3$)	0.23	0.31	0.23	0.31	0.24	0.21	0.29	0.21	0.29	0.22	0.21	0.27	0.21	0.28	0.22

Table 7-1. Air Quality Impact Analysis Summary, Units 4 and 5—Natural Gas Firing (Page 2 of 3)

	Case 4 (100% Load, 59°F Ambient)					Case 5 (75% Load, 59°F Ambient)					Case 6 (50% Load, 59°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts (10 SCCTs):															
High, 1-Hour ($\mu g/m^3$)	2.06	2.04	1.95	1.99	2.07	2.18	2.25	2.43	2.54	2.43	2.82	2.76	2.94	2.68	2.86
High, 3-Hour ($\mu g/m^3$)	0.99	1.20	1.24	1.31	1.26	1.17	1.41	1.46	1.55	1.48	1.35	1.64	1.70	1.79	1.71
High, 8-Hour ($\mu g/m^3$)	0.61	0.83	0.61	0.83	0.65	0.72	0.97	0.73	0.97	0.76	0.83	1.11	0.85	1.13	0.87
High, 24-Hour ($\mu g/m^3$)	0.24	0.24	0.25	0.25	0.26	0.28	0.28	0.30	0.29	0.32	0.33	0.33	0.35	0.34	0.36
Annual ($\mu g/m^3$)	0.012	0.013	0.014	0.013	0.013	0.015	0.017	0.017	0.016	0.016	0.018	0.021	0.021	0.021	0.020
SO_2															
Emission Rate (g/s)	1.20	1.20	1.20	1.20	1.20	0.97	0.97	0.97	0.97	0.97	0.78	0.78	0.78	0.78	0.78
High, 3-Hour ($\mu g/m^3$)	0.12	0.14	0.15	0.16	0.15	0.11	0.14	0.14	0.15	0.14	0.11	0.13	0.13	0.14	0.13
High, 24-Hour ($\mu g/m^3$)	0.029	0.028	0.030	0.030	0.031	0.027	0.027	0.029	0.028	0.031	0.026	0.025	0.027	0.026	0.028
Annual ($\mu g/m^3$)	0.0014	0.0015	0.0016	0.0015	0.0015	0.0015	0.0016	0.0017	0.0016	0.0016	0.0014	0.0016	0.0017	0.0016	0.0015
NO_2															
Emission Rate (g/s)	8.67	8.67	8.67	8.67	8.67	6.91	6.91	6.91	6.91	6.91	5.44	5.44	5.44	5.44	5.44
Tier 2 Annual ($\mu g/m^3$)	0.0077	0.0083	0.0088	0.0083	0.0083	0.0079	0.0086	0.0089	0.0083	0.0084	0.0075	0.0085	0.0087	0.0084	0.0080
PM_{10}															
Emission Rate (g/s)	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27
High, 24-Hour ($\mu g/m^3$)	0.054	0.054	0.057	0.056	0.059	0.064	0.064	0.067	0.066	0.072	0.075	0.074	0.079	0.077	0.083
Annual ($\mu g/m^3$)	0.0027	0.0029	0.0031	0.0029	0.0029	0.0034	0.0038	0.0039	0.0037	0.0037	0.0042	0.0047	0.0048	0.0047	0.0044
CO															
Emission Rate (g/s)	3.63	3.63	3.63	3.63	3.63	2.89	2.89	2.89	2.89	2.89	2.40	2.40	2.40	2.40	2.40
High, 1-Hour ($\mu g/m^3$)	0.75	0.74	0.71	0.72	0.75	0.63	0.65	0.70	0.73	0.70	0.68	0.66	0.71	0.64	0.69
High, 8-Hour ($\mu g/m^3$)	0.22	0.30	0.22	0.30	0.24	0.21	0.28	0.21	0.28	0.22	0.20	0.27	0.20	0.27	0.21

Table 7-1. Air Quality Impact Analysis Summary, Units 4 and 5—Natural Gas Firing (Page 3 of 3)

	Case 7 (100% Load, 90°F Ambient)					Case 8 (80% Load, 90°F Ambient)					Case 9 (50% Load, 90°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts (10 SCCTs):															
High, 1-Hour ($\mu g/m^3$)	2.07	2.16	2.20	2.16	2.08	2.26	2.33	2.52	2.66	2.44	2.91	2.76	**2.94**	2.68	2.94
High, 3-Hour ($\mu g/m^3$)	1.03	1.25	1.29	1.37	1.31	1.20	1.46	1.51	1.60	1.53	1.38	1.68	1.74	**1.84**	1.75
High, 8-Hour ($\mu g/m^3$)	0.63	0.86	0.64	0.86	0.68	0.74	1.00	0.75	1.00	0.78	0.85	1.13	0.87	**1.15**	0.89
High, 24-Hour ($\mu g/m^3$)	0.25	0.25	0.26	0.26	0.27	0.29	0.29	0.31	0.30	0.32	0.34	0.33	0.36	0.35	**0.37**
Annual ($\mu g/m^3$)	0.013	0.014	0.015	0.014	0.013	0.016	0.017	0.018	0.017	0.017	0.019	0.021	**0.022**	0.021	0.020
SO_2															
Emission Rate (g/s)	1.10	1.10	1.10	1.10	1.10	0.91	0.91	0.91	0.91	0.91	0.73	0.73	0.73	0.73	0.73
High, 3-Hour ($\mu g/m^3$)	0.11	0.14	0.14	0.15	0.14	0.11	0.13	0.14	0.15	0.14	0.10	0.12	0.13	0.13	0.13
High, 24-Hour ($\mu g/m^3$)	0.027	0.027	0.029	0.028	0.030	0.027	0.026	0.028	0.027	0.030	0.025	0.024	0.026	0.025	0.027
Annual ($\mu g/m^3$)	0.0014	0.0015	0.0016	0.0015	0.0015	0.0014	0.0016	0.0016	0.0015	0.0015	0.0014	0.0016	0.0016	0.0016	0.0015
NO_2															
Emission Rate (g/s)	7.94	7.94	7.94	7.94	7.94	6.47	6.47	6.47	6.47	6.47	5.15	5.15	5.15	5.15	5.15
Tier 2 Annual ($\mu g/m^3$)	0.0075	0.0082	0.0087	0.0080	0.0079	0.0076	0.0084	0.0087	0.0082	0.0082	0.0074	0.0083	0.0085	0.0083	0.0078
PM_{10}															
Emission Rate (g/s)	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27
High, 24-Hour ($\mu g/m^3$)	0.057	0.056	0.059	0.059	0.062	0.066	0.066	0.070	0.068	0.074	0.076	0.076	0.081	0.079	**0.085**
Annual ($\mu g/m^3$)	0.0029	0.0031	0.0033	0.0031	0.0030	0.0036	0.0039	0.0041	0.0038	0.0038	0.0043	0.0049	**0.0050**	0.0049	0.0046
CO															
Emission Rate (g/s)	3.24	3.24	3.24	3.24	3.24	2.74	2.74	2.74	2.74	2.74	2.31	2.31	2.31	2.31	2.31
High, 1-Hour ($\mu g/m^3$)	0.67	0.70	0.71	0.70	0.67	0.62	0.64	0.69	0.73	0.67	0.67	0.64	0.68	0.62	0.68
High, 8-Hour ($\mu g/m^3$)	0.20	0.28	0.21	0.28	0.22	0.20	0.27	0.21	0.27	0.21	0.20	0.26	0.20	0.27	0.21

Maximum Impacts	Project Impact	Case No.	Year	Class II SIL	% of SIL (%)
SO_2					
High, 3-Hour ($\mu g/m^3$)	0.16	1	1995	25	0.66
High, 24-Hour ($\mu g/m^3$)	0.032	1	1996	5	0.65
Annual ($\mu g/m^3$)	0.0016	2	1994	1	0.16
NO_2					
Annual ($\mu g/m^3$)	0.0093	2	1994	1	0.93
PM_{10}					
High, 24-Hour ($\mu g/m^3$)	0.08	9	1996	5	1.69
Annual ($\mu g/m^3$)	0.0050	9	1994	1	0.50
CO					
High, 1-Hour ($\mu g/m^3$)	0.79	1	1996	2,000	0.039
High, 8-Hour ($\mu g/m^3$)	0.31	1	1993	500	0.06

Source: ECT, 2005.

Table 7-2 Air Quality Impact Analysis Summary, Units 4 and 5—Distillate Fuel Oil Firing

	Case 1 (100% Load, 20°F Ambient)					Case 2 (75% Load, 20°F Ambient)					Case 3 (50% Load, 20°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts (Units 4 and 5):															
High, 1-Hour (μg/m^3)	2.06	1.86	1.95	1.99	2.06	2.10	2.25	2.37	2.43	2.43	2.82	2.76	2.87	2.67	2.86
High, 3-Hour (μg/m^3)	0.96	1.16	1.20	1.28	1.22	1.14	1.38	1.43	1.51	1.45	1.34	1.62	1.68	1.77	1.69
High, 8-Hour (μg/m^3)	0.59	0.81	0.59	0.80	0.63	0.70	0.95	0.71	0.95	0.74	0.82	1.10	0.84	1.11	0.86
High, 24-Hour (μg/m^3)	0.23	0.23	0.24	0.24	0.25	0.28	0.27	0.29	0.29	0.30	0.32	0.32	0.34	0.33	0.36
Annual (μg/m^3)	0.011	0.012	0.013	0.012	0.012	0.015	0.016	0.017	0.015	0.016	0.018	0.021	0.021	0.020	0.019
SO_2															
Emission Rate (g/s)	13.58	13.58	13.58	13.58	13.58	11.02	11.02	11.02	11.02	11.02	8.59	8.59	8.59	8.59	8.59
High, 3-Hour (μg/m^3)	1.30	1.58	1.63	**1.74**	1.66	1.26	1.52	1.58	1.67	1.60	1.15	1.40	1.44	1.52	1.45
High, 24-Hour (μg/m^3)	0.316	0.313	0.329	0.328	**0.343**	0.305	0.302	0.319	0.314	0.336	0.279	0.277	0.295	0.287	0.309
Annual (μg/m^3)	0.0156	0.0167	0.0176	0.0168	0.0168	0.0161	0.0178	**0.0185**	0.0171	0.0171	0.0155	0.0177	0.0180	0.0172	0.0166
NO_2															
Emission Rate (g/s)	42.59	42.59	42.59	42.59	42.59	34.27	34.27	34.27	34.27	34.27	26.46	26.46	26.46	26.46	26.46
Tier 2 Annual (μg/m^3)	0.0366	0.0393	0.0413	0.0395	0.0395	0.0375	0.0415	**0.0432**	0.0398	0.0399	0.0358	0.0409	0.0416	0.0398	0.0384
PM_{10}															
Emission Rate (g/s)	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28
High, 24-Hour (μg/m^3)	0.100	0.099	0.104	0.103	0.108	0.118	0.117	0.124	0.122	0.130	0.139	0.138	0.147	0.143	0.154
Annual (μg/m^3)	0.0049	0.0053	0.0055	0.0053	0.0053	0.0062	0.0069	0.0072	0.0066	0.0066	0.0077	0.0088	0.0090	0.0086	0.0083
CO															
Emission Rate (g/s)	12.31	12.31	12.31	12.31	12.31	9.89	9.89	9.89	9.89	9.89	7.65	7.65	7.65	7.65	7.65
High, 1-Hour (μg/m^3)	2.53	2.29	2.40	2.44	**2.54**	2.08	2.23	2.35	2.41	2.40	2.16	2.11	2.20	2.05	2.19
High, 8-Hour (μg/m^3)	0.73	**0.99**	0.73	0.99	0.78	0.69	0.94	0.70	0.94	0.73	0.63	0.84	0.64	0.85	0.66

Table 7-2 Air Quality Impact Analysis Summary, Units 4 and 5—Distillate Fuel Oil Firing (Page 2 of 3)

	Case 4 (100% Load, 59°F Ambient)					Case 5 (75% Load, 59°F Ambient)					Case 6 (50% Load, 59°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts (10 SCCTs):															
High, 1-Hour ($\mu g/m^3$)	2.06	2.04	1.95	1.99	2.07	2.18	2.25	2.43	2.54	2.43	2.82	2.76	2.94	2.68	2.86
High, 3-Hour ($\mu g/m^3$)	0.99	1.20	1.24	1.31	1.26	1.17	1.41	1.46	1.55	1.48	1.35	1.64	1.70	1.79	1.71
High, 8-Hour ($\mu g/m^3$)	0.61	0.83	0.61	0.83	0.65	0.72	0.97	0.73	0.97	0.76	0.83	1.11	0.85	1.13	0.87
High, 24-Hour ($\mu g/m^3$)	0.24	0.24	0.25	0.25	0.26	0.28	0.28	0.30	0.29	0.32	0.33	0.33	0.35	0.34	0.36
Annual ($\mu g/m^3$)	0.012	0.013	0.014	0.013	0.013	0.015	0.017	0.017	0.016	0.016	0.018	0.021	0.021	0.021	0.020
SO_2															
Emission Rate (g/s)	12.79	12.79	12.79	12.79	12.79	10.40	10.40	10.40	10.40	10.40	8.18	8.18	8.18	8.18	8.18
High, 3-Hour ($\mu g/m^3$)	1.26	1.53	1.58	1.68	1.61	1.21	1.47	1.52	1.61	1.54	1.10	1.34	1.39	1.47	1.40
High, 24-Hour ($\mu g/m^3$)	0.306	0.303	0.318	0.317	0.332	0.294	0.292	0.309	0.303	0.328	0.269	0.267	0.284	0.276	0.298
Annual ($\mu g/m^3$)	0.0151	0.0164	0.0174	0.0164	0.0163	0.0158	0.0172	0.0179	0.0167	0.0168	0.0150	0.0171	0.0173	0.0169	0.0160
NO_2															
Emission Rate (g/s)	40.19	40.19	40.19	40.19	40.19	32.38	32.38	32.38	32.38	32.38	25.20	25.20	25.20	25.20	25.20
Tier 2 Annual ($\mu g/m^3$)	0.0357	0.0386	0.0409	0.0386	0.0384	0.0369	0.0402	0.0418	0.0391	0.0391	0.0347	0.0394	0.0401	0.0389	0.0370
PM_{10}															
Emission Rate (g/s)	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28
High, 24-Hour ($\mu g/m^3$)	0.102	0.101	0.107	0.106	0.111	0.121	0.120	0.127	0.125	0.135	0.140	0.139	0.149	0.145	0.156
Annual ($\mu g/m^3$)	0.0051	0.0055	0.0058	0.0055	0.0054	0.0065	0.0071	0.0074	0.0069	0.0069	0.0079	0.0089	0.0091	0.0088	0.0084
CO															
Emission Rate (g/s)	11.62	11.62	11.62	11.62	11.62	9.32	9.32	9.32	9.32	9.32	7.29	7.29	7.29	7.29	7.29
High, 1-Hour ($\mu g/m^3$)	2.40	2.37	2.26	2.31	2.41	2.03	2.10	2.27	2.37	2.27	2.06	2.01	2.14	1.95	2.09
High, 8-Hour ($\mu g/m^3$)	0.70	0.96	0.71	0.96	0.75	0.67	0.90	0.68	0.91	0.71	0.61	0.81	0.62	0.82	0.64

Table 7-3 Air Quality Impact Analysis Summary, Units 4 and 5—Distillate Fuel Oil Firing (Page 3 of 3)

	Case 7 (100% Load, 90°F Ambient)					Case 8 (80% Load, 90°F Ambient)					Case 9 (50% Load, 90°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts (10 SCCTs):															
High, 1-Hour (μg/m³)	2.07	2.16	2.20	2.16	2.08	2.26	2.33	2.52	2.66	2.44	2.91	2.76	2.94	2.68	2.94
High, 3-Hour (μg/m³)	1.03	1.25	1.29	1.37	1.31	1.20	1.46	1.51	1.60	1.53	1.38	1.68	1.74	1.84	1.75
High, 8-Hour (μg/m³)	0.63	0.86	0.64	0.86	0.68	0.74	1.00	0.75	1.00	0.78	0.85	1.13	0.87	1.15	0.89
High, 24-Hour (μg/m³)	0.25	0.25	0.26	0.26	0.27	0.29	0.29	0.31	0.30	0.32	0.34	0.33	0.36	0.35	0.37
Annual (μg/m³)	0.013	0.014	0.015	0.014	0.013	0.016	0.017	0.018	0.017	0.017	0.019	0.021	0.022	0.021	0.020
SO_2															
Emission Rate (g/s)	11.63	11.63	11.63	11.63	11.63	9.53	9.53	9.53	9.53	9.53	7.54	7.54	7.54	7.54	7.54
High, 3-Hour (μg/m³)	1.20	1.45	1.50	1.59	1.52	1.15	1.39	1.44	1.52	1.46	1.04	1.27	1.31	1.38	1.32
High, 24-Hour (μg/m³)	0.290	0.288	0.303	0.300	0.315	0.278	0.276	0.293	0.287	0.310	0.254	0.252	0.269	0.261	0.281
Annual (μg/m³)	0.0147	0.0160	0.0170	0.0157	0.0155	0.0150	0.0165	0.0171	0.0161	0.0160	0.0144	0.0162	0.0165	0.0161	0.0153
NO_2															
Emission Rate (g/s)	36.54	36.54	36.54	36.54	36.54	29.61	29.61	29.61	29.61	29.61	23.18	23.18	23.18	23.18	23.18
Tier 2 Annual (μg/m³)	0.0346	0.0377	0.0401	0.0370	0.0365	0.0350	0.0386	0.0399	0.0374	0.0373	0.0333	0.0374	0.0381	0.0372	0.0353
PM_{10}															
Emission Rate (g/s)	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28
High, 24-Hour (μg/m³)	0.107	0.106	0.111	0.111	0.116	0.125	0.124	0.131	0.129	0.139	0.144	0.143	0.153	0.148	0.160
Annual (μg/m³)	0.0054	0.0059	0.0063	0.0058	0.0057	0.0067	0.0074	0.0077	0.0072	0.0072	0.0082	0.0092	0.0094	0.0092	0.0087
CO															
Emission Rate (g/s)	10.62	10.62	10.62	10.62	10.62	8.55	8.55	8.55	8.55	8.55	6.70	6.70	6.70	6.70	6.70
High, 1-Hour (μg/m³)	2.20	2.29	2.34	2.30	2.21	1.93	2.00	2.15	2.28	2.08	1.95	1.85	1.97	1.80	1.97
High, 8-Hour (μg/m³)	0.67	0.92	0.68	0.91	0.72	0.63	0.85	0.64	0.86	0.67	0.57	0.76	0.58	0.77	0.60

Maximum Impacts	Project Impact	Case No.	Year	Class II SIL	% of SIL (%)
SO_2					
High, 3-Hour (μg/m³)	1.74	1	1995	25	6.95
High, 24-Hour (μg/m³)	0.343	1	1996	5	6.87
Annual (μg/m³)	0.0161	2	1994	1	1.61
NO_2					
Annual (μg/m³)	0.0432	2	1994	1	4.32
PM_{10}					
High, 24-Hour (μg/m³)	0.16	9	1996	5	3.19
Annual (μg/m³)	0.0094	9	1994	1	0.94
CO					
High, 1-Hour (μg/m³)	2.54	2	1995	2,000	0.13
High, 8-Hour (μg/m³)	0.99	2	1995	500	0.20

Source: ECT, 2005.

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Table 7-3. ISCST3 Model Results—Maximum Criteria Pollutant Impacts

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Significant Impact ($\mu g/m^3$)
NO_x	Annual	0.043	1
PM_{10}	Annual	0.0094	1
	24-hour	0.16	5
SO_2	Annual	0.016	1
	24-hour	0.34	5
	3-hour	1.7	25
CO	8-Hour	0.99	500
	1-Hour	2.5	2,000

Source: ECT, 2005.

8.0 AMBIENT AIR QUALITY MONITORING AND ANALYSIS

8.1 EXISTING AMBIENT AIR QUALITY MONITORING DATA

The nearest FDEP ambient air monitoring station is located in Mulberry, Polk County, approximately 15 km north of the PPS. The FDEP monitoring station at Mulberry monitors PM_{10} and SO_2. The nearest FDEP station that monitors ozone is located in Lakeland, Polk County, approximately 25 km north of the project site. The nearest FDEP station that monitors NO_x is located in Tampa, Hillsborough County, approximately 50 km northwest of the project site. The nearest FDEP station that monitors CO is located in Tampa, Hillsborough County, approximately 35 km northwest of the project site. The nearest FDEP station monitoring for lead is situated in Tampa, Hillsborough County, approximately 50 km northwest of the project site. Summaries of 2003 and 2004 ambient air quality data for these FDEP stations are provided in Tables 8-1 and 8-2.

8.2 PRECONSTRUCTION AMBIENT AIR QUALITY MONITORING EXEMPTION APPLICABILITY

As previously discussed in Section 4.2, PSD review may require continuous ambient air monitoring data to be collected in the area of the proposed source for pollutants emitted in significant amounts. Because several pollutants will be emitted from Units 4 and 5 in excess of their respective significant emission rates, preconstruction monitoring is required. However, Rule 62-212.400(2)(e), F.A.C., provides for an exemption from the preconstruction monitoring requirement for sources with *de minimis* air quality impacts. The *de minimis* ambient impact levels were previously presented in Table 4-1. To assess the appropriateness of monitoring exemptions, dispersion modeling analyses were performed to determine the maximum pollutant concentrations caused by emissions from the proposed Units 4 and 5. The results of these analyses were presented in detail in Section 7.2. The following paragraphs summarize the analyses results as applied to the preconstruction ambient air quality monitoring exemptions.

8.2.1 PM_{10}

The maximum 24-hour PM_{10} impact was predicted to be 0.16 microgram per cubic meter ($\mu g/m^3$). This concentration is below the 10-$\mu g/m^3$ *de minimis* level ambient impact level.

Table 8-1. Summary of FDEP 2003 Ambient Air Quality Data

Pollutant	Site Location County	Site Location City	Site Name	Site No.	Site UTM Coordinates Easting	Site UTM Coordinates Northing	Distance From Plant Origin (km)	Direction From Plant Origin (Vector °)	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m^3) 1st High	2nd High	Arithmetic Mean	Standard
PM_{10}	Polk	Mulberry	SR640 & Anderson Road	1050010	399,800.0	3,081,600.0	15	349	24-Hr	Jan-Dec	346	51	42		150[1]
									Annual					20	50[2]
	Polk	Mulberry	Mulberry High School	1052006	405,500.0	3,086,000.0	19	9	24-Hr	Jan-Dec	355	59	49		150[1]
									Annual					20	50[2]
	Hillsborough	Tampa	Gardinier Park	0570083	363,890.0	3,082,701.0	42	292	24-Hr	Jan-Dec	322	59	58		150[1]
									Annual					25	50[2]
	Hillsborough	Tampa	Eisenhower Jr. High School	0570085	365,199.0	3,074,807.0	38	282	24-Hr	Jan-Dec	58	41	37		150[1]
									Annual					20	50[2]
SO_2	Polk	Mulberry	SR640 & Anderson Road	1050010	399,800.0	3,081,600.0	15	349	1-Hr	Jan-Dec	8,282	431.0	193.3		
									3-Hr			117.6	88.8		1,300[3]
									24-Hr			44.4	39.2		365[3]
									Annual					13.1	80[2]
	Polk	Mulberry	Mulberry High School	1052006	405,500.0	3,086,000.0	19	9	1-Hr	Jan-Dec	3,965	326.5	206.4		
									3-Hr			117.6	81.0		1,300[3]
									24-Hr			26.1	23.5		365[3]
									Annual					10.4	80[2]
NO_2	Hillsborough	Tampa	Simmons Park	0570081	355,544.0	3,069,100.0	47	273	1-Hr	Jan-Dec	8,444	90.1	90.1		100[2]
									Annual					13.1	
	Hillsborough	Tampa	5121 Gandy Blvd	0571065	348,560.0	3,086,060.0	57	289	1-Hr	Jan-Dec	8,636	108.9	107.0		100[2]
									Annual					18.8	
CO	Hillsborough	Tampa	4702 Central Avenue	0571070	357,000.0	3,096,500.0	54	303	1-Hr	Jan-Dec	8,459	8,342.9	6,514.3		40,000[3]
									8-Hr			4,114.3	3,771.4		10,000[3]
	Hillsborough	Plant City	One Raider Place	0574004	389,300.0	3,096,710.0	33	336	1-Hr	Jan-Dec	8,696	2,742.9	2,514.3		40,000[3]
									8-Hr			1,257.1	1,257.1		10,000[3]
O_3	Polk	Lakeland	2727 Shepherd Road	1056005	401,588.0	3,090,755.0	24	358	1-Hr	Mar-Oct	239	176.3			235[4]
	Polk	Lakeland	Sikes Elementary	1056006	404,435.0	3,100,652.0	34	3	1-Hr	Mar-Oct	245	176.3			235[4]
	Hillsborough	Tampa	Simmons Park	0570081	355,544.0	3,069,100.0	47	273	1-Hr	Mar-Oct	239	219.4			235[4]
Lead	Hillsborough	Tampa	Gulf Coast Lead	0571066	364,000.0	3,093,400.0	47	304	24-Hr		59	3.2			
										Jan-Mar		0.74			1.5[2]
										Apr-Jun		0.12			1.5[2]
										Jul-Sep		0.41			1.5[2]
										Oct-Dec		0.55			1.5[2]

[1] 99th percentile
[2] Arithmetic mean
[3] 2nd high
[4] 4th highest day with hourly value exceeding standard over a 3-year period
[5] Indicates that the mean does not sastify summary criteria

Sources: ECT, 2005.
FDEP, 2005.

Table 8-2. Summary of FDEP 2004 Ambient Air Quality Data

Pollutant	Site Location: County	Site Location: City	Site Name	Site No.	Site UTM Coordinates: Easting	Site UTM Coordinates: Northing	Distance From Plant Origin (km)	Direction From Plant Origin (Vector °)	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m^3): 1st High	2nd High	Arithmetic Mean	Standard
PM_{10}	Polk	Mulberry	SR640 & Anderson Road	1050010	399,800.0	3,081,600.0	25	347	24-Hr	Jan-Dec	349	66	51		150[1]
									Annual					20.6	50[2]
	Polk	Mulberry	Mulberry High School	1052006	405,500.0	3,086,000.0	29	0	24-Hr	Jan-Dec	347	68	50		150[1]
									Annual					20.8	50[2]
	Hillsborough	Tampa	Gardinier Park	0570083	363,890.0	3,082,701.0	49	301	24-Hr	Jan-Dec	364	78	61		150[1]
									Annual					26.9	50[2]
	Hillsborough	Tampa	Eisenhower Jr. High School	0570085	365,199.0	3,074,807.0	44	293	24-Hr	Jan-Dec	60	38	30		150[1]
									Annual					19.1	50[2]
SO_2	Polk	Mulberry	Anderson Avenue	1050010	405,500.0	3,086,000.0	29	0	1-Hr	Jan-Dec	8,514	251.5	235.8		
									3-Hr			112.7	104.8		1,300[3]
									24-Hr			41.9	36.7		365[3]
									Annual					10.5	80[2]
NO_2	Hillsborough	Tampa	Simmons Park	0570081	355,544.0	3,069,100.0	51	283	1-Hr	Jan-Dec	8,171	73.4	71.5		100[2]
									Annual					10.5	
	Hillsborough	Tampa	5121 Gandy Blvd	0571065	348,560.0	3,086,060.0	64	297	1-Hr	Jan-Dec	8,182	92.2	90.3		100[2]
									Annual					17.3	
CO	Hillsborough	Tampa	4702 Central Avenue	0571070	357,000.0	3,096,500.0	62	309	1-Hr	Jan-Dec	8,656	5,175.0	5,060.0		40,000[3]
									8-Hr			3,335.0	2,875.0		10,000[3]
	Hillsborough	Plant City	One Raider Place	0574004	389,300.0	3,096,710.0	42	338	1-Hr	Jan-Dec	8,716	2,242.5	2,070.0		40,000[3]
									8-Hr			1,495.0	1,495.0		10,000[3]
O_3	Polk	Lakeland	2727 Shepherd Road	1056005	401,588.0	3,090,755.0	34	354	1-Hr	Mar-Oct	242	164.9			235[4]
									8-Hr	Mar-Oct	97	143.3			
	Polk	Lakeland	Sikes Elementary	1056006	401,588.0	3,090,755.0	34	354	1-Hr	Mar-Oct	235	176.7			235[4]
									8-Hr	Mar-Oct	95	151.2			
	Hillsborough	Tampa	Simmons Park	0570081	355,544.0	3,069,100.0	51	283	1-Hr	Mar-Oct	233	196.3			235[4]
									8-Hr	Mar-Oct	94	164.9			
Lead	Hillsborough	Tampa	Gulf Coast Lead	0571066	364,000.0	3,093,400.0	55	311	24-Hr		61	3.5			
										Jan-Mar		1.26			1.5[2]
										Apr-Jun		0.39			1.5[2]
										Jul-Sep		0.46			1.5[2]
										Oct-Dec		0.59			1.5[2]

[1] 99th percentile
[2] Arithmetic mean
[3] 2nd high
[4] 4th highest day with hourly value exceeding standard over a 3-year period
[5] Indicates that the mean does not sastify summary criteria

Sources: ECT, 2005.
FDEP, 2005.

Therefore, a preconstruction monitoring exemption for PM_{10} is appropriate in accordance with the PSD regulations.

8.2.2 SO_2

The maximum 24-hour SO_2 impact was predicted to be 0.34 $\mu g/m^3$. This concentration is below the 13-$\mu g/m^3$ *de minimis* ambient impact level for the 24-hour averaging period. Therefore, a preconstruction monitoring exemption for SO_2 is appropriate in accordance with the PSD regulations.

8.2.3 NO_2

The maximum annual NO_2 impact was predicted to be 0.043 $\mu g/m^3$. This concentration is below the 14-$\mu g/m^3$ *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption is appropriate for NO_2 in accordance with the FDEP PSD regulations.

8.2.4 CO

The maximum 8-hour CO impact was predicted to be 0.99 $\mu g/m^3$. This concentration is below the 575-$\mu g/m^3$ *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption is appropriate for CO in accordance with the FDEP PSD regulations.

9.0 ADDITIONAL IMPACT ANALYSES

The additional impacts analysis, required for projects subject to PSD review, evaluates project impacts pertaining to associated growth; soils, vegetation, and wildlife; and visibility impairment. Each of these topics is discussed in the following sections.

9.1 GROWTH IMPACT ANALYSIS

The purpose of the growth impact analysis is to quantify growth resulting from the construction and operation of the proposed project and assess air quality impacts that would result from that growth.

Impacts associated with construction of Units 4 and 5 will be minor. While not readily quantifiable, the temporary increase in vehicle miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.

The new SCCTs are being constructed to meet general area electric power demands; therefore, no significant secondary growth effects due to operation of the project are anticipated. When operational, the SCCTs are projected to generate approximately five new jobs; this number of new personnel will not significantly affect growth in the area. The increase in natural gas and distillate fuel oil demand due to operation of the new SCCTs will have no major impact on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected.

9.2 IMPACTS ON SOILS, VEGETATION, AND WILDLIFE

Maximum air quality impacts in the vicinity of the PPS due to operation of the proposed Units 4 and 5 will be well below applicable AAQS. Accordingly, no significant, adverse impacts on soils, vegetation, and wildlife in the vicinity of the PPS are anticipated. The following sections discuss potential impacts on the nearest Class I area; the Chassahowitzka NWR.

9.2.1 IMPACTS ON SOILS

The U.S. Department of Agriculture (USDA) (1991a and 1991b) lists the primary soil type in Chassahowitzka NWR as Weekiwachee-Durbin muck. This soil type is characterized by high levels of sulfur and organic content. Sulfur levels may approach 4 percent in the upper soil layer. Daily flooding by high tides cause the pH to vary between 6.1 and 7.8.

Typically, SO_2 represents the greatest threat to soil since this pollutant causes increased sulfur content and decreased pH. However, for the Unit 4 and 5 project, given the relatively low levels of SO_2 emitted, the distance from the source, the naturally high sulfur content of the Class I area soils, and the pH variability caused by tidal influences, no impacts to soils are expected.

9.2.2 IMPACTS ON VEGETATION

The Chassahowitzka NWR is a complex ecosystem of vegetation assemblages that depend on the subtle interplay of slight changes in elevation, salinity, hydroperiod, and edaphic factors for distribution, extent, and species composition. The mosaic of plant communities at the Chassahowitzka NWR is represented by pine woods and hammock forests within areas of higher ground, various fresh water forested and nonforested wetlands situated within lowland depressions that are inundated/saturated with fresh water for at least part of the year (mixed swamp, marsh, etc.) and brackish to salt water wetlands such as salt marsh and mangrove swamp distributed at lower elevations on land normally inundated by tidal action and freshwater pulses from upland surface water runoff. The predominant flora associated with these associations is typically common to the central Florida region and characterized by a high diversity of terrestrial, wetland, and aquatic species. Common vascular taxa within the Chassahowitzka NWR would include slash pine, laurel oak, live oak, cabbage palm, sweet gum, red maple, saw palmetto, and gallberry in the inland areas and needlerush, red mangrove, cordgrass, and saltgrass in the brackish to marine reaches.

The literature was reviewed as to potential effects of air pollutants on vegetation. It was concluded that even the maximum impacts projected to occur in the immediate vicinity of the PPS due to operation of Units 4 and 5 would be below thresholds shown to cause damage to vegetation. Maximum air pollutant impacts at Chassahowitzka NWR due to emissions from PPS Units 4 and 5 will be far less, as presented previously. The potential for damage at the Chassahowitzka NWR could, therefore, be considered negligible given the much lower air pollution impacts predicted at Chassahowitzka NWR relative to the immediate PPS plant vicinity and the absence of any plant species at Chassahowitzka NWR that would be especially sensitive to the very low predicted pollutant concentrations.

9.2.3 IMPACTS ON WILDLIFE

Wildlife resources in the 30,500-acre Chassahowitzka NWR are fairly typical of central Florida's Gulf Coast. The eastern portions of the site are fringed by hardwood swamp habitats, but the primary habitats are the estuarine and brackish marshes along with the saltwater bays containing many mangrove-covered islands. These habitats support large numbers of resident and migratory waterfowl, water birds, and shorebirds. Wading birds are also quite common. Deer, raccoons, black bears, otters, and bobcats are the notable mammals. Alligators are numerous. Bald eagles and the West Indian manatee are the primary endangered/threatened species utilizing the area.

Air pollution impacts to wildlife have been reported in the literature, although many of the incidents involved acute exposures to pollutants usually caused by unusual or highly concentrated releases or unique weather conditions. Generally, there are three ways pollutants may affect wildlife: through inhalation, through exposure with skin, and through ingestion (Newman, 1980). Ingestion is the most common means and can occur through eating or drinking of high concentrations of pollutants. Bioaccumulation is the process of animals collecting and accumulating pollutant levels in their bodies over time. Other animals that prey on these animals would then be ingesting concentrated pollutant levels.

Based on a review of the limited literature on air pollutant effects on wildlife, it is unlikely that the levels of pollutants produced by Units 4 and 5 will cause injury or death to wildlife. Concentrations of pollutants will be low, emissions will be dispersed over a large area, and mobility of wildlife will minimize their exposure to any unusual concentrations caused by equipment malfunction or unique weather patterns.

Bioaccumulation, particularly of mercury, has been a concern in Florida. There is increasing evidence that mercury may be naturally evolved in Florida and that, combined with manmade sources, is becoming bioaccumulated in certain fish and wildlife. It is unknown what naturally occurring levels may be present in onsite fish and wildlife. However, the likelihood that the small amount attributable to this project would all be methylated, end up in the food chain, and then consumed by predators is considered negligible.

The acid rain effects on wildlife in Florida are primarily those related to aquatic animals. Acidified water may prevent fish egg hatching, damage larvae, and lower immunity factors in adult fish (Barker, 1983). Acid rain can also result in release of metals (especially aluminum) from lake sediments; this can cause a biochemical deterioration of fish gills leading to death by suffocation. However, the sensitivity of Florida lakes to acid rain is in question. Florida lakes have a wide natural range of pH (from 4 to 8.8 pH units). Most well-buffered lakes are in central and south Florida, and rainfall is in the pH range of 4.8 to 5.1. According to Barker (1983) and Charles (1991), no evidence is currently available to clearly show that degradation of aquatic systems have occurred as a direct result of acid precipitation in Florida. Air emissions from PPS Units 4 and 5 SCCTs that could contribute to the formation of atmospheric acids are not predicted to significantly increase acid precipitation and are predicted to have no impact on wildlife at Chassahowitzka NWR.

In conclusion, it is unlikely the projected air emission levels from PPS Units 4 and 5 will have any measurable direct or indirect effects on wildlife utilizing the Chassahowitzka NWR.

9.3 VISIBILITY IMPAIRMENT POTENTIAL

No visibility impairment at the local level is expected due to the types and quantities of emissions projected for Units 4 and 5. Opacity of the SCCTs exhausts will be 10 percent or less, excluding water. Emissions of primary particulates and sulfur oxides from the

SCCTs will be low due to the primary use of pipeline-quality natural gas and low sulfur, low ash distillate fuel oil as the back-up fuel source. Units 4 and 5 will comply with all applicable FDEP requirements pertaining to visible emissions.

10.0 CLASS I IMPACTS

10.1 INTRODUCTION

The required Class I area impact assessments were conducted using the CALPUFF dispersion model in accordance with the recommendations contained in the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts, the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report, and EPA's Guideline on Air Quality Models. The CALPUFF model was employed in a refined mode using three years (1990, 1992, and 1996) of meteorology developed using the CALMET preprocessor program and specific receptors recommended by the National Park Service (NPS) for the Chassahowitzka NWR. The CALPUFF suite of programs, including the POSTUTIL and CALPOST post-processing programs, was employed to develop estimates of SCCT project impacts on the Chassahowitzka NWR for PSD increments, regional haze, and deposition.

10.2 SUMMARY

The CALMET/CALPUFF/CALPOST modeling assessment resulted in the following conclusions:

- Maximum SO_2, NO_2, and PM_{10} impacts at the Chassahowitzka NWR are projected to be well below the EPA Class I area significant levels for all pollutants and averaging periods. The critical averaging time and pollutant was determined to be the 24-hour average SO_2 impact. Maximum 24-hour average SO_2 impact on the Chassahowitzka NWR is projected to be 0.070 $\mu g/m^3$, or only 35 percent of the EPA PSD Class I significant impact level. The EPA PSD Class I significant impact levels were previously provided in Section 4.0, Table 4-3.
- Maximum change in light extinction coefficient (β_{ext}) at the Chassahowitzka NWR is projected to be 9.33 percent or a 0.892 change in deciview (dv). There were only two 24-hour maximum changes in light extinction that exceeded the Federal Land Manager (FLM) significance levels of a 5-percent

change in β_{ext} and 0.5 change in dv over the 3 years of meteorological data evaluated.

- Maximum total (wet and dry) sulfur deposition rate is projected to be 0.0048 kilograms per hectare per year (kg/ha/yr). The maximum nitrogen deposition rate is projected to be 0.0038 kg/ha/yr. These deposition impacts are only 48 and 38 percent of the FLM significance level of 0.01 kg/ha/yr for sulfur and nitrogen deposition, respectively.

10.3 MODEL SELECTION AND USE

The nearest Class I area to the PPS is the Chassahowitzka NWR, located approximately 120 km north of the project site. Steady-state dispersion models do not consider temporal or spatial variations in plume transport direction nor do they limit the downwind transport of a pollutant as a function of wind speed and travel time. Due to these limitations, conventional steady-state dispersion models, such as the ISC3 models, are not considered suitable for predicting air quality impacts at receptors located more than 50 km from an emission source.

Because of the need to assess air quality impacts at PSD Class I areas, which are typically located at distances greater than 50 km from the emission sources of interest, the EPA and FLM have initiated efforts to develop dispersion models appropriate for the assessment of long-range transport of air pollutants. The IWAQM was formed to coordinate the model development efforts of the EPA and FLMs.

The IWAQM work plan indicates that a phased approach would be taken with respect to the implementation of recommendations for long-range transport modeling. In Phase I, the IWAQM would review current EPA modeling guidance and issue an interim modeling approach applicable to projects undergoing permit review. For Phase II, a review would be made of other available long-range transport models and recommendations developed for the most appropriate modeling techniques.

The Phase I recommendation, issued in April 1993, is to use the Lagrangian puff model, MESOPUFF II, for long-range transport air quality assessments.

The Phase II recommendations, issued in December 1998, are contained in the IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts. Additional FLM guidance with respect to the assessment of visibility and deposition impacts is provided in the FLAG Phase I Report dated December 2000. The Phase II IWAQM recommendation is to apply the CALPUFF Modeling System to assess air quality impacts at distances greater than 50 km from an emission source. In April 2003, EPA designated the CALPUFF model as a preferred model (i.e., a model listed in Appendix A to Appendix W of 40 CFR 51, Summaries of Preferred Air Quality Models) for use in assessing the long-range transport of air pollutants. The CALPUFF Modeling System consists of three main components: (a) CALMET, (b) CALPUFF, and (c) CALPOST. Each of these components is described in the following sections.

10.4 CALMET

CALMET is a meteorological model that develops hourly wind and temperature fields on a three-dimensional gridded modeling domain. The meteorological file produced by CALMET for use by CALPUFF also includes two-dimensional parameters such as mixing height, surface characteristics, and dispersion properties.

CALMET requires a number of input data files to develop the gridded three- and two-dimensional meteorological file utilized by CALPUFF. The specific meteorological data used by the CALMET program include:

- Penn State/NCAR Mesoscale Model gridded, prognostic wind field data (terrain elevation, land use code, sea level pressure, rainfall amount, snow cover indicator, pressure, temperature/dew point, wind direction, and wind speed).
- Surface station weather data (windspeed, wind direction, ceiling height, opaque sky cover, air temperature, relative humidity, station pressure, and precipitation type code).
- Upper air sounding (mixing height) data (pressure, height above sea level, temperature, wind direction, and wind speed at each sounding).
- Surface station precipitation data (precipitation rates).

- Overwater data (air-sea surface temperature difference, air temperature, relative humidity, overwater mixing height, wind speed, and wind direction).
- Geophysical data (land use type, terrain elevation, surface parameters including surface roughness, length, albedo, Bowen ratio, soil heat flux, and vegetation leaf area index, and anthropogenic heat flux).

CALMET output files for calendar years 1990, 1992, and 1996 were obtained from the FDEP for use in assessing air quality impacts at the Chassahowitzka NWR. Further details regarding the meteorological data used in the CALMET program are provided in Section 10.5, Meteorological Data. An example CALMET output file is included in Appendix F. This output file shows all of the CALMET options employed by FDEP in developing their CALMET files for the Chassahowitzka NWR.

10.5 CALPUFF

CALPUFF is a transport and puff model that advects "puffs" of material from an emission source. These "puffs" undergo various dispersion and transformation simulation processes as they are advected from an emission source to a receptor of interest. The simulation processes include wet and dry deposition and chemical transformation. CALPUFF typically uses the gridded meteorological data created by the CALMET program. CALPUFF, when used in a screening mode, can also utilize non-gridded meteorological data similar to that used by a steady-state Gaussian model such as the ISC dispersion model. The distribution of puffs by CALPUFF explicitly incorporates the temporal and spatial variations in the meteorological fields thereby overcoming one of the main shortcomings of steady-state dispersion models.

There are a number of optional CALPUFF input files that were not used for the Chassahowitzka NWR impact assessments. These include time-varying emission rates, user-specified deposition velocities and chemical transformation conversion rates, complex terrain receptor and hill geometry data, and coastal boundary data.

CALPUFF generates output files consisting of hourly concentrations, deposition fluxes, and data required for visibility assessments for each receptor. These CALPUFF output files are subsequently processed by the POSTUTIL and CALPOST programs to provide impact summaries for the pollutants and averaging periods of interest.

The various CALPUFF program options are implemented by means of a control file. CALPUFF options selected for the Chassahowitzka NWR impact assessments conform to the recommendations contained in the IWQAM Phase II report and EPA's Guideline on Air Quality Models. Options selected include modeling of six species (SO_2, SO_4, NO_x, HNO_3, NO_3, and PM_{10}), chemical transformation using the MESOPUFF II scheme, wet removal, and a 5-km spacing meteorological and computational grid. The meteorological and computational grids include the PPS Units 4 and 5 emission sources and the Chassahowitzka NWR receptors. The current version of CALPUFF (Version 5.711A, Level 040716) was used in the Chassahowitzka NWR air quality impact assessments.

10.6 POSTUTIL

POSTUTIL is a post-processing program used to process the concentration generated by CALPUFF. POSTUTIL was used to consolidate the wet and dry nitrogen and sulfur fluxes, and convert sulfate and nitrate fluxes to total sulfur and total nitrogen fluxes. The current version of POSTUTIL (Version 1.3, Level 030528) was used in the Chassahowitzka NWR air quality impact assessments.

10.7 CALPOST

CALPOST is a post-processing program used to process the concentration, deposition, and visibility files generated by CALPUFF. The CALPOST program was formulated to average and report pollutant concentrations or wet/dry deposition fluxes using the hourly data contained in the CALPUFF output files. CALPOST can produce summary tables of pollutant concentrations and depositions for each receptor for various averaging times and can develop ranked lists of these impacts. For visibility-related modeling (e.g., regional haze), CALPOST uses the CALPUFF generated pollutant concentrations to calculate extinction coefficients and other related indicators of visibility.

For visibility assessments, background conditions were estimated using "natural" background data (i.e., absent anthropogenic influences) and hourly relative humidity data. The

CALPOST program was then used to compute background extinction coefficients using the natural background data and the IWQAM recommended extinction efficiency for each species.

Similar to the CALPUFF program, the various CALPOST program options are implemented by means of a control file. CALPOST options selected for the Chassahowitzka NWR impact assessments conform to the recommendations contained in the FLAG Phase I Report. Background light extinction Method 2 was selected to develop visibility impacts; this method uses speciated particulate concentration data and hourly relative humidity data. The current version of CALPOST (Version 5.51, Level 030709) was used in the Chassahowitzka NWR air quality impact assessments.

10.8 RECEPTOR GRID

Consistent with FLM modeling guidance, the CALPUFF receptor grid consisted of 113 discrete receptors, obtained from the NPS Web site, located throughout the Chassahowitzka NWR.

10.9 METEOROLOGICAL DATA

Processed CALMET meteorological data for calendar years 1990, 1992, and 1996 were obtained from the FDEP. Meteorological data used by the FDEP to develop the CALMET files consisted of mesoscale data (MM4 data for 1990 and 1992, and MM5 data for 1996) together with four upper air, five overwater, nine surface, and 32 precipitation stations located throughout the modeling domain.

10.10 MODELED EMISSION SOURCES

Modeled emission sources consisted Units 4 and 5 assuming oil firing at Case 4 conditions (i.e., rated load and 59°F ambient temperature). These operating conditions were selected because they result in the highest emission rates. Specific Unit 4 and 5 emission source characteristics used in the CALPUFF modeling assessments are summarized in Table 10-1.

Table 10-1. SCCT CALPUFF Emission Source Data

Parameter	Units	Value
Stack height	ft	114
Stack diameter	ft	18.0
Stack velocity	ft/sec	161.7
Stack temperature	°F	1,098
SO_2 emissions	lb/hr	101.5
H_2SO_4 emissions	lb/hr	11.7
NO_x emissions	lb/hr	319.0
PM_{10} emissions	lb/hr	34.0

Source: ECT, 2005.

10.11 MODEL RESULTS

Refined CALPUFF/CALPOST modeling results for Class I PSD increments, visibility, and deposition impacts at the Chassahowitzka NWR are discussed in the following sections.

10.11.1 PSD CLASS I INCREMENTS

Maximum annual NO_2, SO_2, and PM_{10} impacts are summarized on Tables 10-2, 10-3, and 10-4, respectively. Maximum 3- and 24-hour SO_2 impacts are summarized on Tables 10-5 and 10-6, respectively. Maximum 24-hour PM_{10} impacts are summarized on Table 10-7. These tables provide the highest impact for each pollutant and averaging period, the location of the highest impact, the time of occurrence for short-term (3- and 24-hour average) impacts, and the PSD Class I significant impact levels.

The critical pollutant and averaging period was determined to be the 24-hour average SO_2 impact. The maximum Unit 4 and 5 24-hour average SO_2 impact at the Chassahowitzka NWR is projected to be 0.070 $\mu g/m^3$, or only 35 percent of the EPA PSD Class I significant impact level.

The CALPUFF/CALPOST results demonstrate that maximum Unit 4 and 5 impacts at the Chassahowitzka NWR will be less than the EPA Class I PSD significant impact levels for all pollutants and averaging periods.

10.11.2 REGIONAL HAZE

Maximum 24-hour regional haze impacts are summarized on Table 10-8. This table provides the emission source beta extinction coefficient, β_{ext}, for each species (SO_4, NO_3, and PMC) as well as the total emission source β_{ext}, background β_{ext} based on natural conditions as defined by the FLM, background visual range in Units of km and dv, and the highest changes in β_{ext} and dv as calculated by the CALPOST program. The maximum change in β_{ext} is projected to be 11.01 percent, or slightly above the 5-percent FLM significant impact level. The project regional haze impacts are considered acceptable for the following reasons:

Table 10-2. CALPUFF Model Results—Annual NO_2

Maximum Annual Impacts	1990	1992	1996
Modeled Impact ($\mu g/m^3$)	0.0035	0.0037	0.0047
PSD Class I significant impact ($\mu g/m^3$)	0.1	0.1	0.1
Exceed PSD Class I significant impact (Y/N)	No	No	No
Percent of PSD significant impact (%)	3.5	3.7	4.7
Receptor UTM/LCC (1996) Easting (km)	338.3	342.5	1,402.0
Receptor UTM/LCC (1996) Northing (km)	3,166.0	3,175.2	506.6
Distance from PPS (km)	118.0	123.7	122.4
Direction from PPS (Vector °)	327	331	317

Source: ECT, 2005.

Table 10-3. CALPUFF Model Results, Annual SO_2

Maximum Annual Impacts	1990	1992	1996
Modeled Impact ($\mu g/m^3$)	0.0032	0.0033	0.0042
PSD Class I significant impact ($\mu g/m^3$)	0.1	0.1	0.1
Exceed PSD Class I significant impact (Y/N)	N	N	N
Percent of PSD significant impact (%)	3.2	3.3	4.2
Receptor UTM/LCC (1996) Easting (km)	339.9	339.9	1,403.9
Receptor UTM/LCC (1996) Northing (km)	3,166.0	3,166.0	505.0
Distance from PPS (km)	117.1	117.1	119.9
Direction from PPS (Vector ^{o})	328	328	317

Source: ECT, 2005.

Table 10-4. CALPUFF Model Results, Annual PM_{10}

Maximum Annual Impacts	1990	1992	1996
Modeled Impact ($\mu g/m^3$)	0.0014	0.0014	0.0019
PSD Class I significant impact ($\mu g/m^3$)	0.2	0.2	0.2
Exceed PSD Class I significant impact (Y/N)	No	No	No
Percent of PSD significant impact (%)	0.7	0.7	0.9
Receptor UTM/LCC (1996) Easting (km)	339.9	339.9	1,402.0
Receptor UTM/LCC (1996) Northing (km)	3,166.0	3,166.0	506.6
Distance from PPS (km)	117.1	117.1	122.4
Direction from PPS (Vector °)	328	328	317

Source: ECT, 2005.

Table 10-5. CALPUFF Model Results, 3-Hour SO_2

Maximum Annual Impacts	1990	1992	1996
Modeled Impact ($\mu g/m^3$)	0.2856	0.3194	0.3140
PSD Class I significant impact ($\mu g/m^3$)	1.0	1.0	1.0
Exceed PSD Class I significant impact (Y/N)	No	No	No
Percent of PSD significant impact (%)	28.6	31.9	31.4
Receptor UTM/LCC (1996) Easting (km)	342.5	341.6	1,396.3
Receptor UTM/LCC (1996) Northing (km)	3,175.2	3,174.3	516.1
Distance from PPS (km)	123.7	123.4	133.2
Direction from PPS (Vector °)	331	330	318
Date of maximum impact	03/29/90	07/25/92	08/06/96
Julian date of maximum impact	88	207	217
Ending hour of maximum impact	1100	1100	0700

Source: ECT, 2005.

Table 10-6. CALPUFF Model Results, 24-Hour SO_2

Maximum Annual Impacts	1990	1992	1996
Modeled Impact ($\mu g/m^3$)	0.0629	0.0696	0.0561
PSD Class I significant impact ($\mu g/m^3$)	0.2	0.2	0.2
Exceed PSD Class I significant impact (Y/N)	No	No	No
Percent of PSD significant impact (%)	31.4	34.8	28.1
Receptor UTM/LCC (1996) Easting (km)	340.0	342.5	1,406.4
Receptor UTM/LCC (1996) Northing (km)	3,169.7	3,175.2	505.4
Distance from PPS (km)	120.3	123.7	118.6
Direction from PPS (Vector ^{o})	329	330	318
Date of maximum impact	05/16/90	07/25/92	07/15/96
Julian date of maximum impact	136	207	197

Source: ECT, 2005.

Table 10-7. CALPUFF Model Results, 24-Hour PM_{10}

Maximum Annual Impacts	1990	1992	1996
Modeled Impact ($\mu g/m^3$)	0.0250	0.0273	0.0270
PSD Class I significant impact ($\mu g/m^3$)	0.3	0.3	0.3
Exceed PSD Class I significant impact (Y/N)	No	No	No
Percent of PSD significant impact (%)	8.3	9.1	9.0
Receptor UTM/LCC (1996) Easting (km)	340.0	342.5	1,402.0
Receptor UTM/LCC (1996) Northing (km)	3,169.7	3,175.2	506.6
Distance from PPS (km)	120.3	123.7	122.4
Direction from PPS (Vector °)	329	331	317
Date of maximum impact	05/16/90	07/25/92	05/18/96
Julian date of maximum impact	136	207	139

Source: ECT, 2005.

Table 10-8. CALPUFF Model Results, Regional Haze

Maximum Annual Impacts	Units	1990	1992	1996
B_{ext-s} - SO_4	Mm^{-1}	0.203	0.307	0.750
B_{ext-s} - NO_3	Mm^{-1}	0.291	0.303	1.314
B_{ext-s} - PMF	Mm^{-1}	0.033	0.050	0.090
B_{ext-s} - Total	Mm^{-1}	0.527	0.660	2.154
B_{ext-b} - background	Mm^{-1}	22.4	22.4	23.1
Visual range, background	km	175.0	175.0	169.5
Visual range, background	mi	108.7	108.8	105.3
Visual range, background	dv	8.0	8.0	8.4
Relative humidity factor (FRH)	-	4.29	4.28	5.09
Number of days with B_{ext} >5.0 %	-	0	0	2
Largest B_{ext} change	%	2.36	2.95	9.33
Date of largest B_{ext} change	-	07/04/90	07/19/92	01/16/96
NPS significant impact, B_{ext} change	%	5.00	5.00	5.00
Exceed NPS significant impact	Y/N	No	No	Yes
Percent of NPS significant impact	%	47.2	59.0	186.6
Number of days with delta deciview >0.5 %	-	0	0	1
Largest delta deciview change	-	0.233	0.291	0.892

Source: ECT, 2005.

- Only two 24-hour periods out of 1,097 modeled events (1990, 1992, and 1996) exceeded the FLM 5.0 percent guideline (i.e., the guideline was exceeded for only 0.18 percent of the modeled period).
- The regional haze impacts assumed continuous oil firing. For Units 4 and 5, oil-firing hours will be limited to no more than 750 hr/yr unit.
- The 5-percent FLM guideline is half of the level that is perceptible (i.e. increases in β_{ext} above 10 percent [equivalent to a dv change of 1.0]) are considered to be perceptible at the furthest extent of the visual range. Accordingly, the predicted Unit 4 and 5 maximum regional haze impact will not be perceptible in the Chassahowitzka NWR.
- The regional haze analysis compares project impacts with "natural" background (i.e., a theoretical background that would occur in the absence of all anthropogenic activities). This results in a natural background visual range of approximately 105 miles for the Chassahowitzka NWR. Other than nighttime celestial objects, there are no line-of-sight vistas in the coastal Chassahowitzka NWR that are near this visual range. For example, the theoretical line-of-sight for a 6-ft-tall person on the shoreline of the Gulf of Mexico is 3.2 miles due to the curvature of the earth.
- The 20 percent best visibility over the 1994 to 1998 period for the Chassahowitzka NWR was 18 dv or a visual range of 40 miles. A comparison of maximum Unit 4 and 5 regional haze impacts during oil firing with this actual background level results in a change in β_{ext} of 3.54 percent; well below perceptible levels.

10.12 DEPOSITION

Annual sulfur and nitrogen deposition rates are summarized on Tables 10-9 and 10-10, respectively. These tables provide the CALPUFF/POSTUTIL/CALPOST modeled total (wet and dry) deposition rates impact for nitrogen and sulfur in Units of $\mu g/m^2/s$ and kg/ha/yr. The maximum annual nitrogen and sulfur deposition rates of 0.0038 and 0.0048 kg/ha/yr, respectively, are well below the FLM guideline of 0.01 kg/ha/yr.

Table 10-9. CALPUFF Model Results, Total Nitrogen Deposition

Maximum Annual Impacts	1990	1992	1996
Total dry and wet nitrogen deposition ($\mu g/m^2/s$)	1.30E-05	2.04E-05	1.42E-05
Total dry and wet nitrogen deposition (kg/ha/yr)	0.0024	0.0038	0.0026
PSD Class I significant impact (kg/ha/yr)	0.01	0.01	0.01
Exceed PSD Class I significant impact (Y/N)	No	No	No
Percent of PSD significant impact (%)	23.9	37.6	26.1
Receptor UTM/LCC (1996) Easting (km)	339.9	342.5	1,406.4
Receptor UTM/LCC (1996) Northing (km)	3,166.0	3,175.2	505.4
Distance from PPS (km)	117.1	123.7	118.6
Direction from PPS (Vector °)	328	331	318

Source: ECT, 2005.

Table 10-10. CALPUFF Model Results, Total Sulfur Deposition

Maximum Annual Impacts	1990	1992	1996
Total dry and wet sulfur deposition ($\mu g/m^2/s$)	1.59E-05	2.60E-05	1.76E-05
Total dry and wet sulfur deposition (kg/ha/yr)	0.0029	0.0048	0.0033
PSD Class I significant impact (kg/ha/yr)	0.01	0.01	0.01
Exceed PSD Class I significant impact (Y/N)	No	No	No
Percent of PSD significant impact (%)	29.3	48.0	32.6
Receptor UTM/LCC (1996) Easting (km)	337.5	342.5	1,406.4
Receptor UTM/LCC (1996) Northing (km)	3,166.0	3,175.2	505.4
Distance from PPS (km)	118.5	123.7	118.6
Direction from PPS (Vector °)	327	331	318

Source: ECT, 2005.

10.13 CONCLUSIONS

Comprehensive dispersion modeling using the CALMET/CALPUFF/CALPOST modeling suite demonstrates that Units 4 and 5 will result in ambient air quality impacts that are below the PSD Class I significant impact levels for all pollutants and all averaging periods. Accordingly, a multisource interactive assessment of air quality impacts with respect to the PSD Class I increments is not required.

As discussed above in Section 10.6, regional haze impacts are considered acceptable based on the conservative nature of the regional haze procedures and the Unit 4 and 5 project assumptions. Annual total nitrogen and sulfur deposition rates due to Units 4 and 5 are well below the FLM guideline of 0.01 kg/ha/yr.

Table 10-11 provides a summary of maximum Unit 4 and 5 Chassahowitzka NWR air quality impacts, the PSD Class I area EPA significant impact levels, and FLM guidelines.

Table 10-11. CALPUFF Model Chassahowitzka NWR Results

A. Criteria Pollutants

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Significant Impact ($\mu g/m^3$)
NO_x	Annual	0.0037	0.1
PM_{10}	Annual	0.0014	0.2
	24-hour	0.028	0.3
SO_2	Annual	0.0033	0.1
	24-hour	0.070	0.2
	3-hour	0.32	1.0

B. Deposition

Pollutant	Averaging Time	Maximum Impact (kg/ha/yr)	Significant Impact (kg/ha/yr)
Nitrogen	Annual	0.0038	0.01
Sulfur	Annual	0.0048	0.01

C. Regional Haze

Pollutant	Averaging Time	Maximum Impact (% Change B_{ext})	Significant Impact (% Change B_{ext})
Regional haze	24-Hour	10.01	5.0

Source: ECT, 2005.

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APPENDIX A

APPLICATION FOR AIR PERMIT—
LONG FORM

Department of
Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:

- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:

- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Tampa Electric Company**
2. Site Name: **Polk Power Station**
3. Facility Identification Number: **1050233**
4. Facility Location...:
   Street Address or Other Locator: **9995 State Route 37 South**
   City: **Mulberry** County: **Polk** Zip Code: **33860-0775**
5. Relocatable Facility? ☐ Yes ☒ No
6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Raiza Calderon, Engineer —Air Programs**
2. Application Contact Mailing Address...
   Organization/Firm: **Tampa Electric Company**
   Street Address: **P.O. Box 111**
   City: **Tampa** State: **FL** Zip Code: **33601**
3. Application Contact Telephone Numbers...
   Telephone: **(813) 641-5261** ext. Fax: **(813) 641-5081**
4. Application Contact Email Address: **rcalderon@tecoenergy.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	10-14-05
2. Project Number(s):	1050233-018-AC
3. PSD Number (if applicable):	PSD-FL-363
4. Siting Number (if applicable):	PA 92-32

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

☒ Air construction permit.

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.

☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Tampa Electric Company (TEC) is planning to construct and operate two additional simple-cycle CTGs at the Polk Power Station (PPS). The PPS simple-cycle CTG project will consist of two, nominal 165-megawatt (MW) CTGs (designated as Units 4 and 5) fired primarily with pipeline quality natural gas. Low-sulfur distillate fuel oil will serve as a back-up fuel source. The new simple-cycle CTGs will operate at annual capacity factors up to 50 (equivalent to 4,380 hours per year at baseload) and 8.6 (equivalent to 750 hours per year at baseload) percent for natural gas and oil firing, respectively.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	**Description of Emissions Unit**	**Air Permit Type**	**Air Permit Proc. Fee**
011	Nominal 165 MW simple cycle gas turbine CTG-4	AC1A	N/A
012	Nominal 165 MW simple cycle gas turbine CTG-5	AC1A	

Application Processing Fee

Check one: ☐ Attached - Amount: $ ______________ ☒ Not Applicable

Department of
Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:
- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:
- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Tampa Electric Company**	
2. Site Name: **Polk Power Station**	
3. Facility Identification Number: **1050233**	
4. Facility Location...: Street Address or Other Locator: **9995 State Route 37 South** City: **Mulberry** County: **Polk** Zip Code: **33860-0775**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Raiza Calderon, Engineer —Air Programs**
2. Application Contact Mailing Address... Organization/Firm: **Tampa Electric Company** Street Address: **P.O. Box 111** City: **Tampa** State: **FL** Zip Code: **33601**
3. Application Contact Telephone Numbers... Telephone: **(813) 641-5261** ext. Fax: **(813) 641-5081**
4. Application Contact Email Address: **rcalderon@tecoenergy.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Project Number(s):	
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

☒ Air construction permit.

Air Operation Permit

☐ Initial Title V air operation permit.
☐ Title V air operation permit revision.
☐ Title V air operation permit renewal.
☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.
☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.
☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Tampa Electric Company (TEC) is planning to construct and operate two additional simple-cycle CTGs at the Polk Power Station (PPS). The PPS simple-cycle CTG project will consist of two, nominal 165-megawatt (MW) CTGs (designated as Units 4 and 5) fired primarily with pipeline quality natural gas. Low-sulfur distillate fuel oil will serve as a back-up fuel source. The new simple-cycle CTGs will operate at annual capacity factors up to 50 (equivalent to 4,380 hours per year at baseload) and 8.6 (equivalent to 750 hours per year at baseload) percent for natural gas and oil firing, respectively.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
011	Nominal 165 MW simple cycle gas turbine CTG-4	AC1A	N/A
012	Nominal 165 MW simple cycle gas turbine CTG-5	AC1A	

Application Processing Fee

Check one: ☐ Attached - Amount: $ ______________ ☒ Not Applicable

Note: The PPS is a Florida Power Plant Siting Act certified site. $10,000 Site Certification modification fee has been submitted to the FDEP Siting Coordination Office.

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name: **Mark J. Hornick, General Manager**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Tampa Electric Company** Street Address: **P.O. Box 111** City: **Tampa** State: **FL** Zip Code: **33601-0111**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(813) 288-1111** ext.**39988** Fax: **(863) 428-5927**
4.	Owner/Authorized Representative Email Address: **mjhornick@tecoenergy.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. 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 and all other requirements identified in this application to which the facility is subject. 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 the facility or any permitted emissions unit.* Mark J Hornick 10/17/05 Signature Date

APPLICATION INFORMATION

Application Responsible Official Certification N/A

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:
2. Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source.
3. Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4. Application Responsible Official Telephone Numbers... Telephone: ext. Fax:
5. Application Responsible Official Email Address:
6. Application Responsible Official Certification: *I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. 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 and all other applicable requirements identified in this application to which the Title V source is subject. 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 the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.* ________________ __________ Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **Thomas W. Davis** Registration Number: **36777**
2.	Professional Engineer Mailing Address... Organization/Firm: **Environmental Consulting & Technology, Inc.** Street Address: **3701 Northwest 98th Street** City: **Gainesville** State: **FL** Zip Code: **32606**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 332-0444** ext. Fax: **(352) 332-6722**
4.	Professional Engineer Email Address: **tdavis@ectinc.com**
5.	Professional Engineer Statement:

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

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

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

(3) If the purpose of this application is to obtain a Title V 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 plan and schedule is submitted with this application.

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

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

Thomas W. Davis 10/7/05

Signature Date

(seal)

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **402.45** North (km) **3,067.35**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **27/43/43** Longitude (DD/MM/SS) **81/59/23**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Mike Perkins, Environmental Coordinator**
2. Facility Contact Mailing Address... Organization/Firm: **Tampa Electric Company** Street Address: **P.O. Box 111** City: **Tampa** State: **FL** Zip Code: **33601-0111**
3. Facility Contact Telephone Numbers: Telephone: **(813) 228-1111** ext.**39109** Fax: **(863) 428-5927**
4. Facility Contact Email Address: **mrperkins@tecoenergy.com**

Facility Primary Responsible Official N/A

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1.	☐	Small Business Stationary Source	☐ Unknown
2.	☐	Synthetic Non-Title V Source	
3.	☒	Title V Source	
4.	☒	Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5.	☐	Synthetic Minor Source of Air Pollutants, Other than HAPs	
6.	☐	Major Source of Hazardous Air Pollutants (HAPs)	
7.	☒	Synthetic Minor Source of HAPs	
8.	☒	One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9.	☐	One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10.	☐	One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11.	☐	Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment:			

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NOX	**A**	**N**
SO2	**A**	**N**
CO	**A**	**N**
PM10	**A**	**N**
PM	**A**	**N**
SAM	**A**	**N**
VOC	**A**	**N**
PB	**B**	**N**
H114 (Mercury Compounds)	**B**	**N**
H015 (Arsenic Compounds)	**B**	**N**
H021 (Beryllium Compounds)	**B**	**N**

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps N/A

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID:**Fig 2-2** ☐ Previously Submitted, Date:_____
2.	Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID:**Fig. 2-3** ☐ Previously Submitted, Date:_____
3.	Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID:**Att. A-1** ☐ Previously Submitted, Date:_____

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☒ Attached, Document ID: **Fig 2-1** ☐ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction or Modification: ☒ Attached, Document ID: **Section 2.0**
3.	Rule Applicability Analysis: ☒ Attached, Document ID: **Att. A-2**
4.	List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
6.	Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
7.	Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): ☒ Attached, Document ID: **Section 7.0** ☐ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): ☒ Attached, Document ID: **Section 7.0** ☐ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:_____ ☐ Not Applicable

Additional Requirements for FESOP Applications N/A

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID: ☐ Not Applicable (no exempt units at facility)	

Additional Requirements for Title V Air Operation Permit Applications N/A

1. List of Insignificant Activities (Required for initial/renewal applications only): ☐ Attached, Document ID: ☐ Not Applicable (revision application)	
2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): ☐ Attached, Document ID: ☐ Not Applicable (revision application with no change in applicable requirements)	
3. Compliance Report and Plan (Required for all initial/revision/renewal applications): ☐ Attached, Document ID: Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.	
4. List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): ☐ Attached, Document ID: ☐ Equipment/Activities On site but Not Required to be Individually Listed ☐ Not Applicable	
5. Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : ☐ Attached, Document ID: ☐ Not Applicable	
6. Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID: ☐Not Applicable	

Additional Requirements Comment

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ 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.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ 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.

2. Description of Emissions Unit Addressed in this Section:
   Nominal 165 MW simple cycle combustion turbine – Unit 4

3. Emissions Unit Identification Number: **011**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**N/A**	**N/A**	**49**	☒ Yes ☐ No

9. Package Unit:
   Manufacturer: **General Electric** Model Number: **PG7241(FA)**

10. Generator Nameplate Rating: **175.8 MW**

11. Emissions Unit Comment:

    Unit 4 will be fired primarily with pipeline quality natural gas. Low-sulfur distillate fuel oil will serve as a back-up fuel source.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Dry low-NO_x combustors (natural gas firing)** **Water injection (distillate fuel oil firing)**	
2. Control Device or Method Code(s):	**24 (dry low-NOx), 28 (water injection)**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **N/A**	
2. Maximum Production Rate: **N/A**	
3. Maximum Heat Input Rate: **2,139 (HHV)** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr **N/A** tons/day	
5. Requested Maximum Operating Schedule: hours/day weeks/year	days/week **5,130*** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat rate is higher heating value (HHV) at 100 percent load, 20 ^{o}F, fuel-oil firing operating conditions. Heat input will vary with load, fuel type, and ambient temperature.** *** Maximum of 4,380 hours per year (natural gas firing) and 750 hours per year (distillate fuel oil firing).**	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **CT04**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**	

5. Discharge Type Code: **V**	6. Stack Height: **114** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **1,117** °F	9. Actual Volumetric Flow Rate: **2,393,587** acfm	10. Water Vapor: % **N/A**

11. Maximum Dry Standard Flow Rate: dscfm **N/A**	12. Nonstack Emission Point Height: feet **N/A**
13. Emission Point UTM Coordinates... **N/A** Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... **N/A** Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack temperature and flow rate are at 100 percent load, 59°F, and natural gas-firing operating conditions. Stack temperature and flow rate will vary with load, fuel type, and ambient temperature.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Combustion turbine fired with pipeline quality natural gas.**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **1.913**	5. Maximum Annual Rate: **8,378.9**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: *	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **923**
10. Segment Comment: **Fuel heat content (field 9) represents lower heating value (LHV).** ***Sulfur content of fuel shall be less than 2 grains per 100 standard cubic foot.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Combustion turbine fired with distillate fuel oil.**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **14.724**	5. Maximum Annual Rate: **11,043**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **.05**	8. Maximum % Ash: **.01**	9. Million Btu per SCC Unit: **134**
10. Segment Comment: **Fuel heat content (field 9) represents lower heating value (LHV).**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOX	**024, 028**		**EL**
2 - CO			**EL**
3 – VOC			**NS**
4 – SO2			**EL**
5 – PM			**NS**
6 – PM10			**NS**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **338.0** lb/hour **270.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **338.0 LB/HR** Reference: **GE Data**	7. Emissions Method Code: **5**

8. Calculation of Emissions:

Hourly emission rate based on 100 percent load, 20°F, fuel oil-firing case. Annual emissions based on 68.8 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 319.0 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 750 hrs/yr.

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Maximum of 4,380 hours per year (natural gas-firing) and 750 hours per year (distillate fuel oil-firing).

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 4

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **10.5 ppmvd @ 15% O_2 (24-hour block average)**	4. Equivalent Allowable Emissions: **68.8** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **NOx CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS). Limit applicable for natural gas-firing.**	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **42 ppmvd @ 15% O_2 (24-hour block average)**	4. Equivalent Allowable Emissions: **319** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **NOx CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS). Limit applicable for distillate fuel oil-firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **68.8 lb/hr (at ISO conditions)**	4. Equivalent Allowable Emissions: **68.8** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **EPA Reference Methods 7E and 19 annually. NOx CEMS RATA may be substituted for the annual compliance test.**	
6. Allowable Emissions Comment (Description of Operating Method): **Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS). Limit applicable for gas-firing.**	

Allowable Emissions Allowable Emissions 4 of 4

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **319 lb/hr (at ISO conditions)**	4. Equivalent Allowable Emissions: **319** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **EPA Reference Methods 7E and 19 annually. NOx CEMS RATA may be substituted for the annual compliance test. Annual testing only required if distillate fuel oil is used for more than 400 hours in the preceding 12-month period.**	
6. Allowable Emissions Comment (Description of Operating Method): **Unit is also subject to less stringent NOx limits of 40 CFR Part 60, Subpart GG (NSPS). Limit applicable for distillate fuel oil-firing.**	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **97.7** lb/hour 113.4 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: 97.7 **LB/HR** Reference: **GE Data**	7. Emissions Method Code: **5**
8. Calculation of Emissions: **Hourly emission rate based 100 percent load, 20°F, fuel oil-firing case. Annual emissions based on 36.0 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 92.2 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 750 hrs/yr.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Maximum of 4,380 hours per year (natural gas-firing) and 750 hours per year (distillate fuel oil-firing).**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 4

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **9.0 ppmvd @ 15% O_2 (24-hour block average)**	5. Equivalent Allowable Emissions: **36.0** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit applicable for natural gas-firing.**	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **20.0 ppmvd @ 15% O_2 (24-hour block average)**	4. Equivalent Allowable Emissions: **92.2** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit applicable for distillate oil-firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: 36.0 **lb/hr (at ISO conditions)**	4. Equivalent Allowable Emissions: **36.0** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **EPA Reference Methods 10 and 19 annually. CO CEMS RATA may be substituted for the annual compliance test.**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit applicable for gas-firing.**	

Allowable Emissions Allowable Emissions 4 of 4

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: 92.2 **lb/hr (at ISO conditions)**	4. Equivalent Allowable Emissions: **92.2** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **EPA Reference Methods 10 and 19 annually. CO CEMS RATA may be substituted for the annual compliance test. Annual testing only required if distillate fuel oil is used for more than 400 hours in the preceding 12-month period.**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit applicable for distillate fuel oil-firing.**	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **107.8** lb/hour **59.0** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **107.8 LB/HR** Reference: **GE Data**	7. Emissions Method Code: **5**
8. Calculation of Emissions: **Hourly emission rate based on 100 percent load, 20°F, fuel oil-firing case. Annual emissions based on 9.5 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 101.5 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 750 hrs/yr.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Maximum of 4,380 hours per year (natural gas-firing) and 750 hours per year (distillate fuel oil-firing).**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **Pipeline Quality Natural Gas**	6. Equivalent Allowable Emissions: **9.5** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **Use of pipeline quality natural gas (sulfur content less than 2 grains per 100 standard cubic foot). Natural gas sulfur content monitored using 40 CFR Part 75 procedures.**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit applicable for natural gas-firing.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.05 weight % S oil**	4. Equivalent Allowable Emissions: **101.5** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **Use of distillate fuel oil containing no more than 0.05 weight percent sulfur. Distillate fuel oil sulfur content monitored using applicable 40 CFR Part 75 Appendix D procedures.**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit applicable for distillate fuel oil-firing.**	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **7.6** lb/hour **8.9** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **7.6 LB/HR** Reference: **GE Data**	7. Emissions Method Code: **5**

8. Calculation of Emissions:

Hourly emission rate based on 100 percent load, 20°F, fuel oil-firing case. Annual emissions based on 2.8 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 7.2 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 750 hrs/yr.

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Maximum of 4,380 hours per year (natural gas-firing) and 750 hours per year (distillate fuel oil-firing).

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS – N/A

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	7. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	8. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM/PM_{10}**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **34.0** lb/hour **52.2** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **34.0 LB/HR** Reference: **GE Data**	7. Emissions Method Code: **5**
8. Calculation of Emissions: **Hourly emission rate based on 100 percent load, 59°F, fuel oil-firing case. Annual emissions based on 18.0 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 34.0 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 750 hrs/yr.** **PM/PM_{10} emissions include filterable and condensible particulate.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Maximum of 4,380 hours per year (natural gas-firing) and 750 hours per year (distillate fuel oil-firing).**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS – N/A

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **10 % Opacity**	4. Equivalent Allowable Emissions: **18.0** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **EPA RM 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit applicable for gas-firing.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **10 % Opacity**	4. Equivalent Allowable Emissions: **34.0** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **EPA RM 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit applicable for distillate fuel oil-firing.**	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9 annually.**	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: *	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **N/A**	
5. Visible Emissions Comment: * **Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided best operation practices are adhered to and the duration of excess emissions shall be minimized.**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
6. Continuous Monitor Comment: **Required by 40 CFR Part 75 (Acid Rain Program).** **Specific monitor information not currently available.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Specific monitor information not currently available.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Fig. 2-3** ☐ Previously Submitted, Date _____
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Att. A-3** ☐ Previously Submitted, Date _____
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **Section 5.0** ☐ Previously Submitted, Date _____
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ☐ Previously Submitted, Date _____ ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ _____ ☐ Previously Submitted, Date: Test Date(s)/Pollutant(s) Tested: ☐ To be Submitted, Date (if known):__________ Test Date(s)/Pollutant(s) Tested: _____ _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☒ Attached, Document ID: **Section 5.0** ☐ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☒ Attached, Document ID: **Section 6.0** ☐ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: _____ ☐ Not Applicable **(To be provided)**	

Additional Requirements for Title V Air Operation Permit Applications N/A

1. Identification of Applicable Requirements ☐ Attached, Document ID:	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: _____ ☐ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _____ ☐ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: ☐ Previously Submitted, Date:_____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____ ☐ Not Applicable	

Additional Requirements Comment

NOTE:

POLK POWER STATION EMISSION UNITS 4 AND 5 ARE IDENTICAL UNITS.

SECTION III. EMISSIONS UNIT INFORMATION PROVIDED FOR EU 011 (UNIT 4) IS ALSO APPLICABLE TO EU 012 (UNIT 5).

EMISSIONS UNIT INFORMATION PROVIDED IN SECTION III.A THROUGH III. I FOR UNIT 4 ALSO APPLY TO UNIT 5, WITH THE EXCEPTION OF IDENTIFICATION NUMBERS.

APPENDIX A-1

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Unconfined particulate matter emissions that may result from Polk Power Station operations include:

- Vehicular traffic on unpaved roads and production pads.
- Wind-blown dust from yard areas.
- Periodic abrasive blasting.

The following techniques will be used to control unconfined particulate matter emissions on an as needed basis:

- Chemical or water application to unpaved roads and unpaved yard areas.
- Paving and maintenance of roads, parking areas and yards.
- Landscaping or planting of vegetation.
- Confining abrasive blasting where possible.
- Other techniques, as necessary.

APPENDIX A-2

REGULATORY APPLICABILITY ANALYSES

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 1 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 60 - Standards of Performance for New Stationary Sources.				
Subpart A - General Provisions				
Notification and Recordkeeping	§60.7(b) - (h)		Units 4-5	General recordkeeping and reporting requirements.
Performance Tests	§60.8		Units 4-5	Conduct performance tests as required by EPA or FDEP. **(potential future requirement)**
Compliance with Standards	§60.11(a) thru (d), and (f)		Units 4-5	General compliance requirements. Addresses requirements for visible emissions tests.
Circumvention	§60.12		Units 4-5	Cannot conceal an emission which would otherwise constitute a violation of an applicable standard.
Monitoring Requirements	§60.13(a), (b), (d), (e), and (h)		Units 4-5	Requirements pertaining to continuous monitoring systems.
General notification and reporting requirements	§60.19		Units 4-5	General procedures regarding reporting deadlines.
Subpart GG - Standard of Performance for Stationary Gas Turbines				
Standards for Nitrogen Oxides	§60.332(a)(1) and (b), (f), and (I)		Units 4-5	Establishes NO_x limit of 75 ppmv at 15% (with corrections for heat rate and fuel bound nitrogen) for electric utility stationary gas turbines with peak heat input greater than 100 MMBtu/hr.
Standards for Sulfur Dioxide	§60.333		Units 4-5	Establishes exhaust gas SO_2 limit of 0.015 percent by volume (at 15% O_2, dry) and maximum fuel sulfur content of 0.8 percent by weight.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 2 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart GG - Standard of Performance for Stationary Gas Turbines				
Monitoring Requirements	§60.334(a)	X	Units 4-5	Requires continuous monitoring of fuel consumption and ratio of water to fuel being fired in the turbine. Monitoring system must be accurate to ±5.0 percent. Applicable to CTs using water injection for NO_x control.
Monitoring Requirements	§60.334(b)(2) and ©)		Units 4-5	Requires periodic monitoring of fuel sulfur and nitrogen content. Defines excess emissions
Test Methods and Procedures	§60.335		Units 4-5	Specifies monitoring procedures and test methods.
40 CFR Part 60 - Standards of Performance for New Stationary Sources: Subparts B, C, Cb, Cc, Cd, Ce, D, Da, Db, Dc, E, Ea, Eb, Ec, F, G, H, I, J, K, Ka, Kb, L, M, N, Na, O, P, Q, R, S, T, U, V, W, X, Y, Z, AA, AAa, BB, CC, DD, EE, HH, KK, LL, MM, NN, PP, QQ, RR, SS, TT, UU, VV, WW, XX, AAA, BBB, DDD, FFF, GGG, HHH, III, JJJ, KKK, LLL, NNN, OOO, PPP, QQQ, RRR, SSS, TTT, UUU, VVV, and WWW		X		None of the listed NSPS' contain requirements which are applicable to Polk Power Station Units 4 and 5.
40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants: Subparts A, B, C, D, E, F, H, I, J, K, L, M, N, O, P, Q, R, T, V, W, Y, BB, and FF		X		None of the listed NESHAPS' contain requirements which are applicable to the Polk Power Station Units 4 and 5.
40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories: Subparts A, B, C, D, E, F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, GG, HH, II, JJ, KK, LL, OO, PP, QQ, RR, SS, TT, UU, VV, WW, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, RRR, TTT, VVV, and XXX		X		None of the listed NESHAPS' contain requirements which are applicable to the Polk Power Station Units 4 and 5.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 3 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 72 - Acid Rain Program Permits				
Subpart A - Acid Rain Program General Provisions				
Standard Requirements	§72.9 excluding §72.9(c)(3)(I), (ii), and (iii), and §72.9(d)		Units 4-5	General Acid Rain Program requirements. SO_2 allowance program requirements start January 1, 2000 (**future requirement**).
Subpart B - Designated Representative				
Designated Representative	§72.20 - §72.24		Units 4-5	General requirements pertaining to the Designated Representative.
Subpart C - Acid Rain Application				
Requirements to Apply	§72.30(a), (b)(2)(ii), ©), and (d)		Units 4-5	Requirement to submit a complete Phase II Acid Rain permit application to the permitting authority at least 24 months before the later of January 1, 2000 or the date on which the unit commences operation. (**future requirement**). Requirement to submit a complete Acid Rain permit application for each source with an affected unit at least 6 months prior to the expiration of an existing Acid Rain permit governing the unit during Phase II or such longer time as may be approved under part 70 of this chapter that ensures that the term of the existing permit will not expire before the effective date of the permit for which the application is submitted. (**future requirement**).
Permit Application Shield	§72.32		Units 4-5	Acid Rain Program permit shield for units filing a timely and complete application. Application is binding pending issuance of Acid Rain Permit.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 4 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart D - Acid Rain Compliance Plan and Compliance Options				
General	§72.40(a)(1)		Units 4-5	General SO_2 compliance plan requirements.
General	§72.40(a)(2)	X		General NO_x compliance plan requirements are not applicable to the Polk Power Station Units 4 and 5.
Subpart E - Acid Rain Permit Contents				
Permit Shield	§72.51		Units 4-5	Units operating in compliance with an Acid Rain Permit are deemed to be operating in compliance with the Acid Rain Program.
Subpart H - Permit Revisions				
Fast-Track Modifications	§72.82(a) and ©)		Units 4-5	Procedures for fast-track modifications to Acid Rain Permits. **(potential future requirement)**
Subpart I - Compliance Certification				
Annual Compliance Certification Report	§72.90		Units 4-5	Requirement to submit an annual compliance report. **(future requirement)**

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 5 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 75 - Continuous Emission Monitoring				
Subpart A - General				
Prohibitions	§75.5		Units 4-5	General monitoring prohibitions.
Subpart B - Monitoring Provisions				
General Operating Requirements	§75.10		Units 4-5	General monitoring requirements.
Specific Provisions for Monitoring SO_2 Emissions	§75.11(d)(2)		Units 4-5	SO_2 continuous monitoring requirements for gas- and oil-fired units. Appendix D election will be made.
Specific Provisions for Monitoring NO_x Emissions	§75.12(a) and (b)		Units 4-5	NO_x continuous monitoring requirements for coal-fired units, gas-fired nonpeaking units or oil-fired nonpeaking units
Specific Provisions for Monitoring CO_2 Emissions	§75.13(b)		Units 4-5	CO_2 continuous monitoring requirements. Appendix G election will be made.
Subpart B - Monitoring Provisions				
Specific Provisions for Monitoring Opacity	§75.14(d)		Units 4-5	Opacity continuous monitoring exemption for diesel-fired units.
Subpart C - Operation and Maintenance Requirements				
Certification and Recertification Procedures	§75.20(b)		Units 4-5	Recertification procedures **(potential future requirement)**
Certification and Recertification Procedures	§75.20©)		Units 4-5	Recertification procedure requirements. **(potential future requirement)**
Quality Assurance and Quality Control Requirements	§75.21 except §75.21(b)		Units 4-5	General QA/QC requirements (excluding opacity).

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 6 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Reference Test Methods	§75.22		Units 4-5	Specifies required test methods to be used for recertification testing **(potential future requirement)**.
Out-Of-Control Periods	§75.24 except §75.24(e)		Units 4-5	Specifies out-of-control periods and required actions to be taken when out-of-control periods occur (excluding opacity).
Subpart D - Missing Data Substitution Procedures				
General Provisions	§75.30(a)(3), (b), ©)		Units 4-5	General missing data requirements.
Determination of Monitor Data Availability for Standard Missing Data Procedures	§75.32		Units 4-5	Monitor data availability procedure requirements.
Standard Missing Data Procedures	§75.33(a) and ©)		Units 4-5	Missing data substitution procedure requirements.
Subpart F - Recordkeeping Requirements				
General Recordkeeping Provisions	§75.50(a), (b), (d), and (e)(2)		Units 4-5	General recordkeeping requirements for NO_x and Appendix G CO_2 monitoring.
Monitoring Plan	§75.53(a), (b), ©), and (d)(1)		Units 4-5	Requirement to prepare and maintain a Monitoring Plan.
General Recordkeeping Provisions	§75.54(a), (b), (d), and (e)(2)		Units 4-5	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions for Specific Situations	§75.55©)		Units 4-5	Specific recordkeeping requirements for Appendix D SO_2 monitoring.
General Recordkeeping Provisions	§75.56(a)(1), (3), (5), (6), and (7)		Units 4-5	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions	§75.56(b)(1)		Units 4-5	Requirements pertaining to general recordkeeping for Appendix D SO_2 monitoring.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 7 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart G - Reporting Requirements				
General Provisions	§75.60		Units 4-5	General reporting requirements.
Notification of Certification and Recertification Test Dates	§75.61(a)(1) and (5), (b), and ©)		Units 4-5	Requires written submittal of recertification tests and revised test dates for CEMS. Notice of certification testing shall be submitted at least 45 days prior to the first day of recertification testing. Notification of any proposed adjustment to certification testing dates must be provided at least 7 business days prior to the proposed date change.
Subpart G - Reporting Requirements				
Recertification Application	§75.63		Units 4-5	Requires submittal of a recertification application within 30 days after completing the recertification test. **(potential future requirement)**
Quarterly Reports	§75.64(a)(1) - (5), (b), (c), and (d)		Units 4-5	Quarterly data report requirements.
40 CFR Part 76 - Acid Rain Nitrogen Oxides Emission Reduction Program		X		The Acid Rain Nitrogen Oxides Emission Reduction Program only applies to coal-fired utility units that are subject to an Acid Rain emissions limitation or reduction requirement for SO_2 under Phase I or Phase II.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 8 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 77 - Excess Emissions				
Offset Plans for Excess Emissions of Sulfur Dioxide	§77.3		Units 4-5	Requirement to submit offset plans for excess SO_2 emissions not later than 60 days after the end of any calendar year during which an affected unit has excess SO_2 emissions. Required contents of offset plans are specified **(potential future requirement)**.
Deduction of Allowances to Offset Excess Emissions of Sulfur Dioxide	§77.5(b)		Units 4-5	Requirement for the Designated Representative to hold enough allowances in the appropriate compliance subaccount to cover deductions to be made by EPA if a timely and complete offset plan is not submitted or if EPA disapproves a proposed offset plan **(potential future requirement)**.
Penalties for Excess Emissions of Sulfur Dioxide	§77.6		Units 4-5	Requirement to pay a penalty if excess emissions of SO_2 occur at any affected unit during any year **(potential future requirement)**.
40 CFR Part 82 - Protection of Stratospheric Ozone				
Production and Consumption Controls	Subpart A	X		Polk Power Station Units 4 and 5will not produce or consume ozone depleting substances.
Servicing of Motor Vehicle Air Conditioners	Subpart B	X		Polk Power Station personnel will not perform servicing of motor vehicles which involves refrigerant in the motor vehicle air conditioner. All such servicing will be conducted by persons who comply with Subpart B requirements.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 9 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Ban on Nonessential Products Containing Class I Substances and Ban on Nonessential Products Containing or Manufactured with Class II Substances	Subpart C	X		Polk Power Station will not sell or distribute any banned nonessential substances.
The Labeling of Products Using Ozone-Depleting Substances	Subpart E	X		Polk Power Station Units 4 and 5.will not produce any products containing ozone depleting substances.
Subpart F - Recycling and Emissions Reduction				
Prohibitions	§82.154	X		Polk Power Station personnel will not maintain, service, repair, or dispose of any appliances. All such activities will be performed by independent parties in compliance with §82.154 prohibitions.
Required Practices	§82.156 except §82.156(i)(5), (6), (9), (10), and (11)	X		Contractors will maintain, service, repair, and dispose of any appliances in compliance with §82.156 required practices.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 10 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart F - Recycling and Emissions Reduction				
Required Practices	§82.156(I)(5), (6), (9), (10), and (11)		Appliances as defined by §82.152- any device which contains and uses a Class I or II substance as a refrigerant and which is used for house-hold or com-mercial purpos-es, including any air condi-tioner, refriger-ator, chiller, or freezer	Owner/operator requirements pertaining to repair of leaks.
Technician Certification	§82.161	X		Polk Power Station personnel will not main-tain, service, repair, or dispose of any appliances and therefore are not subject to technician certification requirements.
Certification By Owners of Recov-ery and Recycling Equipment	§82.162	X		Polk Power Station personnel will not main-tain, service, repair, or dispose of any appliances and therefore do not use recovery and recycling equipment.
Reporting and Recordkeeping Requirements	§82.166(k), (m), and (n)		Appliances as defined by §82.152	Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep servicing records documenting the date and type of service, as well as the quantity of refrigerant added.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 11 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 50 - National Primary and Secondary Ambient Air Quality Standards		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 51 - Requirements for Preparation, Adoption, and Submittal of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 52 - Approval and Promulgation of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 62 - Approval and Promulgation of State Plans for Designated Facilities and Pollutants		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 64 - Regulations on Compliance Assurance Monitoring for Major Stationary Sources		X		Exempt per §64.2(b)(1)(iii) since Units 4 and 5 will meet Acid Rain Program monitoring requirements.
40 CFR Part 68 - Provisions for Chemical Accident Prevention			Hydrogen Storage	Subject to provisions of 40 CFR Part 68 due to hydrogen storage.
40 CFR Part 70 - State Operating Permit Programs		X		State agency requirements - not applicable to individual emission sources.
40 CFR Parts 49, 53, 54, 55, 56, 57, 58, 59, 62, 66, 67, 69, 71, 74, 76, 79, 80, 81, 85, 86, 87, 88, 89, 90, 91, 92, 93, 94, 95, 96, 97, 600, and 610		X		The listed regulations do not contain any requirements which are applicable to Polk Power Station Units 4 and 5.

Source: ECT, 2005.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 1 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-4, F.A.C. - Permits: Part I General					
Scope of Part I	62-4.001, F.A.C.	X			Contains no applicable requirements.
Definitions	62-4.020, .021, F.A.C.	X			Contains no applicable requirements.
Transferability of Definitions	62-4.021, .021, F.A.C.	X			Contains no applicable requirements.
General Prohibition	62-4.030, F.A.C		X		All stationary air pollution sources must be permitted, unless otherwise exempted.
Exemptions	62-4.040, F.A.C		X		Certain structural changes exempt from permitting. Other stationary sources exempt from permitting upon FDEP insignificance determination.
Procedures to Obtain Permits	62-4.050, F.A.C.		X		General permitting requirements.
Surveillance Fees	62-4.052, F.A.C.	X			Not applicable to air emission sources.
Permit Processing	62-4.055, F.A.C.	X			Contains no applicable requirements.
Consultation	62-4.060, F.A.C.	X			Consultation is encouraged, not required.
Standards for Issuing or Denying Permits; Issuance; Denial	62-4.070, F.A.C	X			Establishes standard procedures for FDEP. Requirement is not applicable to Polk Power Station Units 4 and 5.
Modification of Permit Conditions	62-4.080, F.A.C	X			Application is for initial contruction permit. Modification of permit conditions is not being requested.
Renewals	62-4.090, F.A.C.		X		Establishes permit renewal criteria. Additional criteria are cited at 62-213.-430(3), F.A.C. **(future requirement)**
Suspension and Revocation	62-4.100, F.A.C.		X		Establishes permit suspension and revocation criteria.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 2 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Financial Responsibility	62-4.110, F.A.C.	X			Contains no applicable requirements.
Transfer of Permits	62-4.120, F.A.C.	X			A sale or legal transfer of a permitted facility is not included in this application.
Plant Operation - Problems	62-4.130, F.A.C.		X		Immediate notification is required whenever the permittee is temporarily unable to comply with any permit condition. Notification content is specified. **(potential future requirement)**
Review	62-4.150, F.A.C.	X			Contains no applicable requirements.
Permit Conditions	62-4.160, F.A.C.	X			Contains no applicable requirements.
Scope of Part II	62-4.2.00, F.A.C.	X			Contains no applicable requirements.
Construction Permits	62-4.210, F.A.C.	X			General requirements for construction permits.
Operation Permits for New Sources	62-4.220, F.A.C.	X			General requirements for initial new source operation permits. **(future requirement)**
Water Permit Provisions	62-4.240 - 250, F.A.C.	X			Contains no applicable requirements.
Chapter 62-17, F.A.C. - Electrical Power Plant Siting		X			Power Plant Siting Act provisions.
Chapter 62-102, F.A.C. - Rules of Administrative Procedure - Rule Making			X		General administrative procedures.
Chapter 62-103, F.A.C. - Rules of Administrative Procedure - Final Agency Action			X		General administrative procedures.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 3 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-204, F.A.C. - State Implementation Plan					
State Implementation Plan	62-204.100, .200, .220(1)-(3), .240, .260, .320, .340, .360, .400, and .500, F.A.C.	X			Contains no applicable requirements.
Ambient Air Quality Protection	62-204.220(4), F.A.C.		X		Assessments of ambient air pollutant impacts must be made using applicable air quality models, data bases, and other requirements approved by FDEP and specified in 40 CFR Part 51, Appendix W.
State Implementation Plan	62-204.800(1) - (6), F.A.C.	X			Referenced federal regulations contain no applicable requirements.
State Implementation Plan	62-204.800(7)(a), (b)16.,(b)39., (c), (d), and (e), F.A.C.			CT 3A-3B	NSPS Subpart GG; see Table A-1 for detailed federal regulatory citations.
State Implementation Plan	62-204.800(8) - (13), (15), (17), (20), and (22) F.A.C.	X			Referenced federal regulations contain no applicable requirements.
State Implementation Plan	62-204.800 (14), (16), (18), (19), F.A.C.			CT 3A-3B	Acid Rain Program; see Table A-1 for detailed federal regulatory citations.
State Implementation Plan	62-204.800(21), F.A.C.		X		Protection of Stratospheric Ozone; see Table A-1 for detailed federal regulatory citations.
Chapter 62-210, F.A.C. - Stationary Sources - General Requirements					
Purpose and Scope	62-210.100, F.A.C.	X			Contains no applicable requirements.
Definitions	62-210.200, F.A.C.	X			Contains no applicable requirements.
Small Business Assistance Program	62-210.220, F.A.C.	X			Contains no applicable requirements.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 4 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Permits Required	62-210.300(1) and (3), F.A.C.		X		Air construction permit required. Exemptions from permitting specified for certain facilities and sources.
Permits Required	62-210.300(2), F.A.C.		X		Air operation permit required. **(future requirement)**
Air General Permits	62-210.300(4), F.A.C.	X			Not applicable to Polk Power Station Units 4 and 5.
Notification of Startup	62-210.300(5), F.A.C.	X			Sources which have been shut down for more than one year shall notify the FDEP prior to startup.
Emission Unit Reclassification	62-210.300(6), F.A.C.		X		Emission unit reclassification **(potential future requirement)**
Public Notice and Comment Public Notice of Proposed Agency Action	62-210.350(1), F.A.C.		X		All permit applicants required to publish notice of proposed agency action.
Additional Notice Requirements for Sources Subject to Prevention of Significant Deterioration or Nonattainment Area New Source Review	62-210.350(2), F.A.C.		X		Additional public notice requirements for PSD and nonattainment area NSR applications.
Additional Public Notice Requirements for Sources Subject to Operation Permits for Title V Sources	62-210.350(3), F.A.C.		X		Notice requirements for Title V operating permit applicants **(future requirement)**.
Public Notice Requirements for FESOPS and 112(g) Emission Sources	62-210.350(4) and (5), F.A.C.	X			Not applicable to Polk Power Station Units 4 and 5.
Administrative Permit Corrections	62-210.360, F.A.C.	X			An administrative permit correction is not requested in this application.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 5 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Reports					
Notification of Intent to Relocate Air Pollutant Emitting Facility	62-210.370(1), F.A.C.	X			Project does not have any relocatable emission units.
Annual Operating Report for Air Pollutant Emitting Facility	62-210.370(3), F.A.C.		X		Specifies annual reporting requirements. **(future requirement)**.
Stack Height Policy	62-210.550, F.A.C.		X		Limits credit in air dispersion studies to good engineering practice (GEP) stack heights for stacks constructed or modified since 12/31/70.
Circumvention	62-210.650, F.A.C.		X		An applicable air pollution control device cannot be circumvented and must be operated whenever the emission unit is operating.
Excess Emissions	62-210.700(1), F.A.C.		X		Excess emissions due to startup, shut down, and malfunction are permitted for no more than two hours in any 24 hour period unless specifically authorized by the FDEP for a longer duration.
Excess Emissions	62-210.700(2) and (3), F.A.C.	X			Not applicable to Polk Power Station Units 4 and 5.
Excess Emissions	62-210.700(4), F.A.C.		X		Excess emissions caused entirely or in part by poor maintenance, poor operations, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction are prohibited. **(potential future requirement)**.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 6 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Excess Emissions	62-210.700(5), F.A.C.	X			Contains no applicable requirements.
Excess Emissions	62-210.700(6), F.A.C.		X		Excess emissions resulting from malfunctions must be reported to the FDEP in accordance with 62-4.130, F.A.C. **(potential future requirement)**.
Forms and Instructions	62-210.900, F.A.C.		X		Contains AOR requirements.
Notification Forms for Air General Permits	62-210.920, F.A.C.	X			Contains no applicable requirements.
Chapter 62-212, F.A.C. - Stationary Sources - Preconstruction Review					
Purpose and Scope	62-212.100, F.A.C.	X			Contains no applicable requirements.
General Preconstruction Review Requirements	62-212.300, F.A.C.		X		General air construction permit requirements.
Prevention of Significant Deterioration	62-212.400, F.A.C.		X		PSD permit required prior to construction of Polk Power Station Units 4 and 5
New Source Review for Nonattainment Areas	62-212.500, F.A.C.	X			Project is not located in a nonattainment area or a nonattainment area of influence.
Sulfur Storage and Handling Facilities	62-212.600, F.A.C.	X			Applicable only to sulfur storage and handling facilities.
Air Emissions Bubble	62-212.710, F.A.C.	X			Not applicable to Polk Power Station Units 4 and 5.
Chapter 62-213, F.A.C. - Operation Permits for Major Sources of Air Pollution					
Purpose and Scope	62-213.100, F.A.C.	X			Contains no applicable requirements.
Annual Emissions Fee	62-213.205(1), (4), and (5), F.A.C.		X		Annual emissions fee and documentation requirements. **(future requirement)**

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 7 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Annual Emissions Fee	62-213.205(2) and (3), F.A.C.	X			Contains no applicable requirements.
Title V Air General Permits	62-213.300, F.A.C.	X			No eligible facilities
Permits and Permit Revisions Required	62-213.400, F.A.C.		X		Title V operation permit required. **(future requirement)**
Changes Without Permit Revision	62-213.410, F.A.C.		X		Certain changes may be made if specific notice and recordkeeping requirements are met **(potential future requirement)**.
Immediate Implementation Pending Revision Process	62-213.412, F.A.C.		X		Certain modifications can be implement-ed pending permit revision if specific criteria are met **(potential future requirement)**.
Fast-Track Revisions of Acid Rain Parts	62-213.413, F.A.C.			CT 3A-3B	Optional provisions for Acid Rain permit revisions **(potential future requirement)**.
Trading of Emissions within a Source	62-213.415, F.A.C.	X			Applies only to facilities with a federally enforceable emissions cap.
Permit Applications	62-213.420(1)(a)2. and (1)(b), (2), (3), and (4), F.A.C.		X		Title V operating permit application required no later than 180 days after commencing operation. **(future requirement)**
Permit Issuance, Renewal, and Revision					
Action on Application	62-213.430(1), F.A.C.	X			Contains no applicable requirements.
Permit Denial	62-213.430(2), F.A.C.	X			Contains no applicable requirements.
Permit Renewal	62-213.430(3), F.A.C.		X		Permit renewal application requirements **(future requirement)**.
Permit Revision	62-213.430(4), F.A.C.		X		Permit revision application requirements **(potential future requirement)**.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 8 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
EPA Recommended Actions	62-213.430(5), F.A.C.	X			Contains no applicable requirements.
Insignificant Emission Units	62-213.430(6), F.A.C.	X			Contains no applicable requirements.
Permit Content	62-213.440, F.A.C.	X			Agency procedures, contains no applicable requirements.
Permit Review by EPA and Affected States	62-213.450, F.A.C.	X			Agency procedures, contains no applicable requirements.
Permit Shield	62-213.460, F.A.C.		X		Provides permit shield for facilities in compliance with permit terms and conditions. **(future requirement)**
Forms and Instructions	62-213.900, F.A.C.		X		Contains annual emissions fee form requirements.
Chapter 62-214—Requirements for Sources Subject to the Federal Acid Rain Program					
Purpose and Scope	§62-214.100, F.A.C.	X			Contains no applicable requirements.
Applicability	§62-214.300, F.A.C.		X		Project includes Acid Rain affected units, therefore compliance with §62-213 and §62-214, F.A.C., is required.
Applications	§62-214.320, F.A.C.			CT 3A-3B	Acid Rain application requirements. Application for new units are due at least 24 months before the later of 1/1/2000 or the date on which the unit commences operation. **(future requirement)**
Acid Rain Compliance Plan and Compliance Options	§62-214.330(1)(a), F.A.C.			CT 3A-3B	Acid Rain compliance plan requirements. Sulfur dioxide requirements become effective the later of 1/1/2000 or the deadline for CEMS certification pursuant to 40 CFR Part 75. **(future requirement)**

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 9 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Exemptions	§62-214.340, F.A.C.		X		An application may be submitted for certain exemptions **(potential future requirement)**.
Certification	§62-214.350, F.A.C.			CT 3A-3B	The designated representative must certify all Acid Rain submissions. **(future requirement)**
Department Action on Applications	§62-214.360, F.A.C.	X			Contains no applicable requirements.
Revisions and Administrative Corrections	§62-214.370, F.A.C.			CT 3A-3B	Defines revision procedures and automatic amendments **(potential future requirement)**..
Acid Rain Part Content	§62-214.420, F.A.C.	X			Agency procedures, contains no applicable requirements.
Implementation and Termination of Compliance Options	§62-214.430, F.A.C.			CT 3A-3B	Defines permit activation and termination procedures **(potential future requirement)**.
Chapter 62-242 - Motor Vehicle Standards and Test Procedures	62-242, F.A.C.	X			Not applicable to Polk Power Station Units 4 and 5.
Chapter 62-243 - Tampering with Motor Vehicle Air Pollution Control Equipment	62-243, F.A.C.	X			Not applicable to Polk Power Station Units 4 and 5.
Chapter 62-252 - Gasoline Vapor Control	62-252, F.A.C.	X			Not applicable to Polk Power Station Units 4 and 5.
Chapter 62-256 - Open Burning and Frost Protection Fires					
Declaration and Intent	62-256.100, F.A.C.	X			Contains no applicable requirements.
Definitions	62-256.200, F.A.C.	X			Contains no applicable requirements.
Prohibitions	**62-256.300, F.A.C.**[1]		X		Prohibits open burning.
Burning for Cold and Frost Protection	62-256.450, F.A.C.	X			Limited to agricultural protection.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 10 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Land Clearing	**62-256.500, F.A.C.**[1]		X		Defines allowed open burning for non-rural land clearing and structure demolition.
Industrial, Commercial, Municipal, and Research Open Burning	**62-256.600, F.A.C.**[1]		X		Prohibits industrial open burning
Open Burning allowed	62-256.700, F.A.C.		X		Specifies allowable open burning activities. **(potential future requirement)**
Effective Date	62-256.800, F.A.C.	X			Contains no applicable requirements.
Chapter 62-257 - Asbestos Fee	62-257, F.A.C.	X			Not applicable to Polk Power Station Units 4 and 5.
Chapter 62-281 - Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling	62-281, F.A.C.	X			Not applicable to Polk Power Station Units 4 and 5.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 11 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-296 - Stationary Source - Emission Standards					
Purpose and Scope	62-296.100, F.A.C.	X			Contains no applicable requirements
General Pollutant Emission Limiting Standard, Volatile Organic Compounds Emissions	62-296.320(1), F.A.C.		X		Known and existing vapor control devices must be applied as required by the Department.
General Pollutant Emission Limiting Standard, Objectionable Odor Prohibited	62-296.320(2), F.A.C.		X		Objectionable odor release is prohibited.
General Pollutant Emission Limiting Standard, Industrial, Commercial, and Municipal Open Burning Prohibited	**62-296.320(3), F.A.C.**[1]		X		Open burning in connection with industrial, commercial, or municipal operations is prohibited.
General Particulate Emission Limiting Standard, Process Weight Table	62-296.320(4)(a), F.A.C.	X			Project does not have any applicable emission units. Combustion emission units are exempt per 62-296.320(4)(a)1a.
General Particulate Emission Limiting Standard, General Visible Emission Standard	62-296.320(4)(b), F.A.C.		X		Opacity limited to 20 percent, unless otherwise permitted. Test methods specified.
General Particulate Emission Limiting Standard, Unconfined Emission of Particulate Matter	62-296.320(4)(c), F.A.C.		X		Reasonable precautions must be taken to prevent unconfined particulate matter emission.
Specific Emission Limiting and Performance Standards	62-296.401 through 62-296.417, F.A.C.	X			None of the referenced standards are applicable to Polk Power Station Units 4 and 5.
Reasonably Available Control Technology (RACT) Volatile Organic Compounds (VOC) and Nitrogen Oxides (NO_x) Emitting Facilities	62-296.500 through 62-296.516, F.A.C.	X			Project is not located in an ozone nonattainment area or an ozone air quality maintenance area.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 12 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NO_x-Emitting Facilities	62-296.570, F.A.C.	X			Project is not located in a specified ozone nonattainment area or a specified ozone air quality maintenance area (i.e., is not located in Broward, Dade or Palm Beach Counties)
Reasonably Available Control Technology (RACT) - Lead	62-296.600 through 62-296.605, F.A.C.	X			Project is not located in a lead nonattainment area or a lead air quality maintenance area.
Reasonably Available Control Technology (RACT)—Particulate Matter	§62-296.700 through 62-296.712, F.A.C.	X			Project is located in a PM air quality maintenance area. However, there are no limits applicable to CTs.
Chapter 62-297 - Stationary Sources - Emissions Monitoring					
Purpose and Scope	62-297.100, F.A.C.	X			Contains no applicable requirements.
General Compliance Test Requirements	62-297.310, F.A.C.		X		Specifies general compliance test requirements.
Compliance Test Methods	62-297.401, F.A.C.	X			Contains no applicable requirements.
Supplementary Test Procedures	62-297.440, F.A.C.	X			Contains no applicable requirements.
EPA VOC Capture Efficiency Test Procedures	62-297.450, F.A.C.	X			Not applicable to Polk Power Station Units 4 and 5.
CEMS Performance Specifications	62-297.520, F.A.C.	X			Contains no applicable requirements.
Exceptions and Approval of Alternate Procedures and Requirements	62-297.620, F.A.C.	X			Exceptions or alternate procedures have not been requested.

[1] - State requirement only; not federally enforceable.

Source: ECT, 2005.

APPENDIX A-3

FUEL ANALYSES OR SPECIFICATIONS

APPENDIX A-3

FUEL ANALYSES OR SPECIFICATIONS

Typical Natural Gas Composition

Component	Mole Percent (by volume)
Gas Composition	
Hexane+	0.018
Propane	0.190
I-butane	0.010
N-butane	0.007
Pentane	0.002
Nitrogen	0.527
Methane	96.195
CO_2	0.673
Ethane	2.379
Other Characteristics	
Heat content (HHV)	1,020 Btu/ft^3 with 14.73 psia, dry
Real specific gravity	0.5776
Sulfur content (maximum)	2.0 gr/100 scf

Note: Btu/ft^3 = British thermal units per cubic foot.
psia = pounds per square inch absolute.
gr/100 scf = grains per 100 standard cubic foot.

Source: TEC, 2005.

Typical No. 2 Fuel Oil Analysis

Parameter	Value
Specific gravity @ 60EF (maximum)	0.876
Viscosity, saybolt (SUS) @ 100EF	
Minimum	40.2
Maximum	32.6
Flash point, EF (minimum)	100
Pour point, EF (minimum)	0
Minimum gross heating value, Btu/lb	
LHV	18,550
HHV	19,626
Water and sediment, percent by volume (maximum)	0.05
Ash, percent by weight (maximum)	0.01
Sulfur, percent by weight (maximum)	0.05
Fuel-bound nitrogen, percent by weight (maximum)	0.015
Trace constituents, ppm (maximum)	
Lead	1.0
Sodium	1.0
Vanadium	0.5

Note: SUS = Saybolt Universal Seconds.
Btu/gal = British thermal units per gallon.
LHV = lower heating value.
HHV = higher heating value.

Source: TEC, 2005.

APPENDIX B

EMISSION RATE CALCULATIONS

Table B-1. TEC Polk Power Station, SCCT Units 4 and 5
CT Operating Scenarios - General Electric 7241FA CT

Case	Ambient Temperature (oF)	Load (%)	Simple Cycle Units 4 and 5	Annual Profile (hr/yr)	Natural Gas Firing	Fuel Oil Firing
1	20	100	X		X	X
2	20	75	X		X	X
3	20	50	X		X	X
4	59	100	X	4,380 (gas), 750 (oil)	X	X
5	59	75	X		X	X
6	59	50	X		X	X
7	90	100	X		X	X
8	90	75	X		X	X
9	90	50	X		X	X

SCCT - simple cycle combustion turbine
CT - combustion turbine

Sources: TEC, 2005.
ECT, 2005.

Table B-2. TEC Polk Power Station, SCCT Units 4 and 5
CT Hourly Emission Rates - General Electric 7241FA CT (Per CT)
Natural Gas-Firing

Temp. (°F)	Case	Load (%)	PM/PM$_{10}$ [1] (lb/hr)	PM/PM$_{10}$ [1] (g/sec)	SO_2 [2] (lb/hr)	SO_2 [2] (g/sec)	H_2SO_4 [3] (lb/hr)	H_2SO_4 [3] (g/sec)	Lead [4] (lb/hr)	Lead [4] (g/sec)
20	1	100	18.0	2.27	10.2	1.28	1.2	0.15	0.0306	0.00386
	2	75	18.0	2.27	8.2	1.03	0.9	0.12	0.0245	0.00309
	3	50	18.0	2.27	6.5	0.82	0.7	0.09	0.0196	0.00247
59	4	100	18.0	2.27	9.5	1.20	1.1	0.14	0.0286	0.00361
	5	75	18.0	2.27	7.7	0.97	0.9	0.11	0.0232	0.00292
	6	50	18.0	2.27	6.2	0.78	0.7	0.09	0.0186	0.00235
90	7	100	18.0	2.27	8.8	1.10	1.0	0.13	0.0264	0.00332
	8	75	18.0	2.27	7.2	0.91	0.8	0.10	0.0216	0.00272
	9	50	18.0	2.27	5.8	0.73	0.7	0.08	0.0174	0.00220
		Maximums	**18.0**	**2.27**	**10.2**	**1.28**	**1.2**	**0.15**	**0.0306**	**0.0039**

Temp. (°F)	Case	Load (%)	NO_x (ppmvd) [5]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd) [5]	CO (lb/hr)	CO (g/sec)	VOC [6] (ppmvd) [5]	VOC [6] (lb/hr)	VOC [6] (g/sec)
20	1	100	10.5	73.5	9.26	7.2	30.3	3.82	1.2	3.0	0.38
	2	75	10.5	58.3	7.35	7.1	23.9	3.02	1.1	2.1	0.26
	3	50	10.5	45.5	5.73	7.4	19.9	2.50	1.2	1.9	0.23
59	4	100	10.5	68.8	8.67	7.2	28.8	3.63	1.2	2.8	0.35
	5	75	10.5	54.8	6.91	7.2	23.0	2.89	1.1	1.9	0.24
	6	50	10.5	43.2	5.44	7.6	19.0	2.40	1.2	1.7	0.21
90	7	100	10.5	63.0	7.94	7.1	25.7	3.24	1.2	2.6	0.33
	8	75	10.5	51.3	6.47	7.3	21.7	2.74	1.2	2.1	0.26
	9	50	10.5	40.8	5.15	7.8	18.4	2.31	1.2	1.7	0.21
		Maximums	**10.5**	**73.5**	**9.26**	**7.8**	**30.3**	**3.82**	**1.2**	**3.0**	**0.38**

[1] Filterable and condensible PM, excluding H_2SO_4 mist.
[2] Based on natural gas sulfur content of 2.0 gr/100 ft^3.
[3] Based on 7.5% conversion of SO_2 to H_2SO_4.
[4] Table 1.4-2, AP-42, EPA, May 1998.
[5] Corrected to 15% O_2.
[6] Non-methane hydrocarbons (NMHC) expressed as methane.

Sources: ECT, 2005.
GE, 1998.

Table B-3. TEC Polk Power Station, SCCT Units 4 and 5
CT Hourly Emission Rates - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing

Temp. ($^{\circ}$F)	Case	Load (%)	PM/PM_{10} [1]		SO_2 [2]		H_2SO_4 [3]		Lead [4]	
			(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)
20	1	100	34.0	4.28	107.8	13.58	12.4	1.56	0.104	0.0131
	2	75	34.0	4.28	87.4	11.02	10.0	1.27	0.084	0.0106
	3	50	34.0	4.28	68.2	8.59	7.8	0.99	0.067	0.0084
59	4	100	34.0	4.28	101.5	12.79	11.7	1.47	0.098	0.0123
	5	75	34.0	4.28	82.5	10.40	9.5	1.19	0.079	0.0100
	6	50	34.0	4.28	64.9	8.18	7.5	0.94	0.063	0.0079
90	7	100	34.0	4.28	92.3	11.63	10.6	1.34	0.093	0.0117
	8	75	34.0	4.28	75.6	9.53	8.7	1.09	0.073	0.0092
	9	50	34.0	4.28	59.8	7.54	6.9	0.87	0.058	0.0073
		Maximums	**34.0**	**4.28**	**107.8**	**13.58**	**12.4**	**1.56**	**0.104**	**0.0131**

Temp. ($^{\circ}$F)	Case	Load (%)	NO_x			CO			VOC [6]		
			(ppmvd) [5]	(lb/hr)	(g/sec)	(ppmvd) [5]	(lb/hr)	(g/sec)	(ppmvd) [5]	(lb/hr)	(g/sec)
20	1	100	42.0	338.0	42.59	20.0	97.7	12.31	2.8	7.6	0.96
	2	75	42.0	272.0	34.27	20.0	78.5	9.89	2.7	5.8	0.73
	3	50	42.0	210.0	26.46	20.0	60.6	7.64	2.8	5.1	0.64
59	4	100	42.0	319.0	40.19	20.0	92.2	11.62	2.8	7.2	0.91
	5	75	42.0	257.0	32.38	20.0	74.1	9.34	2.7	5.7	0.72
	6	50	42.0	200.0	25.20	20.0	57.7	7.28	2.9	4.6	0.58
90	7	100	42.0	290.0	36.54	20.0	84.3	10.62	2.8	6.5	0.82
	8	75	42.0	235.0	29.61	20.0	67.9	8.55	2.8	5.6	0.71
	9	50	42.0	184.0	23.18	20.0	53.2	6.70	3.0	4.5	0.57
		Maximums	**42.0**	**338.0**	**42.59**	**20.0**	**97.7**	**12.31**	**3.0**	**7.6**	**0.96**

[1] Filterable and condensible PM, excluding H_2SO_4 mist.
[2] Based on fuel oil sulfur content of 0.05 wt percent.
[3] Based on 7.5% conversion of SO_2 to H_2SO_4.
[4] Based on 1.0 ppmw lead content of fuel oil.
[5] Corrected to 15% O_2.
[6] Non-methane hydrocarbons (NMHC) expressed as methane.

Sources: ECT, 2005.
GE, 1998.

Table B-4. TEC Polk Power Station, SCCT Units 4 and 5 CT Emission Rates - General Electric 7241FA CT Natural Gas-Firing: Hazardous Air Pollutants

Maximum Hourly Heat Input: (Case 1)	1,960	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	1,834	10^6 Btu/hr
Maximum Annual Hours: (Case 4)	4,380	hrs/yr

Pollutant	Emission Factor[1] (lb/10^6 Btu)	HAP Emissions (Per CT) (lb/hr)[2]	(g/s)[2]	(ton/yr)[3]	HAP Emissions Units 4 & 5 (ton/yr)[4]
1,3-Butadiene	4.30E-08	8.43E-05	1.06E-05	1.73E-04	3.45E-04
Acetaldehyde	4.00E-06	7.84E-03	9.88E-04	1.61E-02	3.21E-02
Acrolein	6.40E-07	1.25E-03	1.58E-04	2.57E-03	5.14E-03
Benzene	1.20E-06	2.35E-03	2.96E-04	4.82E-03	9.64E-03
Ethylbenzene	3.20E-06	6.27E-03	7.90E-04	1.29E-02	2.57E-02
Formaldehyde[4]	2.19E-04	4.29E-01	5.40E-02	8.78E-01	1.76E+00
Naphthalene	1.30E-07	2.55E-04	3.21E-05	5.22E-04	1.04E-03
Polycyclic Aromatic Hydrocarbons (PAH)	2.20E-07	4.31E-04	5.43E-05	8.84E-04	1.77E-03
Propylene Oxide	2.90E-06	5.68E-03	7.16E-04	1.16E-02	2.33E-02
Toluene	1.30E-05	2.55E-02	3.21E-03	5.22E-02	1.04E-01
Xylene	6.40E-06	1.25E-02	1.58E-03	2.57E-02	5.14E-02

[1] HAP emission factors for lean premix (LPM) combustion are based on EPA AP-42, Section 3.1, Table 3.1-3 April, 2000 diffusion flame emission factors and 90% reduction for LPM combustion.
[2] Hourly (lb/hr and g/s) emission rates based on Case 1 (100% load, 0°F ambient temperature).
[3] Annual (ton/yr) emission rates based on Case 4 (100% load, 59°F ambient temperature).
[4] Formaldehyde emission factor based on GE guarantee of 91 parts per billion by volume dry (ppbvd), corrected to 15% O_2.

Sources: ECT, 2005.
GE, 2005.

Table B-5. TEC Polk Power Station, SCCT Units 4 and 5
CT Emission Rates - General Electric 7241FA CT
Distillate Fuel Oil-Firing: Hazardous Air Pollutants

Maximum Hourly Heat Input: (Case 1)	2,139	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	2,015	10^6 Btu/hr
Maximum Annual Hours: (Case 4)	750	hrs/yr

Pollutant	Emission Factor[1] ($lb/10^6$ Btu)	HAP Emissions (Per CT) (lb/hr)[2]	(g/s)[2]	(ton/yr)[3]	HAP Emissions Units 4 & 5 (ton/yr)[4]
1,3-Butadiene	1.60E-05	3.42E-02	4.31E-03	1.21E-02	2.42E-02
Arsenic	1.10E-05	2.35E-02	2.96E-03	8.31E-03	1.66E-02
Benzene	5.50E-05	1.18E-01	1.48E-02	4.16E-02	8.31E-02
Beryllium	3.10E-07	6.63E-04	8.35E-05	2.34E-04	4.68E-04
Cadmium	4.80E-06	1.03E-02	1.29E-03	3.63E-03	7.25E-03
Chromium	1.10E-05	2.35E-02	2.96E-03	8.31E-03	1.66E-02
Formaldehyde[4]	2.31E-04	4.94E-01	6.22E-02	1.74E-01	3.49E-01
Lead	1.40E-05	2.99E-02	3.77E-03	1.06E-02	2.12E-02
Manganese	7.90E-04	1.69E+00	2.13E-01	5.97E-01	1.19E+00
Mercury	1.20E-06	2.57E-03	3.23E-04	9.07E-04	1.81E-03
Naphthalene	3.50E-05	7.49E-02	9.43E-03	2.64E-02	5.29E-02
Nickel	4.60E-06	9.84E-03	1.24E-03	3.48E-03	6.95E-03
PAH	4.00E-05	8.55E-02	1.08E-02	3.02E-02	6.04E-02
Selenium	2.50E-05	5.35E-02	6.74E-03	1.89E-02	3.78E-02

[1] AP-42 Section 3.1, Tables 3.1-4. And 3.1-5., EPA April, 2000.

[2] Hourly (lb/hr and g/s) emission rates based on Case 1 (100% load, 0°F ambient temperature).

[3] Annual (ton/yr) emission rates based on Case 4 (100% load, 59°F ambient temperature).

[4] Formaldehyde emission factor based on GE guarantee of 91 parts per billion by volume dry (ppbvd), corrected to 15% O_2.

Sources: ECT, 2005.
GE, 2005.

Table B-6. TEC Polk Power Station, SCCT Units 4 and 5
CT Emission Rates - General Electric 7241FA CT
Hazardous Air Pollutants; Annual Summary

Pollutant	HAP Emissions Units 4 & 5		
	Gas-Firing (ton/yr)	Oil-Firing (ton/yr)	Totals (ton/yr)
1,3-Butadiene	0.00035	0.02418	0.02452
Acetaldehyde	0.03213	N/A	0.03213
Acrolein	0.00514	N/A	0.00514
Arsenic	N/A	0.01662	0.01662
Benzene	0.00964	0.08311	0.09275
Beryllium	N/A	0.00047	0.00047
Cadmium	N/A	0.00725	0.00725
Chromium	N/A	0.01662	0.01662
Ethylbenzene	0.02571	N/A	0.02571
Formaldehyde	**1.75696**	0.34874	**2.10569**
Lead	N/A	0.02116	0.02116
Manganese	N/A	**1.19383**	1.19383
Mercury	N/A	0.00181	0.00181
Naphthalene	0.00104	0.05289	0.05394
Nickel	N/A	0.00695	0.00695
PAH	0.00177	0.06045	0.06221
Propylene Oxide	0.02330	N/A	0.02330
Selenium	N/A	0.03778	0.03778
Toluene	0.10443	N/A	0.10443
Xylene	0.05141	N/A	0.05141
Maximum Individual HAP	1.76	1.19	2.11
Maximum Total HAPs	2.01	1.87	3.88

Note: Maximum individual HAPs shown in bold-face font.

Sources: ECT, 2005.
GE, 2005.

Table B-7. TEC Polk Power Station, SCCT Units 4 and 5 Annual Emission Rates

Source	Case	Annual Operations (hrs/yr)	Emission Rates: NO_x (lb/hr)	NO_x (tpy)	CO (lb/hr)	CO (tpy)	VOC (lb/hr)	VOC (tpy)
Unit 4	4 - NG	4,380	68.8	150.7	36.0	78.8	2.8	6.2
Unit 5	4 - NG	4,380	68.8	150.7	36.0	78.8	2.8	6.2
Unit 4	4 - Oil	750	319.0	119.6	92.2	34.6	7.2	2.7
Unit 5	4 - Oil	750	319.0	119.6	92.2	34.6	7.2	2.7
		Totals	**N/A**	**540.7**	**N/A**	**226.8**	**N/A**	**17.7**

Source	Case	Annual Operations (hrs/yr)	Emission Rates: PM/PM_{10} (lb/hr)	PM/PM_{10} (tpy)	SO_2 (lb/hr)	SO_2 (tpy)	H_2SO_4 (lb/hr)	H_2SO_4 (tpy)	Lead (lb/hr)	Lead (tpy)
Unit 4	4 - NG	4,380	18.0	39.4	9.5	20.9	1.09	2.4	0.029	0.063
Unit 5	4 - NG	4,380	18.0	39.4	9.5	20.9	1.09	2.4	0.029	0.063
Unit 4	4 - Oil	750	34.0	12.8	101.5	38.1	11.66	4.4	0.098	0.037
Unit 5	4 - Oil	750	34.0	12.8	101.5	38.1	11.66	4.4	0.098	0.037
		Totals	**N/A**	**104.3**	**N/A**	**117.9**	**N/A**	**13.5**	**N/A**	**0.199**

Sources: GE, 1998.
ECT, 2005.
TEC, 2005.

Table B-8. TEC Polk Power Station, SCCT Units 4 and 5
General Electric 7241FA CT
NSPS GG NO_x Limits

Fuel	7241FA Gas Turbine ISO Heat Rate		F	NO_x Std (ppmvd)
	(Btu/kw-hr)	(kj/w-hr)		
Gas	9,370	9.886	0.0	109.2
Distillate	10,040	10.593	0.0	102.0

Sources: ECT, 2005.
GE, 1998.

Table B-9A. TEC Polk Power Station, SCCT Units 4 and 5
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Natural Gas-Firing

A. Exhaust MW

Component	MW (lb/mole)	Exhaust Gas Composition - Volume %								
		100 % Load			75 % Load			50 % Load		
		20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.90	0.89	0.87	0.91	0.88	0.87	0.90	0.89	0.86
N_2	28.016	75.06	74.38	72.32	75.07	74.43	72.37	75.18	74.54	72.50
O_2	32.000	12.56	12.38	11.96	12.59	12.52	12.10	12.90	12.85	12.48
CO_2	44.010	3.87	3.87	3.80	3.85	3.80	3.73	3.71	3.65	3.56
H_2O	17.008	7.61	8.49	11.06	7.59	8.37	10.93	7.31	8.07	10.60
	Totals	100.00	100.01	100.01	100.01	100.00	100.00	100.00	100.00	100.00
Exhaust MW (lb/mole)		28.41	28.30	27.99	28.41	28.31	28.00	28.43	28.33	28.02
Exhaust Flow (lb/sec)		1,053.08	981.13	910.01	839.46	801.53	751.61	689.69	664.87	630.85
Exhaust Temp. (°F)		1,081	1,117	1,141	1,111	1,139	1,166	1,160	1,184	1,200
(K)		856	876	889	873	888	903	900	913	922
Exhaust O_2 (Vol %, Dry)		13.59	13.53	13.45	13.62	13.66	13.58	13.92	13.98	13.96

Sources: ECT, 2005.
GE, 1998.

Table B-9B. TEC Polk Power Station, SCCT Units 4 and 5
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Natural Gas-Firing

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
ACFM	2,501,394	2,393,587	2,279,099	2,032,504	1,982,448	1,911,361	1,720,962	1,689,336	1,636,463
Velocity (fps)	163.8	156.8	149.3	133.1	129.8	125.2	112.7	110.6	107.2
Velocity (m/s)	49.9	47.8	45.5	40.6	39.6	38.2	34.4	33.7	32.7
SCFM, Dry[1]	791,825	733,365	668,502	631,260	599,825	552,825	519,904	498,776	465,339
ACFM ($15\% \ O_2$, Dry)	2,861,380	2,736,637	2,560,494	2,316,258	2,227,959	2,110,800	1,887,869	1,822,012	1,720,949

Sources: ECT, 2005.
GE, 1998.

Table B-10A. TEC Polk Power Station, SCCT Units 4 and 5
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing

A. Exhaust MW

Component	MW (lb/mole)	Exhaust Gas Composition - Volume % 100 % Load 20 °F	100 % Load 59 °F	100 % Load 90 °F	75 % Load 20 °F	75 % Load 59 °F	75 % Load 90 °F	50 % Load 20 °F	50 % Load 59 °F	50 % Load 90 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.87	0.85	0.85	0.85	0.86	0.85	0.87	0.87	0.85
N_2	28.016	71.82	71.31	70.02	71.53	71.26	70.24	72.47	72.21	71.08
O_2	32.000	11.17	11.04	10.85	10.49	10.63	10.77	11.37	11.59	11.69
CO_2	44.010	5.61	5.61	5.50	6.02	5.88	5.59	5.60	5.40	5.12
H_2O	17.008	10.54	11.19	12.79	11.11	11.37	12.56	9.70	9.94	11.27
	Totals	100.01	100.00	100.01	100.00	100.00	100.01	100.01	100.01	100.01
Exhaust MW (lb/mole)		28.30	28.22	28.02	28.28	28.23	28.06	28.40	28.35	28.16
Exhaust Flow (lb/sec)		1,085.99	1,021.29	941.25	811.85	784.24	751.05	677.70	667.94	645.91
Exhaust Temp. (°F)		1,067	1,098	1,130	1,184	1,195	1,200	1,200	1,200	1,200
(K)		848	865	883	913	919	922	922	922	922
Exhaust O_2 (Vol %, Dry)		12.49	12.43	12.44	11.80	11.99	12.32	12.59	12.87	13.17

Sources: ECT, 2005.
GE, 1998.

Table B-10B. TEC Polk Power Station, SCCT Units 4 and 5
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
ACFM	2,565,225	2,468,510	2,338,219	2,066,743	2,012,963	1,945,329	1,734,167	1,712,182	1,666,850
Velocity (fps)	168.0	161.7	153.1	135.4	131.8	127.4	113.6	112.1	109.2
Velocity (m/s)	51.2	49.3	46.7	41.3	40.2	38.8	34.6	34.2	33.3
SCFM, Dry[1]	793,504	742,956	677,155	590,027	569,184	541,040	498,086	490,465	470,428
ACFM (15% O_2, Dry)	3,272,679	3,146,844	2,923,523	2,833,193	2,693,164	2,474,511	2,205,243	2,098,885	1,936,533

Sources: ECT, 2005.
GE, 1998.

Table B-11. TEC Polk Power Station, SCCT Units 4 and 5
CT Fuel Flow Rate Data - General Electric 7241FA CT (Per CT)

A. Natural Gas-Firing

	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
Heat Input - HHV[1] (MMBtu/hr)	1,960	1,834	1,688	1,572	1,487	1,383	1,255	1,193	1,116
Fuel Rate (lb/hr)	84,521	79,074	72,781	67,796	64,104	59,624	54,119	51,448	48,113
Fuel Rate (10^6 ft^3/hr)	1.913	1.790	1.647	1.534	1.451	1.349	1.225	1.164	1.089
Fuel Rate (lb/sec)	23.478	21.965	20.217	18.832	17.807	16.562	15.033	14.291	13.365

B. Distillate Fuel Oil-Firing

	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
Heat Input - HHV[1] (MMBtu/hr)	2,139	2,015	1,832	1,735	1,638	1,501	1,353	1,288	1,187
Fuel Rate (lb/hr)	107,764	101,532	92,336	87,438	82,517	75,612	68,180	64,922	59,832
Fuel Rate (10^3 gal/hr)	14.742	13.889	12.631	11.961	11.288	10.343	9.327	8.881	8.185
Fuel Rate (lb/sec)	29.935	28.203	25.649	24.288	22.921	21.003	18.939	18.034	16.620

[1] Includes a 3.5% margin to account for heat rate degradation over time.

Sources: ECT, 2005.
GE, 1998.

APPENDIX C

DISPERSION MODELING FILES

Polk Power Station
Units 4 and 5 Simple Cycle Combustion Turbine Project
Dispersion Modeling Files

Directory Name	No. of Files	File Name	File Description
ISC Met Data	5	spgXX.asc	St.Petersburg/Clearwater< FL surface meteorological data
		XX = 92 - 96	Ruskin, FL upper air meteorological data
GEP Files	1	45.bpi	Building Profile Input Program (BPIP) input file
	1	45.bpo	Building Profile Input Program (BPIP) output file - brief
	1	45.sum	Building Profile Input Program (BPIP) output file - detailed
Subtotal Files	3		
ISC Files	10	XXy.inp	ISC input files, 1992-1996
	10	XXy.out	ISC output files, 1992-1996
		y = g (gas), o (oil)	
		XX = 92 - 96	
Subtotal Files	20		
CALPUFF Files	3	oilXX.inp	CALPUFF input files for 1990, 1992, and 1996
	3	oilXX.con	CALPUFF output concentration files for 1990, 1992, and 1996
	3	oilXX.lst	CALPUFF output list files for 1990, 1992, and 1996
	3	oilXXdf.dat	CALPUFF output dry deposition flux files for 1990, 1992, and 1996
	3	oilXXwf.dat	CALPUFF output wet deposition flux files for 1990, 1992, and 1996
Subtotal Files	15		
POSTUTIL Files	3	postutilXX.inp	POSTUTIL HNO_3/NO_3 partitioning input files for 1990, 1992, and 1996
	3	oilXXp.lst	POSTUTIL HNO_3/NO_3 partitioning output list files for 1990, 1992, and 1996
	3	oilXXp.con	CALPUFF output concentration files for 1990, 1992, and 1996 (processed for HNO_3/NO_3 partitioning)
	3	utilXXdep.inp	POSTUTIL total deposition flux input files for 1990, 1992, and 1996
	3	XXtflx.lst	POSTUTIL total deposition flux output list files for 1990, 1992, and 1996
	3	XXtflx.con	CALPUFF output total deposition flux files for 1990, 1992, and 1996 (processed for total S and N deposition)
		XX = 90, 92, 96	
Subtotal Files	18		
CALPOST Files	3	XXso2.pol	CALPOST SO_2 input files for 1990, 1992, and 1996
	3	XXso2.lst	CALPOST SO_2 output list files for 1990, 1992, and 1996
	3	XXno2.poi	CALPOST NO_2 input files for 1990, 1992, and 1996
	3	XXno2.lst	CALPOST NO_2 output list files for 1990, 1992, and 1996
	3	XXpm.poi	CALPOST PM input files for 1990, 1992, and 1996
	3	XXpm.lst	CALPOST PM output list files for 1990, 1992, and 1996
	3	XXvis.poi	CALPOST regional haze input files for 1990, 1992, and 1996
	3	XXvis.lst	CALPOST regional haze output list files for 1990, 1992, and 1996
	3	XXndep.poi	CALPOST nitrogen deposition input files for 1990, 1992, and 1996
	3	XXndep.pol	CALPOST nitrogen deposition output list files for 1990, 1992, and 1996
	3	XXsdep.pol	CALPOST nitrogen deposition input files for 1990, 1992, and 1996
	3	XXsdep.pol	CALPOST nitrogen deposition output list files for 1990, 1992, and 1996
Subtotal Files	36		
RH Files	1	rh.zip	CALMET relative humidity files for 1990, 1992, and 1996 (compressed)
Total Files	98		

Source: ECT, 2005.

APPENDIX D

PROPOSED AIR CONSTRUCTION PERMIT
(To be submitted as an addendum)

7000 1670 0013 3110 0420

U.S. Postal Service

CERTIFIED MAIL RECEIPT

(Domestic Mail Only; No Insurance Coverage Provided)

OFFICIAL USE

Postage	$	Postmark Here
Certified Fee		
Return Receipt Fee (Endorsement Required)		
Restricted Delivery Fee (Endorsement Required)		

Mr. Mark J. Hornick
General Manager
Polk Power Station
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

PS Form 3800, May 2000 — See Reverse for Instructions

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. Mark J. Hornick
General Manager
Polk Power Station
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33601-0111

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X ☐ Agent ☐ Addressee

B. Received by (Printed Name) OSMAN

C. Date of Delivery

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

MAY - 2 2005
TAMPA FL

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 *(Transfer from service label)* 7000 1670 0013 3110 0680

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

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

7000 1670 0013 3110 0680

Mr. Mark J. Hornick, General Manager

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

Postmark Here

Sent To
Mr. Mark J. Hornick, General Manager
Street, Apt. No.; or PO Box No.
P.O. Box 111
City, State, ZIP+4
Tampa, Florida 33601-0111

PS Form 3800, May 2000 See Reverse for Instructions

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:

Facility ID #: 1050233
Mr. Mark J. Hornick, General Manager
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33~~604-5927~~

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature]
☐ Agent
☐ Addressee

B. Received by (*Printed Name*) [signature]

C. Date of Delivery

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

DOWNTOWN TAMPA FL 33601 NOV 28 2005

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
(*Transfer from service label*) 7003 1680 0002 4617 3974

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1540

7003 1680 0002 4617 3974

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OFFICIAL USE

Postage	$
Certified Fee	
Return Reciept Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total	

Postmark Here

Sent T
Street, or PO
City, S

Facility ID #: 1050233
Mr. Mark J. Hornick, General Manager
Tampa Electric Company
P.O. Box 111
Tampa, Florida 33604-5927

PS Form 3800, June 2002 See Reverse for Instructions