Florida Power & Light Company
Martin Plant
Facility ID No. **0850001**
Martin County

DRAFT Permit Revision No. **0850001-017-AV**
Revision to **FINAL** Title V Permit No. **0850001-013-AV**

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

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Southeast District
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DRAFT Permit Revision No. **0850001-017-AV**

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Permittee	**DRAFT Permit Revision No. 0850001-017-AV**
Florida Power & Light Company	**Facility ID No. 0850001**
700 Universe Boulevard	**SIC Nos.:** 49, 4911
Juno Beach, FL 33408	**Project:** Title V Air Operation Permit Revision

The purpose of this permit is to revise the Title V Air Operation Permit by incorporating the "4 on 1" new 1,150 MW combined cycle gas turbines system, identified as Unit 8. This facility is located 7 miles North of Indiantown on State Road 710, Indiantown, Martin County; UTM Coordinates: Zone 17, 542.68 km East and 2992.65 km North; Latitude: 27° 03' 25" North and Longitude: 80° 33' 55" 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 revision.

Referenced attachments made a part of this permit revision:

Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix U-1, List of Unregulated Emissions Units and/or Activities
APPENDIX TV-4, TITLE V CONDITIONS (version dated 02/12/02)
APPENDIX SS-1, STACK SAMPLING FACILITIES (version dated 10/27/96)
Phase II Acid Rain Part Renewal Application received July 3, 2003
NSPS Custom Fuel Monitoring Schedule dated October 14, 1997
Appendix CP-1, Compliance Plan dated August 29, 2003, updated August 21, 2006.
Appendix A, NSPS Subpart A, General Provisions
Appendix A-1, NESHAP Subpart A, General Provisions
Appendix Da, NSPS Subpart Da Requirements for Duct Burners
Appendix GG, NSPS Subpart GG Requirements for Gas Turbines
Appendix SC, Standard Conditions
Appendix BD, Best Available Control Technology Determination
Appendix Dc: NSPS Requirements for Small Steam Generating Units, 40 CFR 60, Subpart Dc.
Appendix DDDDD: NESHAP Subpart DDDDD, Requirements for Industrial, Commercial, and Institutional Boilers and Process Heaters.
Appendix GG: NSPS Requirements for Gas Turbines, 40 CFR 60, Subpart GG.
Appendix ZZZZ: NESHAP Subpart ZZZZ, Requirements for Stationary Reciprocating Internal Combustion Engines.
FIGURE 1, Summary Report- Gaseous and Opacity Excess Emissions and Monitoring System Performance Report

Revision Effective Date:
Renewal Effective Date: January 1, 2004
Renewal Application Due Date: July 5, 2008
Expiration Date: December 31, 2008

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Joseph Kahn, P.E., Acting Director
Division of Air Resource Management

JK/TLV/SMS/TH

Section I. Facility Information

Subsection A. Facility Description

This facility consists of two oil and natural gas fired conventional fossil fuel steam electric generating stations (Units 1 and 2), two oil and natural gas fired combined cycle units (Units 3 and 4), four two oil and natural gas fired combined-cycle combustion turbines (Unit 8), and associated support equipment.

Unit 1 and 2 fossil fuel fired steam electric generators, each consists of a boiler/steam generator which drives a single reheat turbine generator, and is equipped with low NOx dual fuel firing burners to reduce emissions of nitrogen oxides; and, multicyclones, with fly ash reinjection, to control particulate matter emissions. The maximum capacity of each generator is 863.3 megawatts (MW).

Units 3 and 4 c*ombined cycle combustion turbine systems* (two "2-on-1" sets) consist of two General Electric Model PG7221(FA) combustion turbines (CTs) each nominally rated at 170 MW, with matched unfired heat recovery steam generator (HRSG) and a 160 MW single steam turbine-electrical generator that serves each pair of gas turbines/HRSG system. In addition, the system also includes inlet foggers installed at the compressor inlet to each of the CTs which reduce the turbine inlet air temperature. The temperature reduction improves the heat rate and increases power due to the cooler/denser inlet air. Nitrogen oxide emissions are controlled by using dry low NOx combustors for natural gas with steam injection for fuel oil firing. Steam injection is also used for power augmentation. The total generating capacity of each turbine system is approximately 500 MW.

Unit 8 combined cycle combustion turbine system ("4-on-1") consists of four General Electric Model PG7241(FA), each nominally rated at 170 MW, with matched 495 MMBtu/hr gas-fired heat recovery steam generator (HRSG), and a 470 MW single steam turbine-electrical generator that serves all four gas turbines/HRSG systems. In addition, the system also includes an automated gas turbine control system, inlet air filtration systems, evaporative inlet air cooling systems, exhaust stacks that are 120 feet in height and 19 feet in diameter, and associated support equipment. Natural gas is the primary fuel, with very low sulfur distillate oil as a limited backup fuel. Emissions of CO, PM/PM_{10}, SO_2, and VOC are minimized by the efficient combustion of these clean fuels at high temperatures. Dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing reduce NOx emissions during simple cycle operation. A selective catalytic reduction system in combination with the other NOx controls further reduces NOx emissions during combined cycle operation. The total generating capacity of the turbines system is approximately 1150 MW.

This facility also includes one auxiliary boiler, two diesel generators (one unregulated), two storage oil tanks, a mechanical cooling tower, and four natural gas fuel heaters. Also included in this permit are two unregulated emissions units identified as facility-wide particulate matter emissions, and facility-wide VOC emissions.

Based on the Title V permit Revision application received on March 3, 2006, this facility *is* a major source of hazardous air pollutants (HAPs).

Subsection B. Summary of Emissions Unit ID Nos. and Brief Descriptions

E.U. ID No.	Brief Description
-001	Fossil Fuel Fired Steam Generator No. 1
-002	Fossil Fuel Fired Steam Generator No. 2
-003	Combustion Turbine with Heat Recovery Steam Generator (CT 3A)
-004	Combustion Turbine with Heat Recovery Steam Generator (CT 3B)
-005	Combustion Turbine with Heat Recovery Steam Generator (CT 4A)
-006	Combustion Turbine with Heat Recovery Steam Generator (CT 4B)
-007	Auxiliary Boiler (for Units -003 to -006)
-009	Diesel Generator (0.718 MW, for Units -003 to -006)
-011	Combustion Turbine with Heat Recovery Steam Generator (CT 8A)
-012	Combustion Turbine with Heat Recovery Steam Generator (CT 8B)
-013	Four gas-fired fuel heaters for Unit 8
-014	Two distillate oil storage tanks for Unit 8 gas turbines
-017	Combustion Turbine with Heat Recovery Steam Generator (CT 8C)
-018	Combustion Turbine with Heat Recovery Steam Generator (CT 8D)
-019	Mechanical draft cooling tower for Unit 8

Unregulated Emissions Units and/or Activities

-015	Diesel Generator (for Units -001 and -002)
-016	Facility-wide Fugitive Emissions for PM
-016	Facility-wide Fugitive Emissions for VOCs

Please reference the Permit No., Facility ID No., and appropriate Emissions Units ID Nos. 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.

These documents are provided to the permittee for information purposes only:

Table 1-1, Summary of Air Pollution Standards and Terms
Table 2-1, Summary of Compliance Requirements
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix H-1, Permit History/ID Number Changes
Statement of Basis

These documents and all their related applications and correspondence are on file with the permitting authority:

Initial Title V Air Operation Permit 0850001-004-AV effective January 1, 1999
Title V Air Operation Permit Administrative Correction 0850001-006-AV effective July 26, 2000
Title V Air Operation Permit Revision 0850001-007-AV effective July 26, 2000
Title V Air Operation Permit Revision 0850001-012-AV effective June 20, 2003
Title V Air Operation Permit Renewal 0850001-013-AV effective January 1, 2004
Title V Air Operation Permit Revision 0850001-014-AV: Withdrawn
Title V Air Operation Permit Revision 0850001-017-AV: Pending

Section II. Facility-wide Conditions

The following conditions apply facility-wide:

1. Appendix TV-4, Title V Conditions, is a part of this permit.

   {Permitting note: Appendix TV-4, Title V Conditions is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided one copy when requested or otherwise appropriate.}

2. **Not federally enforceable:** General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. The permittee shall not 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. Prevention of Accidental Releases (Section 112(r) of CAA).

   (a) The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable. Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to:

   RMP Reporting Center
   Post Office Box 3346
   Merrifield, VA 22116-3346
   Telephone: 703/816-4434

   and,

   (b) The permittee shall submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C. [40 CFR 68]

4. 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.]

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. 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 of 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 that designated as Number 1 on the Ringelmann Chart (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.]

7. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility shall include the following activities. The following conditions are not federally enforceable:

   (a) In order to perform sandblasting on fixed plant equipment, sandblasting enclosures shall be constructed and operated as necessary. Thick poly flaps shall be used over doorways to prevent sandblasting material from leaving the facility.

   (b) Maintenance of paved areas and roads shall be performed as needed.

   (c) Mowing of grass and care of vegetation shall be done on a regular basis.

   (d) Access to plant property by unnecessary vehicles shall be controlled and limited. Vehicles shall be restricted to slow speeds at the plant site.

   (e) Bagged chemical products (e.g., soda ash, di-, tri-, and monosodium phosphate) shall be stored in weather tight buildings until they are used.

(f) Spills of powdered chemical products shall be cleaned up as soon as practical.

[Rule 62-296.320(4)(c)2., F.A.C.; and proposed by applicant in the Title V permit renewal application received on July 3, 2003.]

{Note: This condition implements the requirements of Rules 62-296.320(4)(c)1., 3., & 4., F.A.C. (see Condition 57. of Appendix TV-4, Title V Conditions).}

8. All fugitive dust generated at this site shall be adequately controlled. This includes, but is not limited to, roadway dust. [Rule 62-296.320(4)(c)2, F.A.C.; AC43-4037; and AC43-4038]

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

    Department of Environmental Protection
    Southeast District
    400 North Congress Avenue
    West Palm Beach, Florida 33416-5425
    Telephone: 407/681-6600
    Fax: 407/681-6755

11. Please be advised that the Department does not condone nor authorize the permittee to by-pass waste materials from either air or wastewater facilities at any time that would result in a violation of the rules and regulations of the Department. In case of breakdown or lack of proper functioning of the facility causing or likely to cause discharge of improperly treated sewage or air emissions, it shall be the duty of the owner of the facility to promptly notify the Department. In addition to notifying this Department, the permittee shall notify the local County Health Officer. The owner of the impaired facility causing the violation shall be responsible for any and all damages which may result. If violations of State standards occur, enforcement actions may be initiated.
[AC43-4037; and AC43-4038]

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: 404/562-9163

13. <u>Statement of Compliance</u>. The annual statement of compliance pursuant to Rule 62-213.440(3)(a)2., F.A.C., shall be submitted to the Department and EPA within 60 (sixty) days after the end of the calendar year using DEP Form No. 62-213.900(7), F.A.C.
[Rules 62-213.440(3) and 62-213.900, F.A.C.]

    {Permitting Note: This condition implements the requirements of Rules 62-213.440(3)(a)2. & 3., F.A.C. (see Condition 51. of Appendix TV-4, Title V Conditions).}

14. <u>Certification by Responsible Official (RO)</u>. 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.]

15. Compliance Plan. Appendix CP-1, Compliance Plan, is a part of this permit. Emissions units 011 and 012 have not, to date, been operated under the gas firing with peaking, and/or gas firing with power augmentation modes. Therefore, a compliance plan is included to cover initial testing requirements for these alternate methods of operation for emissions of CO and NO_x. Please see Specific Conditions **H.9**, **H.18** and **H.19.** [Rule 62-213.440(2), F.A.C.]

Section III. Emissions Units and Conditions.

Subsection A. Subsection A. This section addresses the following emissions units.

E.U. ID No.	Brief Description
-001	Fossil Fuel Fired Steam Generator No. 1
-002	Fossil Fuel Fired Steam Generator No. 2

Both emissions units are identical in configuration and each one is an 863.3 MW maximum capacity fossil fuel fired steam generator unit, equipped with low NOx dual fuel firing burners to reduce emissions of nitrogen oxides; and, multicyclones (mechanical dust collectors), with fly ash reinjection, to control particulate matter emissions. In addition, the units have a continuous emission monitoring system for measuring opacity, NOx, and sulfur dioxide. Emissions Unit 001 commenced commercial operation in December 1980. Emissions Unit 002 commenced commercial operation in June 1981.

The mechanical dust collectors are excluded from compliance assurance monitoring (CAM), because they are (a) inherent process equipment contained entirely within the flue ductwork, (b) use a passive method of particulate matter separation from the flue gas stream, (c) recover unburned carbon and ash from the flue gas system, and (d) have no moving parts, no control inputs, nor any controllable parameters.

{Permitting note: The emissions units are regulated under Acid Rain, Phase II and NSPS - 40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators; adopted and incorporated by reference in Rule 62-204.800(7)(b)1., F.A.C.}

The following conditions apply to the emissions units listed above:

General

A.1. Definitions. For the purposes of Rule 62-204.800(7), F.A.C., the definitions contained in the various provisions of 40 CFR 60, shall apply except that the term "Administrator" when used in 40 CFR 60, shall mean the Secretary or the Secretary's designee.
[40 CFR 60.2; Rule 62-204.800(7)(a), F.A.C.]

Essential Potential to Emit (PTE) Parameters

A.2. Permitted Capacity. Each boiler's maximum heat input is 8,650 mmBtu/hr on oil and 9,040 mmBtu/hr on natural gas. When a blend of fuel oil and natural gas is burned, the heat input is prorated based on the percent heat input of each fuel.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; AC43-4037; AC43-4038]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability.}

A.3. Methods of Operation. Fuels. The only fuels allowed to be burned are low sulfur fuel oil containing a maximum of 0.7% sulfur content, by weight; natural gas; or, a mixture of low sulfur fuel oil containing a maximum of 1.0% sulfur content, by weight, and natural gas in a ratio that shall not exceed the sulfur dioxide emission limiting standard of 0.80 pounds per million Btu heat input. [Rule 62-213.410, F.A.C.; AC43-4037; AC43-4038]

A.4. Hours of Operation. The emissions units may operate continuously, i.e., 8760 hours/year.
[Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions A.5. through A.11. are based on the specified averaging time of the applicable test method.}

A.5. Particulate Matter. No owner or operator shall cause to be discharged into the atmosphere from each of these emissions units any gases which:

(a) Contain particulate matter in excess of 43 nanograms per joule heat input (0.10 lb per million Btu) derived from fossil fuel.
(b) In addition, emissions shall not exceed 865 pounds per hour when firing 100 percent oil. [40 CFR 60.42(a)(1); AO43-170568 and AO43-170567]

A.6. [Reserved.]

A.7. Opacity. The opacity standards set forth in 40 CFR 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard. [40 CFR 60.11(c)]

A.8. Visible Emissions. No owner or operator shall cause to be discharged into the atmosphere from each of these emissions units any gases which exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity. [40 CFR 60.42(a)(2)]

A.9. Sulfur Dioxide.

(a) No owner or operator shall cause to be discharged into the atmosphere from each of these emissions units any gases which contain sulfur dioxide in excess of:

1. 340 nanograms per joule heat input (0.80 lb per million Btu) derived from liquid fossil fuel.
2. In addition, emissions shall not exceed 6,920 pounds per hour when firing 100 percent oil.

(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

[40 CFR 60.43(a)(1) and (c); AO43-170568 and AO43-170567]

A.10. Nitrogen Oxides.

(a) No owner or operator shall cause to be discharged into the atmosphere from each of these emissions units any gases which contain nitrogen oxides, expressed as NO_2 in excess of:

1. 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel. In addition, emissions shall not exceed 1,808 pounds per hour.

2. 129 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel. In addition, emissions shall not exceed 2,595 pounds per hour.

(b) When different fossil fuels are burned simultaneously in any combination, the applicable standard (in lb/mmBtu) is determined by proration using the following formula:

$$PS_{NOx} = [x(.20)+y(.30)] / (x + y)$$

where:

PS_{NOx} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in lb/mmBtu heat input derived from all fossil fuels fired;

x = is the percentage of total heat input derived from gaseous fossil fuel;

y = is the percentage of total heat input derived from liquid fossil fuel.

[40 CFR 60.44(a)(1)and (2); 40 CFR 60.44(b); AO43-170568; and AO43-170567.]

A.11. "On-Specification" Used Oil. Only "on-specification" used oil generated by the Florida Power and Light Company in the production and distribution of electricity shall be fired in these emissions units. The total combined quantity allowed to be fired at these emissions units shall not exceed 1,500,000 gallons per calendar year. "On-specification" used oil is defined as each used oil delivery that meets the 40 CFR 279 (Standards for the Management of Used Oil) specifications listed below. Used oil that does not meet all of the following specifications is considered "off-specification" used oil and shall not be fired. See Specific Conditions A.21., A.42. and A.43.

CONSTITUENT/PROPERTY*	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flashpoint	100 degrees F minimum
PCBs	less than 50 ppm

* As determined by approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).

[40 CFR 279.11; AO43-170568; and AO43-170567]

Excess Emissions

A.12. 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.13. In order to minimize excess emissions during startup/shutdown/malfunction the following general procedures shall be followed:

Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

[Rules 62-210.700(1) & (2), F.A.C.; AO43-170568, Specific Condition 9.; and AO43-170567, Specific Condition 9.]

A.14. Excess emission and monitoring system performance reports shall be submitted to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. Each excess emission and MSP report shall include the information required in 40 CFR 60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

1. Opacity. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

2. Sulfur dioxide. Excess emissions for affected facilities are defined as:

   Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under 40 CFR 60.43.

3. Nitrogen oxides. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under 40 CFR 60.44.

[40 CFR 60.45(g)(1), (2), & (3)]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

A.15. Opacity. Compliance with opacity standards in 40 CFR 60 shall be determined by conducting observations in accordance with Reference Method 9 in Appendix A of 40 CFR 60, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5). [40 CFR 60.11(b)]

A.16. Compliance with standards in 40 CFR 60, other than opacity standards, shall be determined in accordance with performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard. [40 CFR 60.11(a)]

A.17. Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard. [40 CFR 60.8(c)]

A.18. Compliance.

(b) The owner or operator shall determine compliance with the particulate matter, SO2**,** and NOx standards in 40 CFR 60.42, 60.43, and 60.44 as follows:

1. The emission rate (E) of particulate matter, SO_2, or NO_X shall be computed for each run using the following equation:

   $E = C\ F_d\ (20.9)/(20.9 - \%\ O_2)$

   Where,

   E = emission rate of pollutant, ng/J (1b/million Btu).

   C = concentration of pollutant, ng/dscm (1b/dscf).

   $\%\ O_2$ = oxygen concentration, percent dry basis.

   F_d = factor as determined from Method 19.

2. Method 5 shall be used to determine the particular matter concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B shall be used to determine the particulate matter concentration (C) after FGD systems.

   i. The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train may be set to provide a gas temperature no greater than 160 ± 14 °C (320 ± 25 °F).

   ii. The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration ($\%O_2$). The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate

sample. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of all the individual O_2 sample concentrations at each traverse point.

iii. If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points.

3. Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity.

4. Method 6 shall be used to determine the SO2 concentration.

   i. The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

   ii. The emission rate correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration (%O_2). The O_2 sample shall be taken simultaneously with, and at the same point as, the SO_2 sample. The SO_2 emission rate shall be computed for each pair of SO_2 and O_2 samples. The SO_2 emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

5. Method 7 shall be used to determine the NO_X concentration.

   i. The sampling site and location shall be the same as for the SO2 sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

   ii. For each NOX sample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B shall be used to determine the O2 concentration (%O2). The sample shall be taken simultaneously with, and at the same point as, the NOX sample.

   iii. The NOX emission rate shall be computed for each pair of NOX and O2 samples. The NO_X emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

(c) When combinations of fossil fuels are fired, the owner or operator (in order to compute the prorated standard as shown in 40 CFR 60.43(b) and 60.44(b)) shall determine the percentage (x or y) of the total heat input derived from each type of fuel as follows:

1. The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.

2. ASTM Methods D 240-76 (liquid fuels), or D 1826-77 (gaseous fuels) (incorporated by reference-see 40 CFR 60.17) shall be used to determine the gross calorific values of the fuels.

3. Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.

(d) The owner or operator may use the following as alternatives to the reference methods and procedures in 40 CFR 60.46 or in other sections as specified:

1. The emission rate (E) of particulate matter, SO_2 and NO_X may be determined by using the Fc factor, provided that the following procedure is used:

   i. The emission rate (E) shall be computed using the following equation:

$E = C\ F_c\ (100 / \%CO_2)$

where:

E = emission rate of pollutant, ng/J (lb/million Btu).

C = concentration of pollutant, ng/dscm (lb/dscf).

%CO2 = carbon dioxide concentration, percent dry basis.

Fc = factor as determined in appropriate sections of Method 19.

ii. If and only if the average F_c factor in Method 19 is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B shall be used to determine the O_2 and CO_2 concentration according to the procedures in 40 CFR 60.46(b) (2)(ii), (4)(ii), or (5)(ii). Then if F_o (average of three runs), as calculated from the equation in Method 3B, is more than ± 3 percent than the average F_o value, as determined from the average values of F_d and F_c in Method 19, i.e., $F_{oa} = 0.209\ (F_{da} / F_{ca})$, then the following procedure shall be followed:

(A) When F_o is less than 0.97 F_{oa}, then E shall be increased by that proportion under 0.97 F_{oa}, e.g., if F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(B) When F_o is less than 0.97 F_{oa} and when the average difference ($\bar{d}$) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under 0.97 F_{oa}, e.g., if Fo is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(C) When F_o is greater than 1.03 F_{oa} and when $\bar{d}$ is positive, then E shall be decreased by that proportion over 1.03 F_{oa}, e.g., if F_o is 1.05 F_{oa}, E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

2. For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 2.1 and 2.3 of Method 5B maybe used with Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

3. Particulate matter and SO_2 may be determined simultaneously with the Method 5 train provided that the following changes are made:

   i. The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 is used in place of the condenser (section 2.1.7) of Method 5.

   ii. All applicable procedures in method 8 for the determination of SO_2 including moisture) are used.

4. For Method 6, Method 6C may be used. Method 6A may also be used whenever Methods 6 and 3B data are specified to determine the SO2 emission rate, under the conditions in 40 CFR 60.46(d)(1).

5. For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O2 concentration (%O2) for the emission rate correction factor.

6. For Method 3, Method 3A or 3B may be used.
7. For Method 3B, Method 3A may be used.

[40 CFR 60.46(b), (c) and (d)]

A.19. Operating Rate During Testing. Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate at the permitted capacity. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.; AO43-170568, Specific Condition 1.; and AO43-170567, Specific Condition 1.]

A.20. All compliance tests shall be performed using reference test methods as given in 40 CFR 60, Appendix A, as adopted by reference in Rule 62-297.400, F.A.C. Any deviations from the test methodology in order to facilitate "representative" testing shall be approved by the Department pursuant to Rule 62-297.620, F.A.C., prior to conducting the tests.
[40 CFR 60, Appendix A; Rule 62-297.400, F.A.C.; Rule 62-297.620, F.A.C.; AO43-170568, Specific Condition 3.; and AO43-170567, Specific Condition 3.]

A.21. Compliance with the "on-specification" used oil requirements will be determined from a sample collected from each batch delivered for firing. See Specific Conditions A.11., A.42., and A.43.
[Rules 62-4.070 and 62-213.440; and 40 CFR 279.]

A.22. Testing While Injecting Additives. The owner or operator shall conduct emission tests while injecting additives consistent with normal operating practices.
[Rule 62-213.440, F.A.C.; and applicant agreement with EPA on March 3, 1998.]

Continuous Monitoring Requirements

A.23. The permittee has installed and shall continue to calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, and carbon dioxide emissions. [40 CFR 60.45(a)]

A.24. For the purposes of 40 CFR 60.13, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of 40 CFR 60.13 upon promulgation of performance specifications for continuous monitoring systems under Appendix B of 40 CFR 60 and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, Appendix F of 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987. [40 CFR 60.13(a)]

A.25. If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, Appendix B, of 40 CFR 60 before the performance test required under 40 CFR 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under 40 CFR 60.8 or within 30 days thereafter in accordance with the applicable performance specification in Appendix B of 40 CFR 60. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act. [40 CFR 60.13(c)]

A.26. The owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during

any performance test required under 40 CFR 60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under 40 CFR 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under 40 CFR 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under 40 CFR 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in 40 CFR 60.13(c), that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine opacity compliance. [40 CFR 60.11(e)(5)]

A.27.

(1) Owners and operators of all continuous emission monitoring systems (CEMS) installed in accordance with the provisions of this part shall check the zero (or low-level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in Appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified. For continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments except that for systems using automatic zero adjustments. The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures shall be followed for continuous monitoring systems measuring opacity of emissions. Minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photo detector assembly.

[40 CFR 60.13(d)(1) and (2)]

A.28. Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems (CMS) shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

[40 CFR 60.13(e)(1) and (2)]

A.29. All continuous monitoring systems (CMS) or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of Appendix B of 40 CFR 60 shall be used. [40 CFR 60.13(f)]

A.30. When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems (CMS) on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system. [40 CFR 60.13(g)]

A.31. Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in 40 CFR 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non reduced form (e.g., ppm pollutant and percent O_2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity). [40 CFR 60.13(h)]

A.32. For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:

(1) Methods 6, 7, and 3B, as applicable, shall be used for the performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B are given in 40 CFR 60.46(d).

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of Appendix B to 40 CFR 60.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:

Fossil fuel	**Span value for sulfur dioxide (ppm)**	**Span value for nitrogen oxides (ppm)**
Gas	{1}	500
Liquid	1,000	500
Combinations	1,000y	500(x+y)

{1}Not applicable.

where:

x = the fraction of total heat input derived from gaseous fossil fuel, and

y = the fraction of total heat input derived from liquid fossil fuel.

(4) All span values computed under 40 CFR 60.45(c)(3) for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm.

(5) For a fossil fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all continuous monitoring systems shall be subject to the Administrator's approval.

[40 CFR 60.45(c)]

A.33. For any continuous monitoring system installed under 40 CFR 60.45(a), the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):

(1) When a continuous monitoring system for measuring oxygen is selected, the measurement of the pollutant concentration and oxygen concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$E = CF[20.9/(20.9\text{-percent } O_2)]$

where:

E, C, F, and % O_2 are determined under 40 CFR 60.45(f).

(2) When a continuous monitoring system for measuring carbon dioxide is selected, the measurement of the pollutant concentration and carbon dioxide concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$E = CF_c\,[100/\text{percent } CO_2]$

where:

E, C, F_c and %CO_2 are determined under 40 CFR 60.45(f).

[40 CFR 60.45(e)]

A.34. The values used in the equations under 40 CFR 60.45(e) (1) and (2) are derived as follows:

(1) E = pollutant emissions, ng/J (lb/million Btu).

(2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^4 M ng/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for sulfur dioxide and 46.01 for nitrogen oxides.

(3) % O_2, %CO_2 = oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under 40 CFR 60.45(a).

(4) F, Fc = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

iii. For liquid fossil fuels including crude, residual, and distillate oils, $F = 2.476 \times 10^{-7}$ dscm/J (9,220 dscf/million Btu) and $F_c = 0.384 \times 10^{-7}$ scm CO_2 /J (1,430 scf CO_2 /million Btu).

iv. For gaseous fossil fuels, F = 2.347 $\times 10^{-7}$ dscm/J (8,740 dscf/million Btu). For natural gas, propane, and butane fuels, $F_c = 0.279 \times 10^{-7}$ scm CO_2 /J (1,040 scf CO_2 /million Btu) for natural gas, 0.322×10^{-7} scm CO_2 /J (1,200 scf CO_2/million Btu) for propane, and 0.338×10^{-7} scm CO_2 /J (1,260 scf CO_2 /million Btu) for butane.

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/million Btu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or F_c factor (scm CO_2 /J, or scf CO_2 /million Btu) on either basis in lieu of the F or F_c factors specified in 40 CFR 60.45(f)(4):

SI Units:

$$F = 10^{-6} \frac{[227.2\ (\text{pct. II}) + 95.5\ (\text{pct. C}) + 35.6\ (\text{pct. S}) + 8.7\ (\text{pct. N}) - 28.7\ (\text{pct. O})]}{\text{GCV}}$$

$$F_c = \frac{2.0\text{x}10^{-5}\ (\text{pct. C})}{\text{GCV}}$$

English Units:

$$F = 10^{6}\ \frac{3.64(\%\text{H}) + 1.53(\%\text{C}) + 0.57(\%\text{S}) + 0.14(\%\text{N}) - 0.46(\%\text{O})}{\text{GCV}}$$

SI Units:

$$F_c = \frac{20.0(\%\text{C})}{\text{GCV}}$$

English Units:

$$F_c = \frac{321\text{x}10^{3}\ (\%\text{C})}{\text{GCV}}$$

i. H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, or computed from results using ASTM method D1137-53(75), D1945-64(76), or D1946-77 (gaseous fuels) as applicable. (These three methods are incorporated by reference-see 40 CFR 60.17.)

ii. GCV is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test method D1826-77 for gaseous fuels as applicable. (This method is incorporated by reference-see 40 CFR 60.17.)

iii. For affected facilities which fire both fossil fuels and nonfossil fuels, the F or F_c value shall be subject to the Administrator's approval.

(6) For affected facilities firing combinations of fossil fuels, the F or F_c factors determined by paragraphs 40 CFR 60.45(f)(4) or (f)(5) shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \qquad \text{or} \qquad F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

where:

X_i = the fraction of total heat input derived from each type of fuel (e.g. natural gas, etc.)

F_i or $(F_c)_i$ = the applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section.

n = the number of fuels being burned in combination.

[40 CFR 60.45(f)]

A.35. Operation and maintenance of continuous emissions monitoring (CEM) systems shall be carried out according to the requirements of 40 CFR 60; reports thereof shall be submitted to the Department's Southeast District Office within thirty (30) days following each calendar quarter and will include information required under 40 CFR 60.7(c). The Department reserves the right to modify the format of the reports. For any periods of excess emissions, as defined in 40 CFR 60.45(g), the reports shall specify the cause and corrective actions taken as well as the specific operational conditions existing (i.e., steady-state output, load charging rate; sootblowing, limiting, or air preheated steam cleaning sequences), during the period of excess emissions.
[AO43-170568, Specific Condition No. 4; AO43-170567, Specific Condition No. 4]

Recordkeeping and Reporting Requirements

A.36. The owner or operator subject to the provisions of 40 CFR 60 shall furnish the Administrator written notification as follows:

(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.

[40 CFR 60.7(a)(4)]

A.37. The owner or operator subject to the provisions of 40 CFR 60 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)]

A.38. The owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form [see 40 CFR 60.7(d)] to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or, the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or, the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate). 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), (2), (3), and (4)]

A.39. The summary report form shall contain the information and be in the format shown in Figure 1 (attached) unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 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 Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 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.

{See attached Figure 1: Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance}

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

A.40. (1)Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), an owner or operator 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 full 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. The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and

iii. The Administrator 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 the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator 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 an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator 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 owner or operator 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 the applicable standard for another

full year, the owner or operator may again request approval from the Administrator 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)]

A.41. The owner or operator subject to the provisions of 40 CFR 60 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); Rule 62-213.440(1)(b)2.b., F.A.C.]

A.42. Records shall be kept of each delivery of "on-specification" used oil with a statement of the origin of the used oil and the quantity delivered/stored for firing. In addition, monthly records shall be kept of the quantity of "on-specification" used oil fired in these emissions units. The above records shall be maintained in a form suitable for inspection, retained for a minimum of five years, and be made available upon request. See Specific Conditions **A.11., A.21**., and **A.4**3.
[Rule 62-213.440(1)(b)2.b., F.A.C.; and 40 CFR 279.61 and 761.20(e)]

A.43. The permittee shall include in the "Annual Operating Report for Air Pollutant Emitting Facility" a summary of the "on-specification" used oil analyses for the calendar year and a statement of the total quantity of "on-specification" used oil fired in Fossil Fuel Fired Steam Generators Nos. 1 and 2 during the calendar year. See Specific Conditions **A.11., A.21**., and **A.42**.
Rule 62-213.440(1)(b)2.b., F.A.C.]

A.44. Until such time when the Environmental Protection Agency (EPA) promulgates final rules regarding fuel sampling and test methods, the Department will accept the current fuel sampling and analysis program, provided that daily as fired fuel oil samples are composited and analyzed for sulfur content on a monthly basis to demonstrate compliance with fuel oil sulfur content limits. Quarterly reports containing the results of the monthly fuel oil sampling and analysis shall be submitted to the Department no later than thirty (30) days after the end of each quarter.

The permittee shall be allowed 90 days after promulgation of fuel sampling and analysis methods to implement an EPA approved method of monitoring sulfur dioxide emissions either by fuel sampling and analysis methods or continuous in-stack monitoring or other methods as approved under the provisions of 40 CFR 60.45.
[AO43-170568, Specific Condition No. 5; and AO43-170567, Specific Condition No. 5.]

A.45. <u>COMS for Periodic Monitoring</u>. The owner or operator is required to install continuous opacity monitoring systems (COMS) pursuant to 40 CFR Part 75. The owner or operator shall maintain and operate COMS and shall make and maintain records of opacity measured by the COMS, for purposes of periodic monitoring.
[Rule 62-213.440, F.A.C.; and applicant agreement with EPA on March 3, 1998.]

<u>Miscellaneous</u>

A.46. <u>Circumvention.</u> No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere. [40 CFR 60.12]

A.47. The emissions units are also subject to the conditions contained in **Subsection E. Common Conditions.**

Subsection B. This section addresses the following emissions units.

E.U. ID No.	Brief Description
-003	Combustion Turbine with Heat Recovery Steam Generator (CT 3A)
-004	Combustion Turbine with Heat Recovery Steam Generator (CT 3B)
-005	Combustion Turbine with Heat Recovery Steam Generator (CT 4A)
-006	Combustion Turbine with Heat Recovery Steam Generator (CT 4B)

All four combined cycle units are identical in configuration. Nitrogen oxide emissions are controlled by using dry low NOx combustors for natural gas with steam injection for fuel oil firing. Steam injection is also used for power augmentation. Inlet foggers installed at the compressor inlet to each of the four CTs reduce the turbine inlet air temperature. The temperature reduction improves the heat rate and increases power due to the cooler/denser inlet air. Duct modules suitable for future installation of selective catalytic reduction (SCR) equipment have been installed on each combined cycle generating unit. Based on information contained in the initial Title V Permit Application, and recent correspondence from the Applicant, only natural gas has been fired in the units to date. Units 003 and 004 commenced commercial operation in February 1994. Units 005 and 006 commenced commercial operation in April 1994.

Compliance assurance monitoring (CAM) is not applicable to these combustion turbines since dry low-NOx combustors when firing natural gas are not considered a pollution control device under 40 CFR 64. When firing distillate fuel oil, the underlying emissions limits are based on CEMS and, therefore, the requirements of CAM are not required.

{Permitting notes: the emissions units are regulated under Acid Rain, Phase II and NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines; adopted and incorporated by reference in Rule 62-204.800(7)(b)38., F.A.C; PSD-FL-146, Prevention of Significant Deterioration (PSD), in Rule 62-212.400, F.A.C.; and Best Available Control Technology (BACT), in Rule 62-212.410, F.A.C.}

The following conditions apply to the emissions units listed above:

General

B.1. Definitions. For the purposes of Rule 62-204.800(7), F.A.C., the definitions contained in the various provisions of 40 CFR 60, shall apply except that the term "Administrator" when used in 40 CFR 60, shall mean the Secretary or the Secretary's designee. [40 CFR 60.2; Rule 62-204.800(7)(a), F.A.C.]

B.2. Circumvention. No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere. [40 CFR 60.12]

Essential Potential to Emit (PTE) Parameters

B.3. Permitted Capacity. The maximum heat input to each Combustion Turbine (CT) shall neither exceed 1966 mmBtu/hr while firing natural gas, nor 1846 mmBtu/hr while firing fuel oil @ 40 degrees F. These heat input limitations are subject to change. Any changes shall be provided at least 90 days before commercial operation for each fuel available to the site which a unit is capable of firing, at which time this condition may be modified to reflect those parameters. Each combined cycle's fuel consumption shall be continuously determined and recorded.

Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

If tested at less than capacity, the entire heat input versus inlet temperature curves will be adjusted by the increment equal to the difference between the design heat input value and 110 percent of the value reached during the test. Data, curves, and calculations necessary to demonstrate the heat input rate correction at both design and test conditions shall be submitted to the Department with the compliance test report.

[Rules 62-4.160(2), Rule 62-297.310(2), and 62-210.200(PTE), F.A.C.; and PSD-FL-146 and PSD-FL-146A (0850001-002 and 0850001-003-AC issued 9/6/96), Specific Condition No. 1 and Applicant Request dated April 5, 2006, Permit No. 0850001-016-AC]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability.}

B.4. Methods of Operation.

(a) Fuels. Only natural gas or No. 2 fuel oil shall be fired in the CTs.

(b) Inlet Foggers. Operation of the foggers on each unit may not exceed the following limits: 181,661 degree F-hours in aggregate firing natural gas fuel if no distillate fuel is fired. If distillate oil is fired in any of the CTs during a calendar year, the allowable degree F-hours for natural gas shall be decreased by 2.77 degree F-hours for every hour operated on distillate oil fuel. No CT may exceed 4,000 degree F-hours per year firing distillate oil fuel.

{Permitting Note: The permittee shall monitor both the hours of operation for the inlet foggers and the degrees of cooling afforded by the inlet foggers. Computation of the degree-hour will be performed as follows:

Degree-hours = # hours inlet fogger operating time X degrees F of cooling

Degrees of Cooling shall be calculated by subtracting the fogged compressor inlet air temperature from the unfogged compressor inlet temperature (upstream of the fogger). The above calculation shall be performed for each hour of fogger operation. Calculation records shall be maintained on the plant site and made available for inspection upon request.}

The temperature drop across the inlet foggers shall be monitored whenever water is injected at the foggers and hourly average temperature drops shall be calculated and recorded along with hours of operation automatically using a computer system. The product of each hour of fogger operation and the average temperature depression for that hour (degree F-hours) shall be summed for each calendar year and shall be submitted to the DEP SE District Office with the Annual Operating Report. The temperature monitoring system shall be calibrated annually (see Specific Condition **B.52.**).

[PSD-FL-146, Specific Condition No. 3; PSD-FL-146(G); and 0850001-005-AC.]

B.5. Hours of Operation. The emissions units may operate continuously, i.e., 8760 hours/year/CT. [Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

*{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions **B.6.** through **B.8.** are based on the specified averaging time of the applicable test method.}*

B.6. The maximum allowable emissions from each CT, in accordance with the BACT determination, shall not exceed the following, at 40 degrees F, except during periods of startup and shutdown:

		Emission Limitations [d]		
Pollutant	**Fuel**	**Concentration**	**lb/hr/CT**	**TPY/CT** [a]
NOx	Gas Oil	25 ppmvd @ 15% O_2 65 ppmvd @ 15% O_2	177 461	3108 (combined gas and oil total)
VOC [b]	Gas Oil	1.6 ppmvd 6 ppmvd	3 11.0	57 (combined gas and oil total)
CO	Gas Oil	30 ppmvd 33 ppmvd	94.3 105.8	871 (combined gas and oil total)
PM/PM_{10}	Gas Oil		18 60.6	100 (combined gas and oil total)
Pb	Gas Oil		negligible 0.015	0.015 (combined gas and oil total)
SO_2	Gas Oil [c]		91.5 920	568 (combined gas and oil total)

[a] Tons per year (TPY) emission limits listed for natural gas and oil combined apply as an emissions cap based on limiting oil firing to an annual aggregate of 2,000 hours for the 4 CT's, with compliance to be demonstrated in annual operation reports.

[b] Exclusive of background concentrations.

[c] Sulfur dioxide emissions based on a maximum of 0.5 percent sulfur content, by weight, in oil for hourly emissions and an average sulfur content of 0.3 percent, by weight, for annual emissions. These sulfur content limitations are subject to change based on the analysis required in PSD Specific Condition No. 12. (See specific condition B.49.)

[d] These limitations for Units 5 and 6 shall not be binding for subsequent BACT determinations.

[PSD-FL-146, Specific Condition No. 4.]

B.7. The following emissions, determined by BACT, are tabulated for PSD and inventory purposes:

		Maximum Allowable Emissions (@40 ^{0} F)	
Pollutant	**Fuel**	**lb/hr/CT**	**TPY/CT** [a]
H_2SO_4 Acid Mist [b]	Gas Oil	11.2 113	70 (combined gas and oil total)
Mercury	Gas Oil	0.021 0.0052	0.34 (combined gas and oil total)
Fluoride	Oil	0.055	0.055
Beryllium	Oil	0.004	0.004

[a] Tons per year (TPY) emission limits for natural gas and oil combined apply as an emissions cap based on limiting oil firing to an annual aggregate of 2,000 hours for the 4 CT's, with compliance to be demonstrated in annual operation reports.

[b] Sulfuric acid mist emissions assume a maximum of 0.5 percent sulfur content, by weight, in fuel oil for hourly emissions and an average sulfur content of 0.3 percent, by weight, for annual emissions.

[PSD-FL-146, Specific Condition No. 5.]

B.8. Opacity. Visible emissions shall neither exceed 10% opacity while burning natural gas, nor 20% opacity while burning distillate oil. [PSD-FL-146, Specific Condition No. 8.]

B.9. Opacity. Compliance with standards in 40 CFR 60, other than opacity standards, shall be determined in accordance with performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard. [40 CFR 60.11(a)]

B.10. Opacity. The opacity standards set forth in 40 CFR 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard. [40 CFR 60.11(c)]

B.11. Nitrogen Oxides. Nitrogen oxide emissions from each gas turbine/heat recovery steam generator unit shall be controlled by using dry low NOx combustors for natural gas with steam injection for fuel oil firing. The permittee has installed duct modules suitable for future installation of SCR equipment on each combined cycle generating unit. [PSD-FL-146, Specific Condition No. 9.]

Excess Emissions

B.12. 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 hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

B.13. 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.]

B.14. 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.]

B.15. The excess emissions authorized under Rule 62-210.700(1), F.A.C., shall be extended an additional two hours (four hours total) for a cold steam turbine start for the first CT of a unit. The second CT of each unit shall comply with established emission limits in accordance with Rule 62-210.700(1), F.A.C. [PSD-FL-146, Specific Condition No. 4.]

B.16. 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)]

Monitoring of Operations

B.17. 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 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)]

B.18. The owner or operator of any stationary gas turbine subject to the provisions of 40 CFR 60, Subpart GG and using water injection to control NOX emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to within ±5.0 percent and shall be approved by the Administrator. This specific condition does not apply if only natural gas is fired in the turbine. [40 CFR 60.334(a)]

B.19. The owner or operator of any stationary gas turbine subject to the provisions of 40 CFR 60, Subpart GG shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

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

(2) If the turbine is supplied its fuel without intermediate bulk storage, the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with 40 CFR 60.334(b).

[40 CFR 60.334(b)(1) and (2)]

B.20. The Martin Plant facility requested approval for and was granted approval to utilize a customized fuel monitoring schedule for natural gas firing, pursuant to 40 CFR 60.334(b). See specific condition **B.19.** The schedule is as follows:

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. The reference methods are ASTM D1072-80, ASTM D3031-81, ASTM D3246-81, and ASTM D4084-82, as referenced in 40 CFR 60.335(b)(2), or the latest edition(s).

b. This custom fuel monitoring schedule shall become effective on the date this permit becomes valid. 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, 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. 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, sample analysis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.

d. d. Should any sulfur analysis as required in items 2(b) or 2(c) above indicate noncompliance with 40 CFR 60.333, the owner or operator shall notify the Department of such excess emissions and thecustom schedule shall be re-examined by the Environmental Protection Agency. 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 fuel quality 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.

[PSD-FL-146; and NSPS Custom Fuel Monitoring Schedule dated 10/14/97.]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

B.21. To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the Department to determine the nitrogen content of the fuel being fired. This specific condition does **not apply** if only natural gas is fired in the turbine. [40 CFR 60.335(a)]

B.22. 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 the permitted NO_X standard 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. This specific condition does **not apply** if only natural gas is fired in the turbine. [40 CFR 60.335(c)(2)]

B.23. The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 as follows:

U.S. EPA. Method 20 (40 CFR 60, Appendix A) 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 NO_X emissions shall be determined at each of the load conditions specified

in 40 CFR 60.335(c)(2). See Specific Condition **B.20.** that describes the approved Custom Fuel Monitoring Schedule for Natural Gas for this facility. After initial testing, subsequent annual NO_X compliance tests for NO_X limits that are more stringent than 40 CFR 60, Subpart GG, shall not require an ISO correction or testing at four load points; rather, the testing shall be done at capacity (see Specific Condition **B.3.**). However, when testing shows that NO_X emissions exceed the standard when operating at capacity, the permittee shall recalibrate the NO_X emission control system using emission testing at four load points.
[40 CFR 60.335(c)(3); and applicant request letter dated July 29, 1998]

B.24. The owner or operator shall determine compliance with the sulfur content standard of 0.5 percent, by weight, as follows: ASTM D 2880-96 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-90(94)E-1, D 3031-81(86), D 4084-94, or D 3246-92 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. See specific condition B.20 that describes the approved Custom Fuel Monitoring Schedule for Natural Gas for this facility.
[40 CFR 60.335(d)]

B.25. To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in 40 CFR 60.335 (a) and 40 CFR 60.335(d) of 40 CFR 60.335 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. See Specific Condition **B.20** that describes the approved Custom Fuel Monitoring Schedule for Natural Gas for this facility. [40 CFR 60.335(e)]

B.26. The owner or operator shall provide, or cause to be provided, stack sampling and performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facilities.

(2) Safe sampling platform(s).

(3) Safe access to sampling platform(s).

(4) Utilities for sampling and testing equipment.

[40 CFR 60.8; PSD-FL-146, Specific Condition No. 21]

B.27. It is not necessary to plan the firing of a fuel solely to complete the initial compliance test, instead, the initial test may be postponed until such time as the untested fuel is ready for service. Initial (I) compliance tests shall be performed on each Combustion Turbine using both fuels. The stack test for each turbine shall be performed within 10% of the maximum heat rate input for the tested operating temperature. Tests shall be conducted using EPA reference methods, or equivalent, in accordance with 40 CFR 60 Appendix A. (Note: based on information provided in the Title V Permit Application, initial testing using distillate oil has **not been done.**) See Specific Condition **B.3** for utilization of ambient temperature versus heat input curves during compliance testing.

Pollutant	**EPA Reference Method**	**Initial testing**		**Annual testing**	
		Gas	**Oil**	**Gas**	**Oil**
Particulate Matter	5 or 17		X		X
Sulfuric Acid Mist	8		X		
Visible Emissions	9	X	X	X	X
Carbon Monoxide	10	X	X	X	X
Nitrogen Oxides	7E, 20	X	X	X	X
Volatile Organic Compounds	18, 25 or 25A	X	X		
	Test Method				
Lead	EMTIC Test Method, or Method 7090, or 7091*		X		
Beryllium	EMTIC Test Method, or Method 104, or Method 7090, or 7091*		X		
Sulfur content	ASTM D 2880-96		X		X
	ASTM D 1072-90(94) E-1, ASTM D 3031-81(86), ASTM D 4084-94, or ASTM D 3246-92	X		X	
Mercury	40 CFR 61, Appendix B EPA Method 101	X	X		

*Method 3040 sample extraction shall be used as described in the EPA solid waste regulations SW 846.

{Note: EPA Method 18 may be conducted to account for the non-regulated methane fraction of the measured VOC emissions}

Annual (A) compliance tests shall be conducted for each combustion turbine to demonstrate compliance with CO, NOx, PM and visible emissions (VE) standards for normal gas firing, gas firing with power augmentation, and backup distillate oil firing. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). CO and NOx performance tests shall be conducted concurrently. If conducted at permitted capacity, NOx emissions data collected during the annual NOx continuous monitor RATA required pursuant to 40 CFR 75 may me substituted for the required annual performance test.

For each combustion turbine that fires distillate oil for less than 200 hours during the previous federal fiscal year, the annual performance tests when firing distillate oil for the current federal fiscal year of operation are not required.

For each combustion turbine that operates with power augmentation for less than 200 hours during the previous federal fiscal year, the annual performance tests when operating with power augmentation for the current federal fiscal year of operation are not required.
[40 CFR Appendix A; Rule 62-204,800, F.A.C. and Rule 62-297.310(7)(a)4.,F.A.C.,PSD-FL-146, Specific Condition No. 10; and applicant request letter dated July 28, 1998 and April 5, 2006.]

B.28. The average sulfur content of the light distillate oil shall not exceed 0.3%, by weight, during any consecutive 12-month period. The maximum sulfur content of the light distillate fuel oil shall not exceed 0.5%, by weight. The 12-month average sulfur content shall be calculated as a weighted average based upon the sulfur content of the oil and the amount burned on a daily basis. Compliance shall be demonstrated in accordance with the requirements of 40 CFR 60.334 by testing for sulfur content, for nitrogen content, and for heating value of oil storage tanks once per day when firing oil using ASTM D 2880-96.
[Rule 62-213.440, F.A.C., applicant agreement with EPA on March 3, 1998, and PSD-FL-146, Specific Condition No. 11]

B.29. Opacity. Compliance with opacity standards in 40 CFR 60 shall be determined by conducting observations in accordance with Reference Method 9 in Appendix A of 40 CFR 60, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5).
[40 CFR 60.11(b)]

B.30. Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard. [40 CFR 60.8(c)]

Continuous Monitoring Requirements

B.31. Continuous emissions monitoring shall be installed, operated, and maintained in accordance with 40 CFR 75 for each combined cycle unit to monitor nitrogen oxides.

(a) Each continuous emissions monitoring system (CEMS) shall meet performance specifications of 40 CFR 75, Appendices A, B, and F.

(b) CEMS data shall be recorded and reported in accordance with 40 CFR 75 and 40 CFR 60.7. The excess emissions report shall include periods of startup, shutdown, and malfunction and shall be based on NOx data corrected to 15 % O_2 and 40 degrees F.

(c) A malfunction means any sudden and unavoidable failure of air pollution 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.

(d) For purposes of reports required under this permit, excess emissions are defined as any calculated average emission concentration which exceeds the applicable emission limits in specific condition **B.6.** See specific condition **B.39.**

[PSD-FL-146, Specific Condition No. 13]

B.32. For the purposes of 40 CFR 60.13, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of 40 CFR 60.13 upon promulgation of performance specifications for continuous monitoring systems under Appendix B of 40 CFR 60 and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, Appendix F of 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987. [40 CFR 60.13(a)]

B.33. If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, Appendix B, of 40 CFR 60 before the performance test required under 40 CFR

60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under 40 CFR 60.8 or within 30 days thereafter in accordance with the applicable performance specification in Appendix B of 40 CFR 60. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act. [40 CFR 60.13(c)]

B.34. The owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under 40 CFR 60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under 40 CFR 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under 40 CFR 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under 40 CFR 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in 40 CFR 60.13(c), that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine opacity compliance. [40 CFR 60.11(e)(5)]

B.35.

(1) Owners and operators of all continuous emission monitoring systems (CEMS) installed in accordance with the provisions of this part shall check the zero (or low-level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in Appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified. For continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments except that for systems using automatic zero adjustments. The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures shall be followed for continuous monitoring systems measuring opacity of emissions. Minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photo detector assembly.

[40 CFR 60.13(d)(1) and (2)]

B.36. Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems (CMS) shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

[40 CFR 60.13(e)(1) and (2)]

B.37. All continuous monitoring systems (CMS) or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of Appendix B of 40 CFR 60 shall be used.
[40 CFR 60.13(f)]

B.38. When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems (CMS) on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system. [40 CFR 60.13(g)]

B.39. Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in 40 CFR 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non-reduced form (e.g., ppm pollutant and percent O_2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity). [40 CFR 60.13(h)]

<u>Recordkeeping and Reporting Requirements</u>

B.40. To determine compliance with the oil firing heat input limitation, the permittee shall maintain daily records of fuel oil consumption and hourly usage for each turbine and heating value for each fuel. All records shall be maintained for a minimum of five (5) years after the date of each record and shall be made available to representatives of the Department upon request.
[PSD-FL-146, Specific Condition No. 14]

B.41. The permittee shall have required sampling tests of the emissions performed within 60 after achieving the maximum turbine firing rate, but not later than 180 days from the start of operations. Thirty (30) days notice prior to the initial sampling test and fifteen (15) days notice before subsequent annual testing shall be provided to the Southeast District Office. Written reports of the

tests shall be submitted to the Southeast District Office within 45 days of test completion. [PSD-FL-146, Specific Condition No. 17]

B.42. Quarterly excess emission reports, in accordance with the July 1, 1996, version of 40 CFR 60.7(c) and 60.334(c), shall be submitted to the Department's Southeast District Office.

Annual reports shall be submitted to the District office in accordance with Rule 62-2.700(7), F.A.C.

[PSD-FL-146, Specific Condition No. 19]

B.43. For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

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 the permitted nitrogen oxide standard by the initial 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 initial performance test. 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).

[Rule 62-296.800, F.A.C.; 40 CFR 60.334(c)(1)]

B.44. The owner or operator subject to the provisions of 40 CFR 60 shall furnish the Administrator written notification as follows:

(4)A notification of any <u>physical or operational change</u> to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.

[40 CFR 60.7(a)(4)]

B.45. The owner or operator subject to the provisions of 40 CFR 60 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)]

B.46. The owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report and/or a summary report form [see 40 CFR 60.7(d)] to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or, the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or, the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate). 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), (2), (3), and (4)]

B.47. The summary report form shall contain the information and be in the format shown in Figure 1 (attached) unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 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 Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 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.

{See attached Figure 1: Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance}

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

B.48. <u>Reporting Frequency Reduction.</u>

(1) Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), an owner or operator 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 full 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. The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and

iii. The Administrator 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 the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator 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 an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the

future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator 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 owner or operator 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 the applicable standard for another full year, the owner or operator may again request approval from the Administrator 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)]

B.49. The owner or operator subject to the provisions of 40 CFR 60 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); Rule 62-213.440(1)(b)2.b., F.A.C.]

Miscellaneous

B.50. In the supplemental application for approval of Phase II of the Project, the applicant shall include a cumulative air quality impact analysis and a PSD increment consumption analysis for the Everglades National Park Class I area. [PSD-FL-146, Specific Condition No. 12]

B.51. The emissions units are also subject to the conditions contained in **Subsection E. Common Conditions.**

B.52. Temperature Monitoring System Calibration. The temperature monitoring system shall be calibrated annually from 10 percent below to 10 percent above its normal operation range by the procedures recommended by the manufacturer. The temperature monitoring system generally consists of a thermocouple, a temperature indicator, and a recorder. The purpose of the calibration is to provide reasonable assurance that the temperature being recorded by the monitoring system is the actual temperature of the inlet air.

If the manufacturer has provided recommended calibration procedures, those procedures should be followed. If the manufacturer has not provided recommended calibration procedures, the following general calibration procedures should be used:

THERMOCOUPLE: The calibration points should bracket the temperature range over which the thermocouple is to be used. The thermocouple should be calibrated against a NIST (National Institute of Standards and Technology) traceable reference thermocouple. The thermocouple may be calibrated using ASTM E 220, Method B. Alternatively, the thermocouple can be replaced each year with a new thermocouple certified by the manufacturer to be accurate to within 0.9% of the temperatures being measured. A certificate of conformance from the manufacturer (certifying that the new thermocouple conforms to published specifications) will satisfy the annual calibration requirements.

TEMPERATURE INDICATOR: The instrument, which converts voltage output from the thermocouple to a temperature reading, can be calibrated by applying known voltages (mv), and reading the reported temperatures. The voltage values should correspond to the voltages generated by the thermocouple for temperatures over a range from 10% below to 10% above the inlet air temperatures to be used. The reference voltage supply should be accurate to within 0.1% of the reading.

RECORDER: The strip chart recorder or digital data acquisition system should be connected to the temperature indicator during its calibration and can be calibrated at the same time. The recorder should be adjusted to reproduce the readings of the temperature indicator.

The temperature monitoring system calibration error should not exceed 1% of the temperature reading.

[PSD-FL-146(G); 0850001-005-AC; and, Rule 62-297.310(5)(b)]

Subsection C. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
-007	Auxiliary Boiler

This emissions unit is used to produce steam (60,000 lb/hr) to actuate the steam seals on the steam turbine components of the combined-cycle units (Emissions Units 003, 004, 005, and 006) during cold starts when steam is not otherwise available for this purpose. Initial startup of Emissions Unit 007 was on July 15, 1993.

Because the unit has no installed pollution control devices, the unit is not subject to compliance assurance monitoring (CAM).

{Permitting Notes: The emissions unit is regulated under NSPS - 40 CFR 60.40c, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units; adopted and incorporated by reference in Rule 62-204.800(8), F.A.C.; and 40 CFR 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, or Institutional Boilers or Process Heaters, adopted by reference in Rule 62-204.800(11), F.A.C., Rule 212.400, F.A.C.; Prevention of Significant Deterioration (PSD), Best Available Control Technology (BACT); and Air Construction Permits PSD-FL-146}.

The following conditions apply to the emissions unit listed above:

General

C.1. Definitions. For the purposes of Rule 62-204.800(7), F.A.C., the definitions contained in the various provisions of 40 CFR 60, shall apply except that the term "Administrator" when used in 40 CFR 60, shall mean the Secretary or the Secretary's designee.
[40 CFR 60.2; Rule 62-204.800(7)(a), F.A.C.]

C.2. Circumvention. No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere. [40 CFR 60.12]

Essential Potential to Emit (PTE) Parameters

C.3. Hours of Operation. The auxiliary boiler shall operate only during startup and shutdown of the combined-cycle units, and for periodic maintenance testing.
[Rule 62-210.200(PTE), F.A.C.; PSD-FL-146, revised 7/19/93]

C.4. Fuels. Only natural gas or No. 2 light distillate fuel oil shall be fired in the auxiliary boiler. Based on the Title V Permit Application, the unit is currently only capable of firing natural gas.
[PSD-FL-146, Specific Condition No. 3]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

*{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions **C.5.** through **C.10.** are based on the specified averaging time of the applicable test method.}*

C.5. Visible Emissions. Visible emissions shall not exceed twenty (20) percent opacity (6-minute average), except for one six-minute period per hour of not more than twenty seven (27) percent

opacity. This standard applies at all times, except during periods of startup, shutdown, or malfunction. [40 CFR 60.43c(c) & (d)]

C.6. Compliance with standards in 40 CFR 60, other than opacity standards, shall be determined in accordance with performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard. [40 CFR 60.11(a)]

C.7. Opacity. The opacity standards set forth in 40 CFR 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard. [40 CFR 60.11(c)]

C.8. Sulfur Dioxide. Sulfur dioxide emissions limitations for the auxiliary steam boiler are established by firing natural gas or limiting the light distillate fuel oil's average sulfur content to 0.3%, by weight, during any consecutive 12-month period. The 12-month average sulfur content shall be calculated as a weighted average based upon the sulfur content of the oil and the amount burned on a daily basis.
[Rule 62-213.440, F.A.C., applicant agreement with EPA on March 3, 1998, and PSD-FL-146, revised 7/19/93]

C.9. For units listed under 40 CFR 60.42c(h)(1), compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under 40 CFR 60.48c(f)(1), as applicable.

(1) Distillate oil-fired units with heat input capacities between 2.9 and 29 MW (10 and 100 million Btu/hr).

[40 CFR 60.42c(h)(1)]

C.10. Nitrogen Oxides. NOx emissions for the auxiliary steam boiler shall not exceed 0.3 lb/mmBtu for natural gas firing or oil firing. [PSD-FL-146, revised 7/19/93]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

C.11. Compliance and performance test methods and procedures for sulfur dioxide. Compliance with the percent reduction requirements and SO2 emission limits under 40 CFR 60.42c is based on the average percent reduction and the average S02 emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO2 emission rate are calculated to show compliance with the standard. **Note:** no annual testing is required if operational hours are less than 400 hours per year on oil. However, testing is required for permit renewal purposes. [40 CFR 60.44c(c); and, Rule 62-297.310(7), F.A.C.]

C.12. If only oil is combusted in a unit, the procedures in Method 19 are used to determine the hourly SO2 emission rate (E_h) and the 30-day average SO2 emission rate (E_a). The hourly averages used to compute the 30-day averages are obtained from the continuous emission monitoring system (CEMS). Method 19 shall be used to calculate E_a when using daily fuel sampling or Method 6B.

E_h is defined as the hourly average pollutant rate, in ng/J (lb/million Btu heat input), and

E_a, defined as the average pollutant rate for the specified performance test period, in ng/J (lb/million Btu heat input), is computed using the following equation:

$$E_a = (1/H)\sum_{j=1}^{n} E_{hj}$$

Where

H= total number of operating hours for which pollutant rates are determined in the performance test period.

[40 CFR 60.44c(d) & 40 CFR 60, Appendix A.]

C.13. EPA Method 9 shall be used for determining the opacity of stack emissions.
[40 CFR 60.45c(a)(7)]

C.14. Testing for the sulfur content, for the nitrogen content, and for the heating value of oil storage tanks shall be conducted once per day when firing oil using ASTM D 2880-96.
[PSD-FL-146, Specific Condition No. 11.]

C.15. Opacity. Compliance with opacity standards in 40 CFR 60 shall be determined by conducting observations in accordance with Reference Method 9 in Appendix A of 40 CFR 60, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5).
[40 CFR 60.11(b)]

C.16. Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard. [40 CFR 60.8(c)]

Recordkeeping and Reporting Requirements

C.17.

(b) The owner or operator of each unit subject to the SO2 emission limits of 40 CFR 60.42c, or the PM or opacity limits of 40 CFR 60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests.

(d) The owner or operator of each unit subject to the SO2 emission limits, fuel oil sulfur limits, or percent reduction requirements under 40 CFR 60.42c shall submit quarterly reports to the Administrator. The initial quarterly report shall be postmarked by the 30th day of the third month following the completion of the initial performance test. Each subsequent quarterly report shall be postmarked by the 30th day following the end of the reporting period.

(e) The owner or operator of each unit subject to the SO2 emission limits, fuel oil sulfur limits, or percent reduction requirements under 40 CFR 60.42c shall keep records and submit quarterly reports as required under 40 CFR 60.48c(d), including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO2 emission rate (ng/J or lb/million Btu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period in the quarter; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO2 emission rate calculated during the reporting period, ending with the last 30-day period in the quarter; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO2 or diluent (oxygen or carbon dioxide) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under 40 CFR 60.48c(f)(1), (2), or (3), as applicable. In addition to records of fuel supplier certifications, the quarterly report shall include a certified statement signed by the owner or operator of the unit that the records of fuel supplier certifications submitted represent all of the fuel combusted during the quarter.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

i. The name of the oil supplier; and

ii. A statement from the oil supplier that the oil complies with the specifications under the following definition of distillate oil:

"Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396-78, “Standard Specification for Fuel Oils”."

(g) The owner or operator of each unit shall record and maintain records of the amounts of each fuel combusted during each day.

(h) The owner or operator of each unit subject to a Federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under 40 CFR 60.42c or 40 CFR 60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

i. All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 5 (five) years following the date of such record. **Note:** As long as the auxiliary boiler operates only during startup and shutdown and for periodic maintenance testing, **C.17(d)** and **(e)** requirements under this specific condition are not applicable. See specific condition **C.3.**

[40 CFR 60.48c]

C.18. The owner or operator subject to the provisions of 40 CFR 60 shall furnish the Administrator written notification as follows:

(4)A notification of any <u>physical or operational change</u> to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.

[40 CFR 60.7(a)(4)]

C.19. The owner or operator subject to the provisions of 40 CFR 60 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)]

C.20. Reporting Frequency Reduction.

(1) Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), an owner or operator 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 full 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. The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and

iii. The Administrator 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 the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator 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 an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator 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 owner or operator 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 the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in 40 CFR 60.7(e)(1) and (e)(2). **Note:** As long as the auxiliary boiler operates only during startup and shutdown and for periodic maintenance testing, requirements under this specific condition are not applicable. See Specific Condition **C.3.**

[40 CFR 60.7(e)(1)]

C.21. The owner or operator subject to the provisions of 40 CFR 60 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); Rule 62-213.440(1)(b)2.b., F.A.C.]

C.22. This emissions unit is also subject to the conditions contained in **Subsection E. Common Conditions.**

Subsection D. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
-009	Diesel Generator

This unit is used to supply power to Emissions Units 003, 004, 005, and 006 during power outages. The nameplate rating is 0.718 MW. Emissions are uncontrolled.

NESHAP and NSPS Applicability

{Permitting Notes: The emissions unit is regulated under 40 CFR 63, Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE) adopted in Rule 62-204.800(11) F.A.C., Rule 212.400, F.A.C.; Prevention of Significant Deterioration (PSD), Best Available Control Technology (BACT); and Air Construction Permits PSD-FL-146}.

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

Essential Potential to Emit (PTE) Parameters

D.1. Hours of Operation. The diesel generator shall operate only for emergency power generation or periodic operational testing. [Rule 62-210.200(PTE), F.A.C.; and PSD-FL-146, revised 7/19/93.]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

*{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions **D.2.** through **D.3.** are based on the specified averaging time of the applicable test method.}*

D.2. Nitrogen Oxides. NOx emissions for the diesel generator shall not exceed 15.0 grams/hp-hr. [PSD-FL-146, revised 7/19/93.]

D.3. Sulfur Dioxide. Sulfur dioxide emissions limitations for the diesel generator are established by limiting the light distillate fuel oil's average sulfur content to 0.3%, by weight, during any consecutive 12-month period. The 12-month average sulfur content shall be calculated as a weighted average based upon the sulfur content of the oil and the amount burned on a daily basis. [Rule 62-213.440, F.A.C.; applicant agreement with EPA on March 3, 1998; and PSD-FL-146, revised 7/19/93.]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

D.4. Distillate fuel oil fired in the emergency diesel generator shall meet the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D 396-78 (or the latest edition), "Standard Specifications for Fuel Oils." Compliance with these specifications shall be verified with a fuel analysis provided by the vendor upon each fuel delivery.

[Requested by the applicant in electronic memorandum dated 09/18/97.]

Subsection E. **Common Conditions.**

E.U. ID No.	Brief Description
-001	Fossil Fuel Fired Steam Generator #1
-002	Fossil Fuel Fired Steam Generator #2
-003	Combustion Turbine with Heat Recovery Steam Generator (CT 3A)
-004	Combustion Turbine with Heat Recovery Steam Generator (CT 3B)
-005	Combustion Turbine with Heat Recovery Steam Generator (CT 4A)
-006	Combustion Turbine with Heat Recovery Steam Generator (CT 4B)
-007	Auxiliary Boiler
-011	Combustion Turbine with Heat Recovery Steam Generator (8A)
-012	Combustion Turbine with Heat Recovery Steam Generator (8B)
-017	Combustion Turbine with Heat Recovery Steam Generator (8C)
-018	Combustion Turbine with Heat Recovery Steam Generator (8D)
-013	Four gas-fired fuel heaters
-014	Two distillate oil storage tanks for Unit 8 gas turbines
-019	Mechanical draft cooling tower for Unit 8

The following conditions apply to the emissions units listed above:

Test Methods and Procedures

E.1. 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.]

E.1.1. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

E.2. 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:

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

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

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

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, 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.

TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass reference thermometer or equivalent, or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calibration liquid in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass reference thermometer, NBS calibrated reference and potentiometer	5 degrees F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Figures 2-2 and 2-3
Probe Nozzles	Before each test, or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of the last three readings; maximum deviation between readings .004"
Dry gas meter and Orifice Meter	1. Full scale: when received, when 5% change observed, annually. 2. One point: Semiannually. 3. Check after each test series.	Spirometer or calibrated wet test or dry gas test meter Comparison check	2% 5%

(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.]

E.3. 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.]

E.4. 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.]

E.5. 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.

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 and/or solid fuel for a total of no more than 400 hours.

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

a. 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.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

10. An annual compliance test conducted for visible emissions shall not be required for units exempted from permitting at Rule 62-210.300(3)(a), F.A.C., or units permitted under the General Permit provisions at Rule 62-210.300(4), F.A.C.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it 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) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means

other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.; SIP approved]

Recordkeeping and Reporting Requirements

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

E.7. 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 on the results of each such test.

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

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

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.

14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

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

Subsection F. Reserved.

Refer to Subsection H which replaced this Subsection. PSD-FL-286 for these units is superseded by PSD-FL-327 for the "4-on-1" combined cycle combustion turbine system.

Subsection G. Reserved.

Refer to Subsection I which replaced this Subsection. PSD-FL-286 for these units is superseded by PSD-FL-327 for the "4-on-1" combined cycle combustion turbine system

Subsection H. This section addresses the following emissions units.

E.U. ID No.	Emission Unit Description
011	Unit 8A gas turbine (170 MW) with heat recovery steam generator (495 MMBtu/hr)
012	Unit 8B gas turbine (170 MW) with heat recovery steam generator (495 MMBtu/hr)
017	Unit 8C gas turbine (170 MW) with heat recovery steam generator (495 MMBtu/hr)
018	Unit 8D gas turbine (170 MW) with heat recovery steam generator (495 MMBtu/hr)

Each unit consists of a nominal 170 MW General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, a heat recovery steam generator (HRSG) each equipped with a 495 MMBtu/hr natural gas fired duct burner, a stack , and associated support equipment. Steam from each HRSG is delivered to the single steam turbine-electrical generator, which has a nominal capacity of 470 MW. The total nominal generating capacity of the "4 on 1" combined cycle unit system is 1150 MW. Each stack is 120 ft tall (19 ft diameter). At a compressor inlet air temperature of 59° F, each gas turbine heat input (LHV) is approximately 1600 MMBtu/hr (gas) and 1811 MMBtu/hour (oil). The exhaust flow rate is 1,004,200 ACFM (gas) and 1,193,900 ACFM (oil) at a temperature of 202° F and 295° F respectively.

The units are fired with natural gas as the primary fuel and distillate oil as a restricted alternate fuel. The efficient combustion of natural gas at high temperatures minimizes emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC. NO_X emissions are reduced by Dry Low-NO_X (DLN) combustion technology (simple cycle mode). A selective catalytic reduction (SCR) system combined with Dry Low-NO_X (DLN) combustion technology further reduces NO_X emissions during combined cycle mode. These emissions units commenced commercial operation in June 2005.

Each gas turbine is equipped with continuous emissions monitoring system (CEMS) to measure and record CO and NO_X emissions as well as flue gas oxygen or carbon dioxide content.

Compliance assurance monitoring (CAM) does not apply since these emissions units have NOx CEMS which are used to demonstrate continuous compliance. The units have the following manufacturers' CEMs installed: (a) Thermo Environmental Instruments (Model 42CHL) for NOx, and (b) Servomex (Model 1420C) for O_2.

Emissions Units 8A and 8B commenced commercial simple cycle operation in November 2001. In a permitting action issued on 2003, these two existing units in addition to two new units conformed the "4-on-1" combined cycle combustion system (Units 8A, 8B, 8C and 8D) that commenced commercial operation on June 30, 2005.

{Permitting note: These emissions units are regulated under Acid Rain-Phase II, 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines; 40CFR60, Subpart Da, Standards of Performance for Electric Utility Generating Units for Which Construction is Commenced After September 18, 1978, and 40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, all adopted by reference in Rule 62-204.800(8) and in Rule 62-204.800(11), F.A.C., Rule 212.400, F.A.C.; Prevention of Significant Deterioration (PSD), Best Available Control Technology (BACT); and Air Construction Permits PSD-FL-286 and PSD-FL-327 (0850001-010-AC) issued 04/16/03 and modified on 7/7/2005. PSD-FL-327 replaces and supersedes PSD-FL-286. On March 5, 2004, EPA promulgated 40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines built after January 14, 2003. Unit 3 was under contractual obligations before this date and is therefore an existing unit. Currently, 'existing combustion turbines' are not required to meet the emission limitations, notifications, reporting or any other requirements of Subpart YYYY. EPA may at a future date promulgate standards for existing units.}

The following conditions apply to the emission units listed above:

Applicable Standards and Regulations

H.1. BACT Determinations: Determinations of the Best Available Control Technology (BACT) were made for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2), and volatile organic compounds (VOC). See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]

H.2. NSPS Requirements: The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the New Source Performance Standards for Subpart Da (duct burners) and Subpart GG (gas turbines) in 40 CFR 60. For completeness, the applicable requirements of Subparts Da and GG are included in Appendices Da and GG of this permit. [Rule 62-204.800(7), F.A.C.]

Equipment

H.3. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain four General Electric Model PG7241FA gas turbine-electrical generator sets each with a generating capacity of 170 MW. Each gas turbine shall include the Speedtronic™ automated gas turbine control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system, an evaporative inlet air-cooling system, and a bypass stack for simple cycle operation. The gas turbines will utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to approximately 290° F before combustion to increase overall unit efficiency. Gas-fired fuel heaters will preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas.

{Permitting Note: In accordance with Air Permit No. PSD-FL-286, two existing simple cycle gas turbines (Emission Unit Nos. 011 and 012) have been installed. These units will be incorporated into the "4-on-1" combined cycle Unit 8.} [Application; Design]

H.4. Gas Turbine NOx Controls

(a) *DLN Combustion*: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NOx 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 to achieve the simple cycle permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

(b) *Water Injection*: The permittee shall install, 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 to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. The automated control system shall be programmed to establish a water-to-fuel ratio designed to achieve the NOx emission standard for simple cycle oil firing on a 1-hour basis.

(c) *(SCR) System*: The permittee shall install, tune, operate, and maintain a selective catalytic reduction (SCR) system to control NOx emissions from each gas turbine during combined cycle operation 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 NOx 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.]

H.5. HRSGs: The permittee is authorized to install, operate, and maintain four new heat recovery steam generators (HRSGs) with separate HRSG exhaust stacks. Each HRSG shall be designed to recover heat energy from one of the four gas turbines (8A-8D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). The duct burners shall be designed in accordance with the following specifications: 0.04 lb CO/MMBtu and 0.08 lb NOx/MMBtu. {Permitting Note: The four HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 470 MW.} [Application; Design]

Performance Restrictions

H.6. Permitted Capacity - Gas Turbines: The maximum heat input rate to each gas turbine is 1600 MMBtu per hour when firing natural gas and 1811 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

H.7. Permitted Capacity - HRSG Duct Burners: The total maximum heat input rate to the duct burners for each HRSG is 495 MMBtu per hour based on the lower heating value (LHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]

H.8. 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 operational restrictions of this permit, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.

(b) *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet 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. Each gas turbine shall fire no more than 500 hours of distillate oil during any consecutive 12 months.

(c) *Simple Cycle Operation*: Each gas turbine may operate individually in simple cycle mode to produce only direct, shaft-driven electrical power subject to the following operational restrictions.

1. Each gas turbine shall operate in simple cycle mode for no more than 3390 hours during any consecutive 12 months.

2. After demonstrating initial compliance in combined cycle mode, the combined group of four gas turbines shall operate in simple cycle mode for no more than an average of 1000 hours per gas turbine during any consecutive 12 months.

(d) *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 four-on-one 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.

(e) Inlet Fogging: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging" and may be used in either simple cycle or combined cycle modes.

(f) Peaking: When firing natural gas, each gas turbine may operate in a high-temperature peaking mode to generate additional direct, shaft-driven electrical power to respond to peak demands. During any consecutive 12 months, each gas turbine shall operate while in the peaking mode for no more than 60 hours of simple cycle operation and no more than 400 hours of combined cycle operation.

(g) Power *Augmentation*: When firing natural gas in either simple cycle or combined cycle modes, steam may be injected into each gas turbine to generate additional direct, shaft-driven electrical power to respond to peak demands. To qualify as "power augmentation", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. The gas turbines shall not operate simultaneously in peaking and power augmentation modes. Total combined operation of power augmentation and peaking modes shall not exceed 400 hours per unit during any consecutive 12 months.

(h) *Combined Cycle Operation with HRSG Duct Firing*: When firing natural gas and operating in combined cycle mode, each HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. The total combined heat input rate to the duct burners (all four HRSGs) shall not exceed 5,702,400 MMBtu (LHV) during any consecutive 12 months.

[Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

Emissions Limitations and Standards

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

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O2	lb/hour	ppmvd @ 15% O2
CO [a]	Oil	Simple or Combined Cycle	14.4	64.7	15.0, 24-hr
	Gas	Simple Cycle	7.4	27.5	8.0, 24-hr
		Simple Cycle w/PA	12.0	45.0	12.0, 24-hr
		Combined Cycle, Normal	7.4	27.5	10.0, 24-hr
		Combined Cycle, All Modes	NA	NA	
NOx [b]	Oil	Simple Cycle	42.0	319.2	42.0, 3-hr
		Combined Cycle w/SCR	10.0	76.0	10.0, 24-hr
	Gas	Simple Cycle	9.0	58.7	9.0, 24-hr
		Simple Cycle w/PA	12.0	76.2	12.0, 24-hr
		Simple Cycle w/Peaking	15.0	95.3	15.0, 24-hr
		Combined Cycle w/SCR, Normal	2.5	16.3	2.5, 24-hr
		Combined Cycle w/SCR and DB	2.5	23.6	
		Combined Cycle w/SCR, All Modes	NA	NA	
PM/PM10 [c]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
		Simple or Combined Cycle	Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO2 [d]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
VOC [e]	Oil	Simple or Combined Cycle	2.5	6.0	NA
	Gas	Simple or Normal Combined Cycle	1.3	2.8	NA
		Combined Cycle, w/DB and/or PA	4.0	10.5	NA
Ammonia [f]	Oil/Gas	Combined Cycle w/SCR	5	NA	NA

a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 10. Compliance with the 24-hour CO CEMS standards shall be determined separately for each method of operation based on the hours of operation for each method. *{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 NOx standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 7E or 20. NOx mass emission rates are defined as oxides of nitrogen expressed as NO2. Compliance with the 24-hour NOx CEMS standards during simple cycle operation shall be determined separately for each method of operation based on the hours of operation for each method. {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. The fuel specifications established in Condition No. H.8 of this section combined with the efficient combustion design and operation of each gas turbine represents the Best Available Control Technology (BACT) determination for PM/PM10 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. *{Permitting Note: PM10 emissions for gas*

firing are estimated at 9 lb/hour for simple cycle operation, 11 lb/hour for combined cycle operation, and 17 lb/hour for combined cycle operation with duct burning. PM_{10} emissions for oil firing are estimated at 17 lb/hour for simple cycle operation and 37 lb/hour for combined cycle operation.}

d. The fuel sulfur specifications in Condition No. H.8 of this section effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent the Best Available Control Technology (BACT) determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. H.27 of this section. {Permitting Note: SO2 emissions for gas firing are estimated at 9.8 lb/hour for simple and combined cycle operation and 12.8 lb/hour for combined cycle operation with duct burning. SO2 emissions for oil firing are estimated at 99 lb/hour for simple and combined cycle operation. SAM emissions are estimated to be less than 10% of the SO2 emissions.}

e. 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 methane.

f. Subject to the requirements of Condition No. H.21 of this section, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen 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 CTC-027.

{Permitting Notes: "DB" means duct burning. "PA" means power augmentation. "SCR" means selective catalytic reduction. "NA" means not applicable. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department. Initial compliance tests under normal conditions for gas and oil firing have already been conducted for the existing Unit 8 gas turbines.}

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

H.10. Combined Cycle Operation With Steam Dumped to Condenser: If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by dumping steam to the condenser. When operating in this manner, each unit shall comply with the standards established for combined cycle operation with ammonia injection (SCR). [Application]

H.11. Duct Burners: The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60, which are summarized in Appendix Da.

{Permitting Note: During duct firing, compliance with the limits of this permit also demonstrates compliance with the standards of NSPS Subpart Da for duct burners.} [Subpart Da, 40 CFR 60]

Excess Emissions

H.12. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and 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.]

H.13. 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.]

H.14. 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.]

H.15. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, oil-to-gas fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases.

(a) *Cold Startup of the Steam Turbine*: For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed eight (8) hours in any 24-hour period. Cold startup of the steam turbine system shall be completed within twelve hours. A cold "startup of the steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours. *{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}*

(b) *Shutdown:* For shutdown of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed three (3) hours in any 24-hour period.

(c) *Cold startup of a Gas Turbine/HRSG system*: For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four (4) hours in any 24-hour period. "Cold startup of a gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

(d) *Fuel Switching*: For oil-to-gas fuel switching, excess emissions shall not exceed one (1) hour in any 24-hour period.

Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, and documented malfunction of the gas turbines. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

H.16. 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.]

Emissions Performance Testing

H.17. 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 Source {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) 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 Volatile Organic Concentrations

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]

H.18. Special 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. Each gas turbine shall be stack tested to demonstrate compliance with the emission standards for CO, NOx, 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 for each unit configuration (i.e., simple cycle and combined cycle operation), but not later than 180 days after startup of each unit configuration. Each unit shall be tested when firing natural gas and distillate oil. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the CO and NOx standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NOx mass rate emissions standards. CO and NOx emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. CO and VOC emissions tests performed during simple cycle operation may be used to satisfy the test requirements for similar operation in combined cycle mode. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

H.19. Continuous Compliance: The permittee shall demonstrate continuous compliance with the CO and NOx emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds. [Rule 62-212.400 (BACT), F.A.C.]

H.20. 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. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period.

{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.]

H.21. 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.]

Continuous Monitoring Requirements

H.22. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NOx from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NOx standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

(a) *CO Monitors.* 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 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.

(b) *NOx Monitors.* Each NOx monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. In addition to the requirements of Appendix A of 40 CFR 75, the NOx monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.

(c) *Diluent Monitors.* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NOx 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) *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. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NOx as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. 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.

(e) 3-hour Block Averages: For oil firing during simple cycle operation, the 3-hour block average shall be calculated from three consecutive hourly average emission rate values. For purposes of determining compliance with the CEMS emission standards of this permit, missing (or excluded) data shall not be substituted. Instead, the 3-hour block average shall be determined using the remaining hourly data in the 3-hour block. [Rule 62-212.400(BACT), F.A.C.]

(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 standards, 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 NOx emissions depending on the use of alternate methods of operation}. [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. 16 and 18 of this section. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

(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 ensure compliance with the other applicable CEM system requirements such as: NSPS Subparts Da and GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 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.]

H.23. Water Injection Monitoring Requirements: 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 NOx CEMS is used to demonstrate compliance with the NOx emissions standards. During NOx 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.

{Permitting Note: The water-to-fuel ratio at maximum load to achieve the NOx standards during simple cycle oil firing is approximately 1.1 or a water injection rate of approximately 101,000 pounds per hour. The actual water-to-fuel ratio will vary depending on operating conditions and load.}

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

H.24. 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 NOx emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NOx 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.]

Records and Reports

H.25. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

H.26. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of power augmentation, hours of peaking, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the

provisions of 40 CFR 75 Appendix D.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

H.27. 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 maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

H.28. Malfunction Notification: Within one working day of a malfunction that causes emissions in excess of a standard (subject to the specified averaging periods), the permittee shall notify the Compliance Authority. 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. [Rule 62-210.700, F.A.C.]

H.29. Semiannual NSPS Excess Emissions Report: In accordance with 40 CFR 60.7(d), the permittee shall submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards within 30 days following the end of each calendar quarter. 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 NOx emission standard identified in Appendix GG; 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. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NOx or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO_2 emissions in excess of the NSPS standards except during startup or shutdown. An example of the report is provided on Appendix XS. [40 CFR 60.7]

H.30. Quarterly Permit Excess Emission Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of excess CO and NOx emissions. Such information shall also be summarized for simple/combined cycle startups, simple/combined cycle shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.
[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

H.31. Definitions. For the purposes of Rule 62-204.800(7), F.A.C., the definitions contained in the various provisions of 40 CFR 60 shall apply, except that the term "Administrator" when used in 40 CFR 60 shall mean the Secretary or the Secretary's designee.
[40 CFR 60.2; and Rule 62-204.800(7)(a), F.A.C.]

H.32. Concealment. No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere. [40 CFR 60.12]

H.33. Circumvention. The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly.
[Rule 62-210.650, F.A.C.; and 0850001-008-AC, Specific Condition 14. (Facility Information Section)]

H.34. These emissions units are also subject to the conditions contained in Subsection E. Common Conditions and all applicable requirements of the attached **Appendices,** made part of the permit**.**

Subsection I. This section addresses the following emissions units.

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

EU No.	Emission Unit Description
013	Four gas-fired fuel heaters with a maximum heat input of 24 MMBtu per hour

NESHAP and NSPS Applicability

{Permitting Notes: The emissions units are regulated under NESHAP - 40 CFR 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, or Institutional Boilers or Process Heaters, adopted by reference in Rule 62-204.800(11), F.A.C., Prevention of Significant Deterioration (PSD), Best Available Control Technology (BACT); and Air Construction Permits PSD-FL-327.

FPL requested a determination from the Department on the applicability of NSPS Subpart Dc to the gas-fired fuel heaters. The Department agreed with FPL that it did not believe that Subpart Dc should apply to these units, but referred the request to EPA Region 4 for interpretation of the federal standards. In a letter dated February 5, 2003, EPA Region 4 concurred that Subpart Dc did not apply to the gas-fired fuel heaters.}

Equipment Specifications

I.1. Equipment: The permittee is authorized to install, operate, and maintain four fuel heaters fired exclusively with natural gas at a maximum heat input rate of 24 MMBtu per hour. The fuel heaters will be designed to preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas. *{Permitting Note: In accordance with Air Permit No. PSD-FL-286, construction of two gas-fired fuel heaters has been completed.}* [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

Emissions and Performance Requirements

I.2. Hours of Operation: The hours of operation for the gas-fired fuel heaters are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

I.3. Good Combustion: If visible emissions are greater than 5% opacity, the permittee shall investigate the cause, take appropriate corrective actions, and document the incident. This condition does not impose any initial or periodic testing.
[Rules 62-4.070(3) and 62-210.700(4), F.A.C.; 40 CFR 60, Appendix A]

Notification, Reporting and Records

I.4. Fuel Records: The permittee shall maintain records of the amount of natural gas fired in the fuel heaters. These records shall be used to prepare the required annual operating reports.
[Rule 62-210.370(3), F.A.C.]

General

I.5. These emissions units are also subject to applicable requirements of the conditions contained in **Subsection E. Common Conditions** and all applicable requirements of the attached **Appendices,** made part of the permit**.**

Subsection J. This section addresses the following emissions units.

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

Emission Unit ID	Emission Unit Description
020	18-cell mechanical draft cooling tower

Equipment

J.1. Cooling Tower: The permittee is authorized to install one new 18-cell mechanical draft cooling tower with the following design characteristics: a circulating water flow rate of 310,000 gpm; design hot/cold water temperatures of 104° F/90° F; a design air flow rate of 1,386,055 per cell; a liquid-to-gas air flow ratio of 1.4; and drift eliminators with a drift rate of no more than 0.001 percent. The permittee shall submit the final design details within 60 days of selecting the vendor. [Application; Design]

Emissions and Performance Requirements

J.2. Drift Rate: Within 60 days of commencing operation, the permittee shall submit certification that the cooling tower was constructed to achieve the specified drift rate of no more than 0.001 percent of the circulating water flow rate.

{Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 34 tons of PM per year and less than 10 tons of PM_{10} per year. Actual emissions are expected be less than half these rates.}.

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

General

J.3. This emissions unit is also subject to applicable requirements of the conditions contained in **Subsection E. Common Conditions** and all applicable requirements of the attached **Appendices,** made part of the permit**.**

Subsection K. This section addresses the following emissions units.

This section of the permit addresses the following emissions units.

Emissions Unit ID	Emission Unit Description
014	Two distillate oil storage tanks for Unit 8 gas turbines (2.1 million gallons each)

NSPS Applicability

K.1. NSPS Subpart Kb Applicability: The distillate oil tanks are subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb except for the record keeping requirements specified below.
[40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]

Equipment Specifications

K.2. Equipment: The permittee is authorized to install, operate, and maintain two, 2.1 million gallon distillate oil storage tank designed to provide low sulfur distillate oil to the Unit 8 gas turbines. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

{Permitting Note: One existing 2.1 million gallon distillate oil storage tank was permitted under PSD-FL-286.}

Emissions and Performance Requirements

K.3. Hours of Operation: The hours of operation are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

Notification, Reporting and Records

K.4. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate oil for each storage tank for use in the Annual Operating Report. [Rule 62-204.800(7)(b)16, F.A.C.; 40 CFR 60.116b(a) and (b)]

{Permitting Note: These new distillate oil storage tanks serve Unit 8. An existing 50,000-barrel distillate oil storage tank was constructed as part of Units 3 and 4. The existing tank was identified for use in Permit No. PSD-FL-268 issued for simple cycle Units 8A and 8B. Unit 8 will utilize both the existing and new distillate oil storage tanks.}

General

K.5. These emissions units are also subject to applicable requirements of the conditions contained in **Subsection E. Common Conditions** and all applicable requirements of the attached **Appendices,** made part of the permit**.**

Section IV. This section is the Acid Rain Part.

Operated by: Florida Power and Light Company

ORIS code: 6043

Subsection A. This subsection addresses Acid Rain, Phase II.

The emissions units listed below are regulated under Phase II of the Federal Acid Rain Program.

E.U. ID No.	EPA ID	Brief Description
-001	**PMR1**	Fossil Fuel Fired Steam Generator #1
-002	**PMR2**	Fossil Fuel Fired Steam Generator #2
-003	**HRSG3A**	Combustion Turbine with Heat Recovery Steam Generator (CT 3A)
-004	**HRSG3B**	Combustion Turbine with Heat Recovery Steam Generator (CT 3B)
-005	**HRSG4A**	Combustion Turbine with Heat Recovery Steam Generator (CT 4A)
-006	**HRSG4B**	Combustion Turbine with Heat Recovery Steam Generator (CT 4B)
-011	**PMR8A**	Combustion Turbine with Heat Recovery Steam Generator (CT 8A)
-012	**PMR8B**	Combustion Turbine with Heat Recovery Steam Generator (CT 8B)
-017	**PMR8C**	Combustion Turbine with Heat Recovery Steam Generator (CT 8C)
-018	**PMR8D**	Combustion Turbine with Heat Recovery Steam Generator (CT 8D)

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

a. DEP Form No. 62-210.900(1)(a), Phase II Acid Rain Part Application, signed by the Designated Representative on April 7, 2003, and received by the Department on July 3, 2003.

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

A.2. Sulfur dioxide (SO2) allowance allocations for each Acid Rain unit are as follows:

E.U. ID No.	EPA ID	Year	2004	2005	2006	2007	2008
-001	**PMR1**	SO2 allowances, under Table 2 of 40 CFR Part 73	5092*	5092*	5092*	5092*	5092*
-002	**PMR2**	SO2 allowances, under Table 2 of 40 CFR Part 73	6039*	6039*	6039*	6039*	6039*

E.U. ID No.	EPA ID	Year	2004	2005	2006	2007	2008
-003	**HRSG3 A**	SO2 allowances, under Table 2 of 40 CFR Part 73	1275*	1275*	1275*	1275*	1275*
-004	**HRSG3 B**	SO2 allowances, under Table 2 of 40 CFR Part 73	1275*	1275*	1275*	1275*	1275*
-005	**HRSG4 A**	SO2 allowances, under Table 2 of 40 CFR Part 73	1275*	1275*	1275*	1275*	1275*
-006	**HRSG4 B**	SO2 allowances, under Table 2 of 40 CFR Part 73	1275*	1275*	1275*	1275*	1275*
-011	**PMR8A**	SO2 allowances to be determined by U.S. EPA	N/A	0	0	0	0
-012	**PMR8B**	SO2 allowances to be determined by U.S. EPA	N/A	0	0	0	0
-017	**PMR8C**	SO2 allowances to be determined by U.S. EPA	N/A	0	0	0	0
-018	**PMR8D**	SO2 allowances to be determined by U.S. EPA	N/A	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 USEPA under Table 2 of 40 CFR 73.

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.

[Rule 62-213.413, F.A.C.]

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

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

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, or that meet the criteria specified in Rule 62-210.300(3)(b)1., F.A.C., Generic Emissions Unit Exemption, are exempt from the permitting requirements of Chapters 62-210, 62-212 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 Rules 62-210.300(3)(a) and (b)1., 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 Rules 62-210.300(3)(a) and (b)1., 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	**Chemical Feed Skid**, consisting of: Ammonia Feed Tanks Vent Hydrazine Feed Tanks Vent H. P. Phosphate Feed Tanks Vent I. P. Phosphate Feed Tanks Vent
2	**Fire Protection Equipment** with: .75” Vents to Atmosphere Diesel Engine Exhaust 2” Diesel Day Tank Vent CT Lube Seal Trip, and Hydraulic Oil 3” Bearing Drain Enlargement Exhausters Vent to Atmosphere **Auxiliary Buildings H.V.A.C.** Vent/Exhaust System for, Switchgear Rooms Chemical Storage Room Water Chemistry Lab Fume Hoods
3	**Main Liquid Fuel** .75” Vents to Atmosphere 2” Liquid Fuel Drain Tank Vent (235 gallon) 8” Vent with Filter for Units 3 and 4 Liquid Fuel Storage Tank (2,000,000 gallon)
4	**Auxiliary Steam, Chemical Feed, Chlorine and Gas Purging,** comprised of: Ash Pit Potable Water Bleach Tank 2” Vent (2,000 gallons)

	Lube Oil Lube Oil Storage Tanks Vent B.F.P. Lube Oil B.F.P. Lube Oil Reservoir Vent Fan 4” B.F.P. Lube Oil Batch Tank 3” Vent and Filter B.F.P. Lube Oil Conditioner Vent Fan 4” Light Oil System Light Oil Tank 6” Vent (2,000 bbl) Water Draw-Off Sump Diesel Day Tank .75” Vent - (550 gallon) Chemical Feed Tank Vent Turbine Gland Seal Steam and Drain Gland Steam Condenser Exhauster 6” Vent to Atmosphere Fuel Oil at Burners 1” Vents to Atmosphere Natural Gas 2” Vent to Atmosphere 6” Vent to Atmosphere Ignition (LP) Gas 1” Control Vent to Atmosphere L.P. Gas Tanks Relief Valve Fuel Oil at Heaters 1” Vents to Atmosphere M.C.C. Areas Exhaust Fans Lab Exhaust Hood Turbine Generator Lube Oil Generator Loop Seal Tank Exhauster 4” Vent to Atmosphere Turbine Lube Oil Reservoir Vapor Extractor 6” Vent Turbine Generator Lube Oil Batch Tank 4” Vent with Filter Turbine Generator Lube Oil Conditioner Vapor Extractor 4” Vent 1” Polishing Filter Vent 1” Air Educator Vent Electrically Heated Equipment Used for Heat Treating, Tracing, Drying, Soaking, Case Hardening or Surface Conditioning
5	**Gas Metering Area** (for Units 1 and 2) Gas Oil Separator Tank 8” Exhaust Vent Gas Oil Separator Tank 1.5” Vent Relief Valve 6” Blowdown Valve Gas Scrubber Relief Valve Condensate Tank with Filter
6	**Sand Blast Booth**
7	**Evaporation of Non-Hazardous Boiler Chemical Cleaning Waste**

Appendix U-1. List of Unregulated Emissions Units and/or Activities.

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 'insignificant emissions units'.

E.U. ID No.	Brief Description of Emissions Units and/or Activities
-015	Diesel Generator (for Units -001 and -002)
-016	Facility-wide Fugitive Emissions for PM
-016	Facility-wide Fugitive Emissions for VOCs