MEMORANDUM

TO: Michael G. Cooke

FROM: Trina L. Vielhauer

DATE: December 19, 2003

SUBJECT: FINAL Permit Renewal No. **0850001-013-AV**
Florida Power & Light Company
Martin Plant

Day 46 = 12/18

This is a Title V Air Operation Permit Renewal for the subject facility.

This facility consists of two fuel oil and natural gas fired conventional steam electric generating stations, two fuel oil and natural gas fired combined-cycle units, and two simple-cycle combustion turbines. In addition, the facility includes one auxiliary boiler, and two diesel generators (one unregulated).

The only comments received concerning the DRAFT Title V Operation Permit Renewal were from the Department's Southeast District Office, and all issues were resolved. *No comments* were received from U.S. EPA, Region 4, concerning the PROPOSED Title V Permit Renewal that was posted on the Department's web site on November 3, 2003.

I recommend your signature.

Attachment

TLV/tbc

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Mr. Keith Hardy
Plant Manager and Responsible Official
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 32408

Title V Permit Renewal No. **0850001-013-AV**
Martin Plant
Facility ID No. **0850001**; ORIS Code: **6043**

Enclosed is FINAL Title V Permit Renewal Number 0850001-013-AV for the Martin Plant, located in the western part of unincorporated Martin County, approximately seven miles north of Indiantown on State Road 710, issued pursuant to Chapter 403, Florida Statutes (F.S.).

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

http://www.dep.state.fl.us/air/permitting/airpermits

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office, and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the permitting authority.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT RENEWAL (including the FINAL permit renewal) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 12/18/08 to the person(s) listed or as otherwise noted:

Mr. Keith Hardy*
Mr. John C. Hampp, Florida Power & Light Co.
Mr. Thomas Tittle, Southeast District Office
U.S. EPA, Region 4 (INTERNET E-mail Memorandum)

Clerk Stamp

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

Barbara J. Friday 12/18/08
(Clerk) (Date)

FINAL PERMIT DETERMINATION

I. Comment(s).

No comments were received from U.S. EPA, Region 4, concerning the PROPOSED Title V Permit Renewal that was posted on the Department's web site on November 3, 2003.

II. Conclusion.

The permitting authority hereby issues the FINAL Permit Renewal No. **08570001-013-AV** with no changes.

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Keith Hardy
Plant Manager and Responsible Official
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 32408

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X B. McCray ☐ Agent ☐ Addressee

B. Received by (*Printed Name)* B. McCray C. Date of Delivery 1-5-4

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

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number
(Transfer from service label) 7001 1140 0002 1577 9878

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1540

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

7001 1140 0002 1577 9878

Mr. Keith Hardy, Plant Manager & R.O. USE

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

Sent To
Mr. Keith Hardy, Plant Manager & R.O.
Street, Apt. No.; or PO Box No. 700 Universe Boulevard
City, State, ZIP+ 4 Juno Beach, Florida 32408

PS Form 3800, January 2001 **See Reverse for Instructions**

STATEMENT OF BASIS

Title V Permit Renewal No. **0850001-013-AV**
Florida Power and Light Company
Martin Plant
Martin County

This Title V air operation permit renewal 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.

This facility consists of two oil and natural gas fired conventional steam electric generating stations, two oil and natural gas fired combined-cycle units, and two simple-cycle combustion turbines. In addition, the facility includes one auxiliary boiler, two diesel generators (one unregulated), and two natural gas fuel heaters.

Each *conventional steam unit* consists of a boiler/steam generator, which drives a single reheat turbine generator and has the maximum capacity of 863.3 megawatts (MW). Each is 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 steam 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 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.

Each *combined-cycle unit* has the net capability of 430 MW and consists of two combustion turbines (CT), each nominally rated at 204 MW, which each exhaust through a separate unfired heat recovery steam generator (HRSG). Nitrogen oxide emissions are controlled by using dry low NOx combustors for natural gas with steam injection for fuel oil firing. Duct modules suitable for future installation of selective catalytic reduction (SCR) equipment have been installed on each combined cycle generating unit. Emissions Units 003 and 004 commenced commercial operation in February 1994. Emissions Units 005 and 006 commenced commercial operation in April 1994.

The combined-cycle 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. 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.

Each *simple-cycle unit* consists of a General Electric Model PG7241(FA) combustion turbine, an electrical generator set (each designed to produce a nominal 170 MW of electrical power), an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an exhaust stack that is 120 feet in height and 20.5 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. NOx emissions are reduced by dry low-NOx (DLN) combustion technology during gas firing, and by water injection during distillate oil firing. 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 011 and 012 commenced commercial operation in November 2001.

These emissions units are regulated under Acid Rain-Phase II, 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C., Rule 212.400, F.A.C., Prevention of Significant Deterioration (PSD), Best Available Control Technology (BACT), and Air Construction Permit PSD-FL-286 (0850001-008-AC). The facility holds ORIS Code **6043** under the federal Acid Rain Program. 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.

The *auxiliary boiler* is used to produce steam to actuate the steam seals on the steam turbine components of the combined-cycle units (Emissions Units 003 to 006) during cold starts when steam is not otherwise available for this purpose. Initial startup of Emissions Unit 007 was on July 15, 1993.

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(7)(b)4, F.A.C.; PSD-FL-146, NSR - BACT. Because the unit has no installed pollution control devices, the unit is not subject to compliance assurance monitoring (CAM).

Also included in this permit are two unregulated emissions units identified as facility-wide particulate matter emissions and facility-wide VOC emissions (Emissions Unit 016).

Based on the Title V permit renewal application received on July 3, 2003, this facility *is* a major source of hazardous air pollutants (HAPs).

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

FINAL Permit Renewal 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

Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979

Compliance Authority:
Department of Environmental Protection
Southeast District
400 North Congress Avenue
West Palm Beach, Florida 33401-5425
Telephone: 407/681-6600
Fax: 407/681-6790

FINAL Permit Renewal No. **0850001-013-AV**

Table of Contents

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

Permittee:
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408

FINAL Permit Renewal No. 0850001-013-AV
Facility ID No. 0850001
SIC Nos.: 49, 4911
Project: Title V Air Operation Permit Renewal

This permit renewal is for the operation of the Martin Plant. 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 renewal 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 renewal.

Referenced attachments made a part of this permit renewal:

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)
FIGURE 1- SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSIONS AND MONITORING SYSTEMS PERFORMANCE REPORT
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.

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

Michael G. Cooke, Director
Division of Air Resource Management

MGC/tbc

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of two oil and natural gas fired conventional steam electric generating stations, two oil and natural gas fired combined cycle units, and two simple-cycle combustion turbines. Each *conventional steam unit* has the maximum capacity of 863.3 megawatts (MW) and 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.

Each *combined cycle unit* has the net capability of 430 MW, at 95 degrees F, and consists of two combustion turbines (CTs), each nominally rated at 204 MW, which exhaust through a separate unfired heat recovery steam generator (HRSG). 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. 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.

Each *simple-cycle unit* consists of a General Electric Model PG7241(FA) combustion turbine, an electrical generator set (each designed to produce a nominal 170 MW of electrical power), an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an exhaust stack that is 120 feet in height and 20.5 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. NOx emissions are reduced by dry low-NOx (DLN) combustion technology during gas firing and by water injection during distillate oil firing. The units have the following manufacturers' CEMs installed: (a) Thermo Environmental Instruments (Model 42CHL) for NOx, and (b) Servomex (Model 1420C) for O_2.

In addition, the facility includes one auxiliary boiler, two diesel generators (one unregulated), and two 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 renewal application received on July 3, 2003, 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	Simple-Cycle Combustion Turbine (8A)
-012	Simple-Cycle Combustion Turbine (8B)
-013	Two Natural Gas Fuel Heaters

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.

<u>These documents are provided to the permittee for information purposes only:</u>
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

<u>These documents are on file with the permitting authority:</u>

Letter from the Florida Power & Light Company received on June 27, 2003, requesting a change to the stack height description in the Title V Permit for the Simple-Cycle Combustion Turbines 8A and 8B (Emissions Units -011 and -012).
Title V Air Operation Permit Renewal Application received on July 3, 2003.
E-mail memorandum from the Florida & Light Company received on August 21, 2003, reporting that Combustion Turbines No. 3 and 4 have not burned any distillate fuel oil.
DRAFT Title V Air Operation Permit Renewal clerked on September 16, 2003.
E-mail memorandum from the Department's Southeast District office dated October 13, 2003, containing comments on the DRAFT Permit Renewal.
PROPOSED Title V Permit Renewal posted for EPA review on November 3, 2003.

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

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 **F.14.** and **F.15.**
[Rule 62-213.440(2), F.A.C.]

Section III. Emissions Units and Conditions.

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:
(1) Contain particulate matter in excess of 43 nanograms per joule heat input (0.10 lb per million Btu) derived from fossil fuel.
(2) 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]

<u>**Excess Emissions**</u>

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) <u>Opacity.</u> 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) <u>Sulfur dioxide.</u> Excess emissions for affected facilities are defined as:
(i) 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) <u>Nitrogen oxides.</u> 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. (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:

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

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 SO_2 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 SO_2 sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each NO_X sample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration ($\%O_2$). The sample shall be taken simultaneously with, and at the same point as, the NO_X sample.

(iii) The NO_X emission rate shall be computed for each pair of NO_X and O_2 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).

$\%CO_2$ = carbon dioxide concentration, percent dry basis.

F_c = 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 ($\overline{d}$) 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 $\overline{d}$ 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 SO_2 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 O_2 concentration (%O_2) 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:

[In parts per million]

Fossil fuel	Span value for sulfur dioxide	Span value for nitrogen oxides
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, F_c = 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):

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

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

(SI units)

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

(English units)

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

(SI units)

$$F_c = \frac{321x10^3\ (\%C)}{GCV}$$

(English units)

(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:

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

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.43.**
[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:

<u>General</u>

B.1. <u>Definitions.</u> 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. <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]

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 units operating at capacity. Capacity is defined as 95-100 percent of the manufacturer's rated heat input achievable for the average ambient (or conditioned) air temperature during the test. If it is impractical to test at capacity, then the units may be tested at less than capacity. In such cases, 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 105 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) and 62-210.200(PTE), F.A.C.; and PSD-FL-146, Specific Condition No. 1.]

{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)

Notes:

[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 °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

Notes:

[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.]

<u>**Excess Emissions**</u>

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 NO_X 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 $\pm$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:

<u>Custom Fuel Monitoring Schedule for Natural Gas (NG)</u>

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. 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. 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.]

<u>**Test Methods and Procedures**</u>

{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:
c. 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. Annual (A) compliance tests shall be performed on each Combustion Turbine with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests shall be conducted using EPA reference methods, or equivalent, in accordance with the July 1, 1996 version of 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	20	X	X	X	X
Volatile Organic Compounds	18	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.

[PSD-FL-146, Specific Condition No. 10; and applicant request letter dated July 28, 1998.]

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)]

Recordkeeping and Reporting Requirements

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:
a. *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 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)]

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. (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 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(7)(b)4, F.A.C.; PSD-FL-146, NSR - BACT.}

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. 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)]

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 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)]

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. (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.

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	Simple-Cycle Combustion Turbine (8A)
-012	Simple-Cycle Combustion Turbine (8B)

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) <u>Minimum Sample Volume</u>. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) <u>Required Flow Rate Range</u>. 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) <u>Calibration of Sampling Equipment</u>. 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. This section addresses the following emissions units.

E.U. ID No.	Brief Description
-011	Simple-Cycle Combustion Turbine (8A)
-012	Simple-Cycle Combustion Turbine (8B)

Each unit consists of a General Electric Model PG7241(FA) combustion turbine, an electrical generator set (each designed to produce a nominal 170 MW of electrical power), an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, an exhaust stack that is 120 feet in height and 20.5 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. NOx emissions are reduced by dry low-NOx (DLN) combustion technology during gas firing and by water injection during distillate oil firing. 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 011 and 012 commenced commercial operation in November 2001.

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 note: These emissions units are regulated under Acid Rain-Phase II, 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C., Rule 212.400, F.A.C., Prevention of Significant Deterioration (PSD), Best Available Control Technology (BACT), and Air Construction Permit PSD-FL-286 (0850001-008-AC).}

General

F.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; and Rule 62-204.800(7)(a), F.A.C.]

F.2.0. 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]

F.2.1. 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)]

Capacities by Fuel and Method of Operation

F.3. Natural Gas.

- Normal Firing: At a compressor inlet air temperature of 35° F and firing 1860 mmBTU per hour of gas, each unit produces a maximum 182 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,461,000 acfm at 1095° F.
- Power Augmentation (Steam Injection): At a compressor inlet air temperature of 59° F and firing 1800 mmBTU per hour of gas with approximately 116,000 pounds per hour of steam injection, each unit produces a maximum 180 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,380,000 acfm at 1115° F.
- Peaking: At a compressor inlet air temperature of 35° F and firing 1920 mmBTU per hour of gas during peaking, each unit produces a maximum 190 MW. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,488,000 acfm at 1110° F.

F.4. Distillate Fuel Oil. At a compressor inlet air temperature of 35° F and firing 2008 mmBTU per hour of oil as a backup fuel, each unit produces a maximum 191 MW. The water injection rate for NOx control is approximately 131,000 pounds per hour. Exhaust gases exit the stack with a volumetric flow rate of approximately 2,539,000 acfm at 1075° F.

{Note: All heat input values are based on the higher heating values (HHV) of the fuels.}
[0850001-008-AC, Emissions Unit Description]

Performance Restrictions

F.5. Permitted Capacity. The heat input rates (HHV) to each combustion turbine shall not exceed the following:

(a) *Normal Gas Firing*: 1860 mmBTU per hour with a compressor inlet air temperature of 35° F and producing a maximum 182 MW.

(b) *Gas Firing With Power Augmentation (Steam Injection)*: 1800 mmBTU per hour of natural gas with a compressor inlet air temperature of 59° F and producing a maximum 180 MW.

(c) *Gas Firing With Peaking*: 1920 mmBTU per hour with a compressor inlet air temperature of 35° F and producing a maximum 190 MW.

(d) *Distillate Oil Firing*: 2008 mmBTU per hour with a compressor inlet air temperature of 35° F and producing a maximum 191 MW.

The heat input rates are based on the higher heating values (HHV) of 23,127 BTU/lb_m for natural gas and 19,490 BTU/lb_m for distillate oil. The permittee shall provide the 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. Heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Compliance shall be determined by data compiled from the automated gas turbine control system. This data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.

[Rule 62-210.200(PTE), F.A.C.; and 0850001-008-AC, Specific Condition 4.]

{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.}

F.6. Simple-Cycle Operation Only. Each combustion turbine shall operate only in simple-cycle mode. This restriction is based on the permittee's request, which formed the basis of the CO and NOx BACT determinations and resulted in the emission standards specified in construction permit 0850001-008-AC. Specifically, the CO and NOx BACT determinations eliminated several control alternatives based on technical considerations due to the elevated temperatures of the exhaust gas as well as costs related to operation as peaking units. Any request to convert these units to combined cycle operation or increase the allowable hours of operation shall be accompanied by a revised CO and NOx BACT analysis and the approval of the Department through a permit modification in accordance with Chapters 62-210 and 62-212, F.A.C. Note: The results of this analysis may validate the initial BACT determinations or result in the submittal of a full PSD permit application, new control equipment, and new emissions standards.
[Rules 62-210.300 and 62-212.400, F.A.C.; and 0850001-008-AC, Specific Condition 5.]

F.7. Allowable Fuels. Each combustion turbine shall be tuned for a primary fuel of pipeline-quality natural gas containing no more than 1 grain of sulfur per 100 dry standard cubic feet of gas. As a backup fuel, each combustion turbine may be fired with low sulfur No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. No other fuels are authorized by this permit. It is noted that both limitations are much more stringent than the sulfur dioxide limitation in 40 CFR 60, NSPS Subpart GG and assures compliance with regulations 40 CFR 60.333 and 60.334 of this subpart. The permittee shall demonstrate compliance with the fuel sulfur limits by keeping the records specified in this permit.
[Rule 62-210.200(PTE), F.A.C.; and 0850001-008-AC, Specific Condition 6.]

F.8. Alternate Gas Firing Methods of Operation.

(a) *Power Augmentation Mode*: In accordance with the manufacturer's recommendations, steam may be injected into each combustion turbine when firing natural gas to provide additional peaking power during periods of high electrical power demand. Each unit shall not exceed 400 hours of power augmentation during any consecutive 12 months. To qualify as "power augmentation mode", 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. Power augmentation when firing distillate oil is prohibited.

(b) *High Temperature Peaking Mode*: In accordance with the manufacturer's recommendations, each combustion turbine may be operated in a high temperature peaking mode when firing natural gas to provide additional power during periods of peak electrical power demands. Peaking is achieved through the automated gas turbine control system by allowing slightly higher exhaust temperatures, calculating a new combustion reference temperature for the peak load, and adjusting the fuel distribution between the fuel nozzles to maintain lean pre-mix firing. During the transfer from base load to peak load and during peak load operation, each unit will remain in the lean pre-mix steady state mode. Each unit shall not exceed 60 hours of peaking during any consecutive 12 months. To qualify as "peaking mode", 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 peaking mode, the operator shall log the date, time, and new mode of operation. Peaking when firing distillate oil is prohibited.

{Permitting note: These emissions units 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 as Appendix CP-1 to cover initial testing requirements for these alternate methods of operation for emissions of CO and NO_x.}

[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; 0850001-008-AC, Specific Condition 7.]

F.9. Restricted Operation.

(a) *Gas Firing*: Each combustion turbine shall fire no more than 5,902,588,000 standard cubic feet of natural gas during any consecutive 12 months (equivalent to 3390 hours per year at the maximum firing rate for a compressor inlet air temperature of 59° F).

(b) *Oil Firing*: Each combustion turbine shall fire no more than 7,358,350 gallons of distillate oil during any consecutive 12 months (equivalent to 500 hours per year at the maximum firing rate for a compressor inlet temperature of 59° F). If oil is fired, the natural gas consumption limit shall be reduced by 127.4 standard cubic feet of gas for every gallon of distillate oil fired.

The permittee shall calibrate, operate and maintain a monitoring system for each combustion turbine to measure and accumulate the quantity of fuel and hours of operation for each method of operation.

[Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.; and 0850001-008-AC, Specific Condition 8.]

F.10. Operating Procedures. The Best Available Control Technology (BACT) determinations established by 085001-008-AC rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbines and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.; and 0850001-008-AC, Specific Condition 9.]

Emissions Controls

F.11. Automated Control System. In accordance with the manufacturer's recommendations, the permittee shall calibrate, tune, operate, and maintain a Speedtronic™ automated gas turbine control system for each unit. Each system shall be designed and operated to monitor and control the gas turbine combustion process and operating parameters including, but not limited to: air/fuel distribution and staging, turbine speed, load conditions, exhaust temperatures, heat input, and fully automated startup and shutdown.
[Rule 62-212.400(BACT), F.A.C.; and 0850001-008-AC, Specific Condition 10.]

F.12. DLN Combustion Technology. In accordance with the manufacturer's recommendations, the permittee shall tune, operate and maintain the General Electric dry low-NOx combustion system (DLN 2.6 or better) to control NOx emissions from each gas turbine.
[Rule 62-212.400(BACT), F.A.C.; and 0850001-008-AC, Specific Condition 11.]

F.13. Tuning. DLN 2.6 combustors and automated gas turbine control systems shall be tuned to optimize the reduction of CO, NOx, and VOC emissions. Each system shall be maintained and tuned in accordance with the manufacturer's recommendations to minimize these pollutant emissions. During tuning sessions, each combustion turbine shall be tuned for CO and NOx emissions performance of 9.0 ppmvd corrected to 15% oxygen or better. The permittee shall provide at least 5 days advance notice prior to any tuning session.
[Rule 62-212.400(BACT), F.A.C.; and 0850001-008-AC, Specific Condition 12.]

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 **F.14.** through **F.17.** are based on the specified averaging time of the applicable test method.}

F.14. Carbon Monoxide (CO).

(a) *Gas Firing, Normal and Peaking*: When firing natural gas under normal operating conditions and in the high temperature peaking mode, CO emissions from each combustion turbine shall not exceed 32.0 pounds per hour and 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load.

(b) *Gas Firing With Power Augmentation*: When firing natural gas and injecting steam to provide power augmentation, CO emissions from each combustion turbine shall not exceed 47.0 pounds per hour and 15.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at peak load.

(c) *Distillate Oil Firing*: When firing low sulfur distillate oil as a backup fuel, CO emissions from each combustion turbine shall not exceed 68.0 pounds per hour and 20.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load.

The permittee shall demonstrate compliance with these standards by conducting performance tests in accordance with EPA Method 10 and the requirements of this permit.

[Rule 62-212.400(BACT), F.A.C.; and 0850001-008-AC, Specific Condition 13.]

F.15. Nitrogen Oxides (NOx).

(a) *Gas Firing, Normal*: When firing natural gas under normal operating conditions, NOx emissions from each combustion turbine shall not exceed 66.0 pounds per hour and 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load. In addition, NOx emissions shall not exceed 10.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average for data collected from the NOx continuous emissions monitor.

(b) *Gas Firing With Power Augmentation*: When firing natural gas and injecting steam to provide power augmentation, NOx emissions from each combustion turbine shall not exceed 82.0 pounds per hour and 12.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at peak load. In addition, NOx emissions shall not exceed 12.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average for data collected from the NOx continuous emissions monitor.

(c) *Gas Firing With Peaking*: When firing natural gas with high temperature peaking, NOx emissions from each combustion turbine shall not exceed 105.0 pounds per hour and

15.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at peak load. In addition, NOx emissions shall not exceed 15.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average for data collected from the NOx continuous emissions monitor.

(d) *Distillate Oil Firing*: When firing low sulfur distillate oil as a backup fuel, NOx emissions from each combustion turbine shall not exceed 334.0 pounds per hour and 42.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load. In addition, NOx emissions shall not exceed 42.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average for data collected from the NOx continuous emissions monitor.

NOx emissions are defined as oxides of nitrogen measured as NO_2. The permittee shall demonstrate compliance by conducting performance tests and emissions monitoring in accordance with EPA Methods 7E, 20, and the requirements of this permit.

[Rule 62-212.400(BACT), F.A.C.; 40 CFR 60.332; and 0850001-008-AC, Specific Condition 14.]

F.16. Particulate Matter (PM/PM_{10}) and Sulfur Dioxide (SO_2).

(a) *Particulate Matter*: When firing natural gas under any method of operation, particulate matter emissions from each combustion turbine shall not exceed 9.0 pounds per hour based on a 3-hour test average conducted at base load. When firing distillate oil, particulate matter emissions from each combustion turbine shall not exceed 17.0 pounds per hour based on a 3-hour test average conducted at base load.

(b) *Fuel Specifications.* Emissions of PM, PM_{10}, and SO_2 shall be limited by the use of pipeline-quality natural gas containing no more than 1 grain per standard cubic feet as the primary fuel and restricted use of No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight as a backup fuel. The fuel specifications are work practice standards established as BACT limits for PM, PM_{10}, and SO_2 emissions. The permittee shall demonstrate compliance with the fuel sulfur limits by maintaining the records specified in this permit. [Rule 62-212.400(BACT), F.A.C.; 40 CFR 60.333]

(c) *VE Standard.* When firing natural gas or distillate oil, visible emissions from each combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The visible emissions limits are work practice standards established as BACT limits for PM and PM_{10} emissions. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit.

[Rule 62-212.400(BACT), F.A.C.; and 0850001-008-AC, Specific Condition 15.]

F.17. Volatile Organic Compounds (VOC).

(a) *Gas Firing*: When firing natural gas under any method of operation, VOC emissions shall not exceed 3.0 pounds per hour and 1.5 ppmvw based on a 3-hour test average conducted at base load.

(b) *Distillate Oil Firing*: When firing distillate oil, VOC emissions shall not exceed 7.5 pounds per hour and 3.5 ppmvw based on a 3-hour test average conducted at base load.

The VOC standards are established as PSD-synthetic minor limits. VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Methods 25, 25A and the performance testing requirements of this permit. Optional testing in accordance with EPA

Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions.
[Rule 62-4.070(3), F.A.C.; and 0850001-008-AC, Specific Condition 16.]

Excess Emissions

F.18. 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.]

F.19. 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.]

F.20. Excess Emissions Prohibited. Excess emissions caused entirely or in part by poor maintenance, poor operation, power augmentation, high temperature peaking or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard.
[Rule 62-210.700(4), F.A.C.; and 0850001-008-AC, Specific Condition 17.]

F.21. Excess Emissions Allowed. For each combustion turbine, excess NOx and visible emissions during startup, shutdown, and documented malfunction shall be allowed, providing:

(a) Operators employ best operational practices to minimize the amount and duration of excess emissions.

(b) Operation below 50% of base load shall not exceed 120 minutes during any calendar day.

(c) During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for up to ten, 6-minute observation periods during any calendar day. Data for each observation period shall be exclusive for the ten periods.

(d) Excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period. Excess emissions resulting from oil-to-gas fuel switching shall not exceed 1 hour in any 24-hour period.

(e) The NOx CEMS shall monitor and record NOx emissions during all periods of operation including startup, shutdown, malfunction, and fuel switching. For excess NOx emissions due to malfunction, the permittee shall notify the Compliance Authority within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

(f) If the permittee provides at least 5 days advance notice prior to tuning in accordance with the manufacturer's recommendations, up to three 1-hour monitoring averages may be excluded from the continuous NOx compliance demonstration for each gas turbine due to excess NOx emissions resulting from tuning. *{Permitting Note: It is expected that no more than two tuning sessions would occur each year.}*

[Rules 62-210.700(1) & (5), and 62-4.130, F.A.C.; and 0850001-011-AC, Specific Condition 18.]

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.}

F.22. Sampling Facilities. The permittee shall design the combustion turbine stack to accommodate adequate testing and sampling locations in order to determine compliance with the applicable emission limits specified by this permit. Permanent stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.
[Rules 62-4.070 and 62-204.800, F.A.C.; 40 CFR 60.40a(b); and 0850001-008-AC, Specific Condition 19.]

F.23. Test Methods. Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C.

(a) EPA Method 5 or 17 - Determination of Particulate Matter Emissions from Stationary Sources
(b) EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources
(c) EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources
(d) EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources
(e) EPA Method 20 - Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
(f) EPA Methods 25 or 25A - Determination of Volatile Organic Concentrations *{Note: EPA Method 18 may be conducted to account for the non-regulated methane fraction of the measured VOC emissions.}*

No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C.
[40 CFR 60, Appendix A; Rule 62-204.800, F.A.C.; and 0850001-008-AC, Specific Condition 20.]

F.24. Annual Performance Tests. *Annual* performance tests shall be conducted for each combustion turbine to demonstrate compliance with CO, NOx, 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 be substituted for the required annual performance test.

(a) 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.

(b) 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.

[Rule 62-297.310(7)(a)4., F.A.C.; and 0850001-009-AC, Specific Condition 22.]

F.25. Tests Prior to Permit Renewal. *Prior to renewing* this Title V Air Operation Permit, performance tests shall be conducted for each combustion turbine to demonstrate compliance with the CO, NOx, PM, VOC, and visible emissions standards for normal gas firing, gas firing with power augmentation, gas firing with high temperature peaking, and backup oil firing. Tests for CO, NOx, and VOC emissions shall be conducted concurrently. Tests for PM and visible emissions shall be conducted concurrently. All tests shall be conducted within the 12 months prior to renewing the air operation permit.

[Rule 62-297.310(7)(a)3., F.A.C.; and 0850001-009-AC, Specific Condition 23.]

F.26. Combustion Turbine Testing Capacity

(a) Required performance tests for compliance with standards specified in this permit shall be conducted with the combustion turbine operating at permitted capacity for each method of operation. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average compressor inlet air temperature during the test (with 100 percent represented by a curve depicting heat input vs. compressor inlet temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. However, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for inlet temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Emissions performance tests shall meet all applicable requirements of Chapters 62-204 and 62-297, F.A.C.

(b) For performance tests conducted when gas firing under the power augmentation mode and under the high temperature peaking mode, the permittee shall document that the combustion turbine was operating under "peak load" for the given ambient conditions. For power augmentation, the steam injection rate shall be no less than 100,000 pounds of steam per hour.

[Rule 62-297.310(2), F.A.C.; 40 CFR 60.335; and 0850001-008-AC, Specific Condition 25.]

Continuous Monitoring Requirements

F.27. NOx CEMS. The permittee shall calibrate, operate, and maintain a CEMS to measure and record NOx and oxygen concentrations in each combustion turbine exhaust stack to meet the requirements of the Acid Rain program and to demonstrate compliance with the NOx standards specified in this permit. A monitor for carbon dioxide may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen. The NOx monitoring devices shall comply with the certification requirements, quality assurance procedures, and all other provisions of the Acid Rain monitoring requirements of 40 CFR Part 75. A monitoring plan shall be provided to the Department's Emissions Monitoring Section, EPA Region 4, and the Compliance Authority for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62. The plan shall consist of the following information: CEM equipment specifications, manufacturer, model, type, calibration and maintenance needs, and the proposed location.

(a) *Data Collection.* Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Each valid 1-hour average shall be calculated using at least two valid data points at least 15 minutes apart.

(b) *Data Reporting.* Data collected by the CEMS shall be used to demonstrate compliance with the emissions standards specified for each 3-hour average. Emissions shall be reported in units of ppmvd corrected to 15% oxygen for each hour of operation. The compliance averages shall be determined by calculating the arithmetic average of three valid 1-hour emission rates. When a monitoring system reports emissions in excess of the standards allowed by this permit, the permittee shall notify the Department within one (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. Notification shall include either a written letter, a phone call, or a fax transmittal to the Compliance Authority. The Department may request a written report summarizing the excess emissions incident. The permittee shall also report excess emissions in a quarterly report as required by this permit.

(c) *Data Exclusion for Compliance.* Unless prohibited by Rule 62-210.700(4), F.A.C., valid 1-hour monitoring averages shall not include periods of excess emissions due to startup, shutdown, documented malfunction, or the result of tuning as described and limited under Specific Condition 18 of this permit. Because such data may be excluded, the 3-hour average to determine compliance need not consist of *consecutive* 1-hour averages.

(d) *Alternate Methods of Operation.* Each 1-hour monitoring average consisting of any data collected during an alternate method of operation (oil firing, power augmentation, or peaking) shall be attributed entirely to the alternate method of operation. For each 3-hour average consisting of more than one method of operation, compliance shall be determined by prorating each emission standard based on the number of 1-hour averages represented. In event of a CEMS malfunction or occurrence of excess emissions while operating in the power augmentation or peaking modes, the permittee shall immediately cease power augmentation or peaking and revert to normal gas firing or shut down the combustion turbine.

[Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-212.400(BACT), and 62-297.520, F.A.C.; 40 CFR 60.7; 40 CFR 75; and 0850001-008-AC, Specific Condition 26.]

Recordkeeping and Reporting Requirements

F.28. Test Notification. The permittee shall notify the Department in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. [Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.7, 60.8; and 0850001-008-AC, Specific Condition 17. (Facility Information)]

F.29. Records Retention. All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C. Specific Condition 22. (Facility Information)]

F.30. Fuel 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) The permittee shall obtain data sheets from the vendor indicating the average sulfur content of the natural gas being supplied by 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 equivalent methods.

(b) The permittee shall obtain data sheets from the vendor indicating the quantity and sulfur content of the distillate oil for each shipment delivered. Methods for determining the sulfur content of distillate oil shall be ASTM D 2880-71 or equivalent methods.

These methods shall be used to determine the sulfur content of the natural gas fired in accordance with any EPA-approved custom fuel monitoring schedule (see Alternate Monitoring Plan), natural gas supplier data or the natural gas sulfur content referenced in 40 CFR 75 Appendix D. The analysis may be performed by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e). However, the permittee is responsible for ensuring that the procedures in 40 CFR 60.335 or 40 CFR 75 are used to determine the fuel sulfur content for compliance with the SO_2 standard in 40 CFR 60.333.

[Rules 62-4.070(3) and 62-4.160(15), F.A.C.; and 0850001-008-AC, Specific Condition 27.]

F.31. Alternate Monitoring Plan. Subject to EPA approval, the following alternate monitoring may be used to demonstrate compliance with the monitoring requirements of 40 CFR 60, Subpart GG.

(a) Data collected from the NOx CEM shall be used in lieu of the water-to-fuel monitoring system required for reporting excess emissions in accordance with 40 CFR 60.334(c)(1) of NSPS, Subpart GG.

(b) When requested by the Department, the CEMS emission rates for NOx on this unit shall be corrected to ISO conditions to demonstrate compliance with the NOx standard established in 40 CFR 60.332.

(c) A *custom fuel monitoring schedule* pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334(b)(2), provided:

(1) The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.

(2) The permittee shall submit a monitoring plan, certified by the Authorized Representative, that commits to using a primary fuel of pipeline-supplied natural gas containing no more than 20 grain of sulfur per 100 SCF of gas pursuant to 40 CFR 75.11(d)(2).

(3) Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

This custom fuel-monitoring schedule will only be valid when pipeline natural gas is used as the primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

[40 CFR 60, Subpart GG; and 0850001-008-AC, Specific Condition 28.]

F.32. Monthly Operations Summary. By the fifth calendar day of each month, the permittee shall record the hours of each mode of operation and the fuel consumption for each combustion turbine. The information shall be recorded in a written or electronic log and shall summarize the previous month of operation and the previous 12 months of operation. Information recorded and

stored as an electronic file shall be available for inspection and printing within at least three (3) days of a request from the Department.
[Rule 62-4.160(15), F.A.C.; and 0850001-008-AC, Specific Condition 29.]

F.33. Quarterly Excess Emissions Reports. Periods of startup, shutdown and malfunction shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. Within 30 days following each calendar quarter, the permittee shall submit a report on any periods of excess emissions that occurred during the previous calendar quarter to the Department.
[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7; and 0850001-008-AC, Specific Condition 30.]

F.34. The emissions units are also subject to the conditions contained in **Subsection E. Common Conditions.**

Subsection G. This section addresses the following emissions unit.

EU ID No.	Brief Description
-013	Two Natural Gas Fuel Heaters

Each gas fuel heater is fired with a maximum heat input of 23.71 mmBTU per hour of natural gas. The manufacturer is the Gastech Engineering Corporation, and the model number is FGA-HX-2.

{Permitting note: These emissions units are regulated under Air Construction Permit PSD-FL-286 (085001-008-AC).}

Performance Restrictions

G.1. Equipment. The permittee is authorized to operate and maintain the following emissions units and supporting equipment: two gas fuel heaters fired solely with natural gas (23.71 mmBTU per hour) designed to heat the natural gas supplied to simple-cycle combustion turbines 8A and 8B.
[0850001-008-AC, Specific Condition 3. (Natural Gas Fuel Heaters section)]

G.2. Hours of Operation. The hours of operation for the gas fuel heaters are not restricted (8760 hours per year).
[Rule 62-210.200(PTE), F.A.C.; and 0850001-008-AC, Specific Condition 4. (Natural Gas Fuel Heaters section)]

Performance Requirements

{Permitting note: Unless otherwise specified, the averaging time for Specific Condition **G.3.** is based on the specified averaging time of the applicable test method.}

G.3. Good Combustion. Visible emissions of 5% opacity or less from the gas fuel heaters shall be an indicator of good combustion as determined by EPA Method 9. 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; and 0850001-008-AC, Specific Condition 5. (Natural Gas Fuel Heaters section)]

Records

G.4. Records. For purposes of reporting in the Annual Operating Report, the permittee shall keep records sufficient to document the annual amount of natural gas fired in the gas fuel heaters.
[Rule 62-210.370(3), F.A.C.; and 0850001-008-AC, Specific Condition 6. (Natural Gas Fuel Heaters section)]

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	Simple-Cycle Combustion Turbine (8A)
-012	PMR8B	Simple-Cycle Combustion Turbine (8B)

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.]

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*

-003	**HRSG3A**	SO2 allowances, under Table 2 of 40 CFR Part 73	1275*	1275*	1275*	1275*	1275*
-004	**HRSG3B**	SO2 allowances, under Table 2 of 40 CFR Part 73	1275*	1275*	1275*	1275*	1275*
-005	**HRSG4A**	SO2 allowances, under Table 2 of 40 CFR Part 73	1275*	1275*	1275*	1275*	1275*
-006	**HRSG4B**	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

*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.

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.]

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.]

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

Appendix H-1. Permit History/ID Number Changes

Permit History (for tracking purposes):

E.U. ID No	Description	Permit No.	Issue Date	Expiration Date	Revised Date(s)
-001	Fossil Fuel Fired Steam Generator	AC-73044 AC43-4037 AO43-170568	3/20/73 6/30/77 2/23/90	 11/29/94	 2/16/93
-002	Fossil Fuel Fired Steam Generator	AC-73045 AC43-4038 AO43-170567	3/20/73 6/30/77 2/20/90	 11/29/94	 2/16/93
-003 -004 -005 -006	Combustion Turbines with HRSGs	PSD-FL-146 0850001-001-AC 0850001-002-AC 0850001-003-AC 0850001-005-AC PA89-27 0850001-004-AV (Initial Title V Permit) 0850001-006-AV (Administrative Permit Correction) 0850001-007-AV (Title V Permit Revision)	6/05/91 Withdrawn 2/20/91 1/01/99 7/26/00	 12/31/03 12/31/03	7/19/93 9/16/94 9/06/96 10/14/97 9/06/96 9/06/96 7/20/99 9/28/94
-007	Auxiliary Boiler	PSD-FL-146 PA89-27	6/05/91 2/20/91		7/19/93 9/06/96 9/28/94
-009	Diesel Generator	PSD-FL-146 PA89-27	6/05/91 2/20/91		7/19/93 9/06/96 9/28/94
-011 -012	Simple-Cycle Combustion Turbines	PSD-FL-286 0850001-008-AC 0850001-011-AC 0850001-009-AV 0850001-010-AC	 3/20/03 Withdrawn 4/16/03	7/01/02 7/01/02 12/01/03 12/30/06	
-013	Two Natural Gas Heaters	PSD-FL-286 0850001-008-AC 0850001-009-AV	 Withdrawn	7/01/02 7/01/02	
	All of the above.	0850001-012-AV (Title V Permit Revision)	6/10/03	12/31/03	

ID Number Changes (for tracking purposes): From: **Facility ID No.** 50WPB430001; To: **Facility ID No.** 0850001

Phase II Permit Application

For more information, see instructions and refer to 40 CFR 72.30 and 72.31 and Chapter 62-214, F.A.C.

This submission is: [X] New [ ] Revised

STEP 1
Identify the source by plant name, State, and ORIS code from NADB

Plant Name	State	ORIS Code
FPL Martin Plant	FL	6043

STEP 2
Enter the boiler ID# from NADB for each affected unit, and indicate whether a repowering plan is being submitted for the unit by entering "yes" or "no" at column c. For new units, enter the requested information in columns d and e

a	b	c	d	e
	Compliance Plan			
Boiler ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)	Repowering Plan	New Units Commence Operation Date	New Units Monitor Certification Deadline
PMR1	Yes	No	N/A	N/A
PMR2	Yes	No	N/A	N/A
HRSG3A	Yes	No	2/16/94	1/1/96
HRSG3B	Yes	No	2/16/94	1/1/96
HRSG4A	Yes	No	4/15/94	1/1/96
HRSG4B	Yes	No	4/15/94	1/1/96
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			

STEP 3
Check the box if the response in column c of Step 2 is "Yes" for any unit

[ ] For each unit that will be repowered, the Repowering Extension Plan form is included and the Repowering Technology Petition form has been submitted or will be submitted by June 1, 1997.

STEP 4
Read the standard requirements and certification, enter the name of the designated representative, and sign and date

Standard Requirements

Permit Requirements.

(1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Submit a complete Acid Rain part application (including a compliance plan) under 40 CFR part 72, Rules 62-214.320 and 330, F.A.C. in accordance with the deadlines specified in Rule 62-214.320, F.A.C.; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain part application and issue or deny an Acid Rain permit;
(2) The owners and operators of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain part application or a superseding Acid Rain part issued by the permitting authority; and
(ii) Have an Acid Rain Part.

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1)(i) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements. The owners and operators of the source and each Acid Rain unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements.

(1) The designated representative of an Acid Rain unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an Acid Rain unit that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

Recordkeeping and Reporting Requirements (cont.)

(iv) Copies of all documents used to complete an Acid Rain part application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an Acid Rain source and each Acid Rain unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain part application, an Acid Rain part, or a written exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR parts 72, 73, 75, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities. No provision of the Acid Rain Program, an Acid Rain part application, an Acid Rain part, or a written exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided*, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

Certification

I am authorized to make this submission on behalf of the owners and operators of the Acid Rain source or Acid Rain units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment. (There are no attachments to this document)

Name William M. Reichel	
Signature William M. Reichel	Date 12/4/95

FINDS

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

October 14, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Richard Piper
Senior Environmental Specialist
Florida Power and Light Company
Post Office Box 14000
Juno Beach, Florida 33408

RE: Amendment to PA 89-27, PSD-FL-146(A) Permit
NSPS Custom Fuel Monitoring Schedule
Florida Power & Light Company
Martin Plant

Dear Mr. Piper:

The Department has reviewed your April 28, 1993 letter with supporting data submitted to EPA and additional data submitted by Fax to the Department on October 1, 1997, requesting an NSPS Custom Fuel Monitoring Schedule. The schedule would only apply to a monitoring schedule for sulfur dioxide (SO_2) and nitrogen oxide (NO_x) when natural gas is being fired at the subject facility (refer to Attachments No. 1 & 2). The facility is required by the permit to comply with Subpart GG of the New Source Performance Standards (NSPS) 40 CFR 60. For sources utilizing pipeline quality natural gas, 40 CFR 60.334(b) and 60.334(b)(2) state that a custom fuel monitoring schedule, if supported by data which demonstrates compliance with NSPS emission limits, may be approved by the Administrator of EPA. This authority has been delegated to EPA's regional offices and, as stated in the letter from EPA on June 2, 1993, the EPA Region IV will provide their determination of this request to the Department. The Department received a letter, dated June 8, 1993, from EPA on October 1, 1997, stating that a custom fuel monitoring schedule for this facility was acceptable, since it complied with all items of the attachment to the custom fuel monitoring guidance memo issued by EPA Headquarters on August 14, 1987 (Refer to attachment No. 3). The results from a minimum of one sampling event each quarter for six quarters were provided by the permittee, which demonstrated consistent compliance with the allowable SO_2 emissions limits specified under 40 CFR 60.333 and this permit. Therefore, upon issuance of the amended permit, the permittee shall begin monitoring the sulfur content of natural gas as specified in 2.c. of the Custom Fuel Monitoring Schedule for Natural Gas. In accordance with the EPA and Department determination, the permit specific condition will be amended as follows:

A. Specific Condition Number:

From

15. This project shall comply with all the applicable requirements of Chapter 17-2, Florida Administrative Code (F.A.C.) and the June 27, 1989 version of 40 CFR Subpart GG, Gas Turbines.

To

15. This source shall be in compliance with all requirements of 40 CFR 60, Subpart GG (Standards of Performance for Stationary Gas Turbines) and Rule 62-204.800(7), F.A.C. (Standards of Performance for New Stationary Sources (NSPS)).

A. Natural Gas

Pursuant to 40 CFR 60.334(b)(2), a custom fuel monitoring schedule shall be followed for the natural gas fired at this facility and shall be 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. 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. 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 the custom 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.

B. New No. 2 Fuel Oil

The records of new No. 2 fuel oil usage shall be kept by the company for a five year period for regulatory agency inspection purposes. For sulfur dioxide, periods of excess emissions shall be reported if the fuel oil being fired in the gas turbine exceeds 0.5 percent sulfur content and 0.3 percent sulfur content, by weight, for hourly and annual emissions, respectively.

B. Attachments to be Incorporated:

- FPL letter dated April 28, 1993
- EPA letter dated June 2, 1993
- EPA letter dated June 8, 1993
- FPL fax dated October 1, 1997

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Petitions filed by the applicant of the amendment request/application and the parties listed below must be filed within 14 days of receipt of this amendment. Petitions filed by other persons must be filed within 14 days of the amendment issuance or within 14 days of their receipt of this amendment, whichever occurs first. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, F.S.

The Petition shall contain the following information:

(a) The name, address and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(d) A statement of the material facts disputed by Petitioner, if any;
(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;
(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action;
(g) A statement of the relief sought by petitioner, stating precisely the action the petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this amendment. Persons whose substantial interests will be affected by any decision of the Department with regard to the request/application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this amendment in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, Florida Administrative Code.

This letter amendment must be attached to PA 89-27, PSD-FL-146(A) Permit and shall become part of the permit.

Sincerely,

Howard L. Rhodes

Howard L. Rhodes
Director
Division of Air Resources
Management

HLR/CSL

Attachments

cc: H. Oven, DEP
I. Goldman, SED
A. Linero, DEP
J. Harper, EPA
J. Lindsay, FPL
J. Bunyak, NPS
K. Kosky, KBN

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this AMENDMENT and all copies were sent by certified mail before the close of business on 10/14/97 to the person(s) listed:

Clerk Stamp

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

(Clerk) 10/14/97 (Date)

Appendix CP-1, Compliance Plan for Alternate Methods of Operation

Florida Power & Light Company Permit No. **0850001-013-AV**
Martin Plant

E.U. ID No.	Brief Description
-011	Simple-Cycle Combustion Turbine (8A)
-012	Simple-Cycle Combustion Turbine (8B)

These emissions units have not, to date, been operated under the gas firing with peaking, and/or gas firing with power augmentation modes. Therefore, this 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 **F.14.** and **F.15.**

CP.1. Test Notification. The permittee shall notify the Department in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. [Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.7, 60.8; and 0850001-008-AC, Specific Condition 17. (Facility Information)]

CP.2. 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.]

Table 1-1, Air Pollutant Standards and Terms

Permit No. **0850001-013-AV**
Facility ID No. **0850001**

Florida Power & Light Company
Martin Plant
This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U.	Brief				Allowable Emissions			Equivalent Emissions*			See Permit
ID No(s).	Description	Pollutant Name	Fuel(s)	Hours/Year	Standard(s)	lbs./hour	TPY	lbs./hour	TPY	Regulatory Citations	Conditions
-001	Fossil Fuel Fired	PM	Oil	8760	0.1 lb/MMBtu			865	3788.7	40 CFR 60.42	A.5
-002	Steam Generators		Gas	8760	0.1 lb/MMBtu						
		SO2	Oil	8760	0.8 lb/MMBtu			6920	30309	40 CFR 60.43	A.9
		NOx	Oil	8760	0.3 lb/MMBtu			2595	11366.1	40 CFR 60.44	A.10
			Gas	8760	0.2 lb/MMBtu			1808	7919.04		
		VE	Oil	8760	Not > 20%						A.8
-003	Combustion Turbines	PM/PM10	Oil	2000		60.6	100			Rule 62-212.410, F.A.C.	B.6
-004	with HRSGs		Gas	8760		18					
-005		SO2	Oil	2000	0.5% sulfur	920	568			40 CFR 60.333	B.6
-006			Gas	8760		91.5					
		NOx	Oil	2000	65 ppmvd @ 15% O2	461	3108			40 CFR 60.332	B.6
			Gas	8760	25 ppmvd @ 15% O2	177					
		VOC	Oil	2000	6 ppmvd	11	57			Rule 62-212.410, F.A.C.	B.6
			Gas	8760	1.6 ppmvd	3					
		CO	Oil	2000	33 ppmvd	105.8	871			Rule 62-212.410, F.A.C.	B.6
			Gas	8760	30 ppmvd	94.3					
		PB	Oil	2000		0.015	0.015			Rule 62-212.410, F.A.C.	B.6
			Gas	8760		Negligible					
		SAM	Oil	2000		113	70			Rule 62-212.410, F.A.C.	B.7
			Gas	8760		11.2					
		H114	Oil	2000		0.0052	0.34			Rule 62-212.410, F.A.C.	B.7
			Gas	8760		0.021					
		FL	Oil	2000		0.055	0.055			Rule 62-212.410, F.A.C.	B.7
		H021	Oil	2000		0.004	0.004			Rule 62-212.410, F.A.C.	B.7
		VE	Oil	2000	Not > 20%					Rule 62-212.410, F.A.C.	B.8
			Gas	8760	Not > 10%						
-007	Auxiliary	VE	Oil	8760	Not > 20%					40 CFR 60.43c	C.5
	Boiler	NOx	Gas/Oil	8760	0.3 lb/MMBtu			4.88	21.37	Rule 62-212.410, F.A.C.	C.10
		SO2	Gas/Oil	8760	0.3% Sulfur in Oil					Rule 62-212.410, F.A.C.	C.8
-009	Diesel Generator	NOx	Oil	400	15 gm./hp-hr.					Rule 62-212.410, F.A.C.	D.2
	(for -003 to -006)	SO2	Oil	400	0.3% Sulfur in Oil					Rule 62-212.410, F.A.C.	D.3
-011	Simple-Cycle	PM/PM10	Oil	500		17					F.16.
-012	Combustion Turbines		Gas	3390		9					
		SO2	Oil	500	.0005 sulfur by weight	103.1					F.16.
			Gas	3390							
		NOx	Oil	500	42 ppmvd	340					F.15.
			Gas	3390	9 ppmvd	66					
		VOC	Oil	500	1.5 ppmvw	3					F.17.
			Gas	3390	3.5 ppmvw	7.5					
		CO	Oil	500	20 ppmvd	68					F.14.
			Gas	3390	9 ppmvd	32					
		VE	Oil	500	Not > 10%						F.16.
			Gas	3390	Not > 10%						

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

Table 2-1, Compliance Requirements

Florida Power & Light Company **Martin Plant**			Permit No. **0850001-013-AV** Facility ID No. **0850001**				
This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.							
E.U. ID Nos.	**Brief Description**						
-001	Fossil Fuel Fired Steam Generator						
-002	Fossil Fuel Fired Steam Generator						
Pollutant Name or parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date **	Min. Compliance Test Duration	CMS*	See Permit Conditions
VE	Oil	DEP Method 9	Annual	1-Oct	1 Hour		**A.15**
PM	Oil	EPA Method 5	Annual	1-Oct	3 Hours		**A.18**
	Gas	EPA Method 5	Annual	1-Oct	3 Hours		**A.18**
SO2	Oil	EPA Method 6C	Annual	1-Oct		Yes	**A.18**
	Gas	EPA Method 6C	Annual	1-Oct		Yes	**A.18**
NOx	Oil	EPA Method 7E	Annual	1-Oct		Yes	**A.18**
	Gas	EPA Method 7E	Annual	1-Oct		Yes	**A.18**
CO2 (Diluent Gas)						Yes	**A.23**
Volumetric Flow						Yes	**A.23**
Opacity						Yes	**A.23**
E.U. ID Nos.	**Brief Description**						
-003	Combustion Turbine with HRSG						
-004	Combustion Turbine with HRSG						
-005	Combustion Turbine with HRSG						
-006	Combustion Turbine with HRSG						
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date **	Min. Compliance Test Duration	CMS*	See Permit Conditions
VE	Oil	DEP Method 9	Annual	1-Oct	1 Hour		**B.27**
	Gas	DEP Method 9	Annual	1-Oct	1 Hour		**B.27**
PM/PM10	Oil	EPA Method 5 or 17	Annual	1-Oct	3 Hours		**B.27**
SO2	Oil	ASTM D 2880-96	Daily				**B.24**
(Sulfur Content of Fuel)	Gas	ASTM D 1072-90(94)E-1 or D 3031--81(86) or D 4084-94 or D 3246-92	Annual	1-Oct			**B.24**
NOx	Oil	EPA Method 20	Annual	1-Oct		Yes	**B.27**
	Gas	EPA Method 20	Annual	1-Oct		Yes	**B.27**
CO	Oil	EPA Method 10	Annual	1-Oct			**B.27**
	Gas	EPA Method 10	Annual	1-Oct			**B.27**
CO2						Yes	

Florida Power & Light Company **Martin Plant**			Permit No.**0850001-012-AV** Facility ID No.**0850001**				
E.U. ID No.	**Brief Description**						
-007	Auxiliary Boiler						
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date **	Min. Compliance Test Duration	CMS*	See Permit Conditions
VE	Oil	DEP Method 9	Annual	1-Oct	1 Hour		**C.13**
SO2	Oil Gas	ASTM D 2880-96 ASTM D 1072-90(94)E-1	Daily Annual	 1-Oct			**C.11**

E.U. ID No.	**Brief Description**						
-009	Diesel Generator						
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date **	Min. Compliance Test Duration	CMS*	See Permit Conditions
SO2	Oil	Verification by vendor receipts	On delivery				**D.4**

E.U. ID No.	**Brief Description**						
-011	Simple-Cycle Combustion Turbines						
-012 Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date **	Min. Compliance Test Duration	CMS*	See Permit Conditions
PM/PM10	Oil Gas	EPA Method 5 or 17	Renewal				**F.23.**
SO2	Oil Gas	Verification by vendor receipts ASTM D 2880-71 (oil) D4084-82, D3246-81(gas)	On delivery				**F.30.**
NOx	Oil Gas	EPA Method 7E and 20	Annual			Yes	**F.23., F.27.**
VOC	Oil Gas	EPA Method 25 or 25A	Renewal				**F.23.**
CO	Oil Gas	EPA Method 10	Annual				**F.23.**
VE	Oil Gas	EPA Method 9	Annual				**F.23.**

Notes:
*CMS [=] Continuous Monitoring System
**Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.