MEMORANDUM

To: Trina L. Vielhauer

Through: Russell A. Wider raw

From: Tom Cascio TOM

Date: June 2, 2008

Re: PROPOSED Title V Permit Revision No. **1050234-016-AV**
Progress Energy Florida, Inc.
Hines Energy Complex

No comments were received from the applicant, the Environmental Protection Agency, or the public at large concerning the draft permit package.

We recommend that this PROPOSED Title V permit package be forwarded to Elizabeth for posting on the Internet for EPA review.

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

June 5, 2008

Electronically Sent – Received Receipt Requested.

Mr. Martin J. Drango (martin.drango@pgnmail.com)
Plant Manager and Responsible Official
Progress Energy
P.O. Box 14042, HE-44
St. Petersburg, Florida 33733-5150

Re: Title V Air Operation Permit Revision No. **1050234-016-AV**
Hines Energy Complex

Dear Mr. Drango:

One copy of the "PROPOSED PERMIT DETERMINATION" for the Hines Energy Complex, located at 7700 County Road 555, 2.5 miles South of County Road 640, Bartow, Florida, Polk County, is enclosed. This letter is only a courtesy to inform you that the DRAFT permit has become a PROPOSED permit.

An electronic version of this determination has been posted on the Division of Air Resource Management's world wide web site for the United States Environmental Protection Agency (U.S.EPA) Region 4 office's review. The web site address is:

http://www.dep.state.fl.us/air/eproducts/apds/default.asp

Pursuant to Section 403.0872(6), Florida Statutes, if no objection to the PROPOSED permit is made by the U.S.EPA within 45 days, the PROPOSED permit will become a FINAL permit no later than 55 days after the date on which the PROPOSED permit was mailed (posted) to USEPA. If U.S.EPA has an objection to the PROPOSED permit, the FINAL permit will not be issued until the permitting authority receives written notice that the objection is resolved or withdrawn. If you have any questions, please contact Tom Cascio at 850/921-9526.

Sincerely,

Jonathan Holtom

for Trina L. Vielhauer, Chief
Bureau of Air Regulation

Enclosures

Martin J. Drango, Progress Energy: martin.drango@pgnmail.com
Thomas W. Davis, P.E., Environmental Consulting & Technology, Inc.: tdavis@ectinc.com
David Meyer, Progress Energy: dave.meyer@pgnmail.com
Mara Nasca, Southwest District Office: mara.nasca@dep.state.fl.us
Gracy Danois, EPA Region 4: danois.gracy@epa.gov

PROPOSED PERMIT DETERMINATION

PROPOSED Permit No. **1050234-016-AV** **Hines Energy Complex**

I. Public Notice.

An "INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" to Progress Energy, for the Hines Energy Complex, located at 7700 County Road 555, 2.5 miles South of County Road 640, Bartow, Polk County, was clerked on April 22, 2008. The "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" was published in the Lakeland Ledger on April 26, 2008. The DRAFT Title V Air Operation Permit was available for public inspection at the Department of Environmental Protection's Southwest District Office in Temple Terrace and the permitting authority's office in Tallahassee. Proof of publication of the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT" was received on May 5, 2008.

II. Public Comments.

No comments were received from the applicant, the Environmental Protection Agency, or the public at large concerning the draft permit package.

III. Conclusion.

The permitting authority hereby issues PROPOSED Title V Permit Revision No. **1050234-016-AV**, with no changes.

Statement of Basis

Florida Power Corporation d/b/a Progress Energy Florida, Inc.
Hines Energy Complex

Facility ID No. **1050234**
Polk County

Title V Air Operation Permit Revision
Permit Project No. **1050234-016-AV**

Applicable State Regulations:

This Title V Air Operation Permit Revision is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.), as noted in the table below. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Applicable Regulations	E.U. ID No.
Rule 62-4, F.A.C. (Permitting Requirements)	001, 002, 014, 015, 016, 017, 018, 019
Rule 62-204, F.A.C. (Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference)	
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)	
Rule 62-296, F.A.C. (Emission Limiting Standards)	
Rule 62-297, F.A.C. (Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures)	
Federal Acid Rain Program, Phase II	
NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800	
PSD-FL-195 and revisions (A, B & C); PPSA: PA 92-33	001, 002
PSD-FL-296 and revisions (A & B)	014, 015
PSD-FL-330 and revision (A)	016, 017
PSD-FL-342; Power Plant Siting Case No. PA 92-33	018, 019

Facility:

The entire facility has a total generating capacity of approximately 2090 megawatts (MW). This facility is a major source of hazardous air pollutants (HAP). This facility consists of four blocks (1, 2, 3 and 4), each with two combined cycle combustion turbines (CT) with unfired heat recovery steam generators (HRSG), a 99 million British thermal unit per hour (MMBtu/hr) auxiliary boiler, two fuel oil storage tanks, and a relocatable diesel generator that can be located at various Florida Power Corporation power plants, as needed. Emissions from each CT and HRSG combination are vented through a single stack. The combustion turbines may fire fuel oil or natural gas. Emissions are monitored by continuous emissions monitors (CEMS) for each power block.

Power Block 1: Emission Units -001 (CT1A) and -002 (CT1B).

Emission units 001 and 002 each consist of a combined cycle Westinghouse 501FC Combustion Turbine, each with a nominal generator rating of 170 MW and each with a maximum heat input rating of 1,915 MMBtu/hr (higher heating value (HHV)), while firing natural gas, and 2,020 MMBtu/hr (HHV), while firing fuel oil, based on a compressor inlet air temperature of 59 °F, the HHV of each fuel, and 100% load. For the CTs, the primary fuel is natural gas (NG), which is supplemented with No. 2 fuel oil (FO) with a sulfur content not to exceed 0.05%, by weight. Nitrogen oxides (NO_x) emissions are controlled with dry low NO_x burners (DLN) for natural gas firing and wet injection for fuel oil firing, complete with Selective Catalytic Reduction (SCR). Each combustion turbine incorporates an unfired heat recovery steam generator (HRSG). Steam from both HRSGs is delivered to a single steam turbine-electrical generator, which has a generating capacity of 160 MW. The total generating capacity of the "2-on-1" combined cycle unit is approximately 500 MW.

Power Block 2: Emission Units -014 (CT2A) and -015 (CT2B).

Emission units 014 and 015 each consist of a combined cycle Westinghouse 501FD Combustion Turbine, each with a nominal generator rating of 170 MW and each with a maximum heat input rating of 2,048 MMBtu/hr (HHV), while firing natural gas, and 2,155 MMBtu/hr (HHV), while firing fuel oil, based on a compressor inlet air temperature of 59 °F, the HHV of each fuel, and 100% load. For the CTs, the primary fuel is NG, which is supplemented with No. 2 FO with a sulfur content not to exceed 0.05%, by weight. NO_x emissions are controlled with DLN burners for natural gas firing and wet injection for fuel oil firing, complete with SCR. Each combustion turbine incorporates an unfired HRSG. Steam from both HRSGs is delivered to a single steam turbine-electrical generator, which has a generating capacity of 190 MW. The total generating capacity of the "2-on-1" combined cycle unit is approximately 530 MW.

Power Block 3: Emission Units -016 (CT3A) and -017 (CT3B).

Emission units 016 and 017 are each a Siemens Westinghouse 501FD gas turbine-electrical generator set with an automated gas turbine control system and an unfired HRSG. In addition, the project also includes a single steam turbine-electrical generator that serves both gas turbine/HRSG systems. Both of the gas turbine-electrical generator sets have a generating capacity of 170 MW for gas firing. Each gas turbine fires natural gas as the primary fuel and distillate oil as a restricted alternate fuel. Steam from both HRSG units is delivered to a single steam turbine-electrical generator, which has a generating capacity of 190 MW. The total generating capacity of the "2-on-1" combined cycle unit is approximately 530 MW. The maximum heat input rate is based on the HHV of the fuel, which is 2,048 MMBtu/hr (HHV), while firing natural gas, and 2,155 MMBtu/hr (HHV), while firing fuel oil, based on a compressor inlet air temperature of 59 °F, the HHV of each fuel, and 100% load.

The efficient combustion of natural gas and restricted firing of low sulfur distillate oil minimizes the emissions of carbon monoxide (CO), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC). Dry low-NO_x (DLN) combustion technology for gas firing and water injection for oil firing reduce NO_x emissions. A selective catalytic reduction system – in combination with DLN combustion technology for gas firing and a water injection system for oil firing – reduces NO_x emissions. The HRSG units are designed and constructed such that an oxidation catalyst can be readily installed if necessary to achieve compliance with CO emission limitations.

Each HRSG has a stack that is 125 feet tall and 19 feet in diameter. Each stack is equipped with CEMS to measure and record CO and NO_x emissions as well as flue gas oxygen or carbon dioxide content. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change.

Power Block 4: Emission Units -018 (CT4A) and -019 (CT4B).

Emission units 018 and 019 each consist of a General Electric Model 7FA gas turbine-electrical generator set, an automated gas turbine control system, and an unfired HRSG. In addition, the project also includes a single steam turbine-electrical generator that serves both gas turbine/HRSG systems. Each gas turbine fires natural gas as the primary fuel and distillate oil as a restricted alternate fuel.

Both of the gas turbine-electrical generator sets have a generating capacity of 170 MW for gas firing. Exhaust from each gas turbine passes through a separate HRSG unit. Steam from both HRSG units is delivered to the single steam turbine-electrical generator, which has a generating capacity of 190 MW. The total generating capacity of the "2-on-1" combined cycle unit is approximately 530 MW.

The efficient combustion of natural gas and restricted firing of low sulfur distillate oil minimizes the emissions of CO, PM/PM_{10}, SAM, SO_2 and VOC. Dry low-NO_x (DLN) combustion technology for gas firing and water injection for oil firing reduce NO_x emissions. A selective catalytic reduction system – in combination with DLN combustion technology for gas firing and a water injection system for oil firing – reduces NO_x emissions. The HRSG units are designed and constructed such that an oxidation catalyst can be readily installed if necessary to achieve compliance with CO emission limitations. Each HRSG has a stack that is 125 feet tall and 18 feet in diameter. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change.

Miscellaneous

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

Incorporation of Air Construction Permit 1050234-010-AC in the Title V Permit Revision

This revision incorporates the specific conditions of air construction permit 1050234-010-AC/PSD-FL-342 that authorized the installation of Power Block 4 at the facility.

Note: The applicant requested that a specific condition be added in the Power Block 1 section of the permit (i.e., Subsection A of Section III) to address DLN tuning. However, because this change would require an air construction permit to implement, this request is not reflected in this Title V permit revision.

Florida Power Corporation (FPC) d/b/a Progress Energy Florida, Inc.
Hines Energy Complex
Facility ID No. **1050234**
Polk County

Title V Air Operation Permit Revision
PROPOSED Permit Project No. **1050234-016-AV**

<u>Permitting Authority:</u>
State of Florida
Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation

Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114
Fax: 850/921-9533

<u>Compliance Authority:</u>
Department of Environmental Protection
Southwest District Office
13051 N. Telecom Parkway
Temple Terrace, FL 33637-0926
Telephone: 813/632-7600
Fax: 813/744-6084

Title V Air Operation Permit Revision
PROPOSED Permit No. **1050234-016-AV**

Table of Contents

Permittee:	**PROPOSED Permit No.** 1050234-016-AV
FPC d/b/a Progress Energy Florida, Inc.	**Facility ID No.** 1050234
100 Central Avenue, HE44	**SIC Nos.:** 49, 4911
St. Petersburg, Florida 33701-5511	**Project:** Title V Air Operation Permit Revision

The purpose of this permitting action is to revise the facility's Title V Air Operation Permit to incorporate the specific conditions of air construction permit No. 1050234-010-AC for Power Block 4. The existing Hines Energy Complex is located at 7700 County Road 555, 2.5 miles South of County Road 640, Bartow, Polk County. UTM Coordinates are: Zone 17, 414.4 km East and 3073.9 km North. Latitude is: 27° 47' 19" North; and, Longitude is: 81° 52' 10" West.

This Title V Air Operation Permit Revision 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 perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:

Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix TV-6, Title V Conditions version dated 06/23/2006
Appendix SS-1, Stack Sampling Facilities version dated 10/07/96
Table 297.310-1, Calibration Schedule version dated 10/07/96
Figure 1: Summary Report-Gaseous and Opacity Excess Emissions and Monitoring System Performance
Alternate Sampling Procedure: ASP Number 97-B-01
Phase II Acid Rain Part Application signed by the Designated Representative on 10/1/2004
Appendix GG - NSPS Subpart GG Requirements for Gas Turbines

Effective Date: January 1, 2007
Revision Effective Date:
Renewal Application Due Date: May 20, 2011
Expiration Date: December 31, 2011

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Joseph Kahn, Director
Division of Air Resource Management

JK/tlv/raw/tbc

Section I. Facility Information.

Subsection A. Facility Description.

Power Block 1 consists of two combined cycle combustion turbines (CT) with unfired heat recovery steam generators (HRSG), for a nominal total of 500 megawatts (MW), a 99 million British thermal unit per hour (mmBtu/hr) auxiliary boiler, and a 97,570 barrel fuel oil storage tank. Emissions from each CT and HRSG combination are vented through a single stack.

Power Block 2 consists of two combined cycle combustion turbines with unfired HRSG, and an associated single steam-turbine electrical generator, for a nominal total of 530 MW. Emissions from each CT and HRSG combination are vented through a single stack.

Power Block 3 consists of two combined cycle combustion turbines with unfired HRSG, and an associated single steam-turbine electrical generator, for a nominal total of 530 MW. Emissions from each CT and HRSG combination are vented through a single stack.

Power Block 4 consists of two combined cycle combustion turbines with unfired HRSG, and an associated single steam-turbine electrical generator, for a nominal total of 530 MW. Emissions from each CT and HRSG combination are vented through a single stack.

The entire facility (inclusive of all Power Blocks 1, 2, 3, and 4) has a total generating capacity of approximately 2090 MW.

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

This facility is a major source of hazardous air pollutants (HAP).

Subsection B. Summary of Emissions Unit ID No(s). and Brief Description(s).

E.U. ID No.	Brief Description
001	170 MW Westinghouse 501FC CT1A with unfired HRSG
002	170 MW Westinghouse 501FC CT1B with unfired HRSG
014	170 MW Westinghouse 501FD CT2A with unfired HRSG
015	170 MW Westinghouse 501FD CT2B with unfired HRSG
016	170 MW Westinghouse 501FD CT3A with unfired HRSG
017	170 MW Westinghouse 501FD CT3B with unfired HRSG
018	170 MW General Electric Model 7FA CT4A with unfired HRSG
019	170 MW General Electric Model 7FA CT4B with unfired HRSG
003	Auxiliary Steam Boiler
001 (7775047)	Relocatable diesel generators with a maximum (combined) heat input of 25.74 MMBtu/hour while being fueled by 186.3 gallons of new No. 2 fuel oil per hour with a maximum (combined) rating of 2460 kilowatts. Emissions from the generators are uncontrolled.

Insignificant Emissions Units and/or Activities
{See Appendix I-1}
Unregulated Emissions Units and/or Activities

{see Appendix U-1}

Please reference the Permit No., Facility ID No., and appropriate Emissions Unit(s) ID No(s). on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action.

<u>These documents are provided to the permittee for information purposes only:</u>
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix H-1, Permit History/ID Number Changes

<u>Documents on file with USEPA:</u>
Risk Management Plan submitted to the RMP Reporting Center on June 21, 2004.

<u>These documents are on file with the permitting authority:</u>
Title V Air Operation Permit Revision Application received on February 25, 2008.
DRAFT Title V Air Operation Permit Revision clerked on April 22, 2008.

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. APPENDIX TV-6, TITLE V CONDITIONS, is a part of this permit.
{Permitting note: APPENDIX TV-6, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}

2. Not federally enforceable. General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

3. General Particulate Emission Limiting Standards. General Visible Emissions Standard.
Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than 20 percent opacity. EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C.
[Rules 62-296.320(4)(b)1. & 4., F.A.C.]

4. Prevention of Accidental Releases (Section 112(r) of CAA).
a. As required by Section 112(r)(7)(B)(iii) of the CAA and 40 CFR 68, the owner or operator shall submit an updated Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center.
b. As required under Section 252.941(1)(c), F.S., the owner or operator shall report to the appropriate representative of the Department of Community Affairs (DCA), as established by department rule, within one working day of discovery of an accidental release of a regulated substance from the stationary source, if the owner or operator is required to report the release to the United States Environmental Protection Agency under Section 112(r)(6) of the CAA.
c. The owner or operator shall submit the required annual registration fee to the DCA on or before April 1, in accordance with Part IV, Chapter 252, F.S., and Rule 9G-21, F.A.C.

Any required written reports, notifications, certifications, and data required to be sent to the DCA, should be sent to:

Department of Community Affairs
Division of Emergency Management
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2100
Telephone: 850/413-9921, Fax: 850/488-1739

Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to:

RMP Reporting Center
P.O. Box 1515
Lanham-Seabrook, Maryland 20703-1515
Telephone: 301/429-5018

Any required reports to be sent to the National Response Center, should be sent to:

National Response Center
EPA Office of Solid Waste and Emergency Response
USEPA (5305 W)
401 M Street, SW
Washington, D.C. 20460
Telephone: 1/800/424-8802

Send the required annual registration fee using approved forms made payable to:

Cashier
Department of Community Affairs
State Emergency Response Commission
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2149

[Part IV, Chapter 252, F.S.; and, Rule 9G-21, F.A.C.]

5. Unregulated Emissions Units and/or Activities. Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.
[Rule 62-213.440(1), F.A.C.]

6. Insignificant Emissions Units and/or Activities. Appendix I-1, List of Insignificant Emissions Units and/or Activities, is a part of this permit.
[Rules 62-213.440(1), 62-213.430(6) and 62-4.040(1)(b), F.A.C.]

7. Not federally enforceable. General Pollutant Emission Limiting Standards. Volatile Organic Compounds Emissions or Organic Solvents Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.
[Rule 62-296.320(1)(a), F.A.C.; and, 1050234-001-AV]

8. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include:

- Maintenance of paved areas as needed;
- Regular mowing of grass and care of vegetation;
- Limiting access to plant property by unnecessary vehicles; and,
- Fugitive dust emissions during the construction period shall be minimized by covering or watering dust generation areas.

[Rule 62-296.320(4)(c)2., F.A.C.; PSD-FL-195(A); and, 1050234-001-AV]

9. When appropriate, any recording, monitoring, or reporting requirements that are time-specific shall be in accordance with the effective date of the permit, which defines day one.
[Rule 62-213.440, F.A.C.]

10. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year. {See condition 51., APPENDIX TV-6, TITLE V CONDITIONS}
[Rule 62-214.420(11), F.A.C.]

11. The permittee shall submit all compliance related notifications and reports required of this permit to the Department's Southwest District office.

Department of Environmental Protection
Southwest District Office
13051 N. Telecom Parkway
Temple Terrace, Florida 33637-0926
Telephone: 813/632-7600, Fax: 813/744-6458

12. Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air and EPCRA Enforcement Branch
Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9155, Fax: 404/562-9164

13. Certification by Responsible Official (RO). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Any responsible official who fails to submit any required information or who has submitted incorrect information shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or correct information.
[Rule 62-213.420(4), F.A.C.]

14. FPC vs. PEF. Where previous text referenced "FPC", for Florida Power Corporation, they have been changed to "PEF" to represent Progress Energy Florida, Inc. FPC is doing business as PEF.

Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description for Power Block 1
001	170 MW Westinghouse 501FC CT1A with unfired HRSG
002	170 MW Westinghouse 501FC CT1B with unfired HRSG

Emission units 001 and 002 each consist of a combined cycle Westinghouse 501FC Combustion Turbine, each with a nominal generator rating of 170 MW and each with a maximum heat input rating of 1,915 MMBtu/hr (HHV), while firing natural gas, and 2,020 MMBtu/hr (HHV), while firing fuel oil, based on a compressor inlet air temperature of 59 °F, the HHV of each fuel, and 100% load. NO_x emissions are controlled with dry low NO_x burners (DLN) and/or Selective Catalytic Reduction (SCR) for natural gas firing and wet injection for fuel oil firing. Each combustion turbine incorporates an unfired heat recovery steam generator (HRSG). Steam from both HRSGs is delivered to a single steam turbine-electrical generator, which has a generating capacity of 160 MW. The total generating capacity of the "2-on-1" combined cycle unit is approximately 500 MW.

{Permitting notes: These emissions units are regulated under Acid Rain, Phase II; NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800, F.A.C.; Rule 212.400(5), F.A.C., Prevention of Significant Deterioration (PSD); PSD-FL-195 and revisions (A, B &C); PPSA: PA 92-33; and, Rule 62-212.400(6), F.A.C.}

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

A.0. Appendix GG - NSPS Subpart GG Requirements for Gas Turbines is a part of the permit and Power Block 1 must comply with it.
[1050234-015-AC/PSD-FL-195(D)]

A.1. Permitted Capacity. At an ambient temperature of 59 °F, each combustion turbine shall not exceed 1,915 MMBtu/hr (HHV), while firing natural gas, or 2,020 MMBtu/hr (HHV), while firing fuel oil. See Attachment G-1 for a plot of heat input versus temperature.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, 1050234-003-AC/PSD-FL-195(C)]

A.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **H.4.**

A.3. Methods of Operation - Fuels. Only natural gas, having a maximum sulfur content of 1 grain per 100 cf of natural gas, or low sulfur fuel oil having a maximum sulfur content of 0.05%, by weight, shall be fired in each combustion turbine at all times. The maximum allowable fuel oil consumption for the two turbines is 13,762,806 gallons per year, which is equivalent to an aggregate of 1,000 hours per year of operation at full load.
[Rule 62-213.410, F.A.C.]

A.4. Hours of Operation. Each of the combustion turbines in Power Block 1 may operate continuously, i.e., 8,760 hours/year.
[Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

A.5. Emission Limitations.
1. Emissions from the CT, while firing natural gas or low sulfur fuel oil, shall not exceed the following (at 59 °F reference temperature for NO_x emissions) (except during periods of startup, shutdown, malfunction):

			CT Allowables	
Pollutant	**Fuel**	**Basis(g)**	**lbs/hr**	**TPY(b)**
NO_x (a)	Gas	12 ppmvd (h)	73(i)	639
	Oil	42 ppmvd (c)(h)	305	153
VOC (d)	Gas	7 ppmvw	10.4	91
	Oil	10 ppmvw	19.0	5.6
SO_2	Gas(f)		4.7	44
	Oil(f)		94	47
CO	Gas	25 ppmvd	77	675
	Oil	30 ppmvd	93	47
VE	Gas	10 percent opacity		
	Oil	20 percent opacity		
PM/PM_{10}	Gas		15.6	79
	Oil(e)		44.8	21

a. Pollutant emission rates may vary depending on ambient conditions (compressor inlet temperatures) and the CT characteristics. Manufacturer's curves for the NO_x emission rate correction to other temperatures at different loads were provided to the DEP for review and are now a part of this permit (see Appendix G-1). The manufacturer's curves shall be used to establish pollutant emission rates over a range of temperatures for the purpose of compliance determination. Emission limitations in lbs/hr/CT of NO_x are blocked 24-hour averages (midnight to midnight) and are calculated as follows:

NO_x emissions shall be determined continuously by a Continuous Emissions Monitoring System (CEMS). A CEMS operated and maintained in accordance with 40 CFR 75 shall be used. Compliance with the NO_x emissions standards in the above table shall be demonstrated with this CEMS system based on a 24-hour block average. Based on CEMS data at the end of each operating day, new 24-hour average emission rates, both actual and allowable (based on compressor inlet temperatures) are calculated from the arithmetic average of all valid hourly emission rates during the previous 24 operating hours. Valid hourly emission rates shall not include periods of startup (including fuel switching), shutdown, or malfunction as defined in Rule 62-210.200, F.A.C., where emissions exceed the NO_x standard. These excess emission periods shall be reported as required in 40 CFR 60.7(b). A valid hourly emission rate shall be calculated for each hour in which two NO_x and carbon dioxide (or oxygen) concentrations are obtained at least 15 minutes apart. When monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate the 24-hour block average.

b. Annual emission limits (TPY) for natural gas are based on a total of two CTs operating at full load 8,760 hours per year [i.e., NO_x: 73 lbs/hr x 2 CTs x 8,760 hrs/yr x 1 ton/2,000 lbs = 639 TPY]. Annual emission limits (TPY) for fuel oil are based on full load operation for a total of 1,000 hours per year for the two CTs [i.e., NO_x: 305 lbs/hr x 1,000 hrs/yr x 1 ton/ 2,000 lbs = 153 TPY].

c. Fuel oil NO_x emissions are based on full load operation and 15 percent oxygen. For fuel oil firing, NO_x levels of 42 ppmvd @ 15 percent O_2 are based on a fuel bound nitrogen content of zero by the firing of No. 2 fuel oil, a distillate, with a maximum sulfur content of 0.05%, by weight. See Specific Condition **A.6.**

d. Exclusive of background concentrations.

e. PM/PM_{10} emission limitations include sulfuric acid mist.

f. SO_2 emissions are based on a maximum of 1 grain of S/100 cf of natural gas and 0.05 percent sulfur, by weight, in the fuel oil.

g. The values are the computational basis for the lbs/hr numbers, which are the actual emission limitations.

h. At 15 percent O_2, not ISO corrected.

i. Control of nitrogen oxides from each CT while firing natural gas shall be accomplished using dry low NO_x burners (DLN) and SCR. Ammonia slip shall not exceed 10 ppm.

2. The following pollutants were evaluated under preconstruction review for PSD purposes:

POLLUTANT	METHOD OF CONTROL	Basis (b)
Benzene	Natural Gas	BACT
Inorganic Arsenic	No. 2 Fuel Oil (a)	BACT
Beryllium	No. 2 Fuel Oil (a)	BACT
Mercury	No. 2 Fuel Oil (a)	(c)
Pb	No. 2 Fuel Oil (a)	(c)

a. The No. 2 fuel oil shall have a maximum sulfur content of 0.05 percent, by weight.
b. Since these pollutants are inherent constituents in the fuel, the basis for control will be by specifying that only natural gas and No. 2 fuel oil can be fired at the facility.
c. Below PSD significant emission levels.

[1050234-002-AC/PSD-FL-195(B); and, 40 CFR 60.334(i)(1)]

A.6. Oxides of Nitrogen. In addition to the specific NO_x emission limits specified for each turbine, NO_x emissions shall not exceed any of the following limits:
a. Nitrogen oxide emissions, expressed as NO_x shall not exceed:

$$STD = 0.0042 + F$$

where:
STD = allowable NO_x emissions (percent by volume at 15 percent O_2 and on a dry basis).
F = NO_x emission allowance for fuel-bound nitrogen defined by the following table:

Fuel-Bound Nitrogen (% by weight)	F (NO_x % by volume)
$0 < N < 0.015$	0
$0.015 < N < 0.03$	0.04(N-0.015)

where: N = the nitrogen content of the fuel (% by weight).

[1050234-002-AC/PSD-FL-195(B)]

Excess Emissions

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS, NESHAP, or Acid Rain program provision.}

A.7. Excess emissions resulting from startup, shutdown, or malfunction, shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two (2) hours in any 24-hour period except in the event that the steam turbine has been shut down for 8 hours or more. During a cold start-up to combined cycle operation, up to four (4) hours of excess emissions are allowed in a 24-hour period. Cold start-up is defined as a start-up to combined cycle operation following a steam turbine shutdown lasting at least 48 hours. During a warm start up to combined cycle operation, up to three (3) hours of excess emissions are allowed in a 24-hour period. Warm start-up is defined as a startup to combined cycle operation following a steam turbine shutdown lasting at least 8 hours. During fuel switches (oil-to-gas or gas-to-oil), up to two (2) hours of excess emissions per fuel switch per emissions unit are allowed.
[Applicant Request; Vendor Combined Cycle Startup Curves Data; Rule 62-210.700(1), F.A.C.; and, Permit No. PSD-FL-195(D)/Project No. 1050234-015-AC]

Monitoring of Operations

A.8. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
[40 CFR 60.11(d)]

A.9. For each combined cycle unit, the permittee shall install, operate, and maintain a continuous emission monitoring system (CEMS) (in accordance with 40 CFR 60, Appendix F, or 40 CFR 75, whichever is more stringent) or use other DEP approved alternate methods to monitor nitrogen oxides and, if necessary, a diluent gas (CO_2 or O_2). The Federal Acid Rain Program requirements of 40 CFR 75 shall apply when those requirements become effective for the CTs.

1. Each CEMS shall meet performance specifications of 40 CFR 60, Appendix B, or 40 CFR 75, whichever is more stringent.

2. CEMS data shall be recorded and reported in accordance with 40 CFR 60, Appendix A and Subpart GG, or 40 CFR 75, whichever is more stringent. The record shall include periods of start up, shutdown, and malfunction. Compliance with specific condition **A.5.** for NO_x shall be determined by CEMS on a mass emission rate basis (lbs/hr) using EPA Method 19 and hourly averaged heat inputs (MMBtu/hr).

3. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

4. The procedures under 40 CFR 60.13 or 40 CFR 75, whichever is more stringent, shall be followed for installation, evaluation, and operation of all CEMS.

5. For purposes of the reports required under this permit, excess emissions are defined as any calculated average emission rate, as determined pursuant to specific condition **A.7.**, which exceeds the applicable emission limits in specific condition **A.5.**

[1050234-002-AC/PSD-FL-195(B)]

A.10. Tests Required.

a. PM, VE, and CO. Except as provided in specific conditions **A.17.**, **A.18.** and **H.3.**, emission testing for particulate matter emissions, visible emissions, and carbon monoxide emissions shall be performed annually.

b. Volatile Organic Compounds (VOCs). The initial test requirement for VOCs has been satisfied.

[Rules 62-4.070(3), 62-213.440 and 62-297.310(7), F.A.C.]

A.11. The permittee shall monitor sulfur content and nitrogen content of the new No. 2 distillate fuel oil and sulfur content of natural gas. These values may be provided by the vendor and the frequency of determinations of these values shall be as follows:
a. New No. 2 Distillate Fuel Oil. The values, sulfur and nitrogen content, shall be determined on each occasion that fuel is transferred to the storage tanks from any other source. Records of these values shall be kept by the facility for a five year period for regulatory agency inspection purposes.
b. Natural Gas. Pursuant to 40 CFR 60, Subpart GG, a custom fuel monitoring schedule for the determination of these values shall be followed for the natural gas fired at this facility and shall be as follows (See Appendix GG, NSPS Subpart GG Requirements for Gas Turbines):

Custom Fuel Monitoring Schedule for Natural Gas (NG)

1. Monitoring of fuel nitrogen content shall not be required if NG is the only fuel being fired in the gas turbines.
2. Sulfur Monitoring:
(a). Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternative method. These methods are referenced in 40 CFR 60, Subpart GG. The permittee can use these methods or their latest editions.
(b). This custom fuel monitoring schedule shall become effective on May 3, 2001, the date the Initial Title V Permit was issued. Effective the date of this custom schedule, sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333 and the conditions of this permit, then sulfur monitoring shall be conducted once per quarter for six quarters. If monitoring data is

provided by the applicant which demonstrates consistent compliance with the requirements herein the applicant may begin monitoring as per the requirements of 2(c).

(c). If after the monitoring required in item 2(b) above, or herein, the sulfur content of the fuel shows little variability and, calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333 and the conditions of this permit, sample analysis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.

(d). Should any sulfur analysis as required in items 2(b) or 2(c) above indicate noncompliance with 40 CFR 60.333 and the conditions of this permit, the owner or operator shall notify the Department of such excess emissions and the custom schedule shall be reexamined. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

3. If there is a change in fuel supply, the owner or operator must notify the Department of such change for re-examination of this custom schedule. A substantial change in natural gas quality (i.e., sulfur content varying by more than 1 grain/100 standard cubic feet of gas) shall be considered as a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

4. Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of five years, and be available for inspection by personnel of federal, state, and local air pollution control agencies.

[40 CFR 60.334; 40 CFR 60.335; PSD-FL-195(B); Custom Fuel Monitoring Schedule Approved on June 1, 2000; and, 1050234-014-AV]

Test Methods and Procedures

A. 12. Critical Fuel Parameters. The maximum sulfur content of the low sulfur fuel oil shall not exceed 0.05 percent, by weight. Compliance shall be demonstrated in accordance with the requirements of 40 CFR 60, Subpart GG, or their latest editions, testing for sulfur content of the fuel oil in the storage tanks on each occasion that fuel is transferred to the storage tanks from any other source. Testing for fuel bound nitrogen content per 40 CFR 60, Subpart GG, or their latest editions, and for fuel oil higher heating value, shall also be conducted on the same schedule. See Appendix GG - NSPS Subpart GG Requirements for Gas Turbines.
[40 CFR 60.334; and, 1050234-015-AC/PSD-FL-195(D)]

A.13. Particulate Matter. The test methods for particulate emissions shall be either EPA Method 5 or Method 17, incorporated by reference in Chapter 62-297, F.A.C.
[Rule 62-297.401, F.A.C.; and, 1050234-002-AC/PSD-FL-195(B)]

A.14. Visible Emissions. The test method for visible emissions shall be EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C.
[Rule 62-297.401, F.A.C.; and, 1050234-002-AC/PSD-FL-195(B)]

A.15. Sulfur Dioxide - NSPS. The permittee shall determine compliance with the sulfur standards for distillate oil by using the ASTM reference methods specified in 40 CFR 60, Subpart GG, or their latest editions. See Appendix GG - NSPS Subpart GG Requirements for Gas Turbines.
[40 CFR 60.334; 40 CFR 60.335; Rules 62-297.440 and 62-297.620(2)(d), F.A.C.; PSD-FL-195(B); and, 1050234-015-AC/PSD-FL-195(D)]

A.16. Carbon Monoxide and Volatile Organic Compounds.

a. Carbon Monoxide. The test method for carbon monoxide shall be EPA Method 10, incorporated and adopted by reference in Chapter 62-297, F.A.C.

b. Volatile Organic Compounds (VOCs). The test method for VOCs shall be EPA Method 18 or Method 25A, incorporated and adopted by reference in Chapter 62-297, F.A.C.

[Rule 62-297.401, F.A.C.; and, 1050234-002-AC/PSD-FL-195(B)]

A.17. Frequency of Compliance Tests. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.
[Rule 62-297.310(7)(a)8., F.A.C.]

A.18. Annual emissions compliance testing for particulate matter emissions, carbon monoxide emissions, and visible emissions shall be performed for oil and only if fuel oil is used for more than 400 hours by the emission unit in the previous federal fiscal year.
[1050234-002-AC/PSD-FL-195(B)]

A.19. Other DEP approved methods may be used for compliance testing after prior Departmental approval.
[1050234-002-AC/PSD-FL-195(B)]

A.20. To meet the requirements of 40 CFR 60, Subpart GG, the permittee shall use the methods specified in 40 CFR 60.334 and 40 CFR 60.335 to determine the sulfur content of the fuel being burned. The analysis may be performed by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. See specific conditions **A.11.** and **A.12.** See Appendix GG, NSPS Subpart GG Requirements for Gas Turbines.
[40 CFR 60.334; 40 CFR 60.335; and, 1050234-015-AC/PSD-FL-195(D)]

Continuous Monitoring Requirements

A.21. Oxides of Nitrogen. NO_x emissions shall be determined continuously by a Continuous Emissions Monitoring System (CEMS). A CEMS operated and maintained in accordance with 40 CFR 75 shall be used. Compliance with the NO_x emissions standards in the above table (see specific condition **A.5.**) shall be demonstrated with this CEMS based on a 24-hour block average. Based on CEMS data at the end of each operating day, new 24-hour average emission rates, both actual and allowable (based on compressor inlet temperatures) are calculated from the arithmetic average of all valid hourly emission rates during the previous 24 operating hours. Valid hourly emission rates shall not include periods of startup (including fuel switching), shutdown, or malfunction as defined in Rule 62-210.200(Definitions), F.A.C., where emissions exceed the NO_x standard. These excess emission periods shall be reported as required by 40 CFR 60.7(b). A valid hourly emission rate shall be calculated for each hour in which two (2) NO_x and carbon dioxide (or oxygen) concentrations are obtained at least 15 minutes apart. When monitoring

data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate the 24-hour block average.
[1050234-002-AC/PSD-FL-195(B)]

Recordkeeping and Reporting Requirements

A.22. To determine compliance with the natural gas and fuel oil firing heat input limitation, the permittee shall maintain daily records of natural gas and fuel oil consumption for each turbine, as well as recent records of the heating value for each fuel. All records shall be maintained for a minimum of five years after the date of each record and shall be made available to representatives of the Department upon request.
[Rule 62-4.070(3), F.A.C.; and, 1050234-002-AC/PSD-FL-195(B)]

Miscellaneous Conditions

A.23. The permittee shall have the option of installing duct module(s) suitable for possible future installation of an oxidation catalyst and/or SCR equipment on each combined cycle generating unit. In the event that the module(s) are not installed in the HRSG, the retrofit costs associated with not making provisions for such technology (initially) shall not be considered in any future economic evaluation to justify not installing SCR or an oxidation catalyst.
[1050234-002-AC/PSD-FL-195(B)]

A.24. Units to be constructed or modified in later phases of the project will be reviewed under the supplementary review process of the Power Plant Siting Act. If site construction has not commenced within 18 months of issuance of this certification, then PEF shall obtain from DEP a review and, if necessary, a modification of the BACT determination and allowable emissions for the unit(s) on which construction has not commenced.
[1050234-002-AC/PSD-FL-195(B)]

Common Conditions

A.25. These emissions unit are also subject to specific conditions **H.1.** through **H.22.** contained in **Subsection H. Common Conditions.**

Subsection B. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description
-003	Auxiliary Steam Boiler

Emission unit 003 is a fossil fuel steam boiler rated at 99 MMBtu at 1,050 Btu/cf natural gas (HHV). The boiler provides steam for periods of combustion turbine startup or quick startup out of a short-term shutdown. The boiler has no add-on pollution control equipment. Air pollution emissions are controlled by efficient combustion and firing natural gas.

{Permitting note: The emissions unit is regulated under NSPS - 40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, adopted and incorporated by reference in Rule 62-204.800, F.A.C.}

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. The maximum operation heat input rate for the boiler is as follows:

Unit No.	Fuel Type	MMBtu/hr Heat Input
003	Natural Gas	99

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, 1050234-002-AC/PSD-FL-195(B)]

B.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **H.4.**

B.3. Methods of Operation - (i.e., Fuels). Only natural gas shall be fired in the auxiliary steam boiler at all times.
[1050234-003-AC/PSD-FL-195(C)]

B.4. Hours of Operation. The operation of the auxiliary steam boiler shall be limited to a maximum of 1000 hours per year and only during periods of cold CT startup or quick startup out of a short-term shutdown mode, when no other source of steam is available or during periodic testing.
[PSD-FL-195(A); and, Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

B.5. Nitrogen Oxides (NO_x). NO_x emissions shall not exceed 0.1 lb/MMBtu for natural gas firing based on vendor-certified stack test data for this model of auxiliary boiler.
[1050234-003-AC/PSD-FL-195(C)]

B.6. Sulfur Dioxide. Emissions shall be limited by firing natural gas.
[Rule 62-296.406(2), F.A.C.; and, 1050234-003-AC/PSD-FL-195(C)]

B.7. Visible Emissions. Visible emissions shall not exceed 10 percent opacity while burning natural gas.
[1050234-003-AC/PSD-FL-195(C)]

Excess Emissions

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS, NESHAP, or Acid Rain program provision.}

B.8. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two (2) hours in any 24-hour period unless specifically authorized by the Department for a longer duration.
[Rule 62-210.700(1), F.A.C.]

B.9. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62.210.700(2), F.A.C.]

Test Methods and Procedures

B.10. Visible Emissions.. The test method for visible emissions shall be EPA Method 9, incorporated in Chapter 62-297, F.A.C.
[1050234-003-AC/PSD-FL-195(C); and, Rules 62-213.440 and 62-297.401, F.A.C.]

B.11. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.
2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:
    a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.
    b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.
[Rule 62-297.401, F.A.C.]

B.12. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.

[Rule 62-297.310(7)(a)4., F.A.C.]

B.13. All recorded data shall be maintained on file by the Source for a period of five (5) years.
[Rule 62-213.440, F.A.C.]

B.14. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department's Southwest District office or Southwest District Branch office on the results of each such test.
(b) The required test report shall be filed with the Department's Southwest District office or Southwest District Branch office as soon as practical but no later than 45 days after the last sampling run of each test is completed.

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

B.15. This emissions unit is also subject to specific conditions **H.1** through **H.22.** contained in **Subsection H. Common Conditions.**

Subsection C. Reserved.

Subsection D. This section addresses the following emissions unit(s).

Facility ID No.	E.U. ID No.	Brief Description
7775047	-001	Relocatable diesel generator(s) with a maximum (combined) heat input of 25.74 MMBtu/hour while being fueled by 186.3 gallons of new No. 2 fuel oil per hour with a maximum (combined) rating of 2,460 kilowatts. Emissions from the generator(s) are uncontrolled.

The generators may be relocated to any of the following facilities:

1. Crystal River Plant, Powerline Road, Red Level, Citrus County.
2. Bartow Plant, Weedon Island, St. Petersburg, Pinellas County.
3. Higgins Plant, Shore Drive, Oldsmar, Pinellas County.
4. Bayboro Plant, 13th Ave. & 2nd St. South, St. Petersburg, Pinellas County.
5. Wildwood Reclamation Facility, State Road 462, 1 mi. east of U.S. 301, Wildwood, Sumter County.
6. Hines Energy Complex, County Road 555, 1 mi. southwest of Homeland, Polk County.
7. Anclote Power Plant, 1729 Baileys Road, Holiday, Pasco County

{Permitting notes: These emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required. Each generator has its own stack. This section of the permit is only applicable when the generator(s) is(are) located at the Hines Energy Complex.}

The following specific conditions apply to the emissions units listed above regardless of location:

__**Essential Potential to Emit (PTE) Parameters**__

D.1. __Permitted Capacity__. The maximum (combined) heat input rate shall not exceed 25.74 million Btu per hour.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

D.2. __Emissions Unit Operating Rate Limitation After Testing__. See specific condition **D.13.**
[Rule 62-297.310(2), F.A.C.]

D.3. __Methods of Operation - Fuels__. Only new No. 2 fuel oil with a maximum sulfur content of 0.5%, by weight, shall be fired in the diesel generator(s).
[Rule 62-213.410, F.A.C.; and, AC09-202080]

D.4. __Hours of Operation__. The hours of operation expressed as "engine-hours" shall not exceed 2,970 hours in any consecutive 12-month period. The total hours of operation expressed as "engine-hours" shall be the summation of the individual hours of operation of each generator.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, AC09-202080]

Emission Limitations and Standards

D.5. Visible Emissions. Visible emissions from each generator shall not be equal to or greater than 20 percent opacity, six minute average.
[Rule 62-296.320(4)(b)1., F.A.C.; and, AC09-202080]

Excess Emissions

D.6. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two (2) hours in any 24-hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

D.7. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

D.8. Fuel Sulfur Analysis. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis provided by the vendor or permittee upon each fuel delivery. See specific conditions **D.3.** and **D.10.**
[Rule 62-213.440, F.A.C.]

Test Methods and Procedures

D.9. The test method for visible emissions shall be EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C.
[Rules 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.]

D.10. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-94, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-95, or the latest edition(s).
[Rules 62-213.440 and 62-297.440, F.A.C.]

D.11. Visible Emissions Testing - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning liquid fuels for less than 400 hours per year.
[Rules 62-297.310(7)(a)4. & 8., F.A.C.]

D.12. After each relocation, each generator shall be tested within 30 days of startup for opacity and the fuel shall be analyzed for the sulfur content. See specific conditions **D.3., D.5.** and **D.8.**
[Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.; and, AO09-205952]

D.13. Operating Rate During Testing. Testing of emissions shall be conducted with the generator(s) operating at 90 to 100 percent of the maximum fuel firing rate for each generator. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity (i.e., at less than 90 percent of the maximum operation rate allowed by the permit); in this case, subsequent emissions unit operations may be limited to 110 percent of the test load until a new test is

conducted, provided however, operations do not exceed 100 percent of the maximum operation rate allowed by the permit. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Failure to submit the actual operating rate may invalidate the test.
[Rules 62-297.310(2), F.A.C.; and, AC09-202080]

Recordkeeping and Reporting Requirements

D.14. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, the owner or operator shall notify the Department's Southwest District Air Section, in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department's Southwest District Air Section.
[Rule 62-210.700(6), F.A.C.]

D.15. Test Reports.
(a) Each generator shall be tested on an annual basis within 30 days of the date October 25.
(b) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
(c) The required test report shall be filed with the Department's Southwest District office, as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(d) The test reports for a unit that has been relocated shall be submitted to the Department's Southwest District office.
[Rule 62-297.310(8), F.A.C.; and, AO09-205952]

D.16. To demonstrate compliance with specific condition **D.4.**, records shall indicate the daily hours of operation for each of the generators, the daily hours of operation expressed as "engine-hours" and the cumulative total hours of operation expressed as "engine-hours" for each month. The records shall be maintained for a minimum of 5 years and made available to the Department's Southwest District office upon request. The records shall be maintained at each individual site.
[Rules 62-213.440 and 62-297.310(8), F.A.C.; and, AO09-205952]

D.17. To demonstrate compliance with specific condition **D.3.**, records of the sulfur content, in percent by weight, of all the fuel burned shall be kept based on either vendor provided as-delivered or as-received fuel sample analysis. The records shall be maintained for a minimum of 5 years and made available to the Department's Southwest District office upon request. The records shall be maintained at each individual site.
[Rule 62-297.310(8), F.A.C.; and, AC09-202080]

Source Obligation

D.18. Source Obligation. Specific conditions in construction permit AC 09-202080, limiting the "engine hours", were accepted by the applicant to escape Prevention of Significant Deterioration new source review. If PEF requests a relaxation of any of the federally enforceable emission limits in this permit, the relaxation of limits may be subject to the preconstruction review requirements of Rule 62-212.400, F.A.C., as though construction had not yet begun.
[Rule 62-212.400(12)(b), F.A.C.; and, AC09-202080]

D.19. PEF shall notify the Department's Southwest District office, in writing, at least 15 days prior to the date on which any diesel generator is to be relocated. The notification shall specify the following:

a. Which generator, by serial number, is being relocated;
b. Which location the generator is being relocated from and which location it is being relocated to; and,
c. The approximate startup date at the new location.

[Rule 62-4.070(3), F.A.C.; and, AC09-202080]

D.20. These emissions units are also subject to specific conditions **H.1.** through **H.22.,** except for specific condition **H.4,** contained in **Subsection H. Common Conditions.**

Subsection E. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description of Power Block 2
014	170 MW Westinghouse 501FD CT2A with unfired HRSG
015	170 MW Westinghouse 501FD CT2B with unfired HRSG

Emission units 014 and 015 each consist of a combined cycle Westinghouse 501FD Combustion Turbine, each with a nominal generator rating of 170 MW and each with a maximum heat input rating of 2,048 MMBtu/hr (HHV), while firing natural gas, and 2,155 MMBtu/hr (HHV), while firing fuel oil, based on a compressor inlet air temperature of 59 °F, the HHV of each fuel, and 100% load. NO_x emissions are controlled with dry low NO_x burners (DLN) for natural gas firing and wet injection for fuel oil firing, complete with Selective Catalytic Reduction (SCR). Each combustion turbine incorporates an unfired heat recovery steam generator (HRSG). Steam from both HRSGs is delivered to a single steam turbine-electrical generator, which has a generating capacity of 190 MW. The total generating capacity of the "2-on-1" combined cycle unit is approximately 530 MW.

{Permitting notes: These emissions unit are regulated under Acid Rain, Phase II; NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800, F.A.C.; Rule 212.400(5), F.A.C., Prevention of Significant Deterioration (PSD); PSD-FL-296 and revisions (A & B); and, Rule 62-212.400(6), F.A.C.}

The following specific conditions apply to the emissions unit(s) listed above:

General

E.0. Appendix GG - NSPS Subpart GG Requirements for Gas Turbines is a part of the permit and Power Block 2 must comply with it.

[1050234-015-AC/PSD-FL-195(D)]

Essential Potential to Emit (PTE) Parameters

E.1. Permitted Capacity. The maximum heat input rates, based on the higher heating value of the fuels, and an ambient air temperature of 59 °F, shall not exceed 2,048 MMBtu per hour when firing natural gas and 2,155 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59 °F, the HHV of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate fuels, 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.
[Rule 62-210.200(PTE), F.A.C.; 1050234-007-AC/PSD-FL-296(A); and, 1050234-011-AC/PSD-FL-296(B)]

E.2. Equipment and Controls - Gas Turbines. The permittee is authorized to install, tune, operate, and maintain two Siemens Westinghouse Model 501 FD gas turbine-electrical generator sets each with a generating capacity of 170 MW. Each gas turbine shall include the Siemens TXP automated gas turbine control system and have dual-fuel capability. The gas turbines will utilize DLN combustors. [Application; and, Design]

a. Gas Turbine NO_x Controls

1. *DLN Combustion*. The permittee shall operate and maintain the DLN combustion system to control NO_x emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned, in conjunction with any post-combustion emissions control equipment, to achieve the permitted levels for CO and NO_x emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

2. *Water Injection*. The permittee shall install, operate, and maintain a water injection system to reduce NO_x emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned, in conjunction with any post-combustion emissions control equipment, to achieve the permitted levels for CO and NO_x emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

3. *SCR System*. The permittee shall install, tune, operate, and maintain a SCR system to control NO_x emissions from each gas turbine when firing either natural gas or distillate oil. The SCR system consists of an ammonia 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 emissions and ammonia slip.

   {Permitting note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.}

   [Design; and, Rule 62-212.400(BACT), F.A.C.]

b. HRSGs. The permittee is authorized to install, operate, and maintain two unfired HRSGs. Each HRSG shall be designed to recover heat energy from one of the two gas turbines (CT 2A or CT 2B) and deliver steam to the steam turbine-electrical generator through a common manifold.

   {Permitting note: The two HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 190 MW.}

[Application; and, Design]

c. CO Controls. The permittee shall design and construct the HRSGs such that an oxidation catalyst can be readily installed if necessary to achieve compliance with the CO emission limitations.

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

E.3. Methods of Operation. Subject to the restrictions and requirements of this permit, the gas turbines may operate under the following methods of operation.

a. *Hours of Operation*. Subject to the other operational restrictions of this permit, the gas turbines may operate throughout the year (8,760 hours per year).

b. *Authorized Fuels*. Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 1.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur, by weight. Distillate fuel oil consumption of both emissions units shall not exceed 19,703,000 gallons in any consecutive 12-month period.

{Permitting note: This condition limits annual average fuel oil consumption to the equivalent of approximately 720 hours of operation per year per turbine, based on 59 °F annual average temperature. Fuel oil consumption is not limited per turbine, and the allowable fuel may be used in a single turbine.}

c. *Combined Cycle Operation*. Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a "2-on-1" 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.

d. *Ammonia Injection*. Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer.

[Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.; and, 1050234-007-AC/PSD-FL-296(A)]

Emission Limitations and Standards

E.4. Emissions Standards. Emissions from each gas turbine/HRSG shall not exceed the following limits for the listed pollutants at any ambient temperature.

{Permitting note: Unless otherwise specified, the averaging times are based on the specified averaging time of the applicable test method.}

Pollutant	Emission Limit (ppmvd corrected to 15% oxygen)		Averaging Time
	Natural Gas	Fuel Oil	
CO [a]	16	30	24 hour block
NO_x [b]	3.5	12	24 hour block
VOC [c]	2	10	3 hours
Ammonia [d]	5	9	3 hours

Pollutant	Fuel Specification and Emission Limit
PM/PM_{10} [e]	Fuel specifications. Visible emissions shall not exceed 10% opacity for each 6-minute block average.
SAM/SO_2 [f]	Fuel specifications.

a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance with the 24-hour CO CEMS standards shall be determined separately based on the hours of operation for each alternative fuel.

   {Permitting note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}

b. Compliance with the NO_x standards shall be demonstrated based on data collected by the required CEMS. NO_x mass emission rates are defined as oxides of nitrogen expressed as NO_2. Compliance with the 24-hour NO_x CEMS standards shall be determined separately based on the hours of operation for each alternative fuel.

   {Permitting note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}

c. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as propane.

d. Subject to the requirements of this permit, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen when firing natural gas based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.

e. The fuel specifications established in specific condition **E.3.** combined with the efficient combustion design and operation of each gas turbine represents the BACT determination for PM/PM_{10} 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. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

f. The fuel sulfur specifications in specific condition **E.3.** effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent the BACT determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in specific condition **E.18.**

{Permitting note: The concentration limits and fuel specifications for the control of the above pollutants are equivalent to the following mass emission rates (at 20 °F):

- *CO = 78.7 lbs/hr for natural gas firing and 119.5 lbs/hr for distillate fuel oil firing,*
- *NO_x = 27.0 lbs/hr for natural gas firing and 99.7 lbs/hr for distillate fuel oil firing,*
- *VOC = 5.0 lbs/hr for natural gas firing and 23.5 lbs/hr for distillate fuel oil firing,*
- *PM_{10} = 7.3 lbs/hr for natural gas firing and 64.8 lbs/hr for distillate fuel oil firing, and*
- *SO_2 = 5.6 lbs/hour for natural gas firing and 105.6 lbs/hr for distillate fuel oil firing.*

SAM emissions are estimated to be less than 10% of the SO_2 emissions.}

[Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.; 1050234-007-AC/PSD-FL-296(A); and, 1050234-011-AC/PSD-FL-296(B)]

Excess Emissions

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS, NESHAP, or Acid Rain program provision.}

E.5. 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, 1050234-007-AC/PSD-FL-296(A)]

E.6. 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, 1050234-007-AC/PSD-FL-296(A)]

Monitoring of Operations

E.7. The 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 maintain the gas turbines, HRSGs, 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 of minimizing excess emissions.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; and, 1050234-007-AC/PSD-FL-296(A)]

E.8. CEMS Data Exclusion. As provided in this paragraph, NO_x and CO emissions data recorded during periods of startup, shutdown, fuel switches (oil-to-gas or gas-to-oil), and documented malfunctions may be excluded from the block average calculated to demonstrate compliance with the emission limits of this permit. See specific condition **E.4.**

a. Periods of excess emissions excluded due to startup shall not exceed two (2) hours per startup per unit except for the following cold startups. A "cold STG startup" is defined as a startup following a complete steam turbine generator (STG) shutdown lasting a minimum of 48 hours. Periods of excess emissions excluded due to cold STG startup shall not exceed six (6) hours per startup per unit. A "cold CT-HRSG startup" is defined as startup following a complete shutdown of the combustion turbine-heat recovery steam generator (CT-HRSG) lasting a minimum of 8 hours. Periods of excess emissions excluded due to cold CT-HRSG startup shall not exceed three (3) hours per startup per unit.

b. Periods of data excluded for shutdown shall not exceed two (2) hours per shutdown per unit.

c. Periods of data excluded for fuel switches shall not exceed two (2) hours per fuel switch per unit.

d. Periods of data excluded for documented malfunctions shall not exceed two (2) hours per unit in any 24-hour block. A "documented malfunction" means a malfunction that meets the notification requirements specified in specific condition **E.19.**

e. All periods of data excluded for any startup, shutdown, fuel switches, or documented malfunction shall be consecutive for each episode.

f. The permittee shall minimize the duration of data excluded to the extent practicable. Data shall not be excluded if the startup, shutdown, or documented malfunction was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably have been prevented. Best operating practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown, fuel switching, or documented malfunction.

[Rules 62-212.400(BACT) and 62-210.700, F.A.C.; and, Permit No. PSD-FL-296(C)/Project No. 1050234-015-AC]

E.9. CEMS Data Exclusion – 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 Department's Southwest District Compliance Authority with an advance notice 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, 1050234-007-AC/PSD-FL-296(A)]

E.10. Tests Required.

a. Initial Compliance Determinations. Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_x, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit. Each unit shall be tested when firing natural gas and when firing distillate fuel oil. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial CO and NO_x standards. CO and NO_x emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc.

[Rule 62-297.310(7)(a)1., F.A.C.; and, 40 CFR 60.8]

b. Annual Compliance Tests. During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia.

1. *Visible Emissions*. Each unit shall be tested for visible emissions when firing natural gas and when firing distillate fuel oil. Annual emissions testing while firing fuel oil is not required during any federal fiscal year in which less than 5,473,000 gallons of distillate fuel oil is fired in both emission units combined. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period.

   {Permitting note: The fuel limitation for waiving testing while firing distillate fuel oil corresponds to the equivalent of approximately 200 hours of operation per year per turbine.}

2. *Ammonia.* Annual testing to determine the ammonia slip shall be conducted while firing natural gas. NO_x emissions recorded by the CEMS shall be reported for each ammonia slip test run.

   {Permitting note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.}

[Rules 62-212.400(BACT) and 62-297.310(7)(a)4., F.A.C.; and, 1050234-007-AC/PSD-FL-296(A)]

c. Continuous Compliance. The permittee shall demonstrate continuous compliance with the CO and NO_x emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any RATA on a CEMS, the permittee shall submit a report to the Department's Southwest District Compliance Authority summarizing results of the RATA.

{Permitting note: Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of PM/PM_{10} and VOC.}

[Rule 62-212.400(BACT), F.A.C.; and, 1050234-007-AC/PSD-FL-296(A)]

Test Methods and Procedures

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

Method	Description of Method and Comments
CTM-027	*Procedure for Collection and Analysis of Ammonia in Stationary Sources* This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.
7E	*Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)*
9	*Visual Determination of the Opacity of Emissions from Stationary Sources* The test shall be conducted for a minimum of 30 minutes.
10	*Determination of Carbon Monoxide Emissions from Stationary Sources* This method shall be based on a continuous sampling train.
18	*Measurement of Gaseous Organic Compound Emissions by Gas Chromatography* (Optional) EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.
20	*Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines*
25A	*Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer*

Note: Method CTM-027 is published on EPA's Technology Transfer Network Web Site at http://www.epa.gov/ttn/emc/ctm.html. The other methods are described in Appendix A, 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department.

[Rule 62-204.800, F.A.C.; and, 40 CFR 60, Appendix A]

E. 12. Operating Procedures. The 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 maintain the gas turbines, HRSGs, 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 of minimizing excess emissions.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; and, 1050234-007-AC/PSD-FL-296(A)]

Continuous Monitoring Requirements

E.13. CEMS. The permittee shall install, calibrate, maintain, and operate CEMS to measure and record the emissions of CO and NO_x from the combined cycle gas turbine. The CEMS shall be used to demonstrate continuous compliance with the CEMS emission standards specified in this permit. Upon request by the Department's Southwest District Compliance Authority, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332. Each monitoring system shall be installed, 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 Department's Southwest District Compliance Authority.

a. *CO Monitors*. Except as otherwise specified by this condition, the CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Department's Southwest District Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A, 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and 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. The CO monitor shall be a dual range monitor. The span for the lower range shall not be greater than 50 ppm. The span for the upper range shall be set at a level that provides for accurate measurement during startups and shutdowns.

b. *NO_x Monitors*. Except as otherwise specified by this condition, the NO_x monitor shall be certified pursuant to 40 CFR 75, and shall be operated and maintained in accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR 75, Subparts F and G. The RATA tests required for the NO_x monitor shall be performed using EPA Method 20 or 7E in Appendix A, 40 CFR 60. The NO_x monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm. The span for the upper range shall be set at a level that provides for accurate measurement during startups and shutdowns.

c. *Diluent Monitors*. The oxygen 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.

d. *Moisture Correction*. Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. If the CEMS measures concentration on a wet basis, the CEMS 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 permittee 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). If the CEMS measures concentration on a wet basis and the diluent monitor measures CO_2 on a wet basis, then the permittee may develop an algorithm to enable correction of the CEMS results to a dry basis (0% moisture) without determining the corresponding moisture content.

e. *1-Hour Block Averages*. 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. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour.

f. *24-hour Block Average*. 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 available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block.

{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 fuels}.

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

g. <u>Data Exclusion</u>. Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, and DLN tuning. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of specific conditions **E.8.** and **E.9.**

h. <u>Availability</u>. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly permit excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department's Southwest District Compliance Authority 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 Southwest District Compliance Authority.

{Permitting note: Compliance with these requirements assures compliance with the other applicable CEM system requirements such as: NSPS Subpart GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR 60, Appendix B - Performance Specifications; and, 40 CFR 60, Appendix F - Quality Assurance Procedures.}

[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; and, 1050234-007-AC/PSD-FL-296(A)]

E.14. <u>Water Injection Monitoring Requirements</u>. In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a monitoring system to continuously measure and record the water-to-fuel ratio when firing distillate oil. The permittee shall document the water-to-fuel ratio required to meet permitted emissions levels over the range of load conditions allowed by this permit. The NO_x CEMS is used to demonstrate compliance with the NO_x emissions standards. During NO_x CEMS downtimes or malfunctions, the permittee shall monitor the water-to-fuel ratio and operate at a level that is consistent with the documented flow rate for the gas turbine load condition.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; and, 1050234-007-AC/PSD-FL-296(A)]

E.15. <u>Ammonia Monitoring Requirements</u>. In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document 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 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, 1050234-007-AC/PSD-FL-296(A)]

Recordkeeping and Reporting Requirements

E.16. Monitoring of Operation. To demonstrate compliance with the fuel consumption limits of this permit, the permittee shall record the distillate fuel oil consumption on a rolling 12-month basis. [Rules 62-4.070(3) and 62-212.400, F.A.C.; and, 1050234-007-AC/PSD-FL-296(A)]

E.17. Frequency of Recordkeeping. Specific condition **E.12.** requires the calculation of one or more 24-hour block average emission rates for each operating day. Within 24 hours of the conclusion of each operating day, the permittee shall complete the calculations and record the results for that operating day. [Rule 62-4.070(3), F.A.C.; and, 1050234-007-AC/PSD-FL-296(A)]

E.18. 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. 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 in 40 CFR 60, Subpart GG, or their latest editions. See Appendix GG - NSPS Subpart GG Requirements for Gas Turbines.

b. Compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling and analysis for the fuel oil sulfur content shall be conducted using the ASTM methods in 40 CFR 60, Subpart GG, or their latest editions. More recent editions of these methods may be used. For each subsequent fuel delivery, the permittee shall either (1) maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor, or (2) take and analyze a sample according to the above procedures and maintain a permanent file of the results of the analysis. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content. See Appendix GG - NSPS Subpart GG Requirements for Gas Turbines.

c. 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.; 40 CFR 75, Appendix D; and, Permit No. PSD-FL-296(C)/Project No. 1050234-015-AC]

E.19. Malfunction Notification. Within one working day of a malfunction for which CEMS data is excluded pursuant to specific condition **E.8.**, the permittee shall notify the Department's Southwest District Compliance Authority by telephone, facsimile transmittal, or electronic mail. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Department's Southwest District Compliance Authority, the permittee shall submit written quarterly reports summarizing the malfunctions in lieu of the individual malfunction notifications otherwise required. [Rule 62-210.700, F.A.C.; and, 1050234-007-AC/PSD-FL-296(A)]

E.20. Semiannual NSPS Excess Emissions Report. In accordance with 40 CFR 60.7(c), the permittee shall semiannually submit a report to the Department's Southwest District Compliance Authority summarizing any emissions in excess of the NSPS standards. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the information specified in 40 CFR 60.7(c)(1) through (c)(4). For purposes of reporting emissions in excess

of 40 CFR 60, Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NO_x emission standard identified in Appendix GG - NSPS Subpart GG Requirements for Gas Turbines (i.e., 112.5 ppmvd corrected to 15% oxygen for both natural gas and fuel oil); and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG - NSPS Subpart GG Requirements for Gas Turbines (i.e., sulfur in excess of 0.8% by weight). An example of an acceptable report format is provided in Figure 1 - Summary Report-Gaseous And Opacity Excess Emissions and Monitoring System Performance.
[40 CFR 60.7(c); and, 1050234-007-AC/PSD-FL-296(A)]

E.21. Quarterly Data Exclusion and Monitor Availability Report. The permittee shall quarterly submit a report to the Department's Southwest District Compliance Authority summarizing all periods of valid hourly CO and NO_x emissions data excluded from the 24-hour block average compliance determinations pursuant to specific conditions **E.13.** and **E.14.** In addition, the quarterly report shall summarize the CEMS availability for the previous quarter. All reports shall be postmarked by the 30th day following the end of each calendar quarter. An example of an acceptable report format for monitoring systems availability is provided in Figure 1 - Summary Report-Gaseous And Opacity Excess Emissions and Monitoring System Performance.
[Rules 62-4.130, 62-204.800 and 62-210.700(6), F.A.C.; 40 CFR 60.7(c) and (d); and, 1050234-007-AC/PSD-FL-296(A)]

Miscellaneous Conditions

E.22. Additional Ammonia Slip Testing. If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and,

c. Test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis.

[Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.; and, 1050234-007-AC/PSD-FL-296(A)]

E.23. These emissions unit are also subject to specific conditions **H.1.** through **H.22.** contained in **Subsection H. Common Conditions.**

Subsection F. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description of Power Block 3
-016	170 MW Westinghouse 501FD CT3A with unfired HRSG
-017	170 MW Westinghouse 501FD CT3B with unfired HRSG

Emission units (EU) 016 and 017 are each a Siemens Westinghouse 501 FD gas turbine-electrical generator set with an automated gas turbine control system and an unfired heat recovery steam generator (HRSG). In addition, the project also includes a single steam turbine-electrical generator that serves both gas turbine/HRSG systems. Both of the gas turbine-electrical generator sets have a generating capacity of 170 MW for gas firing. Each gas turbine fires natural gas as the primary fuel and distillate oil as a restricted alternate fuel. Steam from both HRSGs is delivered to a single steam turbine-electrical generator, which has a generating capacity of 190 MW. The total generating capacity of the "2-on-1" combined cycle unit is approximately 530 MW. The maximum heat input rate is based on the higher heating value (HHV) of the fuel, which is 2,048 MMBtu/hr (HHV), while firing natural gas, and 2,155 MMBtu/hr (HHV), while firing fuel oil, based on a compressor inlet air temperature of 59 °F, the HHV of each fuel, and 100% load.

The efficient combustion of natural gas and restricted firing of low sulfur distillate oil minimizes the emissions of CO, PM/PM_{10}, SAM, SO_2 and VOC. Dry low-NO_x (DLN) combustion technology for gas firing and water injection for oil firing reduce NO_x emissions. A selective catalytic reduction (SCR) system – in combination with DLN combustion technology for gas firing and a water injection system for oil firing – reduces NO_x emissions. The HRSGs are designed and constructed such that an oxidation catalyst can be readily installed if necessary to achieve compliance with CO emission limitations.

Each HRSG has a stack that is 125 feet tall and 19 feet in diameter. Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NO_x emissions as well as flue gas oxygen or carbon dioxide content. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following table summarizes the exhaust characteristics for the combined cycle systems. Heat input rate is based on the higher heating value (HHV) of the fuel, assuming 1,030 British thermal units (Btu) per standard cubic feet of natural gas and 19,892 Btu/lb of fuel oil.

Fuel	Heat Input Rate (HHV)	Compressor Inlet Temp	Exhaust Temperature	Exit Velocity	Flow Rate
Natural Gas	1,830 MMBtu/hour	59 °F	190 °F	59.2 ft/sec	1,009,487 acfm
Oil	1,932 MMBtu/hour	59 °F	270 °F	67.0 ft/sec	1,139,394 acfm

{Permitting notes: These emissions unit are regulated under Acid Rain, Phase II; NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800, F.A.C.; Rule 212.400(5), F.A.C., Prevention of Significant Deterioration (PSD); PSD-FL-330 and revisions (A); and, Rule 62-212.400(6), F.A.C.}

The following specific conditions apply to the emissions unit(s) listed above:

General

F.0. Appendix GG - NSPS Subpart GG Requirements for Gas Turbines is a part of the permit and Power Block 3 must comply with it.

[1050234-015-AC/PSD-FL-330(B)]

F.1. BACT Determinations. Determinations of BACT were made for CO, NO_x, PM/PM_{10}, sulfuric acid mist (SAM), SO_2, and VOC.
[1050234-006-AC/PSD-FL-330]

F.2. New Source Performance Standards (NSPS). The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the NSPS for gas turbines at 40 CFR 60, Subpart GG. See Appendix GG of this permit for a summary of the applicable NSPS requirements.
[Rule 62-212.400(BACT), F.A.C.; and, 1050234-006-AC/PSD-FL-330]

F.3. Applicable Regulations, Forms and Application Procedures. Unless otherwise indicated in the permit, No. 1050234-006-AC/PSD-FL-330, the construction and operation of this emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S.; Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C.; and, 40 CFR Parts 60, 72, 73, and 75, adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the F.A.C. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C., and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.
[Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.; and, 1050234-006-AC/PSD-FL-330]

F.4. Operating Procedures. The 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 maintain the gas turbines, HRSGs, 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 of minimizing excess emissions.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; and, 1050234-006-AC/PSD-FL-330]

Essential Potential to Emit (PTE) Parameters

F.5. Permitted Capacity. The maximum heat input rate to each gas turbine is 2,048 MMBtu per hour when firing natural gas and 2,155 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59 °F, the HHV of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate fuels, 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.
[Rule 62-210.200(Definitions-PTE), F.A.C.; 1050234-006-AC/PSD-FL-330; and, 1050234-013-AC/PSD-FL-330(A)]

F.6. Gas Turbines. The permittee is authorized to tune, operate, and maintain two Siemens Westinghouse Model 501FD gas turbine-electrical generator sets each with a generating capacity of 170 MW. Each gas turbine shall include the Siemens TXP automated gas turbine control system and have dual-fuel capability. The gas turbines will utilize DLN combustors.
[Application and design; and, 1050234-006-AC/PSD-FL-330]

a. Gas Turbine NO_x Controls

1. DLN Combustion. The permittee shall operate and maintain the DLN combustion system to control NO_x emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned, in conjunction with any post-combustion emissions control equipment, to achieve the permitted levels for CO and NO_x emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

2. Water Injection. The permittee shall operate and maintain a water injection system to reduce NOx emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned, in conjunction with any post-combustion emissions control equipment, to achieve the permitted levels for CO and NO_x emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

3. SCR System.. The permittee shall tune, operate, and maintain a SCR system to control NO_x emissions from each gas turbine when firing either natural gas or distillate oil. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be operated to achieve the permitted levels for NO_x emissions and ammonia slip.

   Permitting note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.}

[Design; Rule 62-212.400(BACT), F.A.C.; and, 1050234-006-AC/PSD-FL-330]

b. HRSGs. The permittee is authorized to operate and maintain two HRSGs. Each HRSG shall recover heat energy from one of the two gas turbines (CT 3A or CT 3B) and deliver steam to the steam turbine-electrical generator through a common manifold.

{Permitting note: The two HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 190 MW.}

[Application and design; and, 1050234-006-AC/PSD-FL-330]

c. CO Controls. The permittee shall design and construct the HRSGs such that an oxidation catalyst can be readily installed if necessary to achieve compliance with the CO emission limitations. The oxidation catalyst, should it be installed, shall be designed and operated to achieve a maximum outlet concentration of 3.5 ppmvd corrected to 15% oxygen when natural gas is fired and 7.0 ppmvd corrected to 15% oxygen when distillate oil is fired.

[Rule 62-4.070(3), F.A.C.; and, 1050234-006-AC/PSD-FL-330]

F.7. Methods of Operation. Subject to the restrictions and requirements of this permit, the gas turbines may operate under the following methods of operation.

a. Hours of Operation. Subject to the other operational restrictions of this permit, the gas turbines may operate throughout the year (8,760 hours per year).

b. Authorized Fuels. Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 1.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Distillate fuel oil consumption of both emissions units shall not exceed 19,703,000 gallons in any consecutive 12 month period.

{Permitting note: This condition limits annual average fuel oil consumption to the equivalent of approximately 720 hours of operation per year per turbine, based on 59 °F annual average temperature. Fuel oil consumption is not limited per turbine, and the allowable fuel may be used in a single turbine.}

c. Combined Cycle Operation. Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a "2-on-1" 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.

d. Ammonia Injection. Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer.

[Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.; and, 1050234-006-AC/PSD-FL-330]

Emission Limitations and Standards

F.8. Emissions Standards. Emissions from each gas turbine/HRSG shall not exceed the following limits for the listed pollutants at any ambient temperature.

Pollutant	Emission Limit (ppmvd corrected to 15% oxygen)		Averaging Time
	Natural Gas	Fuel Oil	
CO [a]	10	20	24 hour block
NO_x [b]	2.5	10	24 hour block
VOC [c]	2	10	3 hours
Ammonia [d]	5	5	3 hours

Pollutant	Fuel Specification and Emission Limit
PM/PM_{10} [e]	Fuel specifications. Visible emissions shall not exceed 10% opacity for each 6-minute block average.
SAM/SO_2 [f]	Fuel specifications.

a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance with the 24-hour CO CEMS standards shall be determined separately based on the hours of operation for each alternative fuel.

{Permitting note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data. The Department shall revise the CO emissions

*standards following any future installation of an oxidation catalyst pursuant to specific condition **F.6.c.**}*

b. Compliance with the NO_x standards shall be demonstrated based on data collected by the required CEMS. NO_x mass emission rates are defined as oxides of nitrogen expressed as NO_2. Compliance with the 24-hour NO_x CEMS standards shall be determined separately based on the hours of operation for each alternative fuel.

{Permitting note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}

c. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as propane.

d. Subject to the requirements of specific condition **F.17.**, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen when firing natural gas based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.

e. The fuel specifications established in specific condition **F.7.** combined with the efficient combustion design and operation of each gas turbine represents the BACT determination for PM/PM_{10} 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. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

f. The fuel sulfur specifications in specific condition **F.7.** effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent the BACT determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in specific condition **F.23.**

{Permitting note: The concentration limits and fuel specifications for the control of the above pollutants are equivalent to the following mass emission rates (at 20 °F):

- *CO = 49.2 lbs/hr for natural gas firing and 80.0 lbs/hr for distillate fuel oil firing,*
- *NO_x = 19.1 lbs/hr for natural gas firing and 82.0 lbs/hr for distillate fuel oil firing,*
- *VOC = 5.7 lbs/hr for natural gas firing and 23.5 lbs/hr for distillate fuel oil firing,*
- *PM_{10} = 8.5 lbs/hr for natural gas firing and 64.8 lbs/hr for distillate fuel oil firing, and*
- *SO_2 = 5.6 lbs/hour for natural gas firing and 105.6 lbs/hr for distillate fuel oil firing.*

SAM emissions are estimated to be less than 10% of the SO_2 emissions.}

[Rule 62-212.400(BACT), F.A.C.; and, 1050234-013-AC/PSD-FL-330(A)]

F.9. 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, 1050234-006-AC/PSD-FL-330]

Excess Emissions

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS, NESHAP, or Acid Rain program provision.}

F.10. 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, 1050234-006-AC/PSD-FL-330]

Monitoring of Operations

F.11. CEMS Data Exclusion. As provided in this paragraph, NO_x and CO emissions data recorded during periods of startup, shutdown, fuel switches (oil-to-gas and gas-to-oil), and documented malfunctions may be excluded from the block average calculated to demonstrate compliance with the emission limits of specific condition **F.8.**

a. Periods of excess emissions excluded due to startup shall not exceed two (2) hours per startup per unit except for the following cold startups. A "cold STG startup" is defined as a startup following a complete steam turbine generator (STG) shutdown lasting a minimum of 48 hours. Periods of excess emissions excluded due to cold STG startup shall not exceed six (6) hours per startup per unit. A "cold CT-HRSG startup" is defined as startup following a complete shutdown of the combustion turbine-heat recovery steam generator (CT-HRSG) lasting a minimum of 8 hours. Periods of excess emissions excluded due to cold CT-HRSG startup shall not exceed three (3) hours per startup per unit.

b. Periods of data excluded for shutdown shall not exceed two (2) hours per shutdown per unit.

c. Periods of data excluded for fuel switches shall not exceed two (2) hours per fuel switch per unit.

d. Periods of data excluded for documented malfunctions shall not exceed two (2) hours per unit in any 24-hour block. A "documented malfunction" means a malfunction that meets the notification requirements specified in specific condition **F.24.**

e. All periods of data excluded for any startup, shutdown, fuel switches, or documented malfunction shall be consecutive for each episode.

f. The permittee shall minimize the duration of data excluded to the extent practicable. Data shall not be excluded if the startup, shutdown, or documented malfunction was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably have been prevented. Best operating practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown, fuel switching, or documented malfunction.

[Rules 62-212.400(BACT) and 62-210.700, F.A.C.; and, Permit No. PSD-FL-330(B)/Project No. 1050234-015-AC]

F.12. CEMS Data Exclusion – 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 Department's Southwest District Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail.
[Design; Rule 62-4.070(3), F.A.C.; and, 1050234-006-AC/PSD-FL-330]

Test Methods and Procedures

F.13. Test Methods. Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027	*Procedure for Collection and Analysis of Ammonia in Stationary Sources* This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.
7E	*Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)*
9	*Visual Determination of the Opacity of Emissions from Stationary Sources* The test shall be conducted for a minimum of 30 minutes.
10	*Determination of Carbon Monoxide Emissions from Stationary Sources* This method shall be based on a continuous sampling train.
18	*Measurement of Gaseous Organic Compound Emissions by Gas Chromatography* (Optional) EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.
20	*Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines*
25A	*Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer*

Note: Method CTM-027 is published on EPA's Technology Transfer Network Web Site at http://www.epa.gov/ttn/emc/ctm.html. The other methods are described in Appendix A, 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department.

[Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A; and, 1050234-006-AC/PSD-FL-330]

F.14. Initial and Subsequent Compliance Determinations. Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_x, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit. Each unit shall be tested when firing natural gas and when firing distillate fuel oil. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial CO and NO_x standards. CO and NO_x emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc.
[Rule 62-297.310(7)(a)1., F.A.C.; and, 40 CFR 60.8]

F.15. Continuous Compliance. The permittee shall demonstrate continuous compliance with the CO and NO_x emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any RATA on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA.

{Permitting note: Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of PM/PM_{10} and VOC.}

[Rule 62-212.400 (BACT), F.A.C.; and, 1050234-006-AC/PSD-FL-330]

F.16. Annual Compliance Tests. During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia.

1. Visible Emissions. Each unit shall be tested for visible emissions when firing natural gas and when firing distillate fuel oil. Annual emissions testing while firing fuel oil is not required during any federal fiscal year in which less than 5,473,000 gallons of distillate fuel oil is fired in both emission units combined. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period.

   {Permitting note: The fuel limitation for waiving testing while firing distillate fuel oil corresponds to the equivalent of approximately 200 hours of operation per year per turbine.}

2. Ammonia. Annual testing to determine the ammonia slip shall be conducted while firing natural gas. NO_x emissions recorded by the CEMS shall be reported for each ammonia slip test run.

   {Permitting note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.}

[Rules 62-212.400(BACT) and 62-297.310(7)(a)4., F.A.C.; and, 1050234-006-AC/PSD-FL-330]

F.17. Additional Ammonia Slip Testing. If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

c. Test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis.

[Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.; and, 1050234-006-AC/PSD-FL-330]

Continuous Monitoring Requirements

F.18. Continuous Emissions Monitoring System (CEMS). 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. The CEMS shall be used to demonstrate continuous compliance with the CEMS emission standards specified in this permit. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332. Each monitoring system shall be installed, 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 Department's Southwest District Compliance Authority.

a. CO Monitors. Except as otherwise specified by this condition, the CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Department's Southwest District Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A, 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and 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. The CO monitor shall be a dual range monitor. The span for the lower range shall not be greater than 50 ppm. The span for the upper range shall be set at a level that provides for accurate measurement during startups and shutdowns.

b. NO_x Monitors. Except as otherwise specified by this condition, the NO_x monitor shall be certified pursuant to 40 CFR 75, and shall be operated and maintained in accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR 75, Subparts F and G. The RATA tests required for the NO_x monitor shall be performed using EPA Method 20 or 7E in Appendix A, 40 CFR 60. The NO_x monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm. The span for the upper range shall be set at a level that provides for accurate measurement during startups and shutdowns.

c. Diluent Monitors. The oxygen 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.

d. Moisture Correction. Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. If the CEMS measures concentration on a wet basis, the CEMS 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 permittee 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). If the CEMS measures concentration on a wet basis and the diluent monitor measures CO_2 on a wet basis, then the permittee may develop an algorithm to enable correction of the CEMS results to a dry basis (0% moisture) without determining the corresponding moisture content.

e. 1-Hour Block Averages. 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. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour.

f. 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 available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block.

{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 fuels}

g. Data Exclusion. Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, and DLN tuning. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of specific conditions **F.11.** and **F.12.**

h. Availability. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly permit excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department's Southwest District Compliance Authority 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 Southwest District Compliance Authority.

{Permitting note: Compliance with these requirements assures compliance with the other applicable CEM system requirements such as: NSPS Subpart GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR 60, Appendix B - Performance Specifications; and, 40 CFR 60, Appendix F - Quality Assurance Procedures.}

[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; and, 1050234-006-AC/PSD-FL-330]

F.19. Water Injection Monitoring Requirements. In accordance with the manufacturer's specifications, the permittee shall calibrate, operate and maintain a monitoring system to continuously measure and record the water-to-fuel ratio when firing distillate oil. The permittee shall document the water-to-fuel ratio required to meet permitted emissions levels over the range of load conditions allowed by this permit. The NO_x CEMS is used to demonstrate compliance with the NO_x emissions standards. During NO_x CEMS downtimes or malfunctions, the permittee shall monitor the water-to-fuel ratio and operate at a level that is consistent with the documented flow rate for the gas turbine load condition.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; and, 1050234-006-AC/PSD-FL-330]

F.20. 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. The permittee shall document 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 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, 1050234-006-AC/PSD-FL-330]

Recordkeeping and Reporting Requirements

F.21. Monitoring of Operation. To demonstrate compliance with the fuel consumption limits of specific condition **F.7.**, the permittee shall record the distillate fuel oil consumption on a rolling 12-month basis.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; and, 1050234-006-AC/PSD-FL-330]

F.22. Frequency of Recordkeeping. Specific condition **F.18.** requires the calculation of one or more 24-hour block average emission rates for each operating day. Within 24 hours of the conclusion of each operating day, the permittee shall complete the calculations and record the results for that operating day.
[Rule 62-4.070(3), F.A.C.; and, 1050234-006-AC/PSD-FL-330]

F.23. 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. 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 in 40 CFR 60, Subpart GG, or their latest editions. See Appendix GG - NSPS Subpart GG Requirements for Gas Turbines.

b. Compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling and analysis for the fuel oil sulfur content shall be conducted using the ASTM methods in 40 CFR 60, Subpart GG, or their latest editions. More recent editions of these methods may be used. For each subsequent fuel delivery, the permittee shall either (1) maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor, or (2) take and analyze a sample according to the above procedures and maintain a permanent file of the results of the analysis. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content. See Appendix GG - NSPS Subpart GG Requirements for Gas Turbines.

c. 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.; 40 CFR 75, Appendix D; and, Permit No. PSD-FL-330(B)/Project No. 1050234-015-AC]

F.24. Malfunction Notification. Within one working day of a malfunction for which CEMS data is excluded pursuant to specific condition **F.11.**, the permittee shall notify the Department's Southwest District Compliance Authority by telephone, facsimile transmittal, or electronic mail. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Department's Southwest District Compliance Authority, the permittee shall submit written quarterly reports summarizing the malfunctions in lieu of the individual malfunction notifications otherwise required.
[Rule 62-210.700, F.A.C.; and, 1050234-006-AC/PSD-FL-330]

F.25. Semiannual NSPS Excess Emissions Report. In accordance with 40 CFR 60.7(c), the permittee shall semiannually submit a report to the Department's Southwest District Compliance Authority summarizing any emissions in excess of the NSPS standards. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the

information specified in 40 CFR 60.7(c)(1) through (c)(4). For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NO_x emission standard identified in Appendix GG - NSPS Subpart GG Requirements for Gas Turbines (i.e., 112.5 ppmvd corrected to 15% oxygen for both natural gas and fuel oil); and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG - NSPS Subpart GG Requirements for Gas Turbines (i.e., sulfur in excess of 0.8% by weight). See in Figure 1 - Summary Report-Gaseous And Opacity Excess Emissions and Monitoring System Performance.
[40 CFR 60.7(c); and, 1050234-006-AC/PSD-FL-330]

F.26. Quarterly Data Exclusion and Monitor Availability Report. The permittee shall quarterly submit a report to the Department's Southwest District Compliance Authority summarizing all periods of valid hourly CO and NO_x emissions data excluded from the 24-hour block average compliance determinations pursuant to specific conditions **F.11.** and **F.12.** In addition, the quarterly report shall summarize the CEMS availability for the previous quarter. All reports shall be postmarked by the 30th day following the end of each calendar quarter. See in Figure 1 - Summary Report-Gaseous And Opacity Excess Emissions and Monitoring System Performance.
[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7(c) and (d); and, 1050234-006-AC/PSD-FL-330]

Subsection G. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description of Power Block 4
-018	170 MW General Electric Model 7FA CT4A with unfired heat recovery steam generator
-019	170 MW General Electric Model 7FA CT4B with unfired heat recovery steam generator

Emission Units 018 and 019

Description: Emission units 018 and 019 each consist of a General Electric Model 7FA gas turbine-electrical generator set, an automated gas turbine control system, and an unfired heat recovery steam generator (HRSG). In addition, the project also includes a single steam turbine-electrical generator that serves both gas turbine/HRSG systems.

Fuels: Each gas turbine fires natural gas as the primary fuel and distillate oil as a restricted alternate fuel.

Generating Capacity: Both of the gas turbine-electrical generator sets have a generating capacity of 170 megawatt (MW) for gas firing. Exhaust from each gas turbine passes through a separate HRSG unit. Steam from both HRSG units is delivered to the single steam turbine-electrical generator, which has a generating capacity of 190 MW. The total generating capacity of the "2-on-1" combined cycle unit is approximately 530 MW.

Controls: The efficient combustion of natural gas and restricted firing of low sulfur distillate oil minimizes the emissions of carbon monoxide (CO), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2) and volatile organic compounds (VOC). Dry low-NO_x (DLN) combustion technology for gas firing and water injection for oil firing reduce NO_x emissions. A selective catalytic reduction (SCR) system – in combination with DLN combustion technology for gas firing and a water injection system for oil firing – reduces NO_x emissions. The HRSG units are designed and constructed such that an oxidation catalyst can be readily installed if necessary to achieve compliance with CO emission limitations.

Stack Parameters: Each HRSG has a stack that is 125 feet tall and 18 feet in diameter. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following table summarizes the exhaust characteristics for the combined cycle systems. Nominal heat input values are based on the higher heating value (HHV) of the fuel, assuming 1,021 British thermal units (Btu) per standard cubic feet of natural gas and 19,075 Btu/lb of fuel oil.

Fuel	Nominal Heat Input (HHV)	Compressor Inlet Temp	Exhaust Temperature	Exit Velocity	Flow Rate
Gas	1,915 MMBtu/hour	59 °F	202 °F	67.9 ft/sec	1,036,271 acfm
Oil	2,122 MMBtu/hour	59 °F	295 °F	80.0 ft/sec	1,220,938 acfm

Continuous Monitors: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NO_x emissions as well as flue gas oxygen or carbon dioxide content.

Applicable Standards and Regulations

G.1. Best Available Control Technology (BACT) Determinations. Determinations of BACT were made for CO, NO_x, PM/PM_{10}, sulfuric acid mist (SAM) and SO_2.
[Rule 62-212.400(BACT), F.A.C. and 1050234-010-AC, Specific Condition 1]

G.2. New Source Performance Standards (NSPS). The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the NSPS for gas turbines at 40 CFR part 60, subpart GG. See Appendix GG of this permit for a summary of the applicable NSPS requirements. [Rule 62-204.800(8), F.A.C. and 1050234-010-AC, Specific Condition 2]

G.3. National Emission Standards for Hazardous Air Pollutants (NESHAP). The Department determines that compliance with the stationary combustion turbine requirements of 40 Code of Federal Regulations (CFR) 63, Subpart YYYY (currently stayed) is required. See Appendix YYYY of this permit. Compliance shall be required when the final rule is promulgated. [1050234-010-AC, Specific Condition 3.]

Equipment

G.4. Gas Turbines. The permittee is authorized to tune, operate, and maintain two General Electric Model 7FA gas turbine-electrical generator sets each with a generating capacity of 170 MW. Each gas turbine shall have dual-fuel capability. The gas turbines utilize DLN combustors. [1050234-010-AC, Specific Condition 4.]

G.5. Gas Turbine NO_x Controls.

a. *DLN Combustion*: The permittee shall operate and maintain the DLN combustion system to control NO_x emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned, in conjunction with any post-combustion emissions control equipment, to achieve the permitted levels for CO and NO_x emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

b. *Water Injection*: The permittee shall operate, and maintain a water injection system to reduce NO_x emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned, in conjunction with any post-combustion emissions control equipment, to achieve the permitted levels for CO and NO_x emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

c. *SCR System*: The permittee shall tune, operate, and maintain a SCR system to control NO_x emissions from each gas turbine when firing either natural gas or distillate oil. The SCR system consists of an ammonia 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 emissions and ammonia slip. *{Permitting Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.}*

[Design; Rule 62-212.400(BACT), F.A.C. and 1050234-010-AC, Specific Condition 5.]

G.6. HRSG Units. The permittee is authorized to operate, and maintain two HRSG units. Each HRSG unit shall be designed to recover heat energy from one of the two gas turbines (CT 4A or CT 4B) and deliver steam to the steam turbine-electrical generator through a common manifold. *{Permitting Note: The two HRSG units deliver steam to a single steam turbine-electrical generator with a generating capacity of 190 MW.}* [1050234-010-AC, Specific Condition 6.]

G.7. CO Controls. The permittee shall design and construct the HRSG units such that an oxidation catalyst can be readily installed if necessary to achieve compliance with the CO emission limitations. The oxidation catalyst, should it be installed, shall be designed and operated to achieve a maximum outlet concentration of 2.5 ppmvd corrected to 15% oxygen when natural gas is fired and 5.0 ppmvd corrected to 15% oxygen when distillate oil is fired. [Rule 62-4.070(3), F.A.C. and 1050234-010-AC, Specific Condition 7.]

Performance Restrictions

G.8. Permitted Capacity - Gas Turbines. The maximum heat input rate to each gas turbine is 1,915 MMBtu per hour when firing natural gas and 2,122 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59 °F, the HHV of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate fuels, 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. [Rule 62-210.200(PTE), F.A.C. and 1050234-010-AC, Specific Condition 8.]

G.9. Methods of Operation. Subject to the restrictions and requirements of this permit, the gas turbines may operate under the following methods of operation.

a. *Hours of Operation*: Subject to the other operational restrictions of this permit, the gas turbines may operate throughout the year (8,760 hours per year).

b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 1.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Distillate fuel oil consumption of both emissions units shall not exceed 30,700,000 gallons in any consecutive 12 month period. *{Permitting Note: This condition limits annual average fuel oil consumption to the equivalent of approximately 1,000 hours of operation per year per turbine, based on 59 °F annual average temperature. Fuel oil consumption is not limited per turbine, and the allowable fuel may be used in a single turbine.}*

c. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a "2-on-1" 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.

d. *Ammonia Injection*: Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer.

[Rules 62-210.200(PTE), 62-212.400(BACT), F.A.C. and 1050234-010-AC, Specific Condition 9.]

Emissions Standards

G.10. Emissions Standards. Emissions from each gas turbine/HRSG shall not exceed the following limits for the listed pollutants at any ambient temperature.

Pollutant	Emission Limit (ppmvd corrected to 15% oxygen)		Averaging Time
	Natural Gas	Fuel Oil	
CO [a]	8.0	12.0	24 hour block
NO_x [b]	2.5	10.0	24 hour block
VOC [c]	1.3	3.0	3 hours
Ammonia [d]	5.0	5.0 [g]	3 hours

Pollutant	Fuel Specification and Emission Limit
PM/PM_{10} [e]	Fuel specifications. Visible emissions shall not exceed 10% opacity for each 6-minute block average.
SAM/SO_2 [f]	Fuel specifications.

a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance with the 24-hour CO CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data. The Department shall revise the CO emissions standards following any future installation of an oxidation catalyst pursuant to Condition No. G.7 of this section.}*

b. Compliance with the NO_x standards shall be demonstrated based on data collected by the required CEMS. NO_x mass emission rates are defined as oxides of nitrogen expressed as NO_2. Compliance with the 24-hour NO_x CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

c. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as propane. *{Permitting Note: Compliance with this standard is adequate to avoid a PSD/BACT Review.}*

d. Each SCR system shall be designed and operated with an ammonia slip of less than 5 ppmvd corrected to 15% oxygen when firing natural gas based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.

e. The fuel specifications established in Condition No. G.9 of this section combined with the efficient combustion design and operation of each gas turbine represents the BACT determination for PM/PM_{10} 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. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

f. The fuel sulfur specifications in Condition No. G.9 of this section effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent the BACT determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. G.9 of this section.

g. Although the ammonia slip limit is established at 5.0 ppm, compliance shall be demonstrated while combusting natural gas.

{Permitting Note: Informational only - the concentration limits and fuel specifications for the control of the above pollutants are equivalent to the following mass emission rates (at 20 °F):

- *CO = 32.1 lb/hr for natural gas firing and 57.2 lb/hr for distillate fuel oil firing,*
- *NO_x = 17.7 lb/hr for natural gas firing and 82.4 lb/hr for distillate fuel oil firing,*
- *VOC =3.1 lb/hr for natural gas firing and 8.1 lb/hr for distillate fuel oil firing,*
- *PM_{10} = 10.1 lb/hr for natural gas firing and 39.1 lb/hr for distillate fuel oil firing, and*

- *SO_2 = 5.4 lb/hour for natural gas firing and 109.2 lb/hr for distillate fuel oil firing.*

SAM emissions are estimated to be less than 10% of the SO_2 emissions.} [Rule 62-212.400(BACT), F.A.C. and 1050234-010-AC, Specific Condition 10.]

Startup, Shutdown, and Malfunction Emissions

G.11. Operating Procedures. The BACT determinations established by permit 1050234-010-AC rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, 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 of minimizing excess emissions. [Rules 62-4.070(3), 62-212.400(BACT), F.A.C. and 1050234-010-AC, Specific Condition 11.]

G.12. 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 1050234-010-AC, Specific Condition 12.]

G.13. 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 1050234-010-AC, Specific Condition 13.]

G.14. Alternate CO and NO_x Emissions Standard. During any 24 hour period, in which at least one hour of startup or shutdown operation has occurred, the following alternative emission limits shall apply:

a) An alternative NO_x limit of 3000 lb shall apply if natural gas is the exclusively fired fuel;
b) An alternative NO_x limit of 8880 lb shall apply if any fuel oil is fired; and
c) An alternative CO limit of 4200 lb shall apply when firing either natural gas or fuel oil.

G.15. Allowed Excess Emissions. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Best operating practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown, oil-to-gas fuel switching, or documented malfunction. Excess emissions shall in no case exceed two hours in any 24-hour period.

[Rule 62-210.700, F.A.C. and 1050234-010-AC, Specific Condition 15.]

G.16. CEMS Data Exclusion. As provided in this paragraph, NO_x and CO emissions data recorded during certain periods may be excluded from the compliance determination calculation requirements of this section.

a. Periods of data excluded for oil-to-gas fuel switches shall not exceed two hours in any 24-hour block.

b. Periods of data excluded for documented malfunctions shall not exceed two hours in any 24-hour block. A "documented malfunction" means a malfunction that meets the notification requirements specified in Condition No. G.27 of this section. The permittee shall minimize the duration of data excluded to the extent practicable. Data shall not be excluded if the documented malfunction was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably have been prevented.

c. Data collected during periods covered by the alternate emissions standard provisions of Condition No. G.14 may be excluded from the compliance determination calculation requirements of Condition No. G.10.

[Rules 62-212.400(BACT) and 62-210.700, F.A.C. and 1050234-010-AC, Specific Condition 16.]

G.17. CEMS Data Exclusion – 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 that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C. and 1050234-010-AC, Specific Condition 17.]

Emissions Performance Testing

G.18. Test Methods. Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027 or EPA Method 320	*Procedure for Collection and Analysis of Ammonia in Stationary Sources* This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.
7E	*Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)*
9	*Visual Determination of the Opacity of Emissions from Stationary Sources* The test shall be conducted for a minimum of 30 minutes.
10	*Determination of Carbon Monoxide Emissions from Stationary Sources* This method shall be based on a continuous sampling train.
18	*Measurement of Gaseous Organic Compound Emissions by Gas Chromatography* (Optional) EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.
20	*Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines*
25A	*Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer*

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at http://www.epa.gov/ttn/emc/ctm.html. The other methods are described in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A and 1050234-010-AC, Specific Condition 18.]

G.19. Additional Compliance Determinations. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1., F.A.C.; 40 CFR 60.8 and 1050234-010-AC, Specific Condition 19.]

G.20. Continuous Compliance. The permittee shall demonstrate continuous compliance with the CO and NO_x emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any RATA on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. *{Permitting Note: Compliance with the CO emission standards also* *serves as an indicator of efficient fuel combustion, which reduces emissions of PM/PM$_{10}$ and VOC.}* [Rule 62-212.400(BACT), F.A.C. and 1050234-010-AC, Specific Condition 20.]

G.21. Annual Compliance Tests. During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia.

a. *Visible Emissions.* Each unit shall be tested for visible emissions when firing natural gas and when firing distillate fuel oil. Annual emissions testing while firing fuel oil is not required during any federal fiscal year in which less than 6,140,000 gallons of distillate fuel oil is fired in both emission units combined. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. *{Permitting Note: The fuel limitation for waiving testing while firing distillate fuel oil corresponds to the equivalent of approximately 200 hours of operation per year per turbine.}*

b. *Ammonia.* Annual testing to determine the ammonia slip shall be conducted while firing natural gas. NO_x emissions recorded by the CEMS shall be reported for each ammonia slip test run.

{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.} [Rules 62-212.400(BACT), 62-297.310(7)(a)4., F.A.C. and 1050234-010-AC, Specific Condition 21.]

Continuous Monitoring Requirements

G.22. CEMS. 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. The CEMS shall be used to demonstrate continuous compliance with the CEMS emission standards specified in this permit. Upon request by the Department, the CEMS emission rates shall be corrected to International Organization for Standardization (ISO) conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332. Each monitoring system shall be installed, 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 Monitors.* Except as otherwise specified by this condition, the CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, 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. The Method 10 analysis shall be based on a continuous sampling train, and 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. The CO monitor shall be a dual range monitor. The span for the lower range shall not be greater than 50 ppm. The span for the upper range shall be set at a level that provides for accurate measurement during startups and shutdowns.

b. *NO_x Monitors.* Except as otherwise specified by this condition, the NO_x monitor shall be certified pursuant to 40 CFR 75, and shall be operated and maintained in accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR 75, Subparts F and G. 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. The NO_x monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm. The span for the upper range shall be set at a level that provides for accurate measurement during startups and shutdowns.

c. *Diluent Monitors.* The oxygen 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.

d. *Moisture Correction.* Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. If the CEMS measures concentration on a wet basis, the CEMS 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 permittee 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). If the CEMS measures concentration on a wet basis and the diluent monitor measures CO_2 on a wet basis, then the permittee may develop an algorithm to enable correction of the CEMS results to a dry basis (0% moisture) without determining the corresponding moisture content.

e. *1-Hour Block Averages.* 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. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour.

f. *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 available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. *{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 fuels}.* [Rule 62-212.400(BACT), F.A.C.]

g. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, and DLN tuning. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. G.16 and G.17 of this section.

h. *Availability.* Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly permit 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.

{Permitting Note: Compliance with these requirements assures compliance with the other applicable CEM system requirements such as: NSPS Subpart GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13, 40 CFR 60, Appendix B - Performance Specifications, and 40 CFR 60, Appendix F - Quality Assurance Procedures.} [Rules 62-4.070(3), 62-212.400(BACT), F.A.C. and 1050234-010-AC, Specific Condition 22.]

The water injection monitoring is no longer necessary due to the NSPS, Subpart GG revisions.

G.23. Ammonia Monitoring Requirements. In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document 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 that is consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3), 62-212.400(BACT), F.A.C. and 1050234-010-AC, Specific Condition 23.]

Records and Reports

G.24. Monitoring of Operations. To demonstrate compliance with the fuel consumption limits of Condition No. G.9 of this section, the permittee shall record the distillate fuel oil consumption on a rolling 12-month basis. [Rules 62-4.070(3), 62-212.400(BACT), F.A.C. and 1050234-010-AC, Specific Condition 24.]

G.25. Frequency of Recordkeeping. Condition No. G.22 of this section requires the calculation of one or more 24-hour block average emission rates for each operating day. Within 24 hours of the conclusion of each operating day, the permittee shall complete the calculations and record the results for that operating day. [Rule 62-4.070(3), F.A.C. and 1050234-010-AC, Specific Condition 25.]

G.26. 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. 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, D3246-81 or more recent versions.

b. Compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each 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 D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall either (1) maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor, or (2) take and analyze a sample according to the above procedures and maintain a permanent file of the results of the analysis. 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), 62-4.160(15), F.A.C. and 1050234-010-AC, Specific Condition 26.]

G.27. Malfunction Notification. Within one working day of a malfunction for which CEMS data is excluded pursuant to Condition No. G.16 of this section, the permittee shall notify the Compliance Authority by telephone, facsimile transmittal, or electronic mail. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports summarizing the malfunctions in lieu of the individual malfunction notifications otherwise required. [Rule 62-210.700, F.A.C. and 1050234-010-AC, Specific Condition 27.]

G.28. Semiannual NSPS Excess Emissions Report. In accordance with 40 CFR 60.7(c), the permittee shall semiannually submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the information specified in 40 CFR 60.7(c)(1) through (c)(4). For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NO_x emission standard identified in Appendix GG (i.e., 112.5 ppmvd corrected to 15% oxygen for both natural gas and fuel oil); and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG (i.e., sulfur in excess of 0.8% by weight). An example of an acceptable report format is provided in Appendix XS. [40 CFR 60.7(c) and 1050234-010-AC, Specific Condition 28.]

G.29. Quarterly Data Exclusion and Monitor Availability Report. The permittee shall quarterly submit a report to the Compliance Authority summarizing all periods of valid hourly CO and NO_x emissions data excluded from the 24-hour block average compliance determinations pursuant to Condition Nos. G.16 and G.17 of this section. In addition, the quarterly report shall summarize the CEMS availability for the previous quarter. All reports shall be postmarked by the 30th day following the end of each calendar quarter. An example of an acceptable report format for monitoring systems availability is provided in Appendix XS. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7(c) and (d) and 1050234-010-AC, Specific Condition 29.]

Subsection H. Common Conditions.

E.U. ID No.	Brief Description
001	170 MW Westinghouse 501FC CT1A with unfired HRSG
002	170 MW Westinghouse 501FC CT1B with unfired HRSG
014	170 MW Westinghouse 501FD CT2A with unfired HRSG
015	170 MW Westinghouse 501FD CT2B with unfired HRSG
016	170 MW Westinghouse 501FD CT3A with unfired HRSG
017	170 MW Westinghouse 501FD CT3B with unfired HRSG
018	170 MW General Electric Model 7FA CT4A with unfired HRSG
019	170 MW General Electric Model 7FA CT4B with unfired HRSG
003	Auxiliary Steam Boiler
001 (7775047)	Relocatable diesel generator(s) will have a maximum (combined) heat input of 25.74 MMBtu/hour while being fueled by 186.3 gallons of new No. 2 fuel oil per hour with a maximum (combined) rating of 2,460 kilowatts. Emissions from the generator(s) are uncontrolled.

Except as otherwise specified under Subsections A. through G., the following conditions apply to the emissions unit(s) listed above:

Excess Emissions

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS, NESHAP, or Acid Rain program provision.}

H.1. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

H.2. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

H.3. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   a. Did not operate; or
   b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
   a. Visible emissions, if there is an applicable standard;
   b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and,
   c. Each NESHAP pollutant, if there is an applicable emission standard.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) <u>Special Compliance Tests</u>. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

(c) <u>Waiver of Compliance Test Requirements</u>. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7), F.A.C.; SIP approved and AO 09-205952]

Test Methods and Procedures

H.4. Operating Rate During Testing. Testing of emissions shall be conducted with the source operating at capacity (maximum heat input rate for the tested operating temperature). Capacity is defined as 90 - 100 percent of permitted capacity. If it is impracticable to test at capacity, then sources may be tested at less than capacity; in this case subsequent source operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, then operation at higher capacities is allowed for no more than fifteen consecutive days for purposes of additional compliance testing to regain the rated capacity in the permit, with prior notification to the Department.
[Rules 62.297.310(2) and (2)(b), F.A.C.]

H.5. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.
(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.
(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1. (See attachment.)
(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

H.6. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic

mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

H.7. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

Recordkeeping and Reporting Requirements

H.8. Test Reports.
(a) The owner or operator an emissions unit for which a compliance test is required shall file a report with the Department's Southwest District office on the results of each such test.
(b) The required test report shall be filed with the Department's Southwest District office as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and gallons per minute (GPM) scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.

19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

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

H.9. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department's Southwest District office or Southwest District Branch office in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department's Southwest District office or Southwest District Branch office.
[Rule 62-210.700(6), F.A.C.]

H.10. The permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or, any periods during which a continuous monitoring system or monitoring device is inoperative.
[40 CFR 60.7(b)]

H.11. Quarterly Report. PEF shall submit a quarterly excess emissions report and monitoring systems performance report. All reports shall be postmarked by the 30th day following the end of each quarter. Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

[40 CFR 60.7(c)(1) thru (4)]

H.12. Summary Report. The summary report form shall contain the information and be in the format shown in Figure 1 of 40 CFR 60.7(d) unless otherwise specified by the Department. One summary report form shall be submitted for each pollutant monitored.

(1) If the total duration of excess emissions for the reporting period is less than one percent of the operating time for the reporting period and continuous monitoring system (CMS) downtime for the reporting period is less than five percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Department.

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

[40 CFR 60.7(d)(1) and (2)]

H.13. Reporting Frequency. (1) Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), a permittee who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

(i) For 1 year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;
(ii) PEF continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and
(iii) The Department does not object to a reduced frequency of reporting for the affected facility, as provided in 40 CFR 60.7(e)(2).

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after PEF notifies the Department in writing of its intention to make such a change and the Department does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Department may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of a PEF conformance with operation and maintenance requirements. Such information may be used by the Department to make a judgment about the source's potential for noncompliance in the future. If the Department disapproves the PEF's request to reduce the frequency of reporting , the Department will notify the permittee in writing within 45 days after receiving notice of PEF's intention. The notification from the Department to the permittee will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.
(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the permittee shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with applicable standard for another full year, the permittee may again request approval from the Department to reduce the frequency of reporting for that standard as provided for in 40 CFR 60.7(e)(1) and (e)(2).
[40 CFR 60.7(e)(1), (2) and (3)]

H.14. Records Retention. The permittee shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and, all other information required by 40 CFR 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least 5 (five) years following the date of such measurements, maintenance, reports, and records.
[40 CFR 60.7(f) and Rule 62-213.440(1)(b)2.b., F.A.C.]

H.15. Credible Evidence. For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in 40 CFR 60, nothing in 40 CFR 60 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.
[40 CFR 60.11(g)]

Miscellaneous Conditions

H.16. Department Notification. PEF shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted timely and in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and, the anticipated completion date of the change.
[40 CFR 60.7(a)]

Modifications

H.17. Except as provided under 40 CFR 60.14(e) and 40 CFR 60.14(f), any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.
[Rule 62-296.800, F.A.C. and 40 CFR 60.14(a)]

H.18. Emission rate shall be expressed as kg/hr (lbs/hr) of any pollutant discharged into the atmosphere for which a standard is applicable. The Department shall use the following to determine emission rate:
(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors", EPA Publication No. AP-42, or other emission factors determined by the Department to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrate that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.
(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in 40 CFR 60.14(b)(1) does not demonstrate to the Department's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Department's satisfaction that there are reasonable grounds to dispute the result obtained by the Department utilizing emission factors as referenced in 40 CFR 60.14(b)(1). When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in 40 CFR 60, Appendix C, shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Department shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.
[Rule 62-296.800, F.A.C. and 40 CFR 60.14(b)]

H.19. The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of 40 CFR 60 any other facility within that source.
[Rule 62-296.800, F.A.C. and 40 CFR 60.14(c)]

H.20. The following shall not, by themselves, be considered modifications under 40 CFR 60:
(1) Maintenance, repair, and replacement which the Department determines to be routine for a source category, subject to the provisions of 40 CFR 60.14(c) and 40 CFR 60.15.
(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.

(3) An increase in the hours of operation.
(4) Use of an alternative fuel or raw material if, prior to the date any standard under 40 CFR 60 becomes applicable to that source type, as provided by 40 CFR 60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.
(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Department determines to be less environmentally beneficial.
(6) The relocation or change in ownership of an existing facility.
[Rule 62-296.800, F.A.C. and 40 CFR 60.14(e)]

H.21. Special provisions set forth under an applicable subpart of 40 CFR 60 shall supersede any conflicting provisions of this section.
[Rule 62-296.800, F.A.C. and 40 CFR 60.14(f)]

H.22. Within 180 days of the completion of any physical or operational change subject to the control measures specified in 40 CFR 60.14(a), compliance with all applicable standards must be achieved.
[Rule 62-296.800, F.A.C. and 40 CFR 60.14(g)]

Section IV. This section is the Acid Rain Part.

Operated by: Florida Power Corporation d/b/a Progress Energy Florida, Inc.
ORIS code: 7302
Subsection A. This subsection addresses Acid Rain, Phase II.

The emissions unit(s) listed below are regulated under Acid Rain, Phase II.

E.U. ID No.	Brief Description
001	170 MW Combined Cycle Westinghouse 501FC CT1A with unfired HRSG
002	170 MW Combined Cycle Westinghouse 501FC CT1B with unfired HRSG
014	170 MW Combined Cycle Westinghouse 501FD CT2A with unfired HRSG
015	170 MW Combined Cycle Westinghouse 501FD CT2B with unfired HRSG
016	170 MW Combined Cycle Westinghouse 501FD CT3A with unfired HRSG
017	170 MW Combined Cycle Westinghouse 501FD CT3B with unfired HRSG
018	170 MW General Electric Model 7FA CT4A with unfired HRSG
019	170 MW General Electric Model 7FA CT4B with unfired HRSG

A.1. The Phase II permit application(s) 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 unit(s) 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), Chapter 62-210, F.A.C., signed by the Designated Representative on October 1, 2004.
[Chapter 62-213 and Rule 62-214.320, F.A.C.]

A.2. Sulfur dioxide (SO_2) allowance allocations for each Acid Rain unit are as follows:

E.U. ID No.	EPA ID	Year	2007	2008	2009	2010	2011
-001	1A	**SO_2 allowances to be determined by U.S.EPA**	0*	0*	0*	0*	0*
-002	1B	**SO_2 allowances to be determined by U.S.EPA**	0*	0*	0*	0*	0*
-014	2A	**SO_2 allowances to be determined by U.S.EPA**	0*	0*	0*	0*	0*
-015	2B	**SO_2 allowances to be determined by U.S.EPA**	0*	0*	0*	0*	0*

-016	3A	**SO_2 allowances to be determined by U.S.EPA**	0*	0*	0*	0*	0*
-017	3B	**SO_2 allowances to be determined by U.S.EPA**	0*	0*	0*	0*	0*
-018	4A	**SO_2 allowances to be determined by U.S.EPA**	0*	0*	0*	0*	0*
-019	4B	**SO_2 allowances to be determined by U.S.EPA**	0*	0*	0*	0*	0*

*The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the U.S.EPA

A.3. Emission Allowances. 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.
1. 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.
2. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.
3. Allowances shall be accounted for under the Federal Acid Rain Program.
[Rule 62-213.440(1)(c), F.A.C.]

A.4. Fast-Track Revisions of Acid Rain Parts. Those Acid Rain sources making a change described at Rule 62- 214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, F.A.C., Fast-Track Revisions of Acid Rain Parts.
[Rules 62-213.413 and 62-214.370(4), F.A.C.]

A.5. Comments, notes, and justifications: None.

A.6. Where an applicable requirement of the Act is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator.
[40 CFR 70.6(a)(1)(ii); and, Rule 62-210.200(Definitions-Applicable Requirements), F.A.C.]

Appendix H-1: Permit History

Progress Energy Florida, Inc.
Hines Energy Complex

Permit No.: 1050234-016-AV
Facility ID No.: 1050234

E.U. ID No.	Description	Permit No.	Effective Date [1]	Expiration Date	Project Type
All	Facility	1050234-001-AV	01/01/2002	12/31/2006	Initial
Power Block 1					
-001	170 MW Westinghouse 501F CT1A with unfired HRSG and an associated shared steam turbine generator	1050234-014-AV	01/01/2007	12/31/2011	Renewal
		1050234-015-AC	11/20/2006	12/31/2011	Construction (mod.)
-002	170 MW Westinghouse 501F CT1B with unfired HRSG and an associated shared steam turbine generator	1050234-014-AV	01/01/2007	12/31/2011	Renewal
		1050234-015-AC	11/20/2006	12/31/2011	Construction (mod.)
Power Block 2					
-014	170 MW Westinghouse 501FD CT2A with unfired HRSG and an associated shared steam turbine generator	1050234-014-AV	01/01/2007	12/31/2011	Renewal
		1050234-015-AC	11/20/2006	12/31/2011	Construction (mod.)
-015	170 MW Westinghouse 501FD CT2B with unfired HRSG and an associated shared steam turbine generator	1050234-014-AV	01/01/2007	12/31/2011	Renewal
		1050234-015-AC	11/20/2006	12/31/2011	Construction (mod.)
Power Block 3					
-016	170 MW Westinghouse 501FD CT3A with unfired HRSG and an associated shared steam turbine generator	1050234-014-AV	01/01/2007	12/31/2011	Renewal
		1050234-015-AC	11/20/2006	12/31/2011	Construction (mod.)
-017	170 MW Westinghouse 501FD CT3B with unfired HRSG and an associated shared steam turbine generator	1050234-014-AV	01/01/2007	12/31/2011	Renewal
		1050234-015-AC	11/20/2006	12/31/2011	Construction (mod.)
Power Block 4					
-018	170 MW General Electric Model 7FA CT4A with unfired heat recovery steam generator	1050234-010-AC	6/13/05	6/30/09	Construction
-019	170 MW General Electric Model 7FA CT4B with unfired heat recovery steam generator	1050234-010-AC	6/13/05	6/30/09	Construction

[1] Change to an actual date, which is day 55 from the date of posting the PROPOSED Permit for EPA review (see confirmation e-mail from Tallahassee) or the date that EPA confirms resolvement of any objections.

Appendix U-1, List of Unregulated Emissions Units and Activities

Progress Energy Florida, Inc. Permit No. 1050234-016-AV
Hines Energy Complex

Unregulated Emissions Units and/or Activities. An emissions unit which emits no "emissions limited pollutant" and which is subject to no unit-specific work practice standard, though it may be subject to regulations applied on a facility-wide basis (e.g., unconfined emissions, odor, general opacity) or to regulations that require only that it be able to prove exemption from unit specific emissions or work practice standards.

The below listed emissions units and/or activities are neither 'regulated emissions units' nor 'exempt emissions units'.

E.U. ID No.	Brief Description of Emissions Units and/or Activities
-xxx	Two Lube Oil Storage Tanks (10,000 gallon capacity and 6,200 gallon capacity)
	One No. 2 Fuel Oil Storage Tank (1.00 million gallon capacity)
	One No. 2 Fuel Oil Storage Tank (3.80 million gallon capacity)
	Three Ammonium Storage Tanks (30,000 gallon capacity each)
	One Sodium Hypochlorite Storage Tank (10,000 gallon capacity)
	Fuel loading and unloading activities
	Lube oil vents with demisters
	Non-halogenated solvents

Appendix I-1, List of Insignificant Emissions Units and/or Activities

Progress Energy Florida, Inc. Permit No.: 1050234-016-AV
Hines Energy Complex

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, are exempt from the permitting requirements of Chapters 62-210 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rule 62-210.300(3)(a), F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rule 62.210.300(3)(a), F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.

The below listed emissions units and/or activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

Brief Description of Emissions Units and/or Activities

1. Sand blaster, welding, lathes, hand-held tools, etc.
2. Diesel generator.
3. Fire water tank(s).
4. Brazing, soldering, or welding equipment.
5. Fire and safety equipment.
6. Surface coating operations within a single facility if the total quantity of coatings containing greater than 5.0 percent VOCs, by volume, used is 6.0 gallons per day or less, averaged monthly provided:
   a. Such operations are not subject to a volatile organic compound Reasonably Available Control Technology (RACT) requirement of Chapter 62-296, F.A.C.; and
   b. The amount of coatings used shall include any solvents and thinners used in the process including those used for cleanup.
7. Vehicle fueling station with storage – gasoline and diesel.
8. Hydraulic oil storage (300, 200, and 166 gallons).

Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR Part 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in **bold** immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.

The Power Block 4 gas turbines are regulated as emissions units 018 and 019. Each Power Block 4 gas turbine has a heat input at peak load equal to or greater than 10 MMBtu per hour (LHV) and will commence construction after October 3, 1977. Therefore, the gas turbines are subject to NSPS Subpart GG. [40 CFR 60.330(a) and (b), Applicability and Designation of Affected Facility.]

Emissions units subject to a NSPS are also subject to the applicable requirements of 40 CFR Part 60, Subpart A, General Provisions. Individual subparts may exempt specific equipment or processes from some or all of the general provisions. For brevity, the general provisions are not duplicated in this permit. A copy of the most recently updated general provisions may be provided in full upon request.

§ 60.331 Definitions.

The following applicable terms are defined by this subpart:

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

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

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

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

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

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

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

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

§ 60.332 Standard for Nitrogen Oxides.

(a) On and after the date of the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:

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

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

where:

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

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

F = NOx emission allowance for fuel-bound nitrogen as defined in § 60.332(a)(3).

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

Fuel-bound nitrogen (percent by weight)	F (NOx percent by volume)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N–0.1)
$N > 0.25$	0.005

where:

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

Department requirement: **While firing gas, the "F" value shall be assumed to be 0.**

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" values provided by the applicant are approximately 9.6 for both natural gas and fuel oil. The equivalent emission standards are 112.5 ppmvd at 15% oxygen. The BACT limits of this permit are more stringent than this requirement.]

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

§ 60.333 Standard for Sulfur Dioxide.

On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with the following:

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

[Note: The BACT limits of this permit are more stringent than this requirement.]

§ 60.334 Monitoring of Operations.

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

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

Department requirement: **The owner or operator is allowed to use vendor analyses of the fuel as received to satisfy the sulfur content monitoring requirements of this rule for fuel oil. Alternatively, if the fuel oil storage tank is isolated from the combustion turbines while being filled, the owner or**

operator is allowed to determine the sulfur content of the tank after completion of filling of the tank, before it is placed back into service.

[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]

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

Department requirement: The requirement to monitor the nitrogen content of natural gas fired is waived. The requirement to monitor the nitrogen content of fuel oil fired is waived because a NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator is allowed to determine the sulfur content of the pipeline quality natural gas semi-annually, because the owner or operator has the results of bimonthly and quarterly natural gas sulfur content analyses from the operation of the existing Power Block 1.

[Note: This is consistent with EPA's custom fuel monitoring policy and guidance from EPA Region 4.]

(c) For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in 40 CFR 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in 40 CFR 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

Department requirement: NOx emission monitoring by CEMS shall substitute for the requirements of paragraph (c)(1) because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit. Data from the NOx monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 as described in this permit.

Department requirement: NOx and CO monitor availability shall not be less than 95% in any calendar quarter. The report required by this permit shall be used to demonstrate compliance with this requirement.

[Note: As required by EPA's March 12, 1993 determination, the NOx monitor shall meet the applicable requirements of 40 CFR 60.13, Appendix B and Appendix F for certifying, maintaining, operating and assuring the quality of the system; shall be capable of calculating NOx emissions concentrations corrected to 15% oxygen; shall have no less than 95% monitor availability in any given calendar quarter; and shall provide a minimum of four data points for each hour and calculate an hourly average. The requirements for the CEMS specified by the specific conditions of this permit satisfy these requirements.]

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

§ 60.335 Test Methods and Procedures.

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

(b) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as pro-vided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a) as follows:

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

$$NOx = (NOxo)\ (Pr/Po)^{0.5}\ e^{19(Ho-0.00633)}\ (288°K/Ta)^{1.53}$$

where:

NOx = emission rate of NOx at 15 percent O2 and ISO standard ambient conditions, volume percent.

NOxo = observed NOx concentration, ppm by volume.

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

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

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

e = transcendental constant, 2.718.

Ta = ambient temperature, °K.

<u>Department requirement</u>: The owner or operator is not required to have the NOx monitor required by this permit continuously calculate NOx emissions concentrations corrected to ISO conditions. However, the owner or operator shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.

[Note: This is consistent with guidance from EPA Region 4.]

(2) The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with 40 CFR 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

<u>Department requirement</u>: The owner or operator is allowed to conduct initial performance tests at a single load because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit.

[Note: This is consistent with guidance from EPA Region 4.]

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

<u>Department requirement</u>: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEMS data, provided that compliance be based on a

minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in this permit shall be used instead of the span value of 300 ppm specified by paragraph (3) above.

[Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.]

(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

Department requirement: This permit requires the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.

[Note: This requirement establishes different analysis methods than provided by paragraph (d) above, but the requirements are equally stringent and will ensure compliance with this rule.]

(e) To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

[Note: The fuel analysis requirements of this permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]

SEMIANNUAL NSPS EXCESS EMISSIONS REPORT

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

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

Pollutant *(Circle One)* SO_2 NO_X TRS H_2S CO Opacity

Reporting period dates: From ______________________________ to ______________________________

Company: ______________________________

Emission Limitation: ______________________________

Address: ______________________________

Monitor Manufacturer: ______________________________

Model No. : ______________________________

Date of Latest CMS Certification or Audit: ______________________________

Process Unit(s) Description: ______________________________

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

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

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

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

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

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

Name: ______________________________

Signature: ______________________________ *Date*: ______________________________

Title: ______________________________

NESHAP SUBPART YYYY

APPLICABILITY

The Power Block 4 gas turbines are regulated as emissions units 018 and 019. Each Power Block 4 gas turbine is a "stationary combustion turbine located at a major source of HAP emissions" and will commence construction after January 14, 2003. Therefore, the gas turbines will be subject to the new stationary combustion turbine requirements of 40 CFR 63, Subpart YYYY, which is currently stayed.

Emissions units subject to a NESHAP are also subject to the applicable requirements of 40 CFR Part 63, Subpart A, General Provisions. Individual subparts may exempt specific equipment or processes from some or all of the general provisions. For brevity, the general provisions are not duplicated in this permit. A copy of the most recently updated general provisions may be provided in full upon request.

TIMING AND REQUIREMENTS

The combustion turbines NESHAP was proposed on January 14, 2003, and it was signed by the Administrator on August 27, 2003. On August 18, 2004 the final rule was stayed (see Federal Register / Vol. 69, No. 159 / Wednesday, August 18, 2004 / Rules and Regulations).

The permittee shall be responsible for ensuring timely compliance with relevant requirements of 40 CFR 63, Subparts A and YYYY.

[Rule 62-4.070(3), F.A.C. See also 40 CFR 60.6085, proposed at 68 FR 1888, January 14, 2003.]

Friday, Barbara

To: martin.drango@pgnmail.com; 'tdavis@ectinc.com'; Meyer, Dave; Nasca, Mara

Cc: Cascio, Tom

Subject: PROPOSED Title V Permit Revision No.: 1050234-016-AV - Progress Energy Florida, Inc. - Hines Energy Complex

Attachments: Unregulated 2008.pdf; 1050234ProposedCoverLetterpdf.pdf; Appendices 2008.pdf; History 2008.pdf; Insignificant 2008.pdf; Proposed Determination 2008.pdf; Proposed Permit Revision 2008.pdf; Statement of Basis 2008.pdf

Dear Sir/Madam:

A copy of the "PROPOSED PERMIT DETERMINATION" and the related permit documents for the above referenced facility are attached. This e-mail is being provided as a courtesy to inform you that the DRAFT permit has become a PROPOSED permit, and that the PROPOSED permit has been transmitted to the USEPA for their review.

Pursuant to Section 403.0872(6), Florida Statutes, if no objection to the PROPOSED permit is made by the USEPA within 45 days, the PROPOSED permit will become a FINAL permit no later than 55 days after the date on which the PROPOSED permit was mailed (posted) to USEPA. If USEPA has an objection to the PROPOSED permit, the FINAL permit will not be issued until the permitting authority receives written notice that the objection is resolved or withdrawn.

The attached document(s) is(are) in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: http://www.adobe.com/products/acrobat/readstep.html .

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. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,

DEP, Bureau of Air Regulation

Friday, Barbara

From: Exchange Administrator
Sent: Friday, June 06, 2008 9:54 AM
To: Friday, Barbara
Subject: Delivery Status Notification (Relay)

Attachments: ATT12336.txt; PROPOSED Title V Permit Revision No.: 1050234-016-AV - Progress Energy Florida, Inc. - Hines Energy Complex

ATT12336.txt (283 B)   PROPOSED Title V Permit Revisi...

This is an automatically generated Delivery Status Notification.

Your message has been successfully relayed to the following recipients, but the requested delivery status notifications may not be generated by the destination.

tdavis@ectinc.com

Friday, Barbara

From:	System Administrator
To:	Cascio, Tom
Sent:	Friday, June 06, 2008 9:54 AM
Subject:	Delivered:PROPOSED Title V Permit Revision No.: 1050234-016-AV - Progress Energy Florida, Inc. - Hines Energy Complex

Your message

To:	'martin.drango@pgnmail.com'; 'tdavis@ectinc.com'; 'Meyer, Dave'; Nasca, Mara
Cc:	Cascio, Tom
Subject:	PROPOSED Title V Permit Revision No.: 1050234-016-AV - Progress Energy Florida, Inc. - Hines Energy Complex
Sent:	6/6/2008 9:54 AM

was delivered to the following recipient(s):

Cascio, Tom on 6/6/2008 9:54 AM

Friday, Barbara

From: System Administrator
To: Nasca, Mara
Sent: Friday, June 06, 2008 9:54 AM
Subject: Delivered:PROPOSED Title V Permit Revision No.: 1050234-016-AV - Progress Energy Florida, Inc. - Hines Energy Complex

Your message

To: 'martin.drango@pgnmail.com'; 'tdavis@ectinc.com'; 'Meyer, Dave'; Nasca, Mara
Cc: Cascio, Tom
Subject: PROPOSED Title V Permit Revision No.: 1050234-016-AV - Progress Energy Florida, Inc. - Hines Energy Complex
Sent: 6/6/2008 9:54 AM

was delivered to the following recipient(s):

Nasca, Mara on 6/6/2008 9:54 AM

Friday, Barbara

From: Nasca, Mara
Sent: Friday, June 06, 2008 11:01 AM
To: Prickett, Patricia
Cc: Zhang-Torres; Friday, Barbara
Subject: FW: PROPOSED Title V Permit Revision No.: 1050234-016-AV - Progress Energy Florida, Inc. - Hines Energy Complex

Attachments: Unregulated 2008.pdf; 1050234ProposedCoverLetterpdf.pdf; Appendices 2008.pdf; History 2008.pdf; Insignificant 2008.pdf; Proposed Determination 2008.pdf; Proposed Permit Revision 2008.pdf; Statement of Basis 2008.pdf

Unregulated 2008.pdf (13 KB) | 1050234ProposedCoverLetterpdf.... | Appendices 2008.pdf (51 KB) | History 2008.pdf (20 KB) | Insignificant 2008.pdf (15 KB)... | Proposed termination 2008.pc | Proposed Permit Revision 2008.... | Statement of Basis 2008.pdf (2...

Barbara, thanks for this one too !

From: Friday, Barbara
Sent: Friday, June 06, 2008 9:54 AM
To: 'martin.drango@pgnmail.com'; 'tdavis@ectinc.com'; 'Meyer, Dave'; Nasca, Mara
Cc: Cascio, Tom
Subject: PROPOSED Title V Permit Revision No.: 1050234-016-AV - Progress Energy Florida, Inc. - Hines Energy Complex

Dear Sir/Madam:

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Thank you,

DEP, Bureau of Air Regulation

Friday, Barbara

From: Meyer, Dave [Dave.Meyer@pgnmail.com]
To: *undisclosed-recipients*
Sent: Monday, June 09, 2008 10:10 AM
Subject: Read: PROPOSED Title V Permit Revision No.: 1050234-016-AV - Progress Energy Florida, Inc. - Hines Energy Complex

Your message

To: Dave.Meyer@pgnmail.com
Subject:

was read on 6/9/2008 10:10 AM.