Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road, MS#5505
Tallahassee, Florida 32399-2400

March 6, 2007

James M. Chansler, P.E., D.P.A., Chief Operating Officer
Jacksonville Electric Authority (JEA)
Kennedy Generating Station
21 West Church Street
Jacksonville, Florida 32202

Re: Draft Air Permit No. PSD-FL-386
Project No. 0310047-015-AC
JEA – Kennedy Generating Station
Combustion Turbine No. 8

Dear Mr. Chansler:

On December 22, 2006, JEA submitted an application to construct a simple cycle combustion turbine at the Kennedy Generating Station which is located at 21 West Church Street, Jacksonville, in Duval 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 including the draft determinations of the Best Available Control Technology (BACT). 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, Bruce Thomas at (850) 921-7744.

Sincerely,

Jeffery J. Vo[illegible]

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:

Jacksonville Electric Authority (JEA)
Kennedy Generating Station
21 West Church Street
Jacksonville, Florida 32202

Authorized Representative:
James M. Chansler, P.E., D.P.A., Chief Operating Officer

Draft Air Permit No. PSD-FL-386
Project No. 0310047-015-AC
JEA – Kennedy Generating Station
Combustion Turbine No. 8

Duval County, Florida

Facility Location: The Jacksonville Electric Authority (JEA) operates an electrical generating facility in Jacksonville at 21 West Church Street in Duval County, Florida.

Project: The applicant proposes to construct a simple cycle combustion turbine. 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 and fax number is 850/921-9533.

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. A copy of the complete project file is also available at The City of Jacksonville Environmental Resource Management Department, Environmental Quality Division, 117 West Duval Street, Suite 225, Jacksonville, Florida 32202. The phone number for the Jacksonville program is 904/630-4900.

Notice of Intent to Issue 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 comment 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, and all facsimile comments must be received 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 or facsimile. 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 in the Florida Administrative Weekly 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 written comments or comments received at a public meeting 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. 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. If there are none, the petition must so state; (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 F. Koerner

FOR 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 electronic mail (received receipt requested) before the close of business on 3/7/07 to the persons listed below.

Mr. James M. Chansler, JEA (ChanJM@jea.com)
Mr. N. Bert Gianazza, JEA (giannb@jea.com)
Mr. Bob Holmes, Black & Veatch (HolmesAR@bv.com)
Mr. Gregg Worley, EPA Region 4 (worley.gregg@epa.gov)
Mr. Chris Kirts, NED Office (kirts_c@dep.state.fl.us)
Mr. Steve Pace, Duval County RESD (Pace@coj.net)

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.

Mary L. Harvey (Clerk) 3/7/07 (Date)

Memorandum

Florida Department of
Environmental Protection

TO:	Trina Vielhauer, Chief - Bureau of Air Regulation
THROUGH:	Jeff Koerner, Air Permitting North JK
FROM:	Bruce Thomas
DATE:	March 6, 2007
SUBJECT:	Draft Air Permit No. PSD-FL-386 Project No. 0310047-015-AC JEA – Kennedy Generating Station New Combustion Turbine No. 8

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

Attachments

P.E. CERTIFICATION STATEMENT

APPLICANT

Jacksonville Electric Authority (JEA)
21 West Church Street
Jacksonville, Florida 32202

Project No. 0310047-015-AC
Air Permit No. PSD-FL-386
Kennedy Generating Station
Combustion Turbine No. 8
Duval, Florida

PROJECT DESCRIPTION

The applicant proposes to construct a simple cycle combustion turbine, which will emit the following pollutants when combusting fuel: carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC). The new unit will fire natural gas as the primary fuel. Operation will be limited to 3500 hours per year with no more than 500 hours from firing distillate oil. The unit is subject to the federal New Source Performance Standards for new combustion turbines in Subpart KKKK of Title 40, Part 60, of the Code of Federal Regulations (CFR), which establishes the following emissions standards for NO_X and SO_2:

NO_X (gas) $\leq$ 15 ppm at 15% O_2 or 0.43 lb/MWh of useful output

NO_X (oil) $\leq$ 42 ppm at 15% O_2 or 1.3 lb/MWh of useful output

SO_2 (gas/oil) $\leq$ fuel sulfur content limit of 0.060 lb SO_2/MMBtu

The unit will be designed and constructed with dry low-NO_X (DLN) burner technology for the control of NO_X emissions when firing natural gas and water injection when firing distillate oil. The project also requires the permanent shutdown of three existing combustion turbines (Nos. 3, 4, and 5). Considering the emissions decreases from these units as well as the emissions increases from the new combustion turbine, the project will result in the following net emissions based on the application: 60 tons/year of CO; -142.6 of NO_X (decrease); 39.8 tons/year of PM/PM_{10}; -52.7 tons/year of SO_2 (decrease); and 6.1 tons/year of VOC.

The project is subject to preconstruction review for particulate matter (PM/PM_{10}) in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality, which requires a determination of the Best Available Control Technology (BACT) and an ambient air quality analysis. The Department's preliminary BACT determination for PM/PM_{10} is a visible emissions standard of 10% opacity, DLN combustor technology to maximize combustion efficiency, the use of natural gas as the primary fuel, and the use of low sulfur distillate oil as a restricted alternate fuel.

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 — 3-7-07

Jeffery F. Koerner, P.E.
Registration No. 49441

(Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Project No. 0310047-015-AC / Draft Air Permit No. PSD-FL-386
JEA – Kennedy Generating Station
Duval County, Florida

Applicant: The applicant for this project is Jacksonville Electric Authority (JEA). The applicant's authorized representative is James M. Chansler, P.E., D.P.A., Chief Operating Officer. The applicant's mailing address is 21 West Church Street, Jacksonville, Florida 32303.

Facility Location: JEA operates an existing electrical generating facility located in Jacksonville at 21 West Church Street in Duval County, Florida.

Project: The applicant proposes to construct a simple cycle combustion turbine, which will emit the following pollutants when combusting fuel: carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC). The new unit will fire natural gas as the primary fuel. Operation will be limited to 3500 hours per year with no more than 500 hours from firing distillate oil. The unit is subject to the federal New Source Performance Standards for new combustion turbines in Subpart KKKK of Title 40, Part 60, of the Code of Federal Regulations (CFR), which establishes emissions standards for NO_X and SO_2. This federal regulation is adopted in Rule 62-204.800, F.A.C. of the Florida Administrative Code (F.A.C.).

The unit will be designed and constructed with dry low-NO_X (DLN) burner technology for the control of NO_X emissions when firing natural gas and water injection when firing distillate oil. The project also requires the permanent shutdown of three existing combustion turbines (Nos. 3, 4, and 5). Considering the emissions decreases from these units as well as the emissions increases from the new combustion turbine, the project will result in the following net emissions based on the application: 60 tons/year of CO; -142.6 of NO_X (decrease); 39.8 tons/year of PM/PM_{10}; -52.7 tons/year of SO_2 (decrease); and 6.1 tons/year of VOC.

The project is subject to preconstruction review for particulate matter (PM/PM_{10}) in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality, which requires a determination of the Best Available Control Technology (BACT) and an ambient air quality analysis. The Department's preliminary BACT determination for PM/PM_{10} is a visible emissions standard of 10% opacity, DLN combustor technology to maximize combustion efficiency, the use of natural gas as the primary fuel, and the use of low sulfur distillate oil as a restricted alternate fuel.

An air quality impact analysis was conducted for PM_{10} emissions impacts. Based on the results of the air dispersion modeling, the maximum predicted ambient impacts due to the proposed project are less than the applicable PSD Class I and Class II significant impact levels. These results provide reasonable assurance that the project will comply with all applicable air quality regulations and will not cause or contribute to a violation of the state and federal ambient air quality and PSD increments.

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 and fax number is 850/921-9533.

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. A copy of the complete project file is also available at The City of Jacksonville Environmental Resource Management Department, Environmental Quality Division, 117 West Duval Street, Suite 225, Jacksonville, Florida 32202. The phone number for the Jacksonville program is 904/630-4900.

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 appropriate 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 comment 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, and all facsimile comments must be received, 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 or facsimile. 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 in the Florida Administrative Weekly 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 written comments or comments received at a public meeting 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. 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. If there are none, the petition must so state; (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 Public 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.

(Public Notice to be Published in the Newspaper)

TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

PROJECT

Project No. 0310047-015-AC
Air Permit No. PSD-FL-386

JEA – Kennedy Generating Station
ARMS Facility ID No. 0310047
Combustion Turbine No. 8

COUNTY

Duval County, Florida

APPLICANT

Jacksonville Electric Authority (JEA)
Kennedy Generating Station
21 West Church Street
Jacksonville, Fl 32202

PERMITTING AUTHORITY

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

March 6, 2007

1. GENERAL PROJECT INFORMATION

General Facility Information

JEA operates the existing Kennedy Generating Station which is located in Jacksonville at 4215 Talleyrand Avenue in Duval County, Florida. The UTM coordinates are Zone 17, 440.67 km East, and 3359.15 km North. This facility consists of four combustion turbines (CTs), Nos. 3, 4, 5 and 7. All of these units fire virgin No. 2 fuel oil and CT No. 7 also fires natural gas. There is a fuel oil storage tank farm associated with the CTs.

Facility Regulatory Categories

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

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 major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The facility is a PSD-major facility in accordance with Rule 62-212.400, F.A.C.

Application Processing Schedule

The Department received an application to construct a new combustion turbine (CT No.8) on December 22, 2006. On January 22, 2007, we received an email from the applicant requesting the following revisions: total operation will be limited to 3500 hours per year (gas and oil); and operation on oil will be limited to 500 hours per year.

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.

Project Description

The applicant proposes to install one 172 MW General Electric Model No. PG 7241 7FA simple cycle combustion turbine-electrical generator (CT No. 8) equipped with evaporative cooling, dry low-NO_x (DLN) combustion technology and water injection equipment. Operation will be limited to a total of 3,500 hours per year using natural gas as the primary fuel. Of this total, low sulfur distillate oil (0.05 % maximum sulfur by weight) may be used as a restricted alternate fuel for up to 500 hours per year. Emissions of nitrogen oxides (NO_X) will be controlled using DLN combustion when firing gas and water injection when firing oil. The advanced burner design with good operating practices will be used to minimize incomplete combustion and emissions of carbon monoxide (CO), particulate matter (PM/PM_{10}), and volatile organic compounds (VOC) emissions. The use of natural gas and restricted operation on distillate oil will minimize emissions of sulfur dioxide (SO_2), sulfuric acid mist (SAM), and PM/PM_{10}.

CT No. 8 will have a stack that is 90 feet tall with an approximate exit diameter of 18 feet. The following table summarizes the exhaust characteristics of the unit. Values given are approximate for operation at a compressor inlet temperature of 59° F and the characteristics of the actual delivered unit may vary. At a compressor inlet temperature 59° F, the nominal generating capacity is approximately 172 MW when firing natural gas, but could be greater (nominally 180 to 197 MW) for lower compressor inlet temperatures or when firing distillate oil.

Table 1A. Approximate Exhaust Characteristics of Unit 8 at 100% Load and 59° F

Fuel	Total Heat Input (LHV)	Compressor Inlet Temp.	Turbine Exhaust Temperature	Stack Flow ACFM
Gas	1,804 MMBtu/hr	59° F	1,110 °F	2,399,000
Oil	1,989 MMBtu/hr	59° F	1,094 °F	2,491,000

The project also includes the permanent shutdown of existing CT Nos. 3, 4, and 5 (EU-003, 004, and 005). Emissions decreases from the shutdown of these units will be used to avoid PSD preconstruction review for NO_X and SO_2 emissions. This will be discussed further in the section on PSD applicability.

2. APPLICABLE REGULATIONS

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the applicable rules and regulations defined in the following Chapters of the Florida Administrative Code.

Chapter	Description
62-4	Permitting Requirements
62-17	Electrical Power Plant Siting
62-204	Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference
62-210	Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms
62-212	Preconstruction Review, PSD Review and BACT, and Non-attainment Area Review and LAER
62-213	Title V Air Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Emission Limiting Standards
62-297	Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures

Federal Regulations

The Environmental Protection Agency establishes air quality regulations in Title 40 of the Code of Federal Regulations (CFR). Part 60 identifies New Source Performance Standards (NSPS) for a variety of industrial activities. Par t 61 specifies the National Emissions Standards for Hazardous Air Pollutant (NESHAP) based on specific pollutants. Part 63 identifies National Emissions Standards for Hazardous Air Pollutant (NESHAP) base on the Maximum Achievable Control Technology (MACT) for given source categories. The new combustion turbine (CT No. 8) will be subject to NSPS Subpart KKKK in 40 CFR 60, the Standards of Performance for Stationary Combustion Turbines for which Construction is Commenced after February 18, 2005.

General PSD Applicability

The Department regulates major air pollution facilities in accordance with Florida's Prevention of Significant Deterioration (PSD) program defined in Rule 62-212.400, F.A.C. A PSD preconstruction review is required in areas currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or areas designated as "unclassifiable" for a given pollutant. A facility is considered "major" with respect to PSD if it 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 PSD 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 the project emissions increase compared to emissions thresholds known as the significant emission rates identified in Rule 62-210.200 F.A.C. For those pollutants for which the project emissions increase is greater than the respective significant emissions rate, a second test as to whether the net emissions increase exceeds the respective significant emissions rate can be used to determine PSD applicability. A determination of the net emissions increase is commonly referred to as a "netting analysis", which includes creditable contemporaneous emissions increases and decreases. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT), which is defined in Rule 62-210.200, 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.

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. The Department conducts case-by-case BACT determinations in accordance with the requirements given above and generally follows the "top-down methodology" described by EPA in its draft "New Source Review Workshop Manual".

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 be located in Duval County, Florida, which is in an area that is currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or otherwise designated as unclassifiable. The actual and/or potential annual emissions of one or more pollutants from the facility are greater than the applicability thresholds defined above. Therefore, the existing facility is a major stationary source as defined in Rule 62-210.200, F.A.C. The following table shows the estimated emissions increases prior to netting based on the original application.

Table 2A. Summary of the Applicant's PSD Applicability

Pollutant	Emissions Increase CT8 [a]	PSD Significant Emissions Rate [a]	Subject to PSD Review?
Carbon Monoxide (CO)	60.0 TPY	100 TPY	No
Nitrogen Oxides (NOx)	228.7 TPY	40 TPY	Yes
Particulate Matter (PM/PM_{10})	39.8 TPY	15/25 TPY	Yes
Sulfuric Acid Mist (SAM)	4.4 TPY	7 TPY	No
Sulfur Dioxide (SO_2)	41.6 TPY	40 TPY	Yes
Volatile Organic Compounds (VOC)	6.1 TPY	40 TPY	No
Lead (Pb)	14 lb/year	1200 lb/year	No
Mercury (Hg)	2 lb/year	200 lb/year	No
Fluorides (Fl)	Negligible.	3 TPY	No

[a] "TPY" means tons per year.

As shown in Table 2-A, the project results in emissions increases of NO_x, SO_2, PM/PM_{10} that are greater than the respective PSD significant emission rates. Only these pollutants will be included in the netting analysis to determine if the net emissions increases are greater than the PSD significant emission rates when emissions decreases from the permanent shutdown of three existing combustion turbines is also considered. In addition, the applicable PM and PM_{10} emission factors from AP-42 for the existing combustion turbines are relatively low and will not be considered. Therefore, only NO_x and SO_2 emission increases will be considered in the netting analysis.

As defined in the Rules 62-210.200 (Definitions) and 62-212.400 (PSD), F.A.C., the historical actual emissions must be determined for the existing three combustion turbines that will be shutdown. This term is referred to as the "baseline actual emissions", which is defined as the annual average emissions during any consecutive 24-month period during a defined number of years dating back from the change that resulted in the emissions decrease. The time period used to determine the baseline actual emissions levels will be called the "look-back period". Because the units that will be shut down are simple cycle combustion turbines, the look-back period is the 10-year period immediately preceding the date a complete application is received by the Department. The change that results in emissions decreases is the shut down of the existing units. The requested shutdown date for CT Nos. 3, 4, and 5 is the date that CT No. 8 becomes operational. Since the change to the existing units will be permanent shutdown, the post change emissions will be zero and the emissions decrease will be equal to the baseline actual emissions. The baseline actual emissions can be chosen on a pollutant-by-pollutant basis, so the 24-month period used to determine the baseline actual emissions can be different for the different PSD pollutants.

For this specific netting analysis, the only emission increases and decreases occurring at the facility during the contemporaneous period are the emission decreases associated with the shutdown of the existing oil-fired combustion turbines and the emissions increase associated with installation of CT No. 8. The following table shows the results of the netting analysis.

Table 2B. Netting Results

Contemporaneous Changes	NO_x (tpy)	SO_2 (tpy)
Emission Decreases Permanent Shutdown of CT Nos. 3, 4, and 5	-371.3 [a]	-94.3 [b]
Emission Increases New CT No. 8 [c]	228.7	41.6
Net Emissions Change	-142.6	-52.7
Significant Emission Rate	40	40
Subject to PSD?	No	No

[a] The baseline actual emission period is 03/01/1999 – 03/01/2001.

[b] The baseline actual emission period is 02/01/1998 – 02/01/2000.

[c] Potential Emissions are based on 3000 hours per year of firing natural gas, 500 hours per year of firing distillate oil, and a compressor inlet temperature of 59°F.

As shown in the above table, the project nets out of PSD preconstruction review for NO_X and SO_2 emissions. Therefore, the new combustion turbine is only subject to PSD preconstruction review for PM/PM_{10} emissions.

3. BACT REVIEW – CT NO. 8 (EU-016)

Particulate Matter (PM/PM_{10})

Particulate matter (PM/PM_{10}) is emitted from gas turbines due to ash present in the fuels fired and incomplete fuel combustion. Emissions can be minimized by use of clean fuels, with low ash and sulfur contents, and good combustion practices. The applicant proposes the following as BACT: the use of DLN combustor technology to maximize combustion efficiency, the use of natural gas with a sulfur content of no more than 2 grains per 100 scf as the primary fuel, the use of low sulfur distillate oil (0.05 % maximum sulfur by weight) as a restricted alternate fuel, and a visible emissions limit of 10% opacity based on a 6-minute average. The Department concurs with the applicant and makes a preliminary determination to establish these conditions as BACT for PM/PM_{10} emissions from CT No. 8.

4. NEW SOURCE PERFORMANCE STANDARDS (NSPS)

The proposed new combustion turbine is subject to the NO_x and SO_2 standards specified in Subpart KKKK of 40 CFR 60 as follows:

For new units firing natural gas with a maximum heat input rate greater than 850 MMBtu/hour:

$NO_X \leq 15$ ppm at 15% O_2 or 0.43 lb/MWh of useful output

$SO_2 \leq$ fuel sulfur content limit of 0.060 lb SO_2/MMBtu

For new units firing distillate oil with a maximum heat input rate greater than 850 MMBtu/hour:

$NO_X \leq 42$ ppm at 15% O_2 or 1.3 lb/MWh of useful output

$SO_2 \leq$ fuel sulfur content limit of 0.060 lb SO_2/MMBtu

Because the new combustion turbine is subject to the acid rain program, a continuous emissions monitoring system (CEMS) must be installed for NO_X emissions. The permittee will demonstrate continuous compliance with the NO_X standards based on a 4-hour average of CEMS data. Compliance with the fuel sulfur requirements will be demonstrated by record keeping and reporting.

5. OTHER PERMIT LIMITS

In addition to NO_X, SO_2, and PM/PM_{10}, the combustion of natural gas and distillate oil will result in the emissions of carbon monoxide (CO) and volatile organic compounds (VOC). For this project, potential CO emissions are estimated to be 60 tons per year based on the General Electric performance guarantees of 9 ppmvd @ 15% O_2 for gas firing and 20 ppmvd @ 15% O_2 for distillate oil firing. Potential VOC emissions are estimated to be less than 10 tons per year based on the General Electric emissions data.

The Department has permitted numerous General Electric Model PG 7241 combustion turbines used for simple cycle peaking as well as combined cycle operations. Continuous monitoring data for several of these existing units confirms low CO emissions for both fuels, generally less than 5 ppmvd @ 15% O_2. Tested VOC emissions have also been very low, generally less than 1 ppmvd. Therefore, the Department will establish a CO emissions standard of 9 ppmvd @15% O_2 as determined by the average of 3 test runs conducted in accordance with EPA Method 10. Tests shall be conducted to demonstrate initial compliance and during the 12-month period prior to renewal. Due to the very low expected emissions, no such tests will be required for VOC emissions.

6. PERIODS OF EXCESS EMISSIONS

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 for brief periods 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.

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 NO_X emissions.

Excess Emissions Allowed

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 a proposed state emissions standard based on the given characteristics of the specific project. Rule 62-210.200, F.A.C. defines the following terms.

- *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.

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

For purposes of NSPS Subpart KKKK, the excess emission rule (Rule 62-210.700, F.A.C.) cannot vary any NSPS provision. Therefore, the Department will specify the following alternate standard:

> Alternate Visible Emissions Standard: Visible emissions during startup shall not exceed 20% opacity based on a 6-minute averaging period. [Rule 62-210.700(5), F.A.C.]

7. AIR QUALITY ANALYSIS

Introduction

The proposed project is subject to PSD preconstruction review for emissions of PM_{10}, which is a criteria pollutant. PM_{10} has national and state ambient air quality standards (AAQS), PSD increments, significant impact levels, and significant monitoring concentrations (de minimis concentrations) defined for it. The air quality impact analyses required by the Department's regulations for this project include:

- An analysis of existing air quality for PM_{10};
- A significant impact analysis for PM_{10};
- A PSD increment analysis for PM_{10}, if necessary;
- An Ambient Air Quality Standards (AAQS) analysis for PM_{10}, if necessary; and
- An analysis of impacts on soils, vegetation, and visibility and growth-related impacts to air quality.

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The significant impact, PSD increment, and AAQS analyses depend on air quality dispersion modeling carried out in accordance with EPA and department guidelines.

Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. This monitoring requirement may be satisfied by using previously existing representative monitoring data, if available. An exemption to the monitoring requirement shall be granted by rule if either of the following conditions is met: the maximum predicted air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimis ambient concentration; or the existing ambient concentrations are less than a pollutant-specific de minimis ambient concentration.

The table below shows the maximum predicted project air quality PM_{10} impact for comparison to its de minimis level. As shown in the table, the predicted maximum PM_{10} impact from the project is less than the applicable de minimis concentration; therefore, no further monitoring was required for this pollutant.

MAXIMUM PREDICTED PROJECT IMPACTS COMPARED TO THE DE MINIMIS CONCENTRATIONS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Impact Greater than De Minimis? (Yes/No)**	**De Minimis Concentration ($\mu g/m^3$)**
PM_{10}	24-hour	0.7	NO	10

Models and Meteorological Data Used in Significant Impact, PSD Increment and AAQS Analyses

PSD Class II Area Model

The EPA-approved American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model was used to evaluate the pollutant emissions from the proposed project and other existing major facilities. In November, 2005, the EPA promulgated AERMOD as the preferred regulatory model for predicting pollutant concentrations within 50 km from a source. AERMOD is a replacement for the Industrial Source Complex Short-Term Model (ISCST3).

The AERMOD model calculates hourly concentrations based on hourly meteorological data. For evaluating plume behavior within the building wake of structures, the AERMOD model incorporates the Plume Rise Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). AERMOD can predict pollutant concentrations for annual, 24-hour, 8-hour, 3-hour and 1-hour averages. 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 in each modeling scenario, and building downwash effects were evaluated for stacks below the good engineering practice (GEP) stack heights. The stack associated with this project satisfied the good engineering practice (GEP) stack height criteria.

Meteorological data used in the AERMOD model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the Jacksonville International Airport. The 5-year period of meteorological data was from 2001 through 2005. This station was selected for use in the evaluation because it is the closest primary weather station to the project area and is most representative of the project site.

Because five years of data are used in AERMOD, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate AAQS or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards. For determining the project's significant impact area in the vicinity of the facility, and for determining if there are significant impacts occur from the project on any PSD Class I area, both the highest short-term predicted concentrations and the highest predicted yearly averages were compared to their respective significant impact levels.

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.

PSD Class I Area Model

Since the closest PSD Class I areas, the Okefenokee National Wilderness Area (NWA), the Chassahowitzka NWA, Wolf Island NWA and the St. Marks NWA are greater than 50 km from the proposed facility, 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 the Air Quality Related Values (AQRV): regional haze and nitrogen and sulfur deposition. 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. 2001 through 2003, 4-km Florida domain, meteorological data were obtained and processed for use in the Class I analyses. The CALMET wind field and the CALPUFF model options used were consistent with the suggestions of the federal land managers.

Significant Impact Analysis

Preliminary modeling is conducted using only the proposed project's worst-case emission scenario for each pollutant and applicable averaging time. The worst-case representative stack parameters and PM_{10} emission rates at the 100%, 75% and 50% operating loads were used. This was done by representing the 100%, 75% and 50% operating loads with a worst-case set of stack parameters and pollutant emission rates that were conservatively selected from performance data over a range of ambient temperatures (7° F, 59° F, 68.8° F and 105° F) to produce worst-case plume dispersion conditions (i.e., lowest exhaust temperature and exit velocity and the highest emission rate). Over 1200 receptors were placed along the facility's restricted property line and out to 10 km from the facility, which is located in a PSD Class II area.

Four PSD Class I areas are located within 300 km of the project: the Okefenokee NWA, 55 km to the northwest of the project, the Chassahowitzka NWA located 203 km southwest of the site, the Wolf Island NWA located 110 km to the north of the project, and the St. Marks located 227 km west of the project. A total of 744 receptors were placed in the Okefenokee NWA, Chassahowitzka NWA, Wolf Island NWA and St. Marks NWA PSD Class I areas.

For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project were predicted in a PSD Class II area in the vicinity of the facility or in any PSD Class I area. In the event that the maximum predicted impact of a proposed project is less than the appropriate significant impact level, a full impact analysis for that pollutant is not required.

Full impact modeling is modeling that considers not only the impact of the project but also other major sources, including background concentrations, located within the vicinity of the project to determine whether all applicable AAQS or PSD increments are predicted to be met for that pollutant. Consequently, a preliminary modeling analysis, which shows an insignificant impact, is accepted as the required air quality analysis (AAQS and PSD increments) for that pollutant and no further modeling for comparison to the AAQS and PSD increments is required for that pollutant. The tables below show the results of this modeling.

MAXIMUM PREDICTED PROJECT IMPACTS COMPARED TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS IN THE VICINITY OF THE FACILITY				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Significant Impact Level ($\mu g/m^3$)**	**Significant Impact?**
PM_{10}	Annual	0.07	1	NO
	24-hour	0.7	5	NO

MAXIMUM PREDICTED PROJECT IMPACTS IN THE PSD CLASS I AREAS COMPARED TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact (μg/m^3)**	**Significant Impact Level (μg/m^3)**	**Significant Impact? (ug/m^3)**
PM_{10}	Annual	0.004	0.2	NO
	24-hour	0.09	0.3	NO

No Significant impacts were predicted in the Class I and Class II areas for PM_{10}. Therefore, further PM_{10} AAQS and PSD increment analyses in either the Class I or Class II areas were not required for this project.

Additional Impacts Analysis

Impacts on Soils, Vegetation, Wildlife, and Visibility

According to the modeling results, the maximum air quality impacts due to the project emitting at its maximum rate are predicted to be below Class II significant impact levels and in turn the applicable Class II PSD increments and AAQS. AAQS are designed to protect both the public health and welfare. As such, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

An air quality related values (AQRV) analysis was done by the applicant for the Class I and Class II areas. No significant impacts on these areas are expected. A regional haze analysis using the long-range transport model CALPUFF was done for the PSD Class I areas. This analysis showed no significant impact on visibility in this area. Because the project's SO_2 and NOx emissions did not exceed PSD significant emission rates, acid deposition rates for sulfur and nitrogen compounds were not predicted in these Class I areas.

Growth-Related Air Quality Impacts

The proposed modification will not significantly change employment, population, housing or commercial/industrial development in the area to the extent that a significant air quality impact will result.

Conclusion

Based on the required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment.

8. 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 application, reasonable assurances provided by the applicant, and the conditions specified in the draft permit. Bruce Thomas is the project engineer responsible for reviewing the application and drafting the permit changes. Cleve Holladay is the meteorologist responsible for reviewing the ambient air quality analyses. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

DRAFT

PERMITTEE:

Jacksonville Electric Authority
21 West Church Street
Jacksonville, Florida 32202

Authorized Representative:
James M. Chansler, P.E., D.P.A., Chief Operating Officer

Permit No. PSD-FL-386
Project No. 0310047-015-AC
Kennedy Generating Station
Combustion Turbine No. 8
Expires: December 31, 2008

PROJECT AND LOCATION

This permit authorizes the construction of a simple cycle combustion turbine generator with a nominal output of 172 MW at the existing Kennedy Generating Station (SIC No. 4911). The facility is located at 4215 Talleyrand Avenue in Jacksonville, Duval County, Florida.

CONTENTS

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)

Joseph Kahn, Director
Division of Air Resource Management

Date

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. Citation Formats

Appendix B. General Conditions

Appendix C. Common Conditions

Appendix D. Final BACT Determinations and Emissions Standards

Appendix E. NSPS Subpart A, General Provisions

Appendix F. NSPS Provisions, Subparts KKKK for Stationary Combustion Turbines

FACILITY DESCRIPTION

The regulated emissions units at the existing Kennedy Generating Station include: four combustion turbines (CTs): CT Nos. 3, 4, 5 and 7. All of the CTs fire virgin No. 2 distillate oil; in addition, CT No. 7 fires natural gas. There is a distillate oil storage tank farm associated with the CTs.

PROJECT DESCRIPTION

The project is for the addition of one General Electric PG7241(FA) simple cycle combustion turbine generator with a nominal output of 172 MW at the existing facility. The new peaking unit may operate for a total of 3,500 hours per year with natural gas as the primary fuel. The use of low sulfur distillate oil (0.05 % sulfur) as a restricted alternate fuel is allowed for up to 500 hours per year. The unit 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. This project also requires the permanent shutdown of CT Nos. 3, 4, and 5 (EU-003, 004, and 005).

EMISSIONS UNITS

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

EU No.	Emission Unit Description
016	CT No. 8 – 172 MW General Electric PG7241(FA) combustion 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 62-212.400, F.A.C.

NSPS: CT No. 8 is subject to NSPS Subpart KKKK in 40 CFR 60, Standards of Performance for Stationary Combustion Turbines for which Construction is Commenced after February 18, 2005.

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; 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 City of Jacksonville Environmental Resource Management Department, Environmental Quality Division, 117 West Duval Street, Suite 225, Jacksonville, Florida 32202
3. General Conditions: The permittee shall operate under the attached General Conditions listed in Appendix B 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. 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.]
6. 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.]

7. 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.]

8. 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]

9. 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.]

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

EU No.	Emission Unit Description
016	CT No. 8 – 172 MW General Electric PG7241 FA combustion turbine-electrical generator

APPLICABLE STANDARDS AND REGULATIONS

1. Permanent Shutdown: The permittee is required to permanently shutdown existing CT Nos. 3, 4, and 5 (EU-003, 004, and 005) prior to commercial operation of new CT No. 8 (EU-016). *{Permitting Note: Emissions decreases from the shutdown of these units were used in a PSD netting analysis to avoid PSD review on the new CT No. 8 for nitrogen oxides (NO_X) and sulfur dioxide (SO_2).}* [Rule 62-212.400(PSD), F.A.C.]

2. BACT Determinations: CT No. 8 is subject to determinations of the Best Available Control Technology (BACT) for particulate matter (PM/PM_{10}). The project is minor for carbon monoxide (CO), nitrogen oxides (NO_X), sulfur dioxide (SO_2), and volatile organic compounds (VOC). See Appendix D for the final BACT determinations. [Rule 62-212.400(PSD), F.A.C.]

3. NSPS Requirements: The combustion turbine shall comply with the applicable New Source Performance Standards (NSPS) in 40 CFR 60, including: Subpart A (General Provisions) and Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for which Construction is Commenced after February 18, 2005). See Appendix E for the NSPS Subpart A provisions and Appendix F for the NSPS Subpart KKKK provisions. Separate reporting and monitoring may be required by the individual subparts. [Rule 62-204.800(7)(b), F.A.C.; 40 CFR 60, Subparts A and KKKK]

EQUIPMENT DESCRIPTION

4. Combustion Turbine: The permittee is authorized to install, tune, operate, and maintain one General Electric Model PG7241(FA) combustion turbine-electrical generator set with a nominal generating capacity of 172 MW. The combustion turbine will be equipped with a dry low-NO_X (DLN) combustion system, automated combustion turbine control system, and an inlet air filtration system. The combustion turbine will be designed for operation in simple cycle mode and will have dual-fuel capability. [Application No. 0310047-015-AC]

CONTROL TECHNOLOGY

5. 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 combustion turbine when firing natural gas. Prior to the initial emissions performance tests required for the combustion turbine, the DLN combustors and automated combustion 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. 0310047-015-AC]

6. Water Injection Technology: The permittee shall install, operate, and maintain a water injection system to reduce NO_X emissions when firing distillate oil. Prior to the initial emissions performance tests, the water injection system shall be tuned to achieve the permitted NO_X emissions standard. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations or industry standards. [Application No. 0310047-015-AC]

PERFORMANCE REQUIREMENTS

7. Hours of Operation: The new unit shall not operate more than 3,500 hours during any consecutive 12 months. Of this amount, the new unit shall not fire distillate oil for more than 500 hours during any

consecutive 12 months. [Application No. 0310047-015-AC; Rules 62-210.200(PTE) and 62-212.400(12), F.A.C.]

8. Permitted Capacity: The nominal heat input rate to the combustion turbine is 1,804 MMBtu per hour when firing natural gas and 1,989 MMBtu per hour when firing distillate oil based on a compressor inlet air temperature of 59° F, the higher heating value (HHV) of each fuel, and 100% load. Heat input rates will vary depending upon combustion 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(PSD), and 62-210.200(PTE), F.A.C.]

9. Authorized Fuels: The combustion turbine shall fire natural gas as the primary fuel, which shall contain no more than 2 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, the combustion turbine may fire distillate oil containing no more than 0.05% sulfur by weight. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

10. Simple Cycle, Intermittent Operation: The combustion turbine shall operate only in simple cycle mode not to exceed the permitted hours of operation allowed by this permit. This restriction is based on the permittee's request, which formed the basis of the 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(PSD), F.A.C.]

11. 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 combustion turbine, 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.]

EMISSIONS STANDARDS

12. Emission Standards: Emissions from each combustion turbine shall not exceed the following emissions standards.

<table>
<tr><th>Pollutant</th><th>Emission Standard [e]</th><th>Averaging Time</th><th>Compliance Method</th><th>Basis</th></tr>
<tr><td rowspan="2">CO [a] (Gas)</td><td>9.0 ppmvd @ 15% O_2</td><td rowspan="2">3-hour test avg.</td><td rowspan="2">EPA Method 10 Test</td><td rowspan="4">Avoid PSD</td></tr>
<tr><td>32.0 lb/hour</td></tr>
<tr><td rowspan="2">CO [a] (Oil)</td><td>20.0 ppmvd @ 15% O_2</td><td rowspan="2">3-hour test avg.</td><td rowspan="2">EPA Method 10 Test</td></tr>
<tr><td>66.0 lb/hour</td></tr>
<tr><td rowspan="2">NOx [b] (Gas)</td><td>15.0 ppmvd @ 15% O_2</td><td>4 hour rolling average</td><td>CEMS</td><td>Avoid PSD</td></tr>
<tr><td>108.3 lb/hour</td><td>3-hour test avg.</td><td>CEMS and EPA Method 19</td><td>Avoid PSD</td></tr>
</table>

Pollutant	Emission Standard [e]	Averaging Time	Compliance Method	Basis
NO_X [b] (Oil)	42 ppmvd @ 15% O_2	4 hour rolling average	CEMS	Avoid PSD
	335.0 lb/hour	3-hour test avg.	CEMS and EPA Method 19	
PM/PM_{10} [c]	10% Opacity	6-minute block	EPA Method 9 Test	BACT
	Fuel sulfur specifications	N/A	Record Keeping	
SO_2 [d] (Gas)	2 grains S/100 SCF of gas	N/A	Record Keeping	Avoid PSD
SO_2 [d] (Oil)	0.05% sulfur by weight	N/A	Record Keeping	Avoid PSD

a. The permittee shall conduct an initial test to demonstrate compliance with the CO emissions limits for the unit as constructed. Subsequent compliance tests shall be conducted during the year prior to renewing the Title V operating permit.

b. Continuous compliance shall be demonstrated with the 24-hour block NOx emissions limit (ppmvd @ 15% O_2) by data collected from the required continuous emissions monitoring system (CEMS). Compliance with the NO_X emissions limit (lb/hr) shall be demonstrated by converting the NO_X CEMS data collected during the initial CO test by using the applicable F-Factor and EPA Method 19.

c. The fuel sulfur specifications combined with the efficient combustion design and operation of the combustion turbine represents BACT for 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 are approximately 19 lb/hour on natural gas and 45.0 lb/hr on oil.}*

d. The fuel sulfur specifications effectively limit the potential emissions of sulfur dioxide (SO_2) from each combustion turbine. No stack tests are required.

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

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

13. 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.]

TESTING AND MONITORING REQUIREMENTS

14. Continuous Compliance: Continuous compliance with the NOx emissions standard (ppmvd @ 15% O_2) shall be demonstrated with data collected from the required continuous emissions monitoring systems (CEMS). [Rules 62-4.070(3),F.A.C.; 40 CFR 60 Subpart KKKK]

15. 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]

16. 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 Combustion 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 KKKK in 40 CFR 60 (summarized in Appendix E and F of this permit). [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Subpart A, Subpart KKKK, and Appendix A]

17. 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. NOx emissions recorded by the required CEMS shall be reported for each CO and visible emissions test. 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]

18. Testing Prior to Renewal: 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 NOx recorded by the CEMS shall also be reported. [Rules 62-4.070(3), 62-297.310(7)(a) and (b), F.A.C.]

19. 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. 12 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal NSPS, NESHAP, or Acid Rain provision.}

20. Definitions: Startup, shutdown, and malfunction are defined as follows:

   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.

[Rule 62-210.200(Definitions), F.A.C.]

21. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

22. Alternate Visible Emissions Standard: Visible emissions during startup shall not exceed 20% opacity based on a 6-minute averaging period. [Rule 62-210.700(5), F.A.C.]

CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS) REQUIREMENTS

23. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of NO_X from the combustion 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. *NO_X Monitor:* Each NO_X monitor shall be certified pursuant to the specifications of 40 CFR 75 and comply with the applicable requirements of 40 CFR 60 Subpart KKKK. 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.

    b. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where NO_X is 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.]

REPORTING AND RECORD KEEPING REQUIREMENTS

24. Monitoring of Capacity: The permittee shall monitor and record the operating rate of the combustion turbine on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown, and malfunction). 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(PSD), 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 combustion 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(PSD), F.A.C.]

26. Fuel Sulfur Records: The permittee shall monitor fuel sulfur in accordance with 40 CFR 60.4415 as summarized in Appendix F of this permit. [40 CFR 60, Subpart A, Subpart KKKK]

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 of this permit. [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 provide written notification to the Compliance Authority of the schedule (by letter, email, or fax). 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. NSPS Emissions Reports

    a. 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 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines) that occurred during the previous semiannual period to the Compliance Authority.

    b. *Malfunction Notification*: For each malfunction resulting in excess emissions, 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.

    [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 60.4395]

SECTION 4. APPENDICES

CONTENTS

CITATION FORMATS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

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

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located

"2222" represents the specific facility ID number

"001"identifies the specific permit project

"AC" identifies the permit as an air construction permit

"AF" identifies the permit as a minor federally enforceable state operation permit

"AO" identifies the permit as a minor source air operation permit

"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality

"FL" means that the permit was issued by the State of Florida

"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

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

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

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

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) and 62-210.200, 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.]

TESTING REQUIREMENTS

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. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. 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. [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. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.
    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.

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

14. Determination of Process Variables

    a. *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
    b. *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

    [Rule 62-297.310(5), F.A.C.]

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.

16. Test Notification: 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. [Rule 62-297.310(7)(a)9, F.A.C.]

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

18. Test Reports: 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. 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. 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.

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

RECORDS AND REPORTS

19. <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. [Rule 62-213.440(1)(b)2, F.A.C.]

20. <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(3), F.A.C.]

FINAL BACT DETERMINATIONS AND EMISSIONS SUMMARY

Combustion Turbine No. 8

The project authorizes the installation of a simple cycle combustion turbine designed and constructed with dry low-NO_X (DLN) burner technology and water injection for the control of NO_X emissions. Operation will be limited to no more than 3500 hours per year with no more than 500 hours from firing distillate oil. The unit is subject to the federal New Source Performance Standards for new combustion turbines in Subpart KKKK of Title 40, Part 60, of the Code of Federal Regulations (CFR), which establishes emissions standards for nitrogen oxides (NO_X) and sulfur dioxide (SO_2).

The project is subject to preconstruction review for particulate matter (PM/PM_{10}) in accordance with Rule 62-212.400 of the Florida Administrative Code (F.A.C.) for the Prevention of Significant Deterioration (PSD) of Air Quality, which requires a determination of the Best Available Control Technology (BACT) and an ambient air quality analysis. The project includes the permanent shutdown of existing CT Nos. 3, 4, and 5 (EU-003, 004, and 005) prior to commercial operation of new CT No. 8 (EU-016). Emissions decreases from the shutdown of these units were used in a netting analysis to avoid PSD preconstruction review for new CT No. 8 for nitrogen oxides (NO_X) and sulfur dioxide (SO_2). The project is also minor for carbon monoxide (CO) and volatile organic compounds (VOC). The following table summarizes the Department's BACT determination and emissions standards for this project.

Pollutant	Emission Standard [e]	Averaging Time	Compliance Method	Basis
CO [a] (Gas)	9.0 ppmvd @ 15% O_2 32.0 lb/hour	3-hour test avg.	EPA Method 10 Test	Avoid PSD
CO [a] (Oil)	20.0 ppmvd @ 15% O_2 66.0 lb/hour	3-hour test avg.	EPA Method 10 Test	Avoid PSD
NOx [b] (Gas)	15.0 ppmvd @ 15% O_2	4 hour rolling average	CEMS	Avoid PSD
	108.3 lb/hour	3-hour test avg.	CEMS and EPA Method 19	Avoid PSD
NO_X [b] (Oil)	42 ppmvd @ 15% O_2	4 hour rolling average	CEMS	Avoid PSD
	335.0 lb/hour	3-hour test avg.	CEMS and EPA Method 19	
PM/PM_{10} [c]	10% Opacity	6-minute block	EPA METHOD 9 TEST	BACT
	Fuel sulfur specifications	N/A	RECORD KEEPING	
SO_2 [d] (Gas)	2 grains S/100 SCF of gas	N/A	Record Keeping	Avoid PSD
SO_2 [d] (Oil)	0.05% sulfur by weight	N/A	Record Keeping	Avoid PSD

a. The permittee shall conduct an initial test to demonstrate compliance with the CO emissions limits for the unit as constructed. Subsequent compliance tests shall be conducted during the year prior to renewing the Title V operating permit.

b. Continuous compliance shall be demonstrated with the 24-hour block NOx emissions limit (ppmvd @ 15% O_2) by data collected from the required continuous emissions monitoring system (CEMS). Compliance with the NO_X emissions limit (lb/hr) shall be demonstrated by converting the NO_X CEMS data collected during the initial CO test by using the applicable F-Factor and EPA Method 19.

c. The fuel sulfur specifications combined with the efficient combustion design and operation of the combustion turbine represents BACT for 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 are approximately 19 lb/hour on natural gas and 45.0 lb/hr on oil.}*

d. The fuel sulfur specifications effectively limit the potential emissions of sulfur dioxide (SO_2) from each combustion turbine. No stack tests are required.

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

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

NSPS SUBPART A, GENERAL PROVISIONS

Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

NEW SOURCE PERFORMANCE STANDARDS (NSPS)

On July 6, 2006, EPA published the final NSPS Subpart KKKK (40 CFR 60) provisions for combustion turbines in the Federal Register. Although not yet adopted by Rule 62-204.800(8), F.A.C., the combustion turbine shall comply with the applicable federal requirements.

NSPS SUBPART KKKK, 40 CFR 60 – STATIONARY COMBUSTION TURBINES

Provisions that do not apply to this project have been omitted. Numbering remains consistent with the NSPS Subpart.

Sec. 60.4300 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

Sec. 60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part.

Sec. 60.4310 What types of operations are exempt from these standards of performance?

(a) Emergency combustion turbines, as defined in Sec. 60.4420(i), are exempt from the nitrogen oxides (NOX) emission limits in Sec. 60.4320.

(b) Stationary combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements are exempt from the NOx emission limits in Sec. 60.4320 on a case-by-case basis as determined by the Administrator.

(c) Stationary combustion turbines at integrated gasification combined cycle electric utility steam generating units that are subject to subpart Da of this part are exempt from this subpart.

(d) Combustion turbine test cells/stands are exempt from this subpart.

Sec. 60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NOx) and sulfur dioxide (SO_2).

Sec. 60.4320 What emission limits must I meet for nitrogen oxides (NOx)?

(a) You must meet the emission limits for NOx specified in Table 1 to this subpart.

(b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NOx.

Sec. 60.4325 What emission limits must I meet for NOx if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

You must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

Sec. 60.4330 What emission limits must I meet for sulfur dioxide (SO_2)?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1) or (a)(2) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

(b) If your turbine is located in a noncontinental area or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit, you must comply with one or the other of the following conditions:

(1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 780 ng/J (6.2 lb/MWh) gross output, or

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

Sec. 60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

(1) Determine compliance with the applicable NOx emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

(2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

Sec. 60.4335 How do I demonstrate compliance for NOx if I use water or steam injection?

(a) If you are using water or steam injection to control NOx emissions, you must 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 when burning a fuel that requires water or steam injection for compliance.

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NOx monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NOx emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and

(2) For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and

(3) For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and

(4) For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and

operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h).

Sec. 60.4340 How do I demonstrate continuous compliance for NOx if I do not use water or steam injection?

(a) If you are not using water or steam injection to control NOx emissions, you must perform annual performance tests in accordance with Sec. 60.4400 to demonstrate continuous compliance. If the NOx emission result from the performance test is less than or equal to 75 percent of the NOx emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NOx emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in Sec. 60.4335(b) and Sec. 60.4345, or

(2) Continuous parameter monitoring as follows:

(i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NOx formation characteristics, and you must monitor these parameters continuously.

(ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NOx mode.

(iii) For any turbine that uses SCR to reduce NOx emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NOx emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in Sec. 75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in Sec. 75.19(c)(1)(iv)(H).

Sec. 60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

If the option to use a NOx CEMS is chosen:

(a) Each NOx diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NOx diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

(b) As specified in Sec. 60.13(e)(2), during each full unit operating hour, both the NOx monitor and the diluent 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 with each monitor 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 for each monitor to validate the NOx emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

Sec. 60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in Sec. 60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in Sec. 60.4345(b), is obtained for both NOx and diluent monitors, the data acquisition and handling system must calculate and record the hourly NOx emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NOx concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NOx diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under Sec. 60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NOx emission rates, in units of the emission standards under Sec. 60.4320, using either ppm for units complying with the concentration limit. or the following equation for units complying with the output based standard:

(1) For simple-cycle operation:

$$E = \frac{(NO_X)_h * (HI)_h}{P} \qquad \text{(Eq. 1)}$$

Where:

E = hourly NOx emission rate, in lb/MWh,

$(NOx)_h$ = hourly NOx emission rate, in lb/MMBtu,

$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), e.g., calculated using Equation D-15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)_t + (Pe)_c + Ps + Po \qquad \text{(Eq. 2)}$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

$(Pe)_t$ = electrical or mechanical energy output of the combustion turbine in MW,

$(Pe)_c$ = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \quad \text{(Eq. 3)}$$

Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 x 106 = conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

(3) For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_X)_m}{BL * AL} \quad \text{(Eq. 4)}$$

Where:

E = NOx emission rate in lb/MWh,

$(NOX)_m$ = NOx emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

(g) For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in Sec. 60.4380(b)(1).

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in Sec. 60.4380(b)(1).

Sec. 60.4355 How do I establish and document a proper parameter monitoring plan?

(a) The steam or water to fuel ratio or other parameters that are continuously monitored as described in Sec. Sec. 60.4335 and 60.4340 must be monitored during the performance test required under Sec. 60.8, to establish acceptable values and ranges. You 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. You must 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 must:

(1) Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NOx emission controls,

(2) Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,

(3) Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),

(4) Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,

(5) Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and

(6) Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:

(i) All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.

(ii) Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

(b) For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in Sec. 75.19 or the NOx emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in Sec. 75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

Sec. 60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in Sec. 60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in Sec. 60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see Sec. 60.17), which measure the major sulfur compounds, may be used.

Sec. 60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. 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.

Sec. 60.4370 How often must I determine the sulfur content of the fuel?

The frequency of determining the sulfur content of the fuel must be as follows:

(a) 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).

(b) Gaseous fuel. If you elect not to demonstrate sulfur content using options in Sec. 60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) Custom schedules. Notwithstanding the requirements of paragraph (b) 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 (c)(1) and (c)(2) 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 Sec. 60.4330.

(1) The two custom sulfur monitoring schedules set forth in paragraphs (c)(1)(i) through (iv) and in paragraph (c)(2) of this section are acceptable, without prior Administrative approval:

(i) 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 (c)(1)(ii), (iii), or (iv) of this section, as applicable.

(ii) If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, 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 greater than half but less than the applicable limit, follow the procedures in paragraph (c)(1)(iii) of this section. If any measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section.

(iii) If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:

(A) Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(B) of this section.

(B) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, follow the procedures in paragraph (c)(1)(iii)(C) of this section.

(C) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (c)(1)(iv) of this section. Otherwise, continue to monitor at this frequency.

(iv) If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (c)(1)(i) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (c)(1)(ii) or (iii) of this section shall be followed.

(2) 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:

(i) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(ii) 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 half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals.

(iii) If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iii) of this section.

(iv) If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (c)(1)(iv) of this section.

Sec. 60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with Sec. 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with Sec. 60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

Sec. 60.4380 How are excess emissions and monitor downtime defined for NOx?

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

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

(1) An excess emission is any unit operating hour for which the 4-hour rolling 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 Sec. 60.4320, as established during the performance test required in Sec. 60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NOx control will also be considered an excess emission.

(2) A period of monitor downtime is 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.

(3) Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

(b) For turbines using continuous emission monitoring, as described in Sec. Sec. 60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NOx emission rate exceeds the applicable emission limit in Sec. 60.4320. For the purposes of this subpart, a "4-hour rolling average NOx emission rate" is the arithmetic average of the average NOx emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NOx emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NOx emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NOx emission rate" is the arithmetic average of all hourly NOx emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NOx emissions rates for the preceding 30 unit operating days if a valid NOx emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NOx concentration, CO_2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(c) For turbines required to monitor combustion parameters or parameters that document proper operation of the NOx emission controls:

(1) An excess emission is 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.

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

Sec. 60.4385 How are excess emissions and monitoring downtime defined for SO_2?

If you choose the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) 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 combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must 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 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) 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 ends on the date and hour of the next valid sample.

Sec. 60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?

(a) If you operate an emergency combustion turbine, you are exempt from the NOx limit and must submit an initial report to the Administrator stating your case.

(b) Combustion turbines engaged by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements may be exempted from the NOx limit on a case-by-case basis as determined by the Administrator. You must petition for the exemption.

Sec. 60.4395 When must I submit my reports?

All reports required under Sec. 60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

Sec. 60.4400 How do I conduct the initial and subsequent performance tests, regarding NOx?

(a) You must conduct an initial performance test, as required in Sec. 60.8. Subsequent NOx performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NOx concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NOx emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P} \qquad \text{(Eq. 5)}$$

Where:

E = NOx emission rate, in lb/MWh

1.194×10^{-7} = conversion constant, in lb/dscf-ppm

$(NOx)_c$ = average NOx concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to Sec. 60.4350(f)(2); or

(ii) Measure the NOx and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NOx emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in Sec. 60.4350(f) to calculate the NOx emission rate in lb/MWh.

(2) Sampling traverse points for NOx and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must 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.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

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

(A) [Reserved], or

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

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

(A) If each of the individual traverse point NOx concentrations is within 10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than 5ppm or 0.5 percent CO_2 (or O_2) from the mean for all traverse points, then you may use three 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 three points must be located along the measurement line that exhibited the highest average NOx concentration during the stratification test; or

(B) For Turbines with a NOx standard greater than 15ppm @ 15%O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NOx concentrations is within 5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than 3ppm or 0.3 percent CO2 (or O2) from the mean for all traverse points; or

(C) For turbines with a NOx standard less than or equal located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NOx concentrations is within 2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than 1ppm or 0.15 percent CO_2 (or O_2) from the mean for all traverse points.

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

(1) If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.

(2) For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NOx emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

(3) If water or steam injection is used to control NOx with no additional post-combustion NOx control and you choose to monitor the steam or water to fuel ratio in accordance with Sec. 60.4335, then that monitoring system must be operated concurrently with each EPA Method 20 or EPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable Sec. 60.4320 NOx emission limit.

(4) Compliance with the applicable emission limit in Sec. 60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NOx emission rate at each tested level meets the applicable emission limit in Sec. 60.4320.

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in Sec. 60.4405) as part of the initial performance test of the affected unit.

(6) The ambient temperature must be greater than 0° F during the performance test.

Sec. 60.4405 How do I perform the initial performance test if I have chosen to install a NOx-diluent CEMS?

If you elect to install and certify a NOX-diluent CEMS under Sec. 60.4345, then the initial performance test required under Sec. 60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0° F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NOx emission limit under Sec. 60.4320 and to provide the required reference method data for the RATA of the CEMS described under Sec. 60.4335.

(d) Compliance with the applicable emission limit in Sec. 60.4320 is achieved if the arithmetic average of all of the NOx emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

Sec. 60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?

If you have chosen to monitor combustion parameters or parameters indicative of proper operation of NOx emission controls in accordance with Sec. 60.4340, the appropriate parameters must 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 Sec. 60.4355.

Sec. 60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

(a) You must conduct an initial performance test, as required in Sec. 60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see Sec. 60.17) for natural gas or ASTM D4177 (incorporated by reference, see Sec. 60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see Sec. 60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see Sec. 60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see Sec. 60.17).

(2) Measure the SO_2 concentration (in parts per million (ppm), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19-10-1981-Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see Sec. 60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO_2 emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \qquad \text{(Eq. 6)}$$

Where:

E = SO_2 emission rate, in lb/MWh

1.664×10^{-7} = conversion constant, in lb/dscf-ppm

$(SO_2)_c$ = average SO_2 concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to Sec. 60.4350(f)(2); or

(3) Measure the SO_2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19-10-1981-Part 10 (incorporated by reference, see Sec. 60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO_2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in Sec. 60.4350(f) to calculate the SO_2 emission rate in lb/MWh.

(b) [Reserved]

Sec. 60.4420 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (General Provisions) of this part.

Combined cycle combustion turbine means any stationary combustion turbine which recovers heat from the combustion turbine exhaust gases to generate steam that is only used to create additional power output in a steam turbine.

Combined heat and power combustion turbine means any stationary combustion turbine which recovers heat from the exhaust gases to heat water or another medium, generate steam for useful purposes other than additional electric generation, or directly uses the heat in the exhaust gases for a useful purpose.

Combustion turbine model means a group of combustion turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Combustion turbine test cell/stand means any apparatus used for testing uninstalled stationary or uninstalled mobile (motive) combustion turbines.

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.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary combustion 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.

Efficiency means the combustion turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output--based on the higher heating value of the fuel.

Emergency combustion turbine means any stationary combustion turbine which operates in an emergency situation. Examples include stationary combustion turbines used to produce power for critical networks or equipment, including power supplied to portions of a facility, when electric power from the local utility is interrupted, or stationary combustion turbines used to pump water in the case of fire or flood, etc. Emergency stationary combustion turbines do not include stationary combustion turbines used as peaking units at electric utilities or stationary combustion turbines at industrial facilities that typically operate at low capacity factors. Emergency combustion turbines may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are required by the manufacturer, the vendor, or the insurance company associated with the turbine. Required testing of such units should be minimized, but there is no time limit on the use of emergency combustion turbines.

Excess emissions means a specified averaging period over which either (1) the NOx emissions are higher than the applicable emission limit in Sec. 60.4320; (2) the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in Sec. 60.4330; 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.

Gross useful output means the gross useful work performed by the stationary combustion turbine system. For units using the mechanical energy directly or generating only electricity, the gross useful work performed is the gross electrical or mechanical output from the turbine/generator set. For combined heat and power units, the gross useful work performed is the gross electrical or mechanical output plus the useful thermal output (i.e., thermal energy delivered to a process).

Heat recovery steam generating unit means a unit where the hot exhaust gases from the combustion turbine are routed in order to extract heat from the gases and generate steam, for use in a steam turbine or other device that utilizes steam. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle electric utility steam generating unit means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No solid coal is directly burned in the unit during operation.

ISO conditions means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, extreme ambient temperature, or low or transient load.

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. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 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.

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, the Northern Mariana Islands, or offshore platforms.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

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

Simple cycle combustion turbine means any stationary combustion turbine which does not recover heat from the combustion turbine exhaust gases to preheat the inlet combustion air to the combustion turbine, or which does not recover heat from the combustion turbine exhaust gases for purposes other than enhancing the performance of the combustion turbine itself.

Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.

Unit operating day means a 24-hour period between 12 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.

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.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at 15 degrees Celsius and 101.325 kilopascals of pressure.

Table 1 to Subpart KKKK of Part 60. Nitrogen Oxide Emission Limits for Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NOX emission standard
New, modified, or reconstructed turbine firing natural gas.	> 850 MMBtu/h...	15 ppm at 15% O_2 or 0.43 lb/MWh of useful output
New, modified, or reconstructed turbine firing fuels other than natural gas.	> 850 MMBtu/h...	42 ppm at 15% O_2 or 1.3 lb/MWh of useful output