Memorandum

Florida Department of Environmental Protection

TO: Trina Vielhauer, Bureau of Air Regulation

THROUGH: Jon Holtom, Title V Section J.H.

FROM: Teresa Heron T.H.

DATE: May 12, 2010

SUBJECT: Draft/Proposed Permit No. 0950137-031-AV
Orlando Utilities Commission, Stanton Energy Center
Title V Air Operation Permit Revision

Attached for your review are the following items:

- Written Notice of Intent to Issue Air Permit;
- Public Notice of Intent to Issue Air Permit;
- Statement of Basis;
- Draft/proposed permit; and,
- P.E. Certification.

The draft/proposed permit revises the Title V permit for the Stanton Energy Center, which is located in Orange County, Florida. The Statement of Basis provides a summary of the project and the rationale for issuance. The P.E. certification briefly summarizes the proposed project.

The application was received on March 3rd. An RAI letter was not sent and the application was deemed complete. Day 90 is June 1st. There is no ongoing/open enforcement case for this facility, according to the Central District Office.

I recommend your approval of the attached draft/proposed permit.

Attachments

P.E. CERTIFICATION STATEMENT

PERMITTEE

Orlando Utilities Commission
P. O. Box 3193
Orlando, FL 32802

Permit No. 0950137-031-AV
Facility ID No. 0950137
Stanton Energy Center
Title V Air Operation Permit Revision
Orange County, Florida

PROJECT DESCRIPTION

This project is to revise Title V air operation permit No. 0950137-027-AV for the above referenced facility to incorporate the new Unit B, a 300 MW combined cycle combustion turbine and its auxiliary equipment.

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).*

This review was conducted by Teresa Heron under my responsible supervision.

Jonathan Holtom 5/12/10

Jonathan K. Holtom, P.E. Date
Registration Number: 0052664

Florida Department of Environmental Protection

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

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

Electronic Mail – Received Receipt Requested

Ms. Denise M. Stalls, Vice President Environmental Affairs
Orlando Utilities Commission
P. O. Box 3193
Orlando, Florida 32802

Re: Permit No. 0950137-031-AV
Stanton Energy Center
Title V Permit Revision

Dear Ms. Stalls:

Enclosed is the draft/proposed permit package to revise the Title V air operation permit for the Stanton Energy Center. This facility is located in Orange County at 5100 South Alafaya Trail, Orlando, Florida. The permit package includes the following documents:

- The Statement of Basis, which summarizes the facility, the equipment, the primary rule applicability, and the changes since the last Title V renewal.
- The draft/proposed Title V air operation permit revision, which includes the specific permit 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. The Public Notice of Intent to Issue Title V Air Permit must be published as soon as possible and the proof of publication must be provided to the Department within seven days of the date of publication.

If you have any questions, please contact the Project Engineer, Teresa Heron by telephone at (850) 921-9529 or by email at teresa.heron@dep.state.fl.us .

Sincerely,

Trina L. Vielhauer 5/21/10

Trina L. Vielhauer, Chief — Date
Bureau of Air Regulation

Enclosures
TLV/jkh/th

WRITTEN NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT

In the Matter of an
Application for Title V Air Operation Permit by:

Orlando Utilities Commission
P. O. Box 3193, Orlando, FL 32802

Responsible Official:
Denise Stalls, Vice President Environmental Affairs

Permit No. 0950137-031-AV
Facility ID No. 0950137
Stanton Energy Center
Title V Air Operation Permit Revision
Orange County, Florida

Facility Location: Orlando Utilities Commission operates the existing Stanton Energy Center, which is located in Orange County at 5100 South Alafaya Trail, Orlando, Florida.

Project: The purpose of this project is to revise the Title V air operation permit No. 0950137-027-AV to incorporate the new Unit B, a 300 MW combined cycle combustion turbine and its auxiliary equipment. Details of the project are provided in the application and the enclosed Statement of Basis.

Permitting Authority: Applications for Title V air operation permits for facilities that contain Acid Rain units are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, 62-213 and 62-214 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and a Title V air operation permit is required to operate the facility. The Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida. The Permitting Authority's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at the address indicated above for the Permitting Authority. The complete project file includes the draft/proposed permit, the Statement of Basis, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may view the draft permit by visiting the following website: http://www.dep.state.fl.us/air/emission/apds/default.asp and entering the permit number shown above. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address or phone number listed above.

Notice of Intent to Issue Permit: The Permitting Authority gives notice of its intent to issue a renewed Title V air operation permit to the applicant for the project described above. The applicant has provided reasonable assurance that continued operation of the existing 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, 62-213, 62-214, 62-296 and 62-297, F.A.C. The Permitting Authority will issue a final permit in accordance with the conditions of the draft/proposed permit unless a response received in accordance with the following procedures 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 above address or phone number. Pursuant to Rule 62-110.106(5) and (9), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within 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/proposed Title V air operation permit for a period of 30 days from the date of publication of the Public Notice. Written 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. 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 (FAW). If a public meeting is requested within the 30-day comment period and conducted by the Permitting Authority, any oral and written comments received during the public meeting will also be considered by the Permitting Authority. If timely received written comments or comments received at a public meeting result in a significant change to the draft/proposed permit, the Permitting Authority shall issue a revised draft/proposed permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection. For additional information, contact the Permitting Authority at the above address or phone number.

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 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 14 days of publication of the attached Public Notice or within 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 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 (in a proceeding initiated by another party) 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 when and how each petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; 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.

EPA Review: EPA has agreed to treat the draft/proposed Title V air operation permit as a proposed Title V air operation permit and to perform its 45-day review provided by the law and regulations concurrently with the public comment period. Although EPA's 45-day review period will be performed concurrently with the public comment period, the deadline for submitting a citizen petition to object to the EPA Administrator will be determined as if EPA's 45-day review period is performed after the public comment period has ended. The final Title V air operation permit will be issued after the conclusion of the 45-day EPA review period so long as no adverse comments are received that result in a different decision or significant change of terms or conditions. The status regarding EPA's 45–day review of this project and the deadline for submitting a citizen petition can be found at the following website address: http://www.epa.gov/region4/air/permits/Florida.htm.

Objections: Finally, pursuant to 42 United States Code (U.S.C.) Section 7661d(b)(2), any person may petition the Administrator of the EPA within 60 days of the expiration of the Administrator's 45-day review period as established at 42 U.S.C. Section 7661d(b)(1), to object to the issuance of any Title V air operation permit. Any petition shall be based only on objections to the permit that were raised with reasonable specificity during the 30-day public comment period provided in the Public Notice, unless the petitioner demonstrates to the Administrator of the EPA that it was impracticable to raise such objections within the comment period or unless the grounds for such objection arose after the comment period. Filing of a petition with the Administrator of the EPA does not stay the effective date of any permit properly issued pursuant to the provisions of Chapter 62-213, F.A.C. Petitions filed with the Administrator of EPA must meet the requirements of 42 U.S.C. Section 7661d(b)(2) and must be filed with the Administrator of the EPA at: U.S. EPA, 401 M Street, S.W., Washington, D.C. 20460. For more information regarding EPA review and objections, visit EPA's Region 4 web site at http://www.epa.gov/region4/air/permits/Florida.htm .

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Written Notice of Intent to Issue Title V Air Operation Permit Revision (including the Public Notice, the Statement of Basis, and the Draft/Proposed Permit), or a link to these documents available electronically on a publicly accessible server, was sent by electronic mail with received receipt requested before the close of business on 5/24/10 to the persons listed below.

Ms. Denise Stalls, Vice President Environmental Affairs, Orlando Utilities Commission: dstalls@ouc.com
Mr. David R. Baez, Orlando Utilities Commission: dbaez@ouc.com
Mr. Scott H. Osbourn, P.E., Golder & Associates: sosbourn@golder.com
Ms. Caroline Shine, DEP - Central District Office: caroline.shine@dep.state.fl.us
Ms. Katy Forney, U.S. EPA Region 4: forney.kathleen@epamail.epa.gov
Ms. Ana Oquendo, EPA Region 4: oquendo.ana@epamail.epa.gov
Ms. Barbara Friday, DEP - BAR: barbara.friday@dep.state.fl.us (for posting with U.S. EPA, Region 4)
Ms. Victoria Gibson, DEP - BAR: victoria.gibson@dep.state.fl.us (for reading file)

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.

Barbara J. Friday (Clerk) 5/24/10 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT

Florida Department of Environmental Protection
Division of Air Resource Management, Bureau of Air Regulation
Draft/Proposed Permit No. 0950137-031-AV
Orlando Utilities Commission, Stanton Energy Center
Orange County, Florida

Applicant: The applicant for this project is Orlando Utilities Commission. The applicant's responsible official and mailing address are: Denise M. Stalls, Vice President Environmental Affairs, Stanton Energy Center, P.O. Box 3193, Orlando, FL 32802.

Facility Location: The applicant operates the existing Stanton Energy Center, which is located in Orange County at 5100 South Alafaya Trail in Orlando, Florida.

Project: The applicant applied on March 3, 2010 to the Department for a Title V air operation permit revision to incorporate the new Unit B, a 300 megawatt (MW) combined cycle combustion turbine and its auxiliary equipment. This is a revision of Title V air operation permit No. 0950137-027-AV. The existing facility consists of two fossil fuel fired steam electric generating stations, an auxiliary boiler, two combined-cycle combustion turbines, and solid fuels, fly ash, limestone, gypsum, slag, and bottom ash storage and handling facilities.

Permitting Authority: Applications for Title V air operation permits for facilities that contain Acid Rain units are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, 62-213 and 62-214 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and a Title V air operation permit is required to operate the facility. The Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida. The Permitting Authority's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/488-0114.

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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 at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within 14 days of publication of the Public Notice or receipt of a written notice, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within 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 (in a proceeding initiated by another party) 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 rights will be affected by the agency determination; (c) A statement of when and how the petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; 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.

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Mediation: Mediation is not available for this proceeding.

EPA Review: EPA has agreed to treat the draft/proposed Title V air operation permit as a proposed Title V air operation permit and to perform its 45-day review provided by the law and regulations concurrently with the public comment period. Although EPA's 45-day review period will be performed concurrently with the public comment period, the deadline for submitting a citizen petition to object to the EPA Administrator will be determined as if EPA's 45-day review period is performed after the public comment period has ended. The final Title V air operation permit will be issued after the conclusion of the 45-day EPA review period so long as no adverse comments are received that result in a different decision or significant change of terms or conditions. The status regarding EPA's 45–day review of this project and the deadline for submitting a citizen petition can be found at the following website address: http://www.epa.gov/region4/air/permits/Florida.htm.

(Public Notice to be Published in the Newspaper)

Objections: Finally, pursuant to 42 United States Code (U.S.C.) Section 7661d(b)(2), any person may petition the Administrator of the EPA within 60 days of the expiration of the Administrator's 45-day review period as established at 42 U.S.C. Section 7661d(b)(1), to object to the issuance of any Title V air operation permit. Any petition shall be based only on objections to the permit that were raised with reasonable specificity during the 30-day public comment period provided in the Public Notice, unless the petitioner demonstrates to the Administrator of the EPA that it was impracticable to raise such objections within the comment period or unless the grounds for such objection arose after the comment period. Filing of a petition with the Administrator of the EPA does not stay the effective date of any permit properly issued pursuant to the provisions of Chapter 62-213, F.A.C. Petitions filed with the Administrator of EPA must meet the requirements of 42 U.S.C. Section 7661d(b)(2) and must be filed with the Administrator of the EPA at: U.S. EPA, 401 M Street, S.W., Washington, D.C. 20460. For more information regarding EPA review and objections, visit EPA's Region 4 web site at http://www.epa.gov/region4/air/permits/Florida.htm.

STATEMENT OF BASIS
Orlando Utilities Commission, Stanton Energy Center
Title V Air Operation Permit Revision
Permit No. 0950137-031-AV

APPLICANT

The applicant for this project is Orlando Utilities Commission. The applicant's responsible official and mailing address are: Ms. Denise M. Stalls, Vice President Environmental Affairs, Orlando Utilities Commission, Stanton Energy Center, P. O. Box 3193, Orlando, FL 32802.

PROJECT DESCRIPTION

The purpose of this permitting action is to revise the existing Title V permit by incorporating the new 300 megawatt (MW) combined cycle Unit B and its associated equipment, which began commercial operation on October 27, 2009.

FACILITY DESCRIPTION

The applicant operates the existing Stanton Energy Center, which is located in Orange County at 5100 South Alafaya Trail, Orlando, Florida 32193.

On March 25, 2008, a Prevention of Significant Deterioration (PSD) Permit (PSD-FL-373A) was issued to Orlando Utilities Commission (OUC) for the construction of a new 300 MW combined cycle unit.

The Curtis H. Stanton Energy Center currently consists of the following new units:

- Unit B (Emission Unit 037) is comprised of: a nominal 150 MW natural gas-fueled General Electric 7FA combustion turbine generator (CTG) equipped with evaporative inlet air cooling and power (steam) augmentation equipment; a supplementary-fired heat recovery steam generator (HRSG) with a nominal 531 MMBtu/hr duct burner (DB); a HRSG stack; and a nominal 150 MW steam electric generator (STG).

  Unit B is equipped with Dry Low nitrogen oxide (NO_X) combustors as well as a selective catalytic reduction (SCR) system in order to control NO_X emissions to 2 ppmvd at 15% oxygen (O_2) while firing natural gas. During fuel oil firing, emissions shall be held to 8 parts per million by volume, dry basis (ppmvd), at 15% O_2 using SCR plus water injection. Pipeline quality natural gas, 0.0015% ultra low fuel sulfur oil, and good combustion practices shall be employed to control all pollutants.
- Unit B six-cell mechanical cooling tower (Emission Unit 038) with individual exhaust fans and drift eliminators, and;
- Unit B Nominal 1,000,000 gallons ultra low sulfur diesel (ULSD) fuel oil storage tank (Emission Unit 039).

The existing old units at the site are:

- Fossil fuel fired steam generator (FFSG) No. 1 (Emission Unit 001) consists of a Babcock and Wilcox wall fired dry bottom boiler (Model RB 611) and steam turbine which drives a generator with a nameplate rating of 468 megawatts. FFSG No.1 began commercial operation on May 12, 1987.
- Fossil fuel fired steam generator No. 2 (Emission Unit 002) consists of a Babcock and Wilcox boiler/steam generator (Model RB 621) and steam turbine which drives a generator with a nameplate rating of 468 megawatts. FFSG No. 2 began commercial operation on March 29, 1996.

  Each unit has its own 550 foot exhaust stack and is fired primarily on bituminous coal and secondarily on No. 6 fuel oil and on-specification used oil for startup and flame stabilization. The maximum heat input for each unit is 4,286 MMBtu per hour. Pipeline quality natural gas, as well as landfill gas, is also approved for combustion, although petroleum coke is not approved. Particulate matter emissions generated during the operation of each unit are controlled by a dry electrostatic precipitator (ESP) manufactured by Wheelabrator-Frye Inc. The control efficiency of the ESP is 99.7%. Sulfur dioxide emissions are controlled by flue gas desulfurization equipment manufactured by Combustion Engineering. These units are certified under the Florida Power Siting Act.

Generally speaking, the emission limits for FFSG No. 2 are more stringent than those for FFSG No. 1, as can be seen from the permitted SO_2 and NO_X emission rates stated in the permit. This is due to nearly 9 years of time (1987-1996) which elapsed between the startup of these units, the PSD requirements for each unit were different, reflecting improvements in available control technology in later years.

- A Babcock & Wilcox Model No. FM-2919 Auxiliary Boiler (Emission Unit 003) with a maximum heat input of 83 MMBtu/hour. This auxiliary boiler serves both Unit 1 and 2 boilers/steam generators. This auxiliary boiler is fired primarily with "new oil", which means oil which has been refined from crude oil and has not been used. Only No. 2 fuel oil can be burned in the auxiliary boiler.
- Coal processing and conveying equipment including breakers and crushers; limestone and pebble lime handling equipment (Emission Units 004 to 010). Particulate matter emissions generated are controlled by baghouses in addition to reasonable precautions.
- Fly Ash Silos No. 1 and No. 2 (Emissions Units 011 through 016 and 029) handle fly ash from FFSG Units No. 1 and No. 2 respectively. Fly ash is pneumatically conveyed from the individual electrostatic precipitators to Silos No. 1 and No. 2 and then is gravity fed by tubing into totally enclosed tanker trucks. Particulate matter emissions generated by silo loading and unloading to a tanker truck is controlled by baghouses in addition to reasonable precautions.
- Two nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators (Emission Units 025 and 026) equipped with evaporative coolers on the inlet air system; two supplementary fired heat recovery steam generators (HRSG); and one steam turbine-electrical generator rated at approximately 300 MW. These units commercial start date was April 28, 2003.

  These combustion turbine generators ("2-on-1") have a total nominal capacity of 640 MW and will achieve approximately 700 megawatts during extreme winter peaking conditions. These emission units are equipped with Dry Low NO_X combustors as well as a selective catalytic reduction (SCR) system in order to control NO_X emissions to 3.5 ppmvd at 15% O_2 while firing natural gas. During fuel oil firing, emissions shall be held to 10 ppmvd at 15% O_2 using SCR plus water injection. Stack parameters are the same for both units. Pipeline quality natural gas, 0.05% sulfur oil, and good combustion practices shall be employed to control all pollutants.

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

PROJECT REVIEW

The revisions made as part of this project include the addition of Subsections III. F., G. and H. to reflect the terms and conditions of construction permit No. 0950137-020-AC/PSD-FL-373A. Miscellaneous facility description sections have also been revised to include reference to the new Unit B.

In addition to the incorporation of the new Unit B and its associated equipment, the permit emissions unit numbers (EU No.) for these units were corrected to reflect the ARMS emission unit database sequence.
The following changes were made to the permit document (~~strikethrough~~ indicates deletions and double underline indicates new text):

EU ID NO.	EMISSION UNIT DESCRIPTION
~~030~~ 037	Unit B is comprised of: a nominal 150 MW natural gas-fueled General Electric 7FA CTG equipped with evaporative inlet air cooling and power (steam) augmentation equipment; a supplementary-fired HRSG with a nominal 531 MMBtu/hr DB; a HRSG stack; and a nominal 150 MW STG.
~~031~~ 038	A six-cell mechanical cooling tower with individual exhaust fans and drift eliminators.
~~032~~ 039	One nominal 1,000,000 gallons ULSD fuel oil storage tank.

PRIMARY REGULATORY REQUIREMENTS

Title III: The facility is identified as 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 62-213, Florida Administrative Code (F.A.C.).

PSD: The facility is a Prevention of Significant Deterioration (PSD)-major source of air pollution in accordance with Rule 62-212.400, F.A.C.

NSPS: The facility operates units subject to the New Source Performance Standards (NSPS) of 40 Code of Federal Regulations (CFR) 60.

CAIR: The facility operates units subject to the Clean Air Interstate Rule (CAIR) set forth in Rule 62-296.470, F.A.C.

Siting: The facility operates units that were certified under the Florida Power Plant Siting Act, 403.501-518, F.S., and Chapter 62-17, F.A.C.

CAM: Compliance Assurance Monitoring (CAM) does apply to certain units at the facility.

The FFSG No. 1 and No. 2 are subject to CAM for particulate matter (PM) emissions controlled by an ESP. Because the continuous opacity monitoring system (COMS) is required to be used at the facility (for Phase II Acid Rain Program purposes), it must also be used as part of the CAM plan. A CAM plan is included for the ESP. FFSG No.1 and No. 2 are not subject to CAM for the controlled emissions of sulfur dioxide because the SO_2 CEMS are used as a continuous compliance determination method.

The combined cycle combustion turbines (Emissions Units 025 and 026) and the combined cycle Unit B (Emission Unit 037) are not subject to CAM because the NO_X CEMS is used for continuous compliance determination. Thus no CAM plan is included for these units in this permit.

PROCESSING SCHEDULE AND RELATED DOCUMENTS

Application for a Title V Air Operation Permit Revision received March 3, 2010.

CONCLUSION

This project revises Title V air operation permit No. 0950137-027-AV, which was effective on January 1, 2010 with an expiration date of December 31, 2014. This Title V air operation permit revision is issued under the provisions of Chapter 403, Florida Statues (F.S.), and Chapters 62-4, 62-210, 62-213 and 62-214, F.A.C.

Orlando Utilities Commission
Stanton Energy Center
Facility ID No. 0950137
Orange County

Title V Air Operation Permit Revision

Permit No. 0950137-031-AV
(2nd Revision of Title V Air Operation Permit No. 0950137-027-AV)

<u>Permitting Authority:</u>

State of Florida
Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Title V Section

2600 Blair Stone Road
Mail Station #5505
Tallahassee, Florida 32399-2400

Telephone: (850) 488-0114
Fax: (850) 921-9533

<u>Compliance Authority</u>:

Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, FL 32803-3767

Telephone: (407) 894-7555
Fax: (407) 897-5963

(Draft/Proposed Permit)

PERMITTEE:
Orlando Utilities Commission (OUC)
P. O. Box 3193
Orlando, Florida 32802

Permit No. 0950137-031-AV
Curtis H. Stanton Energy Center
Facility ID No. 0950137
Title V Air Operation Permit Revision

The purpose of this permit is to revise the Title V air operation permit 0950137-027-AV to incorporate the new Unit B combined cycle combustion turbine electric generator and its associated equipment. The existing OUC Curtis H. Stanton Energy Center (the Stanton Plant) is located at 5100 South Alafaya Trail in Orlando, Orange County. The Universal Transverse Mercator (UTM) Coordinates are: Zone 17, 483.6 km East and 3151.1 km North. Latitude is: 28° 29' 17" North; and, Longitude is: 81° 10' 03" West.

The Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213 and 62-214. The above named permittee is hereby authorized to operate the facility in accordance with the terms and conditions of this permit.

0950137-027-AV Effective Date: January 1, 2010
0950137-029-AV Revision Effective Date: April 20, 2010
0950137-031-AV Revision Effective Date: *(Day 55)*
Renewal Application Due Date: May 20, 2014
Expiration Date: December 31, 2014

(Draft/Proposed)

Joseph Kahn, Director
Division of Air Resource Management

JK/tlv/jkh/tmh

Title V Air Operation Permit Revision

Permit No. 0950137-031-AV

Table of Contents

Subsection A. Facility Description.

Orlando Utilities Commission (OUC) operates the Curtis H. Stanton Energy Center, which is an existing power plant (SIC No. 4911). The facility site is located 144 km southeast from the Chassahowitzka National Wildlife Area; the nearest Federal Prevention of Significant Deterioration (PSD) Class I Area. The placard page above indicates the exact geographical coordinates.

This facility consists of two fossil fuel fired steam electric generating stations, emissions unit (E.U.) identification (ID) No. 001 (Unit No. 1) and 002 (Unit No. 2); also, there are storage and handling facilities for solid fuels, fly ash, limestone, gypsum, slag, and bottom ash. Unit No. 1 consists of a Babcock and Wilcox boiler/steam generator (Model RB 611) and steam turbine, which drives a generator with a nameplate rating of 468 megawatts (MW). Unit No. 2 consists of a Babcock and Wilcox boiler/steam generator (Model RB 621) and steam turbine, which drives a generator with a nameplate rating of 468 MW. Each boiler/steam generator is a wall fired dry bottom unit. Unit Nos. 1 and 2 are fired with coal, with No. 6 fuel oil used for startup and flame stabilization. Each unit has their individual stacks. Particulate matter emissions generated during the operation of the unit are controlled by a dry electrostatic precipitator (ESP) manufactured by Wheelabrator-Frye Inc. The control efficiency of the ESP is 99.7%. An auxiliary boiler is located at the facility that serves both boilers and has a maximum heat input of 83 million British thermal units (MMBtu)/hour. The auxiliary boiler is fired with No. 2 distillate fuel oil.

Emission Units 001 and 002 are subject to compliance assurance monitoring (CAM) for particulate matter (PM) emissions controlled by an ESP. Because the continuous opacity monitoring system (COMS) is required to be used at the facility (for Phase II Acid Rain Program purposes), it must also be used as part of the CAM plan. A CAM plan is included for the ESP. See Appendix CAM.

Emission Units 025 and 026 (Stanton Unit A) are nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel and equipped with evaporative coolers on the inlet air system, two supplementary fired heat recovery steam generators (HRSG), each with a 160 ft. stack, and one steam turbine-electrical generator rated at approximately 300 MW. Units 25 and 26 have a total nominal capacity of 640 MW and will achieve approximately 700 MW during extreme winter peaking conditions.

The combustion turbines are equipped with dry low nitrogen oxides (NO_X) combustors as well as selective catalytic reduction (SCR) in order to control NO_X emissions to 3.5 parts per million by volume dry (ppmvd) at 15% oxygen (O_2) while firing natural gas. During fuel oil firing, emissions shall be held to 10 ppmvd at 15% O_2 using SCR plus water injection. Pipeline quality natural gas, 0.05% sulfur, by weight, fuel oil, and good combustion practices shall be employed to control all pollutants.

These emissions units (the combustion turbines) are not subject to continuous assurance monitoring (CAM) because the NO_X continuous emissions monitoring system (CEMS) is used for continuance compliance determination. Thus no CAM plan is included for these units in this permit.

Emission Unit 037 (Stanton Unit B) consists of: one nominal 150 megawatts (MW) General Electric 7241 FA combustion turbine-electrical generator (CTG); a supplementary fired heat recovery steam generator (HRSG) with natural gas fueled duct burners; a nominal 150 MW steam turbine generator (STG); and auxiliary equipment. The unit includes highly automated controls, described as the GE Mark VI Gas Turbine Control System to fulfill all of the gas turbine control requirements.

Unit B is equipped with dry low nitrogen oxides (NO_X) combustors as well as selective catalytic reduction (SCR) in order to control NO_X emissions to 2 parts per million by volume dry (ppmvd) at 15% oxygen (O_2) while firing natural gas. During fuel oil firing, emissions shall be held to 8 ppmvd at 15% O_2 using SCR plus water injection. Pipeline quality natural gas, 0.0015% sulfur, by weight, fuel oil, and good combustion practices shall be employed to control all pollutants.

Unit B is not subject to continuous assurance monitoring (CAM) because the NO_X continuous emissions monitoring system (CEMS) is used for continuance compliance determination. Thus no CAM plan is included for this unit in this permit.

Also included in this permit are miscellaneous unregulated emissions units and insignificant emissions units and/or activities.

Subsection B. Summary of Emissions Units.

EU No.	Brief Description
Regulated Emissions Units	
001	Fossil Fuel Fired Steam Electric Generator No. 1
002	Fossil Fuel Fired Steam Electric Generator No. 2
003	Auxiliary Boiler
004	Coal Transfer Baghouse
005	Coal Crusher Building Baghouse
006	Coal Plant Transfer and Silo Fill Area #1 Baghouse
007	Coal Plant Transfer and Silo Fill Area #2 Baghouse
008	Limestone Day Bin Baghouse
009	Pebble Lime Receiving Hopper Baghouse
010	Coal Reclaim Hopper Baghouse
011	Flyash Exhauster Filter #1 Baghouse
012	Flyash Exhauster Filter #2 Baghouse
013	Flyash Exhauster Filter #3 Baghouse
014	Flyash Exhauster Filter #4 Baghouse
015	Flyash Silo Bin Vent Filter Baghouse
016	Adipic Acid Storage Baghouse
025	Stanton Unit A- Combined-Cycle Combustion Turbine
026	Stanton Unit A- Combined-Cycle Combustion Turbine
028	Distillate Fuel Oil Storage Tank
029	Flyash Silo Bin Vent Filter Baghouse
037	Stanton Unit B - 300 MW Combined Cycle Combustion Turbine
038	Stanton Unit B - Cooling Tower
039	Stanton Unit B - Distillate Fuel Oil Storage Tank
041	500 kW Emergency Generator at the Stanton A Plant Site
Unregulated Emissions Units and Activities	
017	Material Handling
018	Fuel Storage Tanks
019	Water Treatment

020	Unconfined Emissions
021	Surface Coating and Solvent Cleaning
022	General Purpose Engines
023	Helper Cooling Towers
024	Emergency Generators
027	Mechanical Draft Cooling Tower
036	Inline Insertable Dust Collector
040	Natural Draft Cooling Towers

Subsection C. Applicable Regulations.

Based on the Title V Air Operation Renewal application received on March 3, 2010, this facility is a major source of hazardous air pollutants (HAP). Because this facility operates stationary reciprocating internal combustion engines, it is subject to regulation under 40 CFR 63, Subpart ZZZZ – National Emissions Standards For Hazardous Air Pollutants For Stationary Reciprocating Internal Combustion Engines. However, since the engines being operated meet the Subpart ZZZZ definition of "existing units", there are no unit specific applicable requirements that must be met pursuant to this rule at this time. Unit B is potentially subject to 40 CFR 63, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. The applicability of this rule has been stayed for lean premix and diffusion flame gas-fired combustion turbines. The existing facility is a PSD major source of air pollutants in accordance with Rule 62-212.400, F.A.C.

A summary of applicable regulations is shown in the following table.

Regulation	**EU No(s).**
Federal Rule Citations	
40 CFR 60, Subpart A, NSPS General Provisions	001, 002, 025, 026
40 CFR 60, Subpart Da, Standards of Performance for Fossil-Fuel Fired Steam Generators	001, 002
NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800	025, 026
NSPS - 40 CFR 60, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines that Commence Construction after February 18, 2005, adopted and incorporated by reference in Rule 62-204.800	037
40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels	028
40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants	004 through 016 and 029
Federal Acid Rain Program, Phase II	001, 002, 025, 026
40 CFR 75 Acid Rain Monitoring Provisions	
State Rule Citations	
Rule 62-4, F.A.C. (Permitting Requirements)	001, 002, 003, 025, 026 004 through 016 and 029
Rule 62-204, F.A.C. (Ambient Air Quality Requirements, PSD Increments,	

Regulation	**EU No(s).**
and Federal Regulations Adopted by Reference)	028
Rule 62-210, F.A.C. (Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms)	
Rule 62-212, F.A.C. (Preconstruction Review, PSD Review and BACT)	
Rule 62-213, F.A.C. (Title V Air Operation Permits for Major Sources of Air Pollution)	
Rule 62-214, F.A.C. (Requirements For Sources Subject To The Federal Acid Rain Program)	001, 002, 025, 026
Rule 62-296, F.A.C. (Emission Limiting Standards)	001, 002, 003, 025, 026 004 through 016 and 029 028
Rule 62-297, F.A.C. (Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures)	
PSD-FL-084	001, 002, 003
PPS PA 81-14/SA2	01, 002, 003, 025, 026
PSD-FL-313, 0950137-002-AC	025, 026, 028

The specific conditions in this section apply to the following emissions units:

EU No.	Brief Description
025	Stanton Unit A- Combined-Cycle Combustion Turbine
026	Stanton Unit A- Combined-Cycle Combustion Turbine

These emissions units include two nominal 170 MW, General Electric "F" Class (PG7241FA) combustion turbine-electrical generators, fired with pipeline natural gas or diesel fuel oil and equipped with evaporative coolers on the inlet air system, two supplementary fired heat recovery steam generators (HRSG), each with a 160 ft. stack, and one steam turbine-electrical generator rated at approximately 300 MW. Units 25 and 26 have a total nominal capacity of 640 MW and will achieve approximately 700 megawatts during extreme winter peaking conditions.

The combustion turbines are equipped with dry low NO_X combustors and a selective catalytic reduction (SCR) system in order to control NO_X emissions to 3.5 ppmvd at 15% O_2 while firing natural gas. During fuel oil firing, emissions shall be held to 10 ppmvd at 15% O_2 using SCR plus water injection. Pipeline quality natural gas, 0.05% sulfur fuel oil, by weight, and good combustion practices shall be used to control all pollutants.

The combustion turbines are subject to the requirements of Phase II of the federal Acid Rain Program. These units hold ORIS code 55821. Unit 025 commercial start date was April 28, 2003, and Unit 026 commercial start date was April 28, 2003. Stack parameters are the same for both units: stack height is 160 feet, exit diameter is 19 feet, exit temperature is 287 degrees Fahrenheit (F) and volumetric flow rate is 1,280,130 actual cubic feet per minute (acfm).

These emissions units are not subject to compliance assurance monitoring (CAM) because the NO_X CEMS is used for continuance compliance determination. Thus, no CAM plan is included in this permit.

General

D.1. NSPS Requirements. Each combustion turbine (CT) shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

a. Subpart A, General Provisions (see Specific Condition **D.2.**)

b. Subpart GG, Standards of Performance for Stationary Gas Turbines. [See attached Appendix GG.]

[0950137-002-AC, Specific Condition 2.]

D.2. General Provisions. These emission units shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions, including:

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

[0950137-002-AC, Specific Condition 4.]

D.3. Subpart GG. Each emissions unit shall comply with all applicable provisions of 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(8), F.A.C. The Subpart GG requirement to correct test data to International Organization for Standardization (ISO) conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). Compliance determination for BACT standards shall comply with all applicable provisions of 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(8), F.A.C. [0950137-002-AC, Specific Condition 5.]

F. Combined Cycle Combustion Unit B

This section of the permit addresses the following emissions unit.

EU ID NO.	EMISSION UNIT DESCRIPTION
037	Stanton Unit B - 300 MW Combined Cycle Combustion Turbine

Unit B consists of: one nominal 150 megawatts (MW) General Electric 7241 FA combustion turbine-electrical generator (CTG); a supplementary fired heat recovery steam generator (HRSG) with natural gas fueled duct burners (DB); and a nominal 150 MW steam turbine generator (STG) for an overall nominal rating of 300 MW. This unit includes highly automated controls, described as the GE Mark VI Gas Turbine Control System to fulfill all of the gas turbine control requirements. The stack height is 205 feet, exit diameter is 20 feet (+1 foot), stack exit temperature is 262 (gas) and 272 (oil) degrees Fahrenheit (F) and volumetric flow rate is 1,239,934 (gas) and 1,031,061 (oil) actual cubic feet per minute (acfm).

Unit B uses natural gas as the primary fuel, and Ultra Low Sulfur Diesel (ULSD) fuel oil (0.0015% Sulfur) as a backup fuel. Carbon monoxide (CO) and particulate matter ($PM/PM_{10}/PM_{2.5}$) emissions are minimized by the efficient combustion of natural gas and ULSD fuel oil at high temperatures. Emissions of sulfuric acid mist (SAM) and sulfur dioxide (SO_2) are minimized by firing natural gas and ULSD fuel oil. Nitrogen oxide (NO_X) emissions are reduced with dry low-NO_X (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NO_X controls, a selective catalytic reduction (SCR) system further reduces NO_X emissions during combined cycle operation.

Unit B is required to continuously monitor NO_X emissions in accordance with the acid rain provisions. The same CEMS as well as CO CEMS are employed for demonstration of continuous compliance with certain Best Available Control Technology (BACT) determinations. Flue gas oxygen content or carbon dioxide content are monitored as a diluent gas.

Unit B is subject to the requirements of Phase II of the federal Acid Rain Program. This unit holds ORIS code 0564. This emissions unit is not subject to compliance assurance monitoring (CAM) because the NO_X CEMS is used for continuous compliance determination. Thus, no CAM plan is included in this permit for this unit. Unit B began commercial operation on October 27, 2009.

{Permitting Note: This emissions unit and its auxiliary equipment were reviewed under the rules for the Prevention of Significant Deterioration (PSD), Rule 62-212.400, F.A.C. Permit No. 0950137-020-AC/PSD-FL-373A was issued on May 9, 2008. Best Available Control Technology (BACT) determinations were made for nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfuric acid mist (SAM), and sulfur dioxide (SO_2)in accordance with Rule 62-210.200 (Definitions). This unit is also regulated under Acid Rain-Phase II, 40 CFR 60 - NSPS, Subpart KKKK and 40 CFR 63 - NESHAP, Subpart YYYY; Rule 62-212.400 (PSD), F.A.C.}

General

F.1. BACT Requirements. Unit B is subject to BACT requirements for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). [Rule 62-212.400, F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.1]

F.2. NSPS Requirements. Unit B shall comply with all applicable requirements of 40 CFR 60, listed below, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Department determines that compliance with the BACT emissions performance requirements also assures compliance with the NSPS for Subpart KKKK. Some separate reporting and monitoring may be required by these subparts.

a. Subpart A, General Provisions, including:
   (1) 40 CFR 60.7, Notification and Record Keeping
   (2) 40 CFR 60.8, Performance Tests
   (3) 40 CFR 60.11, Compliance with Standards and Maintenance Requirements

(4) 40 CFR 60.12, Circumvention
(5) 40 CFR 60.13, Monitoring Requirements
(6) 40 CFR 60.19, General Notification and Reporting Requirements

b. Subpart KKKK, Standards of Performance for Stationary Gas Turbines: These provisions include standards for combustion gas turbines and duct burners.

[Rule 62-204.800, F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.2]

Equipment

F.3. CTG. The permittee is authorized to tune, operate, and maintain one natural gas-fueled GE Model 7FA CTG with a nominal generating capacity of 150 MW. The CTG is equipped with Dry Low NOx (DLN) combustors, an inlet air filtration system with evaporative coolers, power (steam) augmentation capability and the capability to fire ULSD fuel oil. The unit shall be equipped with the SpeedtronicTM Mark VI (or more recent version) automated gas turbine control system. [Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.3]

F.4. HRSG. The permittee is authorized to operate, and maintain one HRSG with a HRSG exhaust stack. The HRSG shall be designed to recover heat energy from the gas turbine and deliver steam to the steam turbine electrical generator with a nominal generating capacity of 150 MW. The HRSG is equipped with supplemental gas-fired DB having a nominal heat input rate of 531 MMBtu (higher heating value (HHV)). [Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.4]

Control Technology

F.5. DLN Combustion. The permittee shall operate and maintain the GE DLN 2.6 combustion system (or better) to control NO_X emissions from the CTG when firing natural gas. Prior to the initial emissions performance tests required for the gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Rule 62-212.400(BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.5]

F.6. Wet Injection. The permittee shall operate, and maintain a wet injection system (water or steam) to reduce NO_X emissions from the CTG when ULSD fuel oil is fired. Prior to the initial emissions performance tests required for the gas turbine, the wet injection system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Rule 62-212.400(BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.6]

F.7. Selective Catalytic Reduction (SCR) System. The permittee shall, tune, operate, and maintain an SCR system to control NO_X emissions from the gas turbine when firing either natural gas or ULSD fuel oil. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions.
Ammonia Storage: In accordance with 40 CFR 68.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.
[Rule 62-212.400(BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.7]

Performance Restrictions

F.8. Capacity – CTG. The nominal heat input rating excluding steam for power augmentation of the CTG is 1,765 MMBtu per hour when firing natural gas and 1,935 MMBtu per hour when firing ULSD fuel oil based on a compressor inlet air temperature of 70° F, the higher heating value (HHV) of each fuel, and 100% load. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.8]

F.9. Capacity - DB. The nominal heat input rating of the DB located within the HRSG is 531 MMBtu per hour based on the higher heating value (HHV) of natural gas. Only natural gas shall be fired in the DB. [Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.9]

F.10. Hours of Operation. The gas turbine may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified in separate conditions. [Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.10]

F.11. Authorized Fuels. The CTG turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet (gr S/100 SCF) of natural gas. As a restricted alternate fuel, the CTG may fire ULSD fuel oil containing no more than 0.0015% sulfur by weight. The CTG shall fire no more than 1000 hours of ULSD fuel oil, regardless of mode, during any calendar year. [Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.11]

F.12. Methods of Operation. Subject to the restrictions and requirements of this permit, the gas turbine may operate under the following methods of operation.

a. *Combined Cycle Operation.* The CTG/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

b. *Pseudo Simple Cycle Operation.* The CTG/HRSG system may operate in a pseudo simple cycle mode where steam from the HRSG bypasses the steam turbine electrical generator and is dumped directly to the condenser. This is not considered a separate mode of operation with respect to emission limits (i.e. emission limits of combined cycle operation still apply).

c. *Evaporative Cooling.* Evaporative cooling is the passing of gas turbine compressor inlet air through a wetted media, which reduces the inlet air temperature through evaporative cooling. Lower compressor inlet temperatures result in more mass flow rate through the gas turbine with a boost in electrical power production. The emissions performance remains within the normal profile of the gas turbine for the lower compressor inlet temperatures. Evaporative cooling may be implemented at ambient temperatures of 60° F or higher.

d. *Power Augmentation (PA).* PA provides additional direct, shaft-driven electrical power by increasing the mass flow rate through the compressor by the injection of steam. Steam for PA is taken from the HRSG and is introduced into the gas turbine compressor discharge, thus increasing the power produced by the expander portion of the turbine.

e. *DB Firing.* The HRSG system may fire natural gas in the DB to provide additional steam-generated electrical power.

[Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.12]

Emissions Standards

F.13. Emission Standards. Emissions from the CTG/HRSG system shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Annual Stack Tests 3-Run Average		CEMS Block Average
			ppmvd @15% O_2	lb/hr[f]	ppmvd @ 15% O_2
CO[a]	Oil	Combustion Turbine (CTG)	8.0	36.7	8.0, 24-hr
	Gas	CTG Normal	4.1	15.9	
		CTG & Duct Burner (DB)	7.6	37.2	
		CTG Low Load	N/A	N/A	
		CTG & PA with or w/o DB	N/A	N/A	14, 24-hr
	Oil/Gas	All Modes	N/A	N/A	6.0, 12-month
NO_X[b]	Oil	CTG	8.0	60.3	8.0, 24-hr
	Gas	CTG Normal	2.0	12.7	2.0, 24-hr
		CTG & DB	2.0	16.1	
		CTG & PA with or w/o DB	N/A	N/A	
$PM/PM_{10}/PM_{2.5}$[c]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2[d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
Ammonia[e]	Oil/Gas	CTG, All Modes	5.0	N/A	N/A

a. Continuous compliance with the 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the PA mode and all other modes based on the hours of operation for each mode.

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart KKKK or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as nitrogen dioxide (NO_2).

c. The fuel sulfur specifications combined with the efficient combustion design and operation of the gas turbine represents (BACT) for $PM/PM_{10}/PM_{2.5}$ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content as detailed in Specific Condition **F. 31.** Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed Specific Condition **F. 31**.
e. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.
f. The mass emission rate standards are based on a turbine inlet condition of 70 °F, evaporative cooling on, and using the HHV of the fuel. Mass emission rate may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

[Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.13]

Excess Emissions

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. F. 13 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, or Acid Rain programs.}

F.14. Operating Procedures. 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 CTG, DB, HRSG, 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.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.14]

F.15. Definitions.

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. [Rule 62-210.200(245), F.A.C.]
b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(230), F.A.C.]
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(159), F.A.C.]

[Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.15]

F.16. 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.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.16]

F.17. Alternate Visible Emissions Standard. Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.17]

F.18. Excess Emissions Allowed. Excess emissions resulting from startup, shutdown, and documented malfunctions shall be permitted, provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For the CTG/HRSG system, excess NO_X and CO emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

a. *CTG/HRSG System Cold Startup.* For cold startup of the CTG/HRSG system, excess NO_X and CO emissions from the CTG/HRSG system shall not exceed six hours in any 24-hour period. A "cold

startup of the CTG/HRSG system" is defined as startup of the combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.
{Permitting Note: During a cold startup of the steam turbine system, the CTG/HRSG system is brought on line at low load to gradually increase the temperature of the steam turbine generator (STG) and prevent thermal metal fatigue}

b. *CTG/HRSG System Warm Startup.* For warm startup of the CTG/HRSG system, excess NO_X and CO emissions shall not exceed four hours in any 24-hour period. A "warm startup of the CTG/HRSG system" is defined as a startup of the combined cycle system following a shutdown of the steam turbine lasting at least 8 hours and less than 48 hours.

c. *Shutdown.* For shutdown of the combined cycle operation, excess NO_X and CO emissions from the CTG/HRSG system shall not exceed three hours in any 24-hour period.

d. *Fuel Switching.* Excess NO_X and CO emissions due to oil-to-gas fuel switching shall not exceed 1 hour in any 24-hour period.

[Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.18]

F.19. Ammonia Injection. Ammonia injection shall begin as soon as operation of the CTG/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above condition allows excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the CTG/HRSG system including the pollution control equipment. [Rules 62-212.400(BACT) and 62-210.700, F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.19]

F.20. DLN Tuning. CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least 14 days that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail.
[Rule 62-4.070(3), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.20]

Emissions Performance Testing

F.21. Test Methods. Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027 or 320	Procedure for Collection and Analysis of Ammonia in Stationary Source. This is an EPA conditional test method. The minimum detection limit shall be 1 ppm. Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources. The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.21]

F.22. Subsequent Initial Compliance Test Determinations After Major Replacement or Major Repair. The Department may, for good reason, require the permittee to conduct additional stack tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, oxidation catalyst, DLN combustors, etc. When requested, the CTG shall be stack tested to demonstrate compliance with the emission standards for CO, NO_X, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after bringing the unit back on-line. The unit shall be tested when firing natural gas, when using the duct burners, and when firing ULSD fuel oil. For each run during tests for visible emissions and ammonia slip, emissions of CO and NO_X recorded by the CEMS shall also be reported. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate initial compliance with the CO and NO_X standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NO_X mass rate emissions standards. [Rule 62-297.310(7)(a)1, F.A.C.; 40CFR 60.8.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.22]

F.23. Annual Compliance Tests. During each federal fiscal year (October 1st, to September 30th), the CTG shall be tested to demonstrate compliance with the emission standard for visible emissions. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the CO and NO_x standards. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.23]

F.24. Continuous Compliance. The permittee shall demonstrate continuous compliance with the 24-hour and 12-month average CO emissions standards, and with the 24-hour average NO_X emission standard based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter.
[Rule 62-212.400 (BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.24]

F.25. Compliance for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$. In stack compliance testing is not required for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$. Compliance with the limits and control requirements for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$ is based on the recordkeeping required in Specific Condition **F.30** and **F.31**, visible emissions testing and CO continuous monitoring. [Rule 62-212.400 (BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.25]

Continuous Monitoring Requirements

F.26. CEM Systems. The permittee shall calibrate, maintain, and operate CEMS to measure and record the emissions of CO and NO_X from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

a. *CO Monitor.* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A within 60 calendar days of achieving permitted capacity as defined in Rule 62-

297.310(2), F.A.C., but no later than 180 calendar days after initial startup. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

b. *NO_X Monitor.* The NO_X monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.

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

[Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.26]

F.27. CEMS Data Requirements.

a. *Data Collection.* Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted.

b. *Valid Hour.* Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values.

c. *24-hour Block Averages.* A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of all available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR Part 75, Subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]
{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_X emissions depending on the use of alternate methods of operation}

d. *12-month Rolling Averages.* Compliance with the long-term emission limit for CO shall be based on a

12-month rolling average. Each 12-month rolling average shall be the arithmetic average of all valid hourly averages collected during the current calendar month and the previous 11 calendar months.

e. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Specific Condition Nos. F.18 and F.20. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, fuel switches, DLN tuning) may be used for the appropriate exclusion periods. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

f. *Availability.* Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.27]

F.28. Ammonia Monitoring Requirements. In accordance with the manufacturer's specifications, the permittee shall calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system prior to the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate and, as applicable for fuel oil firing, the water-to-fuel ratio, that is consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.28]

Records and Reports

F.29. Monitoring of Capacity. The permittee shall monitor and record the operating rate (in units of MMBtu/hr) of the CTG and HRSG DB system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown, malfunction, and fuel switching). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.29]

F.30. Monthly Operations Summary. By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.30]

F.31. Fuel Sulfur Records. The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

a. *Natural Gas.* Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.

b. *ULSD Fuel Oil.* Compliance with the ULSD fuel oil sulfur limit shall be demonstrated by sampling and analysis of the fuel by the permittee or vendor for sulfur, and reporting the results to the Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor, or from an analysis conducted by the permittee, in accordance with the above methods. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.31]

F.32. Emissions Performance Test Reports. A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A ,Specific Condition A.32].

F.33. Excess Emissions Reporting.

a. *Malfunction Notification.* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

b. *SIP Quarterly Permit Limits Excess Emissions Report.* Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NO_X emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

c. *NSPS Semi-Annual Excess Emissions Reports.* Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions that occurred during the previous semi-annual period to the Compliance Authority.

{Note: If there are no periods of excess emissions as defined in NSPS Subpart KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7 and 60.332(j)(1); and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.33]

F.34. Annual Operating Report. The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the fuel oil storage tank for use in the Annual Operating Report. Annual operating reports shall be submitted to the Compliance Authority by April 1st of each year. [Rule 62-210.370(2), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition A.34]

G. Unit B Cooling Tower

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

ID	Emission Unit Description
038	Cooling Tower – consisting of six cells with six individual exhaust fans

This emissions unit is a six-cell mechanical draft cooling tower equipped with drift eliminators, that serves Unit B. This unit commenced operation on October 27, 2009.

{Permitting Note: This emissions unit was reviewed under the rules for the Prevention of Significant Deterioration (PSD), Rule 62-212.400, F.A.C. This unit is regulated under Rule 62-04.070 (3), and Rule 62-212.400, F.A.C.}

Equipment

G.1. Cooling Tower. The permittee is authorized to operate a 6-cell wet evaporative mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 56,000 gallons per minute; drift eliminators; and a drift rate of no more than 0.0005 percent of the circulating water flow. [Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition B.1]

Emissions and Performance Requirements

G.2. Drift Rate. Within 60 days of commencing commercial operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. [Rule 62-212.400(BACT), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition B.2]

{Permitting Note: This work practice standard is established as BACT for PM/PM_{10}/$PM_{2.5}$ emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 3 tons of PM per year and less than 2 tons of PM_{10} per year. Actual emissions are expected to be lower than these rates.}

H. Unit B Storage Tank

ID	Emission Unit Description
039	One nominal 1 million gallons ultra low sulfur diesel (ULSD) fuel oil storage tank

This emissions unit consists of one nominal 1 million gallon ultra low sulfur diesel (ULSD) fuel oil tank that serves Unit B. This unit commenced operation on October 27, 2009.

{Permitting Note: This emissions unit was reviewed under the rules for the Prevention of Significant Deterioration (PSD), Rule 62-212.400, F.A.C. This unit is regulated under Rule 62-04.070 (3), and Rule 62-212.400, F.A.C.}

NSPS Applicability

H.1. NSPS Subpart Kb Applicability. The distillate fuel oil tank is not subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb. [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition C.1]

Equipment Specifications

H.2. Equipment. The permittee is authorized to operate, and maintain one nominal 1 million gallon distillate fuel oil storage tank designed to provide ULSD fuel oil to Unit B or to other units on the site. [Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition C.2]

Emissions and Performance Requirements

H.3. Hours of Operation. The hours of operation are not restricted (8,760 hours per year). [Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition C.3]

Notification, Reporting and Records

H.4. Oil Tank Records. The permittee shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the storage tank for use in the Annual Operating Report. [Rule 62-4.070(3) F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition C.4]

H.5. Fuel Oil Records. The permittee shall keep readily accessible records showing the maximum true vapor pressure of the stored liquid. The maximum true vapor pressure shall be less than 3.5 kPa. Compliance with this condition may be demonstrated by using the information from the respective manufacturers safety data sheets (MSDS) for the ULSD fuel oil stored in the tanks. [62-4.070(3) F.A.C.; and, Permit No. 0950137-020-AC/PSD-FL-373A, Specific Condition C.5]

Federal Acid Rain Program Provisions

The emissions units listed below are regulated under Acid Rain, Phase II.

Operated by: Orlando Utilities Commission
Plant: Stanton Energy Center
ORIS Code: 0564

E.U. ID #	EPA ID	Brief Description
001	1	Fossil Fuel Fired Steam Generator # 1
002	2	Fossil Fuel Fired Steam Generator # 2
037	B	300 megawatt (MW) Combined Cycle Combustion Turbine – Stanton Unit B

Operated by: Southern Power – Florida, LLC
Plant: Stanton Energy Center
ORIS Code: 55821

E.U. ID #	EPA ID	Brief Description
025	25	Combined-Cycle Combustion Turbine – Stanton Unit A
026	26	Combined-Cycle Combustion Turbine – Stanton Unit A

A.1. The Phase II Acid Rain Part application submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of these Phase II acid rain units must comply with the standard requirements and special provisions set forth in the application(s) listed below:

a. DEP Form No. 62-210.900(1)(a), dated 04/29/09, received 05/21/09.
b. DEP Form No. 62-210.900(1)(a), dated 05/13/09, received 05/21/09.

[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

A.2. Nitrogen oxide (NO_X) requirements for each Acid Rain Phase II unit are as follows:

E.U. ID #	EPA ID	NO_X Limit
001	**1**	The Florida Department of Environmental Protection approves a NO_X compliance plan for this unit. The compliance plan is effective for calendar year 2010 through calendar year 2014. This unit's applicable emission limitation for each year of the plan, is 0.46 lb/MMBtu from 40 CFR 76.7(a)(2) for dry bottom wall-fired boilers. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_X compliance plan and the requirements covering excess emissions.
002	**2**	The Florida Department of Environmental Protection approves a NO_X compliance plan for this unit. The compliance plan is effective for calendar year 2010 through calendar year 2014. This unit's applicable emission limitation for each year of the plan, is 0.46 lb/MMBtu from 40 CFR 76.7(a)(2) for dry bottom wall-fired boilers. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_X compliance plan and the requirements covering excess emissions.

A.3. Sulfur Dioxide (SO_2) Emission Allowances. SO_2 emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal

Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.

a. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.
b. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.
c. Allowances shall be accounted for under the Federal Acid Rain Program.

[Rule 62-213.440(1)(c)1., 2. & 3., F.A.C.]

A.4. Comments, notes, and justifications: None.

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Subpart KKKK--Standards of Performance for Stationary Combustion Turbines

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 (SO2).

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 (SO2)?

(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 SO2 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 SO2/J (0.060 lb SO2/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 SO2 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 SO2/J (0.42 lb SO2/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 (O2) or carbon dioxide (CO2)) 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. Sec. 60.4335(b) and 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 O2 concentration exceeds 19.0 percent O2 (or the hourly average CO2 concentration is less than 1.0 percent CO2), a diluent cap value of 19.0 percent O2 or 1.0 percent CO2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NOX concentrations to 15 percent O2 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:

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

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:

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

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

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

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:

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

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 SO2/J (0.060 lb SO2/MMBtu) heat input for units located in continental areas and 180 ng SO2/J (0.42 lb SO2/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 SO2/J (0.060 lb SO2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO2/J (0.42 lb SO2/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 SO2/J (0.060 lb SO2/MMBtu) heat input for continental areas or 180 ng SO2/J (0.42 lb SO2/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, CO2 or O2 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 SO2?

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:

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

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
Qstd = 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 CO2 (or O2) 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%O2, 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 CO2 (or O2) 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 [deg]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 [deg]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 SO2 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 SO2 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 SO2 emission rate:

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

Where:
E = SO2 emission rate, in lb/MWh
1.664×10^{-7} = conversion constant, in lb/dscf-ppm
(SO2)c = average SO2 concentration for the run, in ppm
Qstd = 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 SO2 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 SO2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in Sec. 60.4350(f) to calculate the SO2 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 New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NOX emission standard
New turbine firing natural gas, electric generating.	≤ 50 MMBtu/h	42 ppm at 15 percent O2 or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O2 or 690 ng/J of useful output (5.5 lb/MWh).
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O2 or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas.	> 850 MMBtu/h	15 ppm at 15 percent O2 or 54 ng/J of useful output (0.43 lb/MWh)
New turbine firing fuels other than natural gas, electric generating.	≤ 50 MMBtu/h	96 ppm at 15 percent O2 or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive.	≤ 50 MMBtu/h	150 ppm at 15 percent O2 or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O2 or 460 ng/J of

natural gas		useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas.	> 850 MMBtu/h	42 ppm at 15 percent O2 or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas.	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O2 or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas.	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O2 or 590 ng/J of useful output (4.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0°F.	≤ 30 MW output	150 ppm at 15 percent O2 or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines located north of the Arctic Circle (latitude 66.5 degrees north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbine operating at temperatures less than 0°F.	> 30 MW output	96 ppm at 15 percent O2 or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine.	All sizes	54 ppm at 15 percent O2 or 110 ng/J of useful output (0.86 lb/MWh).

TABLE H
PERMIT HISTORY

E.U. ID No	Description	Permit No.	Issue Date	Expiration Date	Revised Date(s)	Notes
001	Fossil Fuel Steam Generation Unit 001	PPS PA 81-14 PSD-FL-084	12/15/82		12/24/97	
002	Pulverized Coal Fired Unit No. 002	PPS PA 81-14 PSD-FL-084	12/17/91 12/23/91		12/24/97	
003	Auxiliary Boiler	PPS PA 81-14 PSD-FL-084				
	All of the above	0950137-001-AV	1/01/00	12/31/04		Initial Title V
025 026 028	Combined-Cycle Combustion Turbines Combined-Cycle Combustion Turbines Distillate Fuel Oil Storage Tank	0950137-002-AC PSD-FL-313 PA81-14SA2	9/26/01	12/31/04		New unit construction
025 026	Combined-Cycle Combustion Turbine Combined-Cycle Combustion Turbine	0950137-003-AC PSD-FL-313 PA81-14SA2	5/16/03	5/16/08		
025 026	Combined-Cycle Combustion Turbine Combined-Cycle Combustion Turbine	0950137-004-AC PSD-FL-313 PA81-14SA2	5/16/03	5/16/08		
	All of the above	0950137-005-AV	5/09/04	12/31/04		Title V Revision
All Units	Title V Renewal	0950137-006-AV	1/1/05	12/21/09		Renewal
002	Replacement of the primary superheat tube banks for Unit 2	0950137-008-AC	3/3/05	7/1/05		
001	Replacement of burners in Unit 001	0950137-009-AC	2/9/06	7/31/06		
030	285 megawatt coal-fueled integrated gasification combined cycle (IGCC) unit & auxiliary equipment	0950137-010-AC PSD-FL-373	12/26/06	7/31/10		Not constructed
001, 002	Dibasic acid additive system for the Unit 1 and 2 desulfurization systems, and installation of a neural network-based combustion optimization system on Units 1 and 2	0950137-011-AC	1/10/07	1/10/12		Modification

001	Unit 1 Scrubber Upgrade, Phase 2	0950137-012-AC	2/7/08	12/31/08		Modification
008	Silo baghouse	0950137-013-AV	4/10/07	12/31/09		Administrative Correction
001, 002	Installation of forced oxidation equipment	0950137-014-AC	10/1/07	10/1/12		Modification
001, 002	Installation of low nitrogen oxides (NO_x) burners (LNB) and overfire air (OFA) equipment on Units 001 and 002	0950137-015-AC	2/7/08	4/10/09		Modification
002	Replacement of the secondary superheater tubes on Unit 2.	0950137-019-AC	3/19/08	3/31/09		Modification
037 038 039	300 MW Combined Cycle Combustion Turbine (Unit B) and auxiliary equipment	0950137-020-AC PSD-FL-373A	5/12/08	12/31/11		New unit construction
010	Replacement of the existing above ground coal reclaim hopper baghouse (EU-010) with an inline insertable dust collector (EU-036).	0950137-021-AC	6/3/08	12/31/09		Modification
002	Extension of time to install Continuous Emissions Monitoring System (CEMS) on Unit 002	0950137-022-AC	8/22/08	12/31/08		Modification
001, 002, 025, 026	CAIR – Unit 001, 002, 025, 026	0950137-023-AV	1/28/09	12/31/09		Revision
001, 002	Removal of NO_x Emissions Cap on Unit 001 and 002	0950137-025-AC	9/23/08	9/23/13		Modification
001	Extension of time to install Continuous Emissions Monitoring System (CEMS) on Unit 001	0950137-026-AC	11/24/08	4/1/09		Modification
All units	Title V Permit Renewal	0950137-027-AV	12/29/09	12/31/2014		Renewal
001 002	Test Burn in Coal Units 1 and 2	0950137-028-AC	12/28/2009	6/30/2010		Modification

001 002	NOx Burners Installation for Units 1 and 2	0950137-029-AV				Revision
		0950137-030-AC				Modification
037 - 039	Title V Permit Revision to incorporate Unit B and auxiliary equipment	0950137-031-AV		12/31/2014		Revision

ID Number Changes (for tracking purposes): From: **Facility ID No.** 30ORL480137 To: **Facility ID No.** 0950137

Table 2C, Summary of Compliance Requirements

Orlando Utilities Commission — **Permit No.: 0950137-031-AV**

Stanton Energy Center — **Facility ID No.: 0950137**

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. #037			Unit B Combined-Cycle Combustion Turbine				
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time or Frequency	Frequency Base Date[1]	Min. Compliance Test Time	CMS[2]	See Permit Condition(s)
Nitrogen Oxides	Natural gas (NG)	EPA Method 7E	Annual			Yes	**E.21**
	Fuel oil (FO)					Yes	**E.21**
Carbon Monoxide	NG	EPA Method 10	Annual			Yes	**E.21**
	Fuel oil					Yes	**E.21**
Particulate Matter (all)	NG/FO	Fuel analysis				Yes	**E.21**
Ammonia	NG/FO	EPA 320	Annual				**E.21**
Sulfur dioxide and Sulfuric Acid Mist	NG/FO	Fuel analysis					**E.21**
Visible Emissions	N/A	EPA Method 9	Annual				**E.21**

1 - Frequency base date established for planning purposes only; see guidance memo and Rule 62-297.310, F.A.C.

2 - Continuous Monitoring System.

E.U. # 038	Unit B Cooling Tower						
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time or Frequency	Frequency Base Date[1]	Min. Compliance Test Time	CMS[2]	See Permit Condition(s)
Drift Rate		Certification		N/A			**G.2**

E.U. # 039	Unit B Fuel Oil Storage Tank						
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time or Frequency	Frequency Base Date[1]	Min. Compliance Test Time	CMS[2]	See Permit Condition(s)
Fuel Records	F.O.	MSDS		N/A		No	**H.4**

Table 1C, Summary of Air Pollutant Standards

Orlando Utilities Commission — **Permit No.: 0950137-031-AV**

Stanton Energy Center — **Facility ID No.: 0950137**

E.U. ID Nos. **Brief Description**

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

037	Unit B - Combined-Cycle Combustion Turbine								
			Allowable Emissions			Equivalent Emissions			
Pollutant Name	Fuel(s) *	Hours/ Year *	Standards	lb/hour	TPY	lb/hour **	TPY **	Regulatory Citation(s)	See Permit Condition(s)
Nitrogen Oxides	Natural gas		2 ppmvd (24-hr)					PSD-FL-373A (0950137-020-AC)	**E.13.**
	Fuel oil	1000	8 ppmvd (24-hr)					PSD-FL-373A (0950137-020-AC)	**E.13.**
Carbon Monoxide	Natural gas		8 ppmvd (24-hr)					PSD-FL-373A (0950137-020-AC)	**E.13.**
CTG & PA with or w/o Duct Burner	All fuels		14 ppmvd (24-hr)					PSD-FL-373A (0950137-020-AC)	**E.13.**
	Fuel oil	1000	6 ppmvd (12 month)					PSD-FL-373A (0950137-020-AC)	**E.13.**
Particulate Matter (all) Sulfur dioxide and Sulfuric Acid Mist	Natural gas		2 grains per 100 standard cubic foot					PSD-FL-373A (0950137-020-AC)	**E.13.**
	Fuel oil	1000	.0015% sulfur by weight					PSD-FL-373A (0950137-020-AC)	**E.13.**
Ammonia	All modes		5 ppmvd					PSD-FL-373A (0950137-020-AC)	
Visible Emissions	N/A	8760	10% Opacity					PSD-FL-373A (0950137-020-AC)	**E.13.**

** The "Equivalent Emissions" listed are for informational purposes only.

Friday, Barbara

To: Stalls, Denise M.
Cc: dbaez@ouc.com; sosbourn@golder.com; Shine, Caroline; 'Forney.Kathleen@epamail.epa.gov'; Oquendo.Ana@epamail.epa.gov; Gibson, Victoria; Holtom, Jonathan; Heron, Teresa
Subject: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV
Attachments: 0950137031AVSignedWrittenNoticeofIntent.pdf

Dear Sir/ Madam:

Attached is the official **Written Notice of Intent to Issue Air Permit** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Attention: Teresa Heron

Owner/Company Name: ORLANDO UTILITIES COMMISSION
Facility Name: STANTON ENERGY CENTER
Project Number: 0950137-031-AV
Permit Status: DRAFT/PROPOSED
Permit Activity: PERMIT REVISION
Facility County: ORANGE

Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0950137.031.AV.D_pdf.zip

"The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/emission/apds/default.asp . "

Permit project documents that are addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation.

Barbara Friday
Bureau of Air Regulation
Division of Air Resource Management (DARM)
(850)921-9524

Friday, Barbara

From: Microsoft Exchange
To: 'Stalls, Denise M.'; dbaez@ouc.com
Sent: Monday, May 24, 2010 11:13 AM
Subject: Relayed: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

Delivery to these recipients or distribution lists is complete, but delivery notification was not sent by the destination:

'Stalls, Denise M.'

dbaez@ouc.com

Subject: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

Sent by Microsoft Exchange Server 2007

Friday, Barbara

From: Stalls, Denise M. [DStalls@ouc.com]
Sent: Monday, May 24, 2010 11:13 AM
To: Friday, Barbara
Subject: Out of Office AutoReply: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

I am out of the office with uncertain return date. For Environmental issues please contact Garfield Blair. For Human Resource issues please contact German Romero. I have intermittent access to my emails while out of the office.

Friday, Barbara

From:	Stalls, Denise M. [DStalls@ouc.com]
To:	*Friday, Barbara*
Sent:	Monday, May 24, 2010 11:39 AM
Subject:	Read: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

Your message was read on Monday, May 24, 2010 11:38:55 AM (GMT-05:00) Eastern Time (US & Canada).

Friday, Barbara

From: Stalls, Denise M. [DStalls@ouc.com]
Sent: Monday, May 24, 2010 11:39 AM
To: Friday, Barbara
Subject: Re: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

Received

From: Friday, Barbara <Barbara.Friday@dep.state.fl.us>
To: Stalls, Denise M.
Cc: Baez, David R.; sosbourn@golder.com <sosbourn@golder.com>; Shine, Caroline <Caroline.Shine@dep.state.fl.us>; Forney.Kathleen@epamail.epa.gov <Forney.Kathleen@epamail.epa.gov>; Oquendo.Ana@epamail.epa.gov <Oquendo.Ana@epamail.epa.gov>; Gibson, Victoria <Victoria.Gibson@dep.state.fl.us>; Holtom, Jonathan <Jonathan.Holtom@dep.state.fl.us>; Heron, Teresa <Teresa.Heron@dep.state.fl.us>
Sent: Mon May 24 11:12:14 2010
Subject: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

Dear Sir/ Madam:

Attached is the official **Written Notice of Intent to Issue Air Permit** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Attention: Teresa Heron

Owner/Company Name: ORLANDO UTILITIES COMMISSION
Facility Name: STANTON ENERGY CENTER
Project Number: 0950137-031-AV
Permit Status: DRAFT/PROPOSED
Permit Activity: PERMIT REVISION
Facility County: ORANGE

Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0950137.031.AV.D_pdf.zip

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Barbara Friday
Bureau of Air Regulation
Division of Air Resource Management (DARM)
(850)921-9524

The Department of Environmental Protection values your feedback as a customer. DEP Secretary Michael W. Sole is committed to continuously assessing and improving the level and quality of services provided to you. Please take a few minutes to comment on the quality of service you received. Simply click on this link to the DEP Customer Survey. Thank you in advance for completing the survey.

Friday, Barbara

From: Baez, David R. [DBaez@ouc.com]
Sent: Monday, May 24, 2010 11:13 AM
Subject: Read: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

Your message was read on Monday, May 24, 2010 11:13:28 AM (GMT-05:00) Eastern Time (US & Canada).

Friday, Barbara

From: Mail Delivery System [MAILER-DAEMON@mx1.golder.com]
To: sosbourn@golder.com
Sent: Monday, May 24, 2010 11:12 AM
Subject: Relayed: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

Delivery to these recipients or distribution lists is complete, but delivery notification was not sent by the destination:

sosbourn@golder.com

Subject: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

Friday, Barbara

From: Osbourn, Scott [Scott_Osbourn@golder.com]
To: Friday, Barbara
Sent: Monday, May 24, 2010 11:44 AM
Subject: Read: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

Your message was read on Monday, May 24, 2010 11:44:22 AM (GMT-05:00) Eastern Time (US & Canada).

Friday, Barbara

From: Microsoft Exchange
To: Shine, Caroline; Heron, Teresa
Sent: Monday, May 24, 2010 11:12 AM
Subject: Delivered: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

Your message has been delivered to the following recipients:

Shine, Caroline

Heron, Teresa

Subject: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

Sent by Microsoft Exchange Server 2007

Friday, Barbara

From: Heron, Teresa
To: Friday, Barbara
Sent: Monday, May 24, 2010 11:13 AM
Subject: Read: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

Your message was read on Monday, May 24, 2010 11:13:03 AM (GMT-05:00) Eastern Time (US & Canada).

Friday, Barbara

From: Mail Delivery System [MAILER-DAEMON@mseive01.rtp.epa.gov]
To: Forney.Kathleen@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov
Sent: Monday, May 24, 2010 11:13 AM
Subject: Relayed: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

Delivery to these recipients or distribution lists is complete, but delivery notification was not sent by the destination:

Forney.Kathleen@epamail.epa.gov

Oquendo.Ana@epamail.epa.gov

Subject: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

Friday, Barbara

From: Microsoft Exchange
To: Holtom, Jonathan; Gibson, Victoria
Sent: Monday, May 24, 2010 11:12 AM
Subject: Delivered: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

Your message has been delivered to the following recipients:

Holtom, Jonathan

Gibson, Victoria

Subject: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

Sent by Microsoft Exchange Server 2007

Friday, Barbara

From: Gibson, Victoria
To: Friday, Barbara
Sent: Monday, May 24, 2010 11:26 AM
Subject: Read: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

Your message was read on Monday, May 24, 2010 11:25:40 AM (GMT-05:00) Eastern Time (US & Canada).

Friday, Barbara

From: Holtom, Jonathan
To: Friday, Barbara
Sent: Monday, May 24, 2010 12:29 PM
Subject: Read: ORLANDO UTILITIES COMMISSION - STANTON ENERGY CENTER; 0950137-031-AV

Your message was read on Monday, May 24, 2010 12:28:44 PM (GMT-05:00) Eastern Time (US & Canada).