Memorandum

Florida Department of Environmental Protection

TO: Joseph Kahn

THRU: Trina L.Vielhauer
A.A. Linero
Scott Sheplak

FROM: Teresa Heron T.H.

DATE: October 24, 2006

SUBJECT: FPL Manatee 1,150 MW Unit 3 - DEP File No. 0810010-011-AV

Attached is the final Title V Permit Revision package for the FPL Manatee Power Plant to incorporate the Unit 3 Combined Cycle Turbine Generator System.

We recommend your approval and signature.

AAL/sms/th

Attachments

Joe-
No comments from FPL on draft & no comments from EPA on proposed.

NOTICE OF FINAL TITLE V AIR OPERATION PERMIT

In the Matter of an
Application for Permit Revision:

Mr. Paul Plotkin
General Manager
Florida Power & Light Company
19050 State Road 62
Parrish, FL 34219-9220

FINAL Permit Project No.: 0810010-011-AV
Manatee Power Plant
Manatee County

Enclosed is the FINAL Permit, No. 0810010-011-AV. The purpose is for the revision of the Title V Air Operation Permit. The facility is located in Manatee County, Florida. This permit revision is issued pursuant to Chapter 403, Florida Statutes (F.S.). No comments were received from Region 4, U.S. EPA.

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 Department.

Executed in Tallahassee, Florida.

Trina L. Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

TLV/aal/sms/th

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) and all copies were sent electronically (with Received Receipt) before the close of business on 10/30/06 to the person(s) listed below:

Paul Plotkin, FPL (paul_plotkin@fpl.com)
Kennard F. Kosky, P.E. (kkosky@golder.com)
Kevin Washington, FPL (kevin_washington@fpl.com)
Mara Nasca, FDEP-SWD Office (mara.nasca@dep.state.fl.us)
Buck Oven, DEP-PPS Office (hamilton.owen@dep.state.fl.us)
Clarence Troxell (Elihu46fl@aol.com)

FINAL Determination

Title V Air Operation Permit Renewal
FINAL Permit No.: 0810010-011-AV
Florida Power & Light Company
Manatee Plant
Page 1 of 1

I. Comment.

No comments were received from the USEPA during their 45 day review period of the PROPOSED Permit.

II. Conclusion.

In conclusion, the permitting authority hereby issues the FINAL Permit.

STATEMENT OF BASIS

FINAL Title V Operation Permit Revision
DEP File No.: 0810010-011-AV
Florida Power & Light Company
Facility ID No.: 0810010
Manatee County

Related File Nos.: 0810010-006-AC; 0810010-009-AV; and 0810010-012-AC

This Title V Air Operation Permit Revision is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210 and 62-213. The above named permittee is hereby authorized to 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.

The Title V Operation Permit Revision is also based on:

- The Facility Title V Operation Permit 0810010-009-AV effective January 1, 2004 and which expires on December 31, 2008;
- Air Construction Permit No. 0810010-006-AC (PSD-FL-328) to construct a new unit at the existing facility which was issued April 15, 2003 and which expires on December 31, 2006;
- Air Construction Permit Modification No. 0810010-012-AC (PSD-FL-328A) to amend certain conditions to construct a new unit at the existing facility; and
- The application dated October 31, 2005 to revise the Facility Title V Operation permit to incorporate the Air Construction Permit and its subsequent Modification processed concurrently with the Revision of the Title V Operation Permit.

The Title V Operation Permit effective January 1, 2004 authorized the operation of the Florida Power & Light (FP&L) Company Manatee Power Plant in Parrish, Manatee County, Florida. The facility under that permit consisted of two nominal 800 megawatt (900 MW gross capacity) fossil fuel steam generators (Units 1 and 2). Each unit is a Foster-Wheeler Steam Generator rated at 800 megawatts (MW) (900 MW gross capacity) output. These units burn a variable combination of natural gas, No. 6 fuel oil, No. 2 fuel oil, propane, and used oil from FPL operations, discharging pollutants through separate stacks 499 feet above ground level. Each unit is equipped with multiple cyclones, a flue gas recirculation system and staged combustion and a Westinghouse tandem compound, reheat-type extraction turbine.

The Air Construction Permit issued April 15, 2003 authorized construction of Unit 3, which consists of: four nominal 170 megawatt General Electric Model PG7241(FA) gas-fired turbine-electrical generator sets with evaporative inlet cooling systems; an automated gas turbine control system; an inlet air filtration system; four 495 MMBtu/hr supplementary-fired heat recovery steam generators (HRSG's) with SCR reactors; a single nominal 470 MW steam-electrical generator that serves all four gas turbine/HRSG systems, four 120 feet exhaust stacks, and associated support equipment. The total nominal generating capacity of combined cycle system Unit 3 is 1150 MW.

Unit 3 has been constructed and tested. The Department distributed a DRAFT Title V Operation Permit Revision to incorporate Unit 3 on February 2, 2006. The conditions from the original Air Construction (PSD) Permit were included verbatim with the exception of those related to initial testing (e.g. steam blows) and similar items. Notification was published by the applicant on February 21, 2006.

During the comment period, the Department received comments from FP&L regarding the time needed to sequentially start (actually restart) the four <u>combustion turbine</u>-electric generator/heat recovery steam generator (CT/HRSG) sets in conjunction with cold startups of the single <u>steam turbine</u>-electric generator.

FP&L's requested changes affect enforceable conditions in a construction permit. Therefore, the company submitted a request to change the underlying air construction (PSD) Permit for Unit 3 and requested concurrent processing of the two permitting actions pursuant to their separate applicable regulations.

A "Revised" DRAFT Title V Permit Revision was distributed on June 7, 2006, at the same time as a DRAFT Air Construction Permit Modification under a single Public Notice that cites the different program procedures for public comment and further processing. Notification was published by the applicant on July 11, 2006.

The Air Construction (PSD) Permit Modification to allow excess emissions from the CT/HRSG sets for a period of eight rather than six hours during the cold startup of the 470 MW steam turbine electric generator (STG) that receives steam from the four associated CT/HRSG sets was issued on August 30, 2006.

This "Revised" DRAFT Title V Operation Permit Revision incorporates Unit 3 in a manner that reflects the longer startup period for the STG as requested by FP&L. Such cold startups of a STEG are infrequent and typically years apart for baseloaded combined cycle units. The changes in the facility Title V Operation Permit that incorporate Unit 3 are the addition of the paragraphs in Section III, Subsection B, Specific Conditions B.1 through B.32.

Another addition is to briefly describe in Section II-Facility-wide Conditions, Specific Condition 15 another project that is in progress on Units 1 and 2. The project is to add a pollution control system called "reburn technology" for the purpose of nitrogen oxides control. The operation conditions related to that project will be added to the Title V Operation Permit upon completion of construction and subsequent testing that will affect the final emission limits for Unit 1 and 2.

The Department is clarifying the applicability of 40 CFR Part 60, Subpart GG – Standards of Performance for Stationary Gas Turbines. In the previous permits, it was obvious that adherence to the requirements of the determinations of Best Available Control Technology under the various PSD permits issued to the facility would insure compliance with Subpart GG. However the Subpart GG provisions are clearly applicable requirements that must be included in the Title V Operation Permit. Additionally, the most recent version of Subpart GG issued on July 8, 2004 and revised on April 28, 2006, include clearer compliance methods for modern combustion turbines compared with those in existence at the time the original rule was promulgated (1977). These requirements are added as new Appendix GG (part of the permit).

On March 5, 2004, EPA promulgated 40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. The applicability of this new MACT is addressed as part of this project. Unit 3 is subject to 40 CFR 63, Subpart YYYY because it is a combustion turbine to be located at a major source of HAPs. The applicability of Subpart YYYY depends on the date a combustion turbine commenced construction. Unit 3 commenced construction prior to January 14, 2003; the combustion turbine was under contractual obligations before this date. Therefore, Unit 3 is determined to be an 'existing combustion turbine' for purposes of Subpart YYYY. Currently, 'existing combustion turbines' are not required to meet the notification requirements or the emission limitations of Subpart YYYY. EPA may at a future date promulgate standards for existing units.

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

Based on the Title V Air Operation Permit Renewal application received May 27, 2003, this facility is a major source of hazardous air pollutants (HAPs).

A Compliance Report and Plan Certification was submitted with the Application to revise the Title V permit. FPL certified that the facility, including the new emissions units, are in compliance with DEP requirements as required in Rule 62-213.420 (k) F.A.C.

In accordance with the Compliance Section of the DEP District Office in Tampa, this facility is currently in compliance with DEP requirements as required in Rule 62-213.420 (k) F.A.C.

Florida Power and Light Rationale Behind The Request To Extend The Excess Emissions Period From 6-Hours To 8-Hours When Conducting A Cold Start-Up Of The Steam Turbine/Generator At Manatee Plant Combined Cycle Unit 3

Although a Cold Steam Start-Up is a complex procedure done infrequently, actual operating experience now shows that the six hours originally permitted by the PSD and AC permits is inadequate to successfully, and smoothly, execute a cold Steam Turbine start. The Steam Turbine Start Up process has CTs sequentially started so that the respective Heat Recovery Steam Generator (HRSG) is able to provide a sufficient quantity of steam at the appropriate temperature, pressure, and flow to maintain accurate Steam Turbine speed control and warm the Steam Turbine slowly. This requires that the CT's be run at low loads. Typically, one CT is started ahead of the others, and a second CT is started somewhat later. When the steam conditions from the second CT/HRSG matches the pressure and temperature of the first HRSG, it is "blended" by means of valving operations with the first CT/HRSG steam and the start-up progresses. Later, a third CT/HRSG combination is started, warmed up, and "blended". This is done in order to "unblend" the first CT/HRSG as it approaches the 6-hour excess emissions window. That is, the steam from the first CT's HRSG is routed by means of valving operations from the Main Steam Turbine Header to the condenser. The first CT's load is then ramped up to a point where the SCR can be placed into service and render the CT in compliance with its normally permitted emissions. Afterward, it is "re-blended" with the other two starting units.

This process of "unblending" one CT while ensuring the other CT's have been sequentially started up, and in the right configuration to provide steam of adequate temperature, pressure, and quantity to be "blended" to the steam turbine has proven to be challenging. During the "unblending" and "blending" valving operations, CT HRSG's temperatures, pressure and drum levels become very difficult to control. Any HRSG instability can trip the CT's which would require a new restart and potentially more excess emissions, either from a restart of the CTs, or more typically, the start-up must postponed until the next calendar day as insufficient start-up time remains in the current 24-hour period. Postponing the start-up until the next day necessitates that the needed generation is supplied from elsewhere. In the case of Manatee Unit 3, any alternate source is a higher emitting source. Manatee Plant Units 1 or 2 would likely provide that replacement generation.

Extending the 6 hour emission limit to 8 hours would significantly reduce the number of "unblending/blending" operations, and provide more certainty of a successful timely start using as few as two CTs. It also will allow more operational flexibility in cases where the load from 3 or 4 CT's is not needed, or when 2 CT's are out of service for routine maintenance.

Manatee Unit 3 conducted a cold start-up of the Steam Turbine System on June 12, 2005. Three CTs were used during the start-up. To remain within the 6-hour excess emissions window, CT-A was unblended at the end of its 6-hour period, ramped up in firing rate, and the SCR placed into service. The CEM emissions data in Table 1 below is from that start-up. The "Additional 2 hours" of emissions data is projected from the actual emissions of the last 2 hours (hours 5 and 6) of CT-A and CT-C operation.

PMT UNIT 3 COLD TURBINE S/U JUNE 12, 2005
NOx emissions in pounds from CEM data

	CT-A	CT-B	CT-C	A+C	A+B+C
First 6 hours	554	509	574		
Additional 2 hours *Projected from hours 5 and 6 actual emissions	209*		230*		
Projected total for 2 CTs @ 8 hours each (CTs A & C)	763		804	**1,567**	
Total for 3 CTs @ 6 hours each	554	509	574		**1,637**

Table 1

A two CT start-up with 8-hours of excess emissions versus a three CT start-up with 6-hours of excess emissions allows:

- Greater operational flexibility,
- Simplifies the start-up process,
- Has less risk from unintended CT trips associated with blending/unblending operations, and
- Offers a modest net reduction in NOx mass emissions over the duration of the start-up.

This same 8-hour, two CT scenario has applicability to Martin Unit 8, and Turkey Point Unit 5 as well.

FINAL Determination

Title V Air Operation Permit Renewal
FINAL Permit No.: 0810010-011-AV
Florida Power & Light Company
Manatee Plant

I. Comment.

No comments were received from the USEPA during their 45 day review period of the PROPOSED Permit.

II. Conclusion.

In conclusion, the permitting authority hereby issues the FINAL Permit.

Florida Power & Light Company
Manatee Power Plant
Facility ID No. 0810010
Manatee County

Title V Air Operation Permit Revision

FINAL Permit No. 0810010-011-AV

Permitting Authority:
State of Florida
Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation

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

Telephone: 850/488-0114
Fax: 850/921-9533

Compliance Authority:

Department of Environmental Protection
Southwest District Office
N. Telecom Parkway
Temple Terrace, FL 33637-0926
Telephone: 813/632-7600 and Fax: 813/744-6084

Title V Air Operation Permit Revision
FINAL Permit No. 0810010-011-AV

Table of Contents

Jeb Bush
Governor

Department of Environmental Protection

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

Colleen M. Castille
Secretary

Permittee:
Florida Power & Light Company
Manatee Plant
19050 State Road 62
Parrish, FL 34219-9220

FINAL Permit No. 0810010-011-AV
Facility ID No. 0810010
SIC Nos. 49, 4911
Project: Revised Title V Air Operation Permit

The purpose of this permit is to revise the Title V Air Operation Permit by incorporating the "4 on 1" new 1,150 MW combined cycle gas turbines, identified as Manatee Unit 3. This existing facility is located at 19050 State Road 62, Parrish, Manatee County; UTM Coordinates: Zone 17, 367.250 km East and 3054.150 km North; Latitude: 27° 36' 21" North and Longitude: 82° 20' 44" West.

This Title V Air Operation Permit Revision is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-213. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:

Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix TV-6, Title V Conditions (version dated 6/23/06)
Appendix SS-1, Stack Sampling Facilities (version dated 10/07/96)
Table 297.310-1, Calibration Schedule (version dated 10/07/96)
Phase II Acid Rain Application/Compliance Plan received 5/27/03
Alternate Sampling Procedure: ASP Number 97-B-01
Order Granting Reduced Sampling Frequency, OGC Case Nos. 83-0580 and 83-0581, Order dated 4/24/84
Agreement for the Purpose of Ensuring Compliance with Ambient Air Quality Standards for Ozone dated 9/19/02
Appendix A, NSPS Subpart A, General Provisions
Appendix Da, NSPS Subpart Da Requirements for Duct Burners
Appendix GG, NSPS Subpart GG Requirements for Gas Turbines
Appendix SC, Standard Conditions
FIGURE 1, Summary Report - Gaseous and Opacity Excess Emissions and Monitoring System Performance Report
Appendix BACT, Best Available Control Technology

Renewal Effective Date: January 1, 2004
Revision Effective Date: October 12, 2006
Renewal Application Due Date: July 5, 2008
Expiration Date: December 31, 2008

Joseph Kahn, Director
Division of Air Resource Management

JK/tlv/aal/sms/th

Section I. Facility Information.

Subsection A. Facility Description.

This nominal 2,750 MW facility consists of two fossil fuel steam generators, a "4-on-1" gas-fired combined cycle unit and associated support equipment.

Fossil Fuel Steam Generators, Unit 1 and Unit 2: Each unit is a Foster-Wheeler Steam Generator rated at 800 megawatts (MW) (900 MW gross capacity) output. These units burn a variable combination of natural gas, No. 6 fuel oil, No. 2 fuel oil, propane, and used oil from FPL operations, discharging pollutants through a stack 499 feet above ground level. Each unit is equipped with multiple cyclones, a flue gas recirculation system and staged combustion and also operate a Westinghouse tandem compound, reheat-type extraction turbine.

Combined Cycle Gas Turbine, Unit 3: This unit consists of four ("4-on-1") nominal 170 megawatt General Electric Model PG7241(FA) gas-fired turbine-electrical generator sets with evaporative inlet cooling systems, an automated gas turbine control system, an inlet air filtration system, four 495 MMBtu/hr supplementary-fired heat recovery steam generators (HRSG's) with SCR reactors, a single nominal 470 MW steam-electrical generator that serves all four gas turbine/HRSG systems, four 120 feet exhaust stacks, and associated support equipment. The total generating capacity of the "4-on-1" combined cycle system Unit 3 is 1150 MW.

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

Based on the Title V Air Operation Permit Renewal application received May 27, 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 Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2
Unregulated Emissions Units and/or Activities	
003	Emergency Diesel Generator, Miscellaneous Mobile Equipment and Internal Combustion Engines
004	Painting of Plant Equipment and Non Halogenated Solvent Cleaning Operations

E.U. ID No.	Brief Description: "4 on 1" Combined Cycle Unit 3
005	Unit No.3A gas turbine (nominal 170 MW) with heat recovery steam generator
006	Unit No.3B gas turbine (nominal 170 MW) with heat recovery steam generator
007	Unit No.3C gas turbine (nominal 170 MW) with heat recovery steam generator
008	Unit No.3D gas turbine (nominal 170 MW) with heat recovery steam generator
010	Ammonia Storage Tank

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 Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements
Table 3-1, Summary of Reporting Requirements
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix H-1, Permit History/ID Number Changes
Statement of Basis

<u>These documents and all their related correspondence are on file with the permitting authority:</u>
Initial Title V Air Operation Permit 0810010-001-AV issued May 29, 1998
Title V Air Operation Permit Revision 0810010-008-AV issued December 3, 2002
Title V Air Operation Permit Renewal 0810010-009-AV issued December 30, 2003
Title V Air Operation Permit Revision 0810010-011-AV: Pending

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. APPENDIX TV-5, TITLE V CONDITIONS, is a part of this permit.
   {Permitting note: APPENDIX TV-5, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}

2. **Not Federally Enforceable.** General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. 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. General Particulate Emission Limiting Standards. General Visible Emissions Standard.
   Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than 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.
   [Rule 62-296.320(4)(b)1. & 4., F.A.C.]

4. 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 updated to submittals, should be sent to:

   RMP Reporting Center
   Post Office Box 1515
   Lanham-Seabrook, MD 20703-1515
   Telephone: 301/429-5018

   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]

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

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

7. Compliance Plan. [See Specific Conditions **A.38.** Construction Notifications; **A.39.** Initial Compliance Tests for Gas Firing; and **A.40.** PSD Applicability Report.]

8. General Pollutant Emission Limiting Standards. Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. The following requirements are not federally enforceable:

The owner or operator shall:

a. Tightly cover or close all VOC or OS containers when they are not in use.

b. Tightly cover all open tanks which contain VOC or OS when they are not in use.

c. Maintain all pipes, valves, fittings, etc., which handle VOC or OS in good operating condition.

d. Immediately confine and clean up VOC or OS spills and make sure wastes are placed in closed containers for reuse, recycling or proper disposal.

[Rule 62-296.320(1)(a), F.A.C.; 0810010-008-AV]

9. Emissions of Unconfined Particulate Matter. Pursuant to Rules 296.320(4)(c)1., 3., & 4., F.A.C., reasonable precautions to prevent emissions of unconfined particulate matter at this facility include the requirements listed in APPENDIX TV-6, TITLE V CONDITIONS (see Condition 57).

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

a. The facility shall construct temporary sandblasting enclosures when necessary, in order to perform sandblasting on fixed plant equipment.

b. Maintenance of paved areas as needed.

c. Regular mowing of grass and care of vegetation.

d. Limiting access to plant property by unnecessary vehicles.

e. Bagged chemical products are stored in concrete block buildings until they are used.

f. Spills of powdered chemical products are cleaned up as soon as practicable.

[Rule 62-296.320(4)(c)2., F.A.C., proposed by the applicant in the initial Title V permit application received June 12, 1996, and in the renewal Title V permit application received May 27, 2003.]

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

11. 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.
[Rule 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-5, TITLE V CONDITIONS).}

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

Department of Environmental Protection
Southwest District Office
13051 N. Telecom Parkway
Tampa, FL 33637-0926
Telephone: 813/632-7600 Fax: 813/744-6084

13. 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, GA 30303-8960
Phone: 404/562-9155
Fax: 404/562-9163

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. The permittee shall comply with the terms of the attached "AGREEMENT FOR THE PURPOSE OF ENSURING COMPLIANCE WITH AMBIENT AIR QUALITY STANDARDS FOR OZONE" dated 9/19/02.

{Permitting note: FPL obtained an air construction permit from the Department to install equipment on Units 1 and 2 for the purposes of NO_X reductions for the reburn construction project described in the above Agreement. The project is under construction.

Section III. Emissions Units and Conditions.

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

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2

Fossil fuel fired steam generators Unit 1 and Unit 2 are each nominal 800 megawatt (900 MW gross capacity) (electric) steam generators designated as Manatee Plant Unit 1 and Unit 2. The emissions units are fired on a variable combination of natural gas, No. 6 fuel oil, No. 2 fuel oil, propane, and used oil from FPL operations. Propane is utilized primarily for ignition of the main fuel. When firing fuel oil (or combinations of authorized fuels), the maximum heat input for each boiler is 8650 mmBtu per hour. When firing natural gas alone, the maximum heat input for each boiler is 5670 mmBtu per hour.

Each emissions unit consists of a boiler which drives a turbine generator. Emissions are controlled with multiple cyclones, a flue gas recirculation system and staged combustion. The twin register low-NOx burners (ABB Combustion Services, Ltd.) are dual fuel with mechanical atomization for oil firing. Each unit is equipped with a 499 foot stack.

{Permitting notes: These emissions units are regulated under Acid Rain, Phase II; and Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input. Fossil fuel fired steam generator Unit 1 began commercial operation in 1976 and fossil fuel fired steam generator Unit 2 began commercial operation in 1977. These emissions units may inject additives such as magnesium oxide, magnesium hydroxide and related compounds into each boiler.}

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

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity. The maximum operation heat input rates are as follows:

Unit No.	Heat Input (mmBtu/hr)	Fuel Type
1	8650	No. 2 or 6 Fuel Oil (Alone or w/Natural Gas)
	5670	Natural Gas (Alone)
2	8650	No. 2 or 6 Fuel Oil (Alone or w/Natural Gas)
	5670	Natural Gas (Alone)

[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.; Permit No. 0810010-007-AC]

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

A.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **A.26** and **A.27** of this permit. [Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation - Fuels.

a. Startup: The only fuels allowed to be burned are any combination of natural gas, No. 6 fuel oil, No. 2 fuel oil and propane.

b. Normal: The only fuels allowed to be burned are any combination of natural gas, No. 6 fuel oil, No. 2 fuel oil, propane and on-specification used oil from FPL operations.

When available, the Department strongly encourages the permittee to fire natural gas as a clean-burning alternative to fuel oil. [Rule 62-213.410, F.A.C.; Permit No. 0810010-007-AC]

A.4. Hours of Operation. The emissions units may operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

{Permitting Note: Unless otherwise specified, the averaging times for Specific Conditions A.5.-A.10. are based on the specified averaging time of the applicable test method. The attached 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.}

A.5. Visible Emissions. Visible emissions shall not exceed 40 percent opacity. Emissions units governed by this visible emissions standard shall compliance test for particulate matter emissions annually.
[Rule 62-296.405(1)(a), F.A.C.; and OGC Case Nos. 83-0580 & 83-0581, Order dated April 24, 1984.]

A.6. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.

Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed by this condition.

[Rule 62-210.700(3), F.A.C., Note: these units have operational continuous opacity monitors.]

A.7. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods. [Rule 62-296.405(1)(b), F.A.C.]

A.8. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
[Rule 62-210.700(3), F.A.C.]

A.9. Sulfur Dioxide. The sulfur content of fuel oils burned shall not exceed 1.0 percent by weight, as received at the plant. The blending of natural gas shall not be used to demonstrate compliance with the sulfur dioxide standard for "liquid fuel" in Rule 62-296.405(c), F.A.C. See specific conditions **A.9, A.15, A.23 and A.24** of this permit.

{Permitting Note: The maximum fuel sulfur content of pipeline natural gas is 10 grains of sulfur per 100 standard cubic feet of natural gas. However, pipeline natural gas typically contains less than 1 grain of sulfur per 100 SCF of natural gas.}

[Rules 62-213.440 and 62-296.405(1)(c)1.g., F.A.C., applicant agreement with EPA on March 3, 1998, and Permit No. 0810010-007-AC]

A.10. Nitrogen Oxides. Nitrogen oxides emissions shall not exceed 0.30 pounds per million Btu heat input. Compliance shall be demonstrated based on a 30-day rolling average as measured by a continuous emission monitoring system (CEMS). The CEMS must meet the performance specifications contained in 40 CFR 75. [Rules 62-296.405(1)(d)2. and (1)(d)4., F.A.C.; AO 41-204804 and AO 41-219341, Issued August 30, 1993]

Excess Emissions

A.11. 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.]

A.12. 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.]

A.13. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

A.14. Annual Tests Required. Except as provided in specific conditions **A.17** through **A.19** of this permit, emission testing for particulate emissions and visible emissions shall be performed annually, each federal fiscal year, except for units that are not operating because of scheduled maintenance outages and emergency repairs, which will be tested within thirty days of returning to service.
[Rules 62-4.070(3) and 62-213.440, F.A.C.]

A.15. Sulfur Dioxide. **The permittee elected to demonstrate compliance using fuel sampling and analysis.** This protocol is allowed because the emissions unit does not have an operating flue gas desulfurization device. See specific conditions **A.9, A.23 and A.24** of this permit.
[Rule 62-296.405(1)(f)1.b., F.A.C.]

A.16. 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.

c. The permittee shall install, operate, and maintain a system to continuously monitor and record the amount of natural gas consumption and heat input. This system shall be designed to interact with the existing continuous emissions monitors.

[Rule 62-297.310(5) and 62-4.070(3), F.A.C.; Permit No. 0810010-007-AC]

A.17. 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.

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

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

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]

A.18. When VE Tests Not Required. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:

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

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

A.19. When PM Tests Not Required. Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:

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

[Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

Test Methods and Procedures

{Permitting Note: The attached 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.20. Visible emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C. See specific condition **A.21** of this permit. VE testing shall be conducted in accordance with the requirements of specific condition **A.27** of this permit.

[Rule 62-296.405(1)(e)1., F.A.C.]

A.21. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

a. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.

b. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:

1. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.
2. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

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

[Rule 62-297.401, F.A.C.]

A.22. Particulate Matter. The test methods for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with a filter temperature of no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17. Particulate testing shall be conducted in accordance with the requirements of specific conditions **A.26** and **A.27** of this permit.
[Rules 62-213.440, 62-296.405(1)(e)2., and 62-297.401, F.A.C.]

A.23. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards. **The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by permit, the permittee elected to demonstrate compliance using fuel sampling and analysis.** See specific conditions **A.9 and A.24** of this permit. [Rules 62-213.440, 62-296.405(1)(e)3. and 62-297.401, F.A.C.]

A.24. The following fuel sampling and analysis protocol shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance with the sulfur dioxide standard:

a. Compliance with the liquid fuel sulfur limit shall be verified by a fuel analysis provided by the vendor or performed by FPL upon each fuel delivery at the Port Manatee Fuel Oil Terminal with the following exception: in cases where No. 6 fuel oil is received with a sulfur content exceeding 1.0 percent by weight, and blending at the terminal is required to obtain a fuel mix equal to the applicable percent sulfur limit, an analysis of a fuel sample representative of fuel from the fuel storage tanks shall be performed by FPL prior to transferring oil to the Manatee plant. Reports of percent sulfur content of these analyses shall be maintained at the power plant facility.

b. The owner or operator shall maintain records of the as-fired fuel oil heating value, density or specific gravity, and the percent sulfur content. Fuel sulfur content, percent by weight, for liquid fuels shall be determined by either ASTM D2622-94, ASTM D4294-90 (95), ASTM D1552-95, ASTM D1266-91, or both ASTM D4057-88 and ASTM D129-95 (or latest editions) to analyze a representative sample of the fuel oil.

[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.; Applicant agreement with EPA on March 3, 1998.]

A.25. 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.]

A.26. Operating Rate During Testing. Testing of emissions shall be conducted with each emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. 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 emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rules 62-297.310(2) & (2)(b), F.A.C.]

A.27. Operating Conditions During Testing - PM and VE. When required, testing for particulate matter and visible emissions shall be conducted while firing No. 6 fuel oil at the maximum allowable rate of 8650 million Btu per hour, except as provided below. Particulate and visible emissions shall be conducted under both sootblowing and non-sootblowing conditions, and shall be conducted while injecting additives consistent with normal operating practices.

Testing may be conducted while firing No. 6 fuel oil at less than 90 percent of the maximum allowable rate; however, subsequent emissions unit operation is limited as described in specific condition **A.26** of this permit.

[Rules 62-4.070(3) and 62-213.440 F.A.C.; AO 41-204804 Specific Condition 5 and AO 41-219341 Specific Condition 5]

A.28. 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 separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

A.29. 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:

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

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

c. Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

d. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1 (attached to this permit).

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.]

A.30. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit. [Rule 62-297.310(6), F.A.C.]

A.31. 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.; applicant agreement with EPA on March 3, 1998]

Record Keeping and Reporting Requirements

A.32. Excess Emissions - Malfunctions. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department's Southwest District, Air Section, in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department's Southwest District, Air Section. [Rule 62-210.700(6), F.A.C.]

{Permitting Note: In the event of excess emissions as noted above, Manatee Plant agrees to provide an informational notification to the office of the Director of the Manatee County Environmental Management Department.}

A.33. Excess Emissions - Reports. Submit to the Department's Southwest District, Air Section, a written report of emissions in excess of emission limiting standards for opacity and sulfur dioxide as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years. [Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

{Permitting Note: In addition to the quarterly report submitted to the Compliance Authority noted above, Manatee Plant agrees to provide an informational copy to the office of the Director of the Manatee County Environmental Management Department.}

A.34. Test Reports.

a. The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department's Southwest District, Air Section, on the results of each such test.

b. The required test report shall be filed with the Department's Southwest District, Air Section, 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's Southwest District, Air Section, 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.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

A.35. Fuel Analysis Report. The owner or operator shall, by the fifteenth day following each calendar month, submit to the Department's Southwest District, Air Section, a report of fuel analyses that are representative of each fuel received in the preceding month. The report shall document the heating value, density or specific gravity, and the percent sulfur content by weight of each fuel fired.
[Rule 62-4.070(3) and 62-213.440, F.A.C.; AO 41-204804 Specific Condition 6 and AO 41-219341 Specific Condition 6]

A.36. COMS for Periodic Monitoring. 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]

Miscellaneous Conditions

A.37. Used Oil. Burning of on-specification used oil is allowed at this facility in accordance with all other conditions of this permit and the following additional conditions:

a. On-specification Used Oil Allowed as Fuel: This permit allows the burning of used oil fuel meeting EPA "on-specification" used oil specifications, with a PCB concentration of less than 50 ppm, originating from FPL operations. Used oil that does not meet the specifications for on-specification used oil shall not be burned at this facility. On-specification used oil shall meet the following specifications:

   1. Arsenic shall not exceed 5.0 ppm;
   2. Cadmium shall not exceed 2.0 ppm;
   3. Chromium shall not exceed 10.0 ppm;
   4. Lead shall not exceed 100.0 ppm;
   5. Total halogens shall not exceed 1000 ppm;
   6. Flash point shall not be less than 100 degrees F.

   [40 CFR 279, Subpart B.]

b. Quantity Limited: The maximum total quantity of used oil that may be burned in both emissions units is 40,000 gallons in any consecutive 12-month period.

c. Used Oil Containing PCBs Not Allowed: Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.

d. PCB Concentration of 2 to less than 50 ppm: On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating temperatures. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.

e. Testing Required: The owner or operator shall sample and analyze each batch of used oil to be burned for arsenic, cadmium, chromium, lead, total halogens, flash point and PCBs. Additionally:

   1. Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods), latest edition.
   2. Split samples of the used oil shall be retained for three months after analysis for further testing if necessary.

   [AO 41-204804 Specific Condition 9 and AO 41-219341 Specific Condition 9]

f. Record Keeping Required: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department:

   1. The gallons of on-specification used oil received and burned each month. (This record shall be completed no later than the fifteenth day of the succeeding month.)
   2. The total gallons of on-specification used oil burned in the preceding consecutive 12-month period. (This record shall be completed no later than the fifteenth day of the succeeding month.)
   3. Results of the analyses required above.

   [40 CFR 279.61 and 761.20(e)]

g. Reporting Required: The owner or operator shall submit to the Department's Southwest District, Air Section, within thirty days of the end of each calendar month in which used oil is burned, the analytical results and the total amount of on-specification used oil burned during the previous calendar month. The owner or operator shall submit, with the Annual Operation Report form, the analytical results and the total amount of on-specification used oil burned during the previous calendar year.

[Rules 62-4.070(3) and 62-213.440, F.A.C.; 40 CFR 279 and 40 CFR 761, unless otherwise noted]

A.38. Construction Notifications on Natural Gas Firing Project: Within 15 days of beginning construction, the permittee shall notify the Compliance Authority that construction has commenced. Within 15 days of completing construction, the permittee shall notify the Compliance Authority that construction has concluded. Each notification shall include an updated proposed schedule of activities through the initial shakedown period and the firing of natural gas. [Rule 62-4.070(3), F.A.C.; Permit No. 0810010-007-AC]

A.39. Initial Compliance Tests for Gas Firing: When firing 100% natural gas, the permittee shall conduct initial compliance tests to determine the emissions of particulate matter and level of opacity from Units 1 and 2. Test results shall demonstrate compliance with the applicable standards. A transmissometer calibrated in accordance with Rule 62-297.520, F.A.C., may also be used to demonstrate compliance with the visible emissions standard. Initial tests shall be conducted within 60 days after completing shakedown for each unit, but not later than 180 days after first fire on natural gas. [Rule 62-296.405(1)(e)1, F.A.C.; Permit No. 0810010-007-AC]

A.40. PSD Applicability Report:

a. Past actual Emissions. With respect to Gas Firing, the Department determines the "past actual emissions" during 2000-2001 for Units 1 and 2 as follows:

Pollutant	Past Actual Emissions Two-Year Average Tons per Year	Future Representative Actual Annual Emissions Calculation Methods
CO	18,987	AOR (oil); Initial/Annual Performance Tests (gas)
NOx	8762	CEMS; Acid Rain Reporting
PM	2384	AOR (oil); Initial Performance Test (gas)
SO_2	31,753	CEMS; Acid Rain Reporting
VOC	149	AOR (oil); Initial Performance Test (gas)

"Past actual annual emissions" are based on: the two-year average for operation during 2000 and 2001; annual CO, PM, and VOC emissions reported in the certified Annual Operating Reports submitted by the permittee; and data collected by the Continuous Emissions Monitoring Systems for NOx and SO2 emissions as indicated by the EPA Scorecard values for the Acid Rain Program. "Future actual annual emissions" shall be based on: actual annual fuel combustion (heat input) rates; initial tested emission rates for PM (gas) and VOC (gas); a series of annual tested emission rates for CO (gas); certified Annual Operating Report data for CO (oil), PM (oil), and VOC (oil); and data collected by the Continuous Emissions Monitoring Systems for NOx and SO2 emissions as indicated by the EPA Scorecard values for the Acid Rain Program. The calculation methodology shall remain consistent from year to year.

b. Before August 1st of each year, the permittee shall submit a report to the Bureau of Air Regulation and the Compliance Authority summarizing actual annual emissions for the previous calendar year. The reports shall be used to verify the permittee's predictions of future representative actual annual emissions. The reports shall be submitted for five separate years that are representative of normal post-change operations after completing construction of the natural gas project. The reports shall begin during the first year that natural gas is fired and continue for five years. Reports are subject to the following conditions.

   1. In accordance with 40 CFR 52.21(b)(33)(ii), the permittee shall, "Exclude, in calculating any increase in emissions that results from the particular physical change or change in the method of operation at an electric utility steam generating unit, that portion of the unit's emissions following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole." The permittee shall identify and quantify the excluded emissions and present a justification for the exclusion.

   2. Each report shall compare the actual emissions for the given year with the past actual annual emissions as described above. If the difference between the current actual annual emissions and the past actual annual emissions defined above is greater than the PSD significant emission rates defined in Table 212.400-2 of Chapter 62-212, F.A.C., then Units 1 and 2 shall be subject to a full PSD review at that time. This review shall include a determination of the Best Available Control Technology (BACT) for each PSD-significant pollutant.

[Rules 62-204.800, 62-210.200(11) and 62-212.400, F.A.C.; 40 CFR 52.21(b)(33)(ii); Permit No. 0810010-007-AC]

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

E.U. ID No.	Emission Unit Description
005	Unit 3A gas turbine (170 MW) with recovery steam generator (495 MMBtu/hr)
006	Unit 3B gas turbine (170 MW) with heat recovery steam generator (495 MMBtu/hr)
007	Unit 3C gas turbine (170 MW) with heat recovery steam generator (495 MMBtu/hr)
008	Unit 3D gas turbine (170 MW) with heat recovery steam generator (495 MMBtu/hr)
010	Ammonia Storage Tank

Each unit consists of a nominal 170 MW General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, a heat recovery steam generator (HRSG) each equipped with a 495 MMBtu/hr natural gas fired duct burner, a stack , and associated support equipment. Steam from each HRSG is delivered to the single steam turbine-electrical generator, which has a nominal capacity of 470 MW. The total nominal generating capacity of the "4 on 1" combined cycle unit system is 1150 MW. Each stack is 120 ft tall (19 ft diameter). At a compressor inlet air temperature of 59° F, each gas turbine heat input is approximately 1600 MMBtu (LHV) per hour. The exhaust flow rate is 1,004,2000 ACFM at a temperature of 202° F.

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

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

Compliance assurance monitoring (CAM) does not apply since these emissions units have NOx CEMS which are used to demonstrate continuous compliance.

{Permitting note: These emissions units are regulated under Acid Rain-Phase II, 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines; 40CFR60, Subpart Da, Standards of Performance for Electric Utility Generating Units for Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(8), F.A.C.; 40 CFR 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, adopted by reference in Rule 62-204.800(11), F.A.C.; Rule 212.400, F.A.C., Prevention of Significant Deterioration (PSD), Best Available Control Technology (BACT); and Air Construction Permit PSD-FL-328 (0810010-006-AC) issued 04/15/03. On March 5, 2004, EPA promulgated 40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines built after January 14, 2003. Unit 3 was under contractual obligations before this date and is therefore an existing unit. Currently, 'existing combustion turbines' are not required to meet the emission limitations, notifications, reporting or any other requirements of Subpart YYYY. EPA may at a future date promulgate standards for existing units.}

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

Applicable Standards and Regulations

B.1. BACT Determinations: The emissions standards specified for this unit represent Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NOX), particulate matter (PM/PM10), sulfuric acid mist (SAM), volatile organic compounds (VOCs) and sulfur dioxide (SO_2). See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]

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

B.3. NSPS Subpart Da Requirements: Each heat recovery steam generator equipped with a 495 mmBTU/hr natural gas fired Duct Burner (LHV) shall comply with all applicable provisions of 40CFR60, Subpart Da, Standards of Performance for Electric Utility Generating Units for Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The modification of 40CFR60, Subpart Da promulgated on September 3, 1998 also applies to this project. The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with this NSPS. For completeness, the applicable requirements of Subpart Da are included in Appendix Da.
[Rule 62-204.800 (7), F.A.C.]

Equipment

B.4. Gas Turbine Units 3A throughout 3D: The permittee is authorized to operate, tune and maintain the four new General Electric Model PG7241FA gas turbine-electrical generator sets each with a nominal capacity of 170 MW (EU 005, 006, 007 and 008). Each gas turbine shall include the Speedtronic™ automated gas turbine control system . Ancillary equipment includes an inlet air filtration system and an evaporative inlet air cooling system. The gas turbines will utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to approximately 290° F before combustion to increase overall unit efficiency. Hot water/electric heaters will preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas.
[Application; Design]

B.5. Gas Turbine Controls:

a. DLN Combustion Technology: The permittee is authorized to operate, tune and maintain the General Electric DLN-2.6 combustion system to control NO_X emissions from each turbine. Prior to the initial emissions performance tests for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the simple cycle permitted level for CO and NOx. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Design; Rule 62-212.400(BACT), F.A.C.]

b. Selective Catalytic Reduction (SCR) System: The permittee is authorized to operate, tune and maintain a SCR system to control NOx emissions from each turbine during a combined cycle operation mode. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancilliary equipment. The SCR system shall be operated to achieve the permitted levels for NOx emissions and ammonia slip.

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

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

B.6. Heat Recovery Steam Generators: The permittee is authorized to operate, and maintain the four new heat recovery steam generators (HRSGs). Each HRSG shall be designed to recover heat energy from one of the four gas turbines (3A-3D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). [Application; Design]. *{Permitting Note: The four HRSGs deliver steam to a single steam turbine-electrical generator with a nominal capacity of 470 MW.}*

Essential Potential to Emit (PTE) Parameters

Performance Restrictions

B.7. Gas Turbine Permitted Capacity: The maximum heat input rate to each gas turbine is 1600 MMBtu/hr (normal conditions) based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of natural gas, and 100% load. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

B.8. HRSG Duct Burner Permitted Capacity: The total maximum heat input rate to the duct burners for each HRSG is 495 MMBTU/hr based on the lower heating value (LHV) of the natural gas. [Rule 62-210.200(PTE), F.A.C.]

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

a. *Hours of Operation*: Subject to the operational restrictions of this permit, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.

b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain on average no more than 2 grains of sulfur per 100 standard cubic feet of natural gas.

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

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

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

1. Prior to demonstrating compliance in combined cycle mode, each gas turbine shall operate in simple cycle mode for no more than 3390 hours during any consecutive 12 months.
2. After demonstrating initial compliance in combined cycle mode, the combined group of four gas turbines shall operate in simple cycle mode for no more than an average of 1000 hours per unit during any consecutive 12 months.

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

g. *Power Augmentation*: When firing natural gas in either simple cycle or combined cycle modes, steam may be injected into each gas turbine to generate additional direct, shaft-driven electrical power to respond to peak demands. To qualify as "power augmentation", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. Each gas turbine shall operate in this power augmentation mode no more than 400 hours per unit during any consecutive 12 months.

h. *Peaking:* When firing natural gas, each gas turbine may operate in a high-temperature peaking mode to generate additional direct, shaft-driven electrical power to respond to peak demands. During any consecutive 12 months, each gas turbine shall operate in this peaking mode for no more than 60 hours of simple cycle operation and no more than 400 hours of combined cycle operation. The gas turbines shall not operate simultaneously in peaking and power augmentation modes. In addition, total combined operation of power augmentation and peaking modes shall not exceed 400 hours per unit during any consecutive 12 months.

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

Emission Limitations and Standards

B.10. BACT Standards: Emissions from each gas turbine shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hour	ppmvd @ 15% O_2
CO[a]	Gas	Simple Cycle	7.4	27.5	8.0, 24-hr
		Simple Cycle w/PA	12.0	45.0	12.0, 24-hr
		Combined Cycle, Normal Operation	7.4	27.5	10.0, 24-hr
		Combined Cycle, All Modes	NA	NA	10.0, 24-hr
NOx[b]	Gas	Simple Cycle	9.0	58.7	9.0, 24-hr
		Simple Cycle w/PA	12.0	76.2	12.0, 24-hr
		Simple Cycle w/PK	15.0	95.3	15.0, 24-hr
		Combined Cycle w/SCR	2.5	16.3	2.5, 24-hr
		Combined Cycle w/SCR and DB	2.5	23.6	2.5, 24-hr
		Combined Cycle w/SCR, All Modes	N/A	N/A	2.5, 24-hr
PM/PM_{10}[c]	Gas	Simple or Combined Cycle	Fuel Specifications		
		Simple or Combined Cycle	Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2[d]	Gas	Simple or Combined Cycle	Fuel Specifications		
VOC[e]	Gas	Simple or Normal Combined Cycle	1.3	2.8	NA
VOC[e]	Gas	Combined Cycle, w/DB and/or PA	4.0	10.5	NA
Ammonia[f]	Gas	Combined Cycle w/SCR	5	NA	NA

Notes: See Next Page

a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 10. Compliance with the 24-hr CO CEMS standard shall be determined separately for each mode of operation based on the hours of operation in each mode.

{*Permitting Note*: 24-hr compliance average may be based on as little as 1-hr of data or as much as 24-hr of CEMS data.}.

b. Compliance with the NO_X standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 7E or 20. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO2. Compliance with the 24-hr NO_X CEMS standards during simple cycle operation shall be determined separately for each method of operation based on the hours of operation for each method.

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

c. The fuel specifications established in Condition No. B.9 of this subsection combined with the efficient combustion design and operation of each gas turbine represents the Best Available Control Technology (BACT) determination for PM/PM10 emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

{Permitting Note: PM10 emissions for gas firing are estimated at 9 lb/hour for simple cycle operation, 11 lb/hour for combined cycle operation, and 17 lb/hour for combined cycle operation with duct burning.}

d. The fuel sulfur specifications in Condition No.B.9 of this subsection effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent the Best Available Control Technology (BACT) determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 28 of this subsection.

{Permitting Note: SO_2 emissions for gas firing are estimated at 9.8 lb/hour for simple and combined cycle operation and 12.8 lb/hour for combined cycle operation with duct burning. SAM emissions are estimated to be less than 10% of the SO_2 emissions.}

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

f. Subject to the requirements of Condition No. B.23 of this subsection, each SCR system shall be designed and operated for an initial ammonia slip target of less that 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027.

{Permitting Notes: "DB" means duct burning. "PA" means power augmentation. "SCR" means selective catalytic reduction. "NA" means not applicable. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.}

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

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

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

B.12. Combined Cycle Operation With Steam Dumped to Condenser: If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by dumping steam to the condenser. When operating in this manner, each unit shall comply with the standards established for combined cycle operation with ammonia injection (SCR). [Application]

Excess Emissions

B.13. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

B.14. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

B.15. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

B.16. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases.

a. *Steam Turbine/HRSG System Cold Startup*: For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed eight (8) hours in any 24-hour period. Cold startup of the steam turbine system shall be completed within twelve hours. A cold "startup of the steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}

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

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

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

B.17. Work Practice Standard and Load Restriction:

a. *Simple Cycle Work Practice BACT*: Each unit will be operated according to manufacturer specifications and control systems. The CT control system is designed to reach Mode 5Q (i.e. five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire.

b. *Combined Cycle Work Practice BACT*: A Best Operating Practice procedure for minimizing emissions during startup and shutdown shall be submitted to the Department within 60 days following determination of initial compliance with emission limits when operating in combined cycle mode.

c. *Low-Load Restriction*: Except for startup and shutdown, malfunctions, commissioning and recommissioning, operation at loads where the DLN 2.6 system is not in pre-mix mode is prohibited.

B.18. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

Test Methods and Procedures

B.19. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Except for Method CTM-027, the above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Method CTM-027 is published on EPA's Technology Transfer Network Web Site at: www.epa.gov/ttn/emc/ctm.html. No other methods may be used for compliance testing unless prior written approval is received from the Department.
[Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

B.20. Special Compliance Determinations: The Department may require the permittee to conduct additional tests after major replacement or repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. Each gas turbine shall be stack tested to demonstrate compliance with the emission standards for CO, NO_X, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated for each unit configuration (i.e., simple cycle and combined cycle operation), but not later than 180 days after the startup of each unit configuration. Each unit shall be tested under all operating scenarios as required in Specific Condition No. B.10. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the CO and NOx standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may also be used to demonstrate compliance with the CO and NO_X mass emissions standards. CO and NOx emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. CO and VOC emissions tests performed during simple cycle operation may be used to satisfy the test requirement for similar operation in combined cycle mode.
[Rule 62-297.310(7)(a)1., F.A.C.]

B.21. Continuous Compliance: The permittee shall demonstrate continuous compliance with the CO and NO_X emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds. [Rule 62-212.400 (BACT), F.A.C.]

B.22. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia slip. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4., F.A.C.]

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

B.23. Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

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

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

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

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis.
[Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

Continuous Monitoring Requirements

B.24. CEM Systems: The permittee shall calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO_X from each gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NOx standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

a. *CO Monitors*. Each CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.

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

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

d. *1-Hour Block Averages*. Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd, corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NOx as specified in this permit. For purpose of determining compliance with the CEMS emission standard of this permit, missing (or excluded) data shall not be submitted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

e. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, missing (or excluded) data shall not be substituted. Instead the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]

f. Data Exclusion. Each CEMS shall monitor and record emissions during all operations including all episodes of startup, shutdown, malfunction, and DLN tuning. CEMS emissions data recorded during such episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Specific Condition No. 16 and 19 of this subsection.

All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

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

{Permitting Note: Compliance with these requirements will ensure compliance with the other applicable CEM system requirements such as: NSPS Subpart Da and GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.}

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

B.25. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall calibrate, maintain and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

Records, Reports And Notification Requirements

B.26. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

B.27. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following in a written or electronic log for each gas turbine for the previous month of operation: consumption of each fuel, the hours of operation, the hours of power augmentation, the hours of peaking, the hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

B.28. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur specification of this permit by maintaining records of the sulfur content of the natural gas being supplied based on the vendor's analysis for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 (or more recent versions) in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

B.29. Malfunction Notification: Within one working day of a malfunction that causes emissions in excess of a standard (subject to the specified averaging periods), the permittee shall notify the Compliance Authority. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports report of the malfunctions.

B.30. Semiannual NSPS Excess Emissions Report: Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Compliance Authority summarizing emissions in excess of an NSPS standard. In accordance with 40 CFR 60.7(d), the permittee shall submit the NSPS excess emissions report identified as Figure 1 and summarized in Appendix XS. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NO_X emission standard identified in Appendix GG; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NO_X or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO_2 emissions in excess of the NSPS standards except during startup or shutdown. [40 CFR 60.7]

B.31. Quarterly Excess Emission Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of excess emissions. The information shall be summarized for simple/combined cycle startups, simple/combined cycle shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.
[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

B.32. Appendices: These emissions shall comply with applicable requirements listed in the attached Appendices, made part of the permit.

Section IV. This section is the Acid Rain Part.

Operated by: Florida Power and Light Company
ORIS code: 6042

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

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

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2

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

a. DEP Form No. 62-210.900(1)(a), dated 7/1/95, received 5/27/03.

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

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

E.U. ID No.	EPA ID	Year	2004	2005	2006	2007	2008
001	ID No. 01 PMT1	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	13773*	13773*	13773*	13773*	13773 *
002	ID No. 02 PMT2	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	12697*	12697*	12697*	12697*	12697 *
003	MTCT3A MTCT3B MTCT3C MTCT3D	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	0	0	0	0	0

* The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the USEPA under Table 2 of 40 CFR 73.

A.3. Emission Allowances. Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.

a. No permit revision shall be required for increase in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.

b. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.

c. Allowances shall be accounted for under the Federal Acid Rain Program.

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

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

APPENDICES

CONTENTS

Updated 7-9-02

[Source: Federal Register dated 7/1/98, Federal Register 5/8/98, 2/12/99, 10/17/00, 6/28/02]

Subpart A-General Provisions for 40 CFR 60

40 CFR 60.1 Applicability.

(a) Except as provided in 40 CFR 60 subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced
after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution controlagency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (CAA) as amended November 15, 1990 (42 U.S.C. 7661).
[40 CFR 60.1(a), (b) and (c)]

40 CFR 60.5 Determination of construction or modification.

(a) When requested to do so by an owner or operator, the Administrator will make a determination of whether action taken or intended to be taken by such owner or operator constitutes construction (including reconstruction) or modification or the commencement thereof within the meaning of this part.

(b) The Administrator will respond to any request for a determination under paragraph (a) of this section within 30 days of receipt of such request.

§ 60.6 Review of plans.

(a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.

(b)(1) A separate request shall be submitted for each construction or modification project.

(2) Each request shall identify the location of such project, and be accompanied by technical information describing the proposed nature, size, design, and method of operation of each affected facility involved in such project, including information on any equipment to be used for measurement or control of emissions.

(c) Neither a request for plans review nor advice furnished by the Administrator in response to such request shall (1) relieve an owner or operator of legal responsibility for compliance with any provision of this part or of any applicable State or local requirement, or (2) prevent the Administrator from implementing or enforcing any provision of this part or taking any other action authorized by the Act.

40 CFR 60.7 Notification and record keeping.

(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:

NSPS Subpart A, Identification of General Provisions

1. A notification of the date construction (or reconstruction as defined under § 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.
2. Reserved.
3. A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.
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 § 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.
5. A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with 40 CFR 60.13(c). Notification shall be postmarked not less than 30 days prior to such date.
6. A notification of the anticipated date for conducting the opacity observations required by 40 CFR 60.11(e)(1) of this part. The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.
7. A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by 40 CFR 60.8 in lieu of Method 9 observation data as allowed by 40 CFR 60.11(e)(5) of 40 CFR 60. This notification shall be postmarked not less than 30 days prior to the date of the performance test.

(b) Any owner or operator subject to the provisions of this part 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.

(c) Each 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 paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; 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 six-month period. 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.

(d) The summary report form shall contain the information and be in the format shown in Figure 1 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]

(e) (1) Notwithstanding the frequency of reporting requirements specified in paragraph (c) of this section, 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 this subpart and the applicable standard; and

(iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in paragraph (e)(2) of this section.

(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 re-port (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 paragraphs (e)(1) and (e)(2) of this section.

(f) Any owner or operator subject to the provisions of this part 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 this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows:

(1) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.

(2) This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain all subhourly measurements for the most recent reporting

period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator.

(3) The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required by paragraph (f) of this section, if the Administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source.

(g) If notification substantially similar to that in 40 CFR 60.7(a) is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of 40 CFR 60.7(a).
(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.
[40 CFR 60.7(a), (b), (c), (d), (e), (f), (g), (h)]

40 CFR 60.8 Performance tests.

(a) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).
[40 CFR 60.8(a)]

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or (5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in 40 CFR 60.8 shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.
[40 CFR 60.8(b)(1), (2), (3), (4) & (5)]

(c) 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)].

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems , etc) in conducting the scheduled performance test, the owner or operator of an affected facility shall notify the administrator (or delegated State or local agency) as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the perfomance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility. This includes

(i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and

(ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

(2) Safe sampling platform(s).

(3) Safe access to sampling platform(s).
(4) Utilities for sampling and testing equipment.
[40 CFR 60.8(e)].

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.
[40 CFR 60.8(f)].

§ 60.9 Availability of information.
The availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by part 2 of this chapter. (Information submitted voluntarily to the Administrator for the purposes of §§ 60.5 and 60.6 is governed by §§ 2.201 through 2.213 of this chapter and not by § 2.301 of this chapter.)

40 CFR 60.10 State authority.

The provisions of 40 CFR 60 shall not be construed in any manner to preclude any State or political subdivision thereof from:
(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.

(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.
[40 CFR 60.10(a) and (b)].

40 CFR 60.11 Compliance with standards and maintenance requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined only by performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.

(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5). For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).

(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

(d) 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.

(e) (1) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in 40 CFR 60.8 unless one of the following conditions apply. If no performance test under 40 CFR 60.8 is required, then opacity observations shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under 40 CFR 60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in 40 CFR 60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test conducted under 40 CFR 60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in 40 CFR 60.11(e)(5), the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of 40 CFR 60, has been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.

(2) Except as provided in 40 CFR 60.11(e)(3), the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with 40 CFR 60.11(b), shall record the opacity of emissions, and shall report to the Administrator the opacity results along with the results of the initial performance test required under 40 CFR 60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.

(3) The owner or operator of an affected facility to which an opacity standard in this part applies may request the Administrator to determine and to record the opacity of emissions from the affected facility during the initial performance test and at such times as may be required. The owner or operator of the affected facility shall report the opacity results. Any request to the Administrator to determine and to record the opacity of emissions from an affected facility shall be included in the notification required in 40 CFR 60.7(a)(6). If, for some reason, the Administrator cannot determine and record the opacity of emissions from the affected facility during the performance test, then the provisions of 40 CFR 60.7(e)(1) shall apply.

(4) The owner or operator of an affected facility using a continuous opacity monitor (transmissometer) shall record the monitoring data produced during the initial performance test required by 40 CFR 60.8 and shall furnish the Administrator a written report of the monitoring results along with Method 9 and 40 CFR 60.8 performance test results.

(5) 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 compliance with the opacity standard.

(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by 40 CFR 60.8, the opacity observation results and observer certification required by 40 CFR 60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by 40 CFR 60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with 40 CFR 60.8 of this part but

during the time such performance tests are being conducted fails to meet any applicable opacity standard, the shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

(7) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the Federal Register.

(f) Special provisions set forth under an applicable subpart of 40 CFR 60 shall supersede any conflicting provisions of 40 CFR 60.11.
[40 CFR 60.11(a), (b), (c), (d), (e) and (f)]

40 CFR 60.12 Circumvention.

No owner or operator subject to the provisions of this part 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]

40 CFR 60.13 Monitoring requirements.

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section 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 to 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under 40 CFR 60.8. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(c) If the owner or operator of an affected facility elects to submit continuos opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he/she 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.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under 40 CFR 60.8 and as described in 40 CFR 60.11(e)(5), shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in 40 CFR 60.13(c) at least 10 days before the performance test required under 40 CFR 60.8 is conducted.

(2) Except as provided in 40 CFR 60.13(c)(1), the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.

(d) (1) Owners and operators of all continuous emission monitoring systems 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 a COMS, the optical surfaces, exposed to the effluent gases, must be cleaned before performing the zero and upscale drift adjustments, except for systems using automatic zero adjustments. The optical surfaces must 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.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems 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.

(f) All continuous monitoring systems 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.

(g) (1) When more than one continuous monitoring system is used to measure the emissions from only one affected facility (e.g. multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system. 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 installation of fewer systems is approved by the Administrator.

(2) When the effluents from two or more affected facilities subject to the same opacity standard are combined before being released to the atmosphere, the owner or operator may either install a continuous opacity monitoring system at a location monitoring the combined effluent or install an opacity combiner system comprised of opacity and flow monitoring systems on each stream, and shall report as per Sec. 60.7(c) on the combined effluent. When the affected facilities are not subject to the same opacity standard applicable, except for documented periods of shutdown of the affected facility, subject to the most stringent opacity standard shall apply

(3) When the effluents from two or more affected facilities subject to the same emissions standard, other than opacity, are combined before released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the continuous monitoring standard, separate continuous monitoring systems shall be installed on each effluent and the owner or operator shall report as required for each affected facility.

(h) 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 system breakdowns, repairs,

calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. For owners or operators complying with the requirements in Sec. 60.7(f)(1) or (2), data averages must include any data recorded during periods of monitor breakdown or malfunction. 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 O2 or ng or pollutant per J of heat input). 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).
[Rule 62-296.800, F.A.C.; 40 CFR 60.13(h)].

(i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:

(1) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases.

(2) Alternative monitoring requirements when the affected facility is infrequently operated.

(3) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.

(4) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.

(5) Alternative methods of converting pollutant concentration measurements to units of the standards.

(6) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.

(7) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.

(8) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the requirements in Performance Specification 1. The Administrator may require that such demonstration be performed for each affected facility.

(9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities is released to the atmosphere through more than one point.
[Rule 62-296.800, F.A.C.; 40 CFR 60.13(i)].

(j) An alternative to the relative accuracy (RA) test specified in Performance Specification 2 of appendix B may be requested as follows:

(1) An alternative to the reference method tests for determining RA is available for sources with emission rates demonstrated to be less than 50 percent of the applicable standard. A source owner or operator may petition the Administrator to waive the RA test in section 8.4 of Performance Specification 2 and substitute the procedures in section 16.0 if the results of a performance test conducted according to the requirements in 40 CFR 60.8 of this subpart or other tests performed
following the criteria in 40 CFR 60.8 demonstrate that the emission rate of the pollutant of interest in the units of the applicable standard is less than 50 percent of the applicable standard. For sources subject to standards expressed as control efficiency levels, a source owner or operator may petition the Administrator to waive the RA test and substitute the procedures in section 16.0 of Performance Specification 2 if the control device exhaust emission rate is less than 50 percent of the level needed to meet the control efficiency requirement. The alternative procedures do not apply if the continuous emission monitoring system is used to determine compliance continuously with the applicable standard. The petition to waive the RA test shall include a detailed description of the procedures to be applied. Included shall be location and procedure for conducting the alternative, the concentration or response levels of the alternative RA materials, and the other equipment checks included in the alternative procedure. The Administrator will review the petition for completeness and applicability. The determination to grant a waiver will depend on the intended use of the CEMS data (e.g., data collection purposes other than NSPS) and may require specifications more stringent than in Performance Specification 2 (e.g., the applicable emission limit is more stringent than NSPS).

(2) The waiver of a CEMS RA test will be reviewed and may be rescinded at such time, following successful completion of the alternative RA procedure that the CEMS data indicate the source emissions approaching the level. The criterion for reviewing the waiver is the collection of CEMS data showing that emissions have exceeded 70 percent of the applicable standard for seven, consecutive, averaging periods as specified by the applicable regulation(s). For sources

subject to standards expressed as control efficiency levels, the criterion for reviewing the waiver is the collection of CEMS data showing that exhaust emissions have exceeded 70 percent of the level needed to meet the control efficiency requirement for seven, consecutive, averaging periods as specified by the applicable regulation(s) [e.g., 40 CFR 60.45(g)(2) and 40 CFR 60.45(g)(3), 40 CFR 60.73(e), and 40 CFR 60.84(e)]. It is the responsibility of the source operator to maintain records and determine the level of emissions relative to the criterion on the waiver of RA testing. If this criterion is exceeded, the owner or operator must notify the Administrator within 10 days of such occurrence and include a description of the nature and cause of the increasing emissions. The Administrator will review the notification and may rescind the waiver and require the owner or operator to conduct a RA test of the CEMS as specified in section 8.4 of Performance Specification 2.
[Rule 62-296.800, F.A.C.; 40 CFR 60.13(j)].

40 CFR 60.14 Modification.

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

(b) Emission rate shall be expressed as kg/hr (lbs./hour) of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors", EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrates that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in 40 CFR 60.14(b)(1) does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in 40 CFR 60.14(b)(1). When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in 40 CFR 60 appendix C of 40 CFR 60 shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.
[Rule 62-296.800, F.A.C.; 40 CFR 60.14(b)].

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

(d) [Reserved]

(e) The following shall not, by themselves, be considered modifications under this part:

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of 40 CFR 60.14(c) and 40 CFR 60.15.

(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by 40 CFR 60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished

under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally
beneficial.

(6) The relocation or change in ownership of an existing facility.
[Rule 62-296.800, F.A.C.; 40 CFR 60.14(e)].

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

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

(h) No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

(i) Repowering projects that are awarded funding from the Department of Energy as permanent clean coal technology demonstration projects (or similar projects funded by EPA) are exempt from the requirements of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the five years prior to the change.

(j) (1) Repowering projects that qualify for an extension under section 409(b) of the Clean Air Act are exempt from the requirements of this section, provided that such change does not increase the actual hourly emissions of any pollutant regulated under this section above the actual hourly emissions achievable at that unit during the 5 years prior to the change.

(2) This exemption shall not apply to any new unit that:

(i) Is designated as a replacement for an existing unit;

(ii) Qualifies under section 409(b) of the Clean Air Act for an extension of an emission limitation compliance date under section 405 of the Clean Air Act; and

(iii) Is located at a different site than the existing unit.

(k) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project is exempt from the requirements of this section. A *temporary clean coal control technology demonstration project*, for the purposes of this section is a clean coal technology demonstration project that is operated for a period of 5 years or less, and which complies with the State implementation plan for the State in which the project is located and other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(l) The reactivation of a very clean coal-fired electric utility steam generating unit is exempt from the requirements of this section.

40 CFR 60.15 Reconstruction.

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.
[Rule 62-296.800, F.A.C.; 40 CFR 60.15(a)].

(b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

[Rule 62-296.800, F.A.C.; 40 CFR 60.15(b)].

(c) "Fixed capital cost'" means the capital needed to provide all the depreciable components.
[Rule 62-296.800, F.A.C.; 40 CFR 60.15(c)].

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.
(2) The location of the existing facility.
(3) A brief description of the existing facility and the components which are to be replaced.
(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.
(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.
(6) The estimated life of the existing facility after the replacements.
(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

[Rule 62-296.800, F.A.C.; 40 CFR 60.15(d)].

(e) The Administrator will determine, within 30 days of the receipt of the notice required by 40 CFR 60.15(d) and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.
[Rule 62-296.800, F.A.C.; 40 CFR 60.15(e)].

(f) The Administrator's determination under 40 CFR 60.15(e) shall be based on:

(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;
(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;
(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and
(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

[Rule 62-296.800, F.A.C.; 40 CFR 60.15(f)].

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.
[Rule 62-296.800, F.A.C.; 40 CFR 60.15(g)].

§ 60.18 General control device requirements.

(a) *Introduction.* This section contains requirements for control devices used to comply with applicable subparts of parts 60 and 61. The requirements are placed here for administrative convenience and only apply to facilities covered by subparts referring to this section.
(b) *Flares.* Paragraphs (c) through (f) apply to flares.
(c) (1) Flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

(2) Flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f).

(3) An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(4) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section.

(i) (A) Flares shall be used that have a diameter of 3 inches or greater, are nonassisted, have a hydrogen content of 8.0 percent (by volume), or greater, and are designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec) and less than the velocity, V_{max}, as determined by the following equation:

$$V_{max}=(X_{H2}-K_1)* K_2$$

Where:

Vmax=Maximum permitted velocity, m/sec.
K1=Constant, 6.0 volume-percent hydrogen.
K2=Constant, 3.9(m/sec)/volume-percent hydrogen.
XH2=The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946-77. (Incorporated by reference as specified in § 60.17).

(B) The actual exit velocity of a flare shall be determined by the method specified in paragraph (f)(4) of this section.

(ii) Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted being 7.45 MJ/scm (200 Btu/scf) or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in paragraph (f)(3) of this section.

(4) (i) Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4) of this section, less than 18.3 m/sec (60 ft/sec), except as provided in paragraphs (c)(4) (ii) and (iii) of this section.

(ii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf).

(iii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), less than the velocity, Vmax, as determined by the method specified in paragraph (f)(5), and less than 122 m/sec (400 ft/sec) are allowed.

(5) Air-assisted flares shall be designed and operated with an exit velocity less than the velocity, Vmax, as determined by the method specified in paragraph (f)(6).

(6) Flares used to comply with this section shall be steam-assisted, air-assisted, or nonassisted.

(d) Owners or operators of flares used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices.

(e) Flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

(f) (1) Method 22 of appendix A to this part shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation period is 2 hours and shall be used according to Method 22.

(2) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

(3) The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

Eq. 1

where:

HT=Net heating value of the sample, MJ/scm; where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C;

$$K = \text{Constant, } 1.740 \times 10^{-7} \left(\frac{1}{\text{ppm}}\right) \left(\frac{\text{g mole}}{\text{scm}}\right) \left(\frac{\text{MJ}}{\text{kcal}}\right)$$

where the standard temperature for $\left(\frac{\text{g mole}}{\text{scm}}\right)$ is 20°C;

Eq. 2

Ci=Concentration of sample component i in ppm on a wet basis, as measured for organics by Reference Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994) (Incorporated by reference as specified in § 60.17); and

Hi=Net heat of combustion of sample component i, kcal/g mole at 25 °>C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382-76 or 88 or D4809-95 (incorporated by reference as specified in § 60.17) if published values are not available or cannot be calculated.

(4) The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip.

(5) The maximum permitted velocity, Vmax, for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation. Log10 (Vmax)=(HT+28.8)/31.7
Vmax=Maximum permitted velocity, M/sec
28.8=Constant
31.7=Constant
HT=The net heating value as determined in paragraph (f)(3).

(6) The maximum permitted velocity, Vmax, for air-assisted flares shall be determined by the following equation.
Vmax=8.706+0.7084 (HT)
Vmax=Maximum permitted velocity, m/sec
8.706=Constant
0.7084=Constant
HT=The net heating value as determined in paragraph (f)(3).

§ 60.19 General notification and reporting requirements.

(a) For the purposes of this part, time periods specified in days shall be measured in calendar days, even if the word ''calendar'' is absent, unless otherwise specified in an applicable requirement.

(b) For the purposes of this part, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be submitted 15 days before a particular event is scheduled to take place, the notification shall be post-marked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be delivered or postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the post-mark provided by the U.S. Postal Service, or alternative means of delivery, including the use of electronic media, agreed to by the permitting authority, is acceptable.

(c) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information
by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(d) If an owner or operator of an affected facility in a State with delegated authority is required to submit periodic reports under this part to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such facility under this part, the owner or operator may change the dates by which periodic reports under this part shall be submitted (without changing the frequency of reporting) to be consistent with the State's schedule by mutual agreement between the owner or operator and the State. The allowance in the previous sentence applies in each State beginning 1 year after the affected facility is required to be in compliance with the applicable subpart in this part. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(e) If an owner or operator supervises one or more stationary sources affected by standards set under this part and standards set under part 61, part 63, or both such parts of this chapter, he/she may arrange by mutual agreement between the owner or operator and the Administrator (or the State with an approved permit program) a common schedule on which periodic reports required by each applicable standard shall be submitted throughout the year. The allowance in the previous sentence applies in each State beginning 1 year after the stationary source is required to be in compliance with the applicable subpart in this part, or 1 year after the stationary source is required to be in compliance with the applicable 40 CFR part 61 or part 63 of this chapter standard, whichever is latest. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(f) (1) (i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (f)(2) and (f)(3) of this section, the owner or operator of an affected facility remains strictly subject to the requirements of this part.

(ii) An owner or operator shall request the adjustment provided for in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in this part.

(2) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

(3) If, in the Administrator's judgment, an owner or operator's request for an adjustment to a particular time period or postmark deadline is warranted, the Administrator will approve the adjustment. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request.

(4) If the Administrator is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule.

NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

The HRSG duct burners are part of the Unit 3 gas turbine/HRSG systems, which are regulated as Emissions Units 005, 006, 007 and 008.

§ 60.40a Applicability and Designation of Affected Facility.

The HRSG duct burner systems are part of an electric utility steam generating unit that is capable of combusting more than 250 MMBtu per hour heat input of fossil fuel for which construction or modification is commenced after September 18, 1978. Therefore, the requirements of NSPS Subpart Da apply to the HRSG duct burners systems. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. Emissions from the gas turbines are subject to the requirements of NSPS Subpart GG. The HRSG duct burner systems are also subject to the applicable requirements of the General Provisions in Subpart A.

§ 60.41a Definitions.

"Duct burner" means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

"Electric utility combined cycle gas turbine" means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Electric utility steam generating unit" means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

"Gross output" means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical output plus one half the useful thermal output (i.e., steam delivered to an industrial process).

"Potential electrical output capacity" is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100–MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33–MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

"Steam generating unit" means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

§ 60.42a Standard for Particulate Matter.

§ 60.42a(a)(1) establishes a particulate matter limit of 0.03 lb/MMBtu heat input from the combustion of gaseous fuel and an opacity limit of 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Natural gas is the primary fuel for the gas turbines. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum PM/PM_{10} emissions are expected to be less than 0.01 lb/MMBtu heat input from firing natural gas in the gas turbine duct burners. The stack opacity is limited by permit to 10% or less. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

§ 60.43a Standard for Sulfur Dioxide.

In accordance with § 60.43a(b)(2), sulfur dioxide emissions shall not exceed 0.20 lb/MMBtu heat input from the combustion of gaseous fuel for uncontrolled sources. Natural gas is the primary fuel for the gas turbines with very low sulfur. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum SO2 emissions are expected to be less than 0.006 lb/MMBtu heat input from firing natural gas in the duct burners. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

§ 60.44a Standard for Nitrogen Oxides.

In accordance with § 60.44a(d)(1), nitrogen oxides (expressed as NO2) from a gas turbine/HRSG system with duct burners shall not exceed 1.6 pounds per megawatt-hour gross energy output. The permittee shall demonstrate compliance with this requirement based upon an initial test. Thereafter, compliance with the BACT standards of the PSD permit will demonstrate compliance with the NSPS Subpart Da limit. After investigation, if there is good reason to believe that this standard is being violated, the Department may require subsequent compliance testing in accordance with Rule 62-297.310(7)(b), F.A.C.

§ 60.46a Compliance Provisions.

The HRSG duct burner systems are restricted to the exclusive firing of natural gas. The maximum expected emissions of particulate matter and sulfur dioxide are much lower than the limits established by this subpart. Therefore, no testing is required to demonstrate compliance with the standards specified in § 60.42a (particulate matter) and § 60.43a (sulfur dioxide). Compliance with the opacity limit of 10% established in the PSD permit ensures compliance with the NSPS opacity standard.

In accordance with § 60.46a(k)(1), compliance with the nitrogen oxides (NOx) standard specified in § 60.44a(d)(1) for duct burners used in combined cycle systems shall be determined as follows:

$$E = [(Csg \times Qsg) - (Cte \times Qte)]/(Osg \times h) \qquad \text{(Equation 1)}$$

Where:

E	=	Emission rate of NOx from the duct burner, ng/J (lb/Mwh) gross output
Csg	=	Average hourly concentration of NOx exiting the steam generating unit, ng/ dscm (lb/dscf)
Cte	=	Average hourly concentration of NOx in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf)
Qsg	=	Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)
Qte	=	Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr)
Osg	=	Average hourly gross energy output from steam generating unit, J (Mwh)
h	=	Average hourly fraction of the total heat input to the steam generating unit de-rived from the combustion of fuel in the affected duct burner

Method 7E of Appendix A of Part 60 shall be used to determine the NOx concentrations (Csg and Cte). Method 2, 2F or 2G of Appendix A of Part 60, as appropriate, shall be used to determine the volumetric flow rates (Qsg and Qte) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

Compliance with the emissions limits under § 60.44a(d)(1) is determined by the three-run average (nominal 1- hour runs) for the initial performance tests. Thereafter, compliance with the NOx limits established in the PSD permit shall demonstrate compliance with NOx limit specified in NSPS Subpart Da.

In accordance with § 60.46a(k)(3), when an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

Determine compliance with the applicable NOx emissions limits by measuring the emissions combined with the emissions from the other units utilizing the common steam turbine; or

Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under Part 60.

§ 60.47a Emission Monitoring.

In accordance with § 60.47a(o), the owner or operator of a duct burner, as described in § 60.41a, which is subject to the NOx standards of § 60.44a(a)(1) or (d)(1) is not required to install or operate a continuous emissions monitoring system to measure NOX emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

§ 60.48a Compliance Determination Procedures and Methods.

In accordance with § 60.48a (d)(1), EPA Method 19 shall be used to determine the NOx emission rate when demonstrating compliance with the NOx standard specified in § 60.44a. In accordance with § 60.48a(f), electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19. The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

§ 60.49a Reporting requirements.

Compliance with reporting requirements of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

The Unit 3 gas turbines are regulated as Emissions Units 005, 006, 007 and 008.

Updated 4/27/06

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Subpart GG-Standards of Performance for Stationary Gas Turbines

§ 60.330 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of § 60.332.

§ 60.331 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

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

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

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

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

(e) Emergency gas turbine means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) Ice fog means an atmospheric suspension of highly reflective ice crystals.

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

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

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

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

(k) Fire-fighting turbine means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) Turbines employed in oil/gas production or oil/gas transportation means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m) A Metropolitan Statistical Area or MSA as defined by the Department of Commerce.

(n) Offshore platform gas turbines means any stationary gas turbine located on a platform in an ocean.

(o) Garrison facility means any permanent military installation.

(p) Gas turbine model means a group of gas turbines having the same nominal air flow, combuster inlet pressure, combuster inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

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

(r) Emergency fuel is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.

(s) Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

(t) Excess emissions means a specified averaging period over which either:

(1) The NO_X emissions are higher than the applicable emission limit in Sec. 60.332;

(2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in Sec. 60.333; or

(3) The recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

(u) Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

(v) Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

(w) Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(y) Unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

§ 60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

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

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

where:

STD = allowable ISO corrected (if required as given in Sec. 60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),
Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and
F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

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

$$STD = 0.0150\frac{(14.4)}{Y} + F$$

where:
STD = allowable ISO corrected (if required as given in Sec. 60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),
Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and
F = NOX emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this seciton is optional. That is, the owner or operator may choose to apply a NO_X allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

(4) If the owner or operator elects to apply a NO_X emission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under Sec. 60.8 as follows:

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

Where:
N = the nitrogen content of the fuel (percent by weight).or:
Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance
test required by Sec. 60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the Federal Register.

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

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

(d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in § 60.332(b) shall comply with paragraph (a)(2) of this section.

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

(f) Stationary gas turbines using water or steam injection for control of NO_X emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

(j) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour that commenced construction, modification, or reconstruction between the dates of October 3, 1977, and January 27, 1982, and were required in the September 10, 1979, Federal Register (44 FR 52792) to comply with paragraph (a)(1) of this section, except electric utility stationary gas turbines, are exempt from paragraph (a) of this section.

(k) Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from paragraph (a)(2) of this section when being fired with an emergency fuel.

(l) Regenerative cycle gas turbines with a heat input less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) are exempt from paragraph (a) of this section.

§ 60.333 Standard for sulfur dioxide.

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

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

§ 60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NO_X emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_X emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O2 monitors. As an alternative, a CO2 monitor may be used to adjust the measured NO_X concentrations to 15 percent O2 by either converting the CO2 hourly averages to equivalent O2 concentrations using Equation F-14a or F-14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O2, or by using the CO2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NO_X and diluent monitors may be performed individually or on a combined basis, i.e., the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for NO_X) and a percent O2 basis for oxygen; or

(ii) On a ppm at 15 percent O2 basis; or

(iii) On a ppm basis (for NO_X) and a percent CO2 basis (for a CO2 monitor that uses the procedures in Method 20 to correct the NO_X data to 15 percent O2).

(2) As specified in Sec. 60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in Sec. 60.13(h).

(i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both NO_X and diluent, the data acquisition and handling system must calculate and record the hourly NO_X emissions in the units of the applicable NO_X emission standard under Sec. 60.332(a), i.e., percent NO_X by volume, dry basis, corrected to 15 percent O2 and International Organization for Standardization (ISO) standard conditions (if required as given in Sec. 60.335(b)(1)). For any hour in which the hourly average O2 concentration exceeds 19.0 percent O2, a diluent cap value of 19.0 percent O2 may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (Ta), and minimum combustor inlet absolute pressure (Po) into the ISO correction equation.

(iii) If the owner or operator has installed a NO_X CEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in Sec. 60.7(c).

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NOX emissions, the owner or operator may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA, State, or local permitting authority approval of a procedure for monitoring compliance with the applicable NOX emission limit under Sec. 60.332, that approved procedure may continue to be used.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control NO_X emissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NO_X CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NOX emissions, may, but is not required to, elect to use a NOX CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. Other acceptable monitoring approaches include periodic testing approved by EPA or the State or local permitting authority or continuous parameter monitoring as described in paragraph (f) of this section.

(f) The owner or operator of a new turbine that commences construction after July 8, 2004, which does not use water or steam injection to control NOX emissions may, but is not required to, perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NO_X formation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in low-NOX mode.

(3) For any turbine that uses SCR to reduce NO_X emissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in Sec. 75.19 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in Sec. 75.19(c)(1)(iv)(H) of this chapter.

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under Sec. 60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in Sec. 75.19 of this chapter or the NO_X emission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in Sec. 75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in Sec. 60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084-82, 94, D5504-01, D6228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference-see Sec. 60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (i.e., if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in Sec. 60.332). The nitrogen content of the fuel shall be determined using methods described in Sec. 60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in Sec. 60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) Fuel oil. For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) Gaseous fuel. Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) Custom schedules. Notwithstanding the requirements of paragraph (i)(2) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (i)(3)(i) and (i)(3)(ii) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in Sec. 60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), subsequent sulfur content monitoring may be performed at 12 month intervals. If any of the samples taken at 12-month intervals has a total sulfur content between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(1) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(2) of this section.

(2) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(3) of this section.

(3) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (i.e., the maximum total sulfur content of natural gas as defined in Sec. 60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with Sec. 60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under Sec. 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

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

(A) An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with Sec. 60.332, as established during the performance test required in Sec. 60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

(B) A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in Sec. 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of Sec. 60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in Sec. 60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using NO_X and diluent CEMS:

(A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_X concentration exceeds the applicable emission limit in Sec. 60.332(a)(1) or (2). For the purposes of this subpart, a ``4-hour rolling average NO_X concentration'' is the arithmetic average of the average NO_X concentration measured by the CEMS for a given hour (corrected to 15 percent O2 and, if required under Sec. 60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO_X concentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_X concentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in Sec. 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of Sec. 60.335(b)(1).

(iv) For owners or operators that elect, under paragraph (f) of this section, to monitor combustion parameters or parameters that document proper operation of the NOX emission controls:

(A) An excess emission shall be a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

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

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur
content of a delivery exceeds 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(3) *Ice fog.* Each period during which an exemption provided in § 60.332(f) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(4) *Emergency fuel.* Each period during which an exemption provided in § 60.332(k) is in effect shall be included in the report required in § 60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

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

Sec. 60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in Sec. 60.8, using either

(1) EPA Method 20,

(2) ASTM D6522-00 (incorporated by reference, see Sec. 60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine NO_X and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible,

with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

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

(A) [Reserved]

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

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

(A) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O2, is within 10 percent of the mean normalized concentration for all traverse points, then you may use 3 points (located either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The 3 points shall be located along the measurement line that exhibited the highest average normalized NO_X concentration during the stratification test; or

(B) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O2, is within 5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in Sec. 60.332 and shall meet the performance test requirements of Sec. 60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NO_{Xo}) corrected to 15 percent O2 shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

$$NO_X=(NO_{Xo})(P_r/P_o)^{0.5}\, e^{19\,(H_o-0.00633)}\,(288[deg]K/Ta)^{1.53}$$

Where:
NO_X = emission concentration of NO_X at 15 percent O2 and ISO standard ambient conditions, ppm by volume, dry basis,
NO_{Xo} = mean observed NO_X concentration, ppm by volume, dry basis, at 15 percent O2,
P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,
P_o = observed combustor inlet absolute pressure at test, mm Hg,
H_o = observed humidity of ambient air, g H2O/g air,
e = transcendental constant, 2.718, and
T_a = ambient temperature, [deg]K.

(2) The 3-run performance test required by Sec. 60.8 must be performed within 5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding theserequirements, performance testing is not required for any emergency fuel (as defined in Sec. 60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NO_X emissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable NO_X emission limit in Sec. 60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with Sec. 60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522-00 (incorporated by reference,

see Sec. 60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable Sec. 60.332 NO_X emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in Sec. 60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in Sec. 60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NO_X CEMS under Sec. 60.334(e), then the initial performance test required under Sec. 60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under Sec. 60.332 and to provide the required reference method data for the RATA of the CEMS described under Sec. 60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator elects under Sec. 60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NOX emission controls, the appropriate parameters shall be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in Sec. 60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597-94 (Reapproved 1999), D6366-99, D4629-02, D5762-02 (all of which are incorporated by reference, see Sec. 60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under Sec. 60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129-00, D2622-98, D4294-02, D1266-98, D5453-00 or D1552-01 (all of which are incorporated by reference, see Sec. 60.17); or

(ii) For gaseous fuels, ASTM D1072-80, 90 (Reapproved 1994); D3246-81, 92, 96; D4468-85 (Reapproved 2000); or D6667-01 (all of which are incorporated by reference, see Sec. 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 prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section 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.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in Sec. 60.8 to ISO standard day conditions.

PSD-FL-328 Permit Monitoring of Operations

The PSD permit requires keeping monthly records of the fuel sulfur content of natural gas. Appropriate test methods are also specified in the PSD permit. These requirements constitute a custom fuel monitoring schedule that ensures compliance with the NSPS requirements for monitoring the nitrogen and sulfur contents of the fuels. The requirement to monitor the nitrogen contents of these fuels is waived due to negligible concentrations and the PSD conditions that require compliance with the NOx standards to be demonstrated by CEMS. The CEMS shall be installed, operated, and maintained in accordance with the requirements of the PSD permit.

For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are: any 1-hour period of NOx emissions greater than the NSPS standard; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8% sulfur by weight (for sulfur dioxide emissions). The permittee shall submit a semiannual report of emissions in excess of the NSPS standards.

PSD-FL-328 Permit Test Methods and Procedures

Tests for nitrogen oxides emissions shall be conducted in accordance with the schedule and methods specified in the PSD permit. The permittee is allowed to conduct initial performance tests at a single load because a NOx monitor shall be used to demonstrate compliance with the specified NOx limits. The permittee is allowed to make the initial compliance demonstration for NOx emissions using certified CEMS data, provided that compliance is based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The permittee is not required to have the NOx monitor continuously correct NOx emissions concentrations to ISO conditions. However, the permittee shall make the correction when required by the Department or Administrator.

The permittee shall use the methods specified in the PSD permit to demonstrate compliance with the fuel sulfur specification, which will ensure compliance with the NSPS standard.

STANDARDS CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at this facility.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

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

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

5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permitee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]

6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]

7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]

8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]

9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

10. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

11. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

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

13. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. Required Sampling Time. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. [Rule 62-297.310(4), F.A.C.]

    b. Minimum Sample Volume. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet. [Rule 62-297.310(4), F.A.C.]

    c. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C. [Rule 62-297.310(4), F.A.C.]

14. Determination of Process Variables

    a. Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

    b. Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

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

15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C.

16. Test Notification: The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator. [Rule 62-297.310(7)(a)9, F.A.C.]

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

18. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the

test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

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

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

RECORDS AND REPORTS

19. 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.]

20. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

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

Florida Power & Light Company
Manatee Plant

FINAL Permit No.: 0810010-011-AV
Facility ID No.: 0810010

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. Spent boiler chemical cleaning liquid evaporation:
   maximum 6000 gallons per hour, and maximum 1 million gallons per year.
2. Propane relief valves
3. 350-gallon closed hydrazine mixing tank and relief valves. Typical annual usage of hydrazine is 1200 gallons of a 35% solution. The hydrazine is used in the boiler feedwater system to scavenge dissolved oxygen, a highly reactive corrosive agent, from the boiler feedwater. Hydrazine reacts with the dissolved oxygen to yield water and ammonia.
4. Fuel oil storage tanks and related equipment, including two 500,000 BBL #6 Fuel Oil Storage Tanks, two 24,000 BBL fuel metering tanks, and one 2000 BBL #2 Light Oil tank.
5. Lube oil tank vents and extraction vents
6. Oil/water separators and related equipment
7. Miscellaneous mobile vehicle operation (cars, light trucks, heavy-duty trucks, backhoes, tractors, forklifts, cranes, etc.)
8. Internal combustion engines in boats, aircraft and vehicles used for transportation of passengers or freight.
9. Vacuum pumps in laboratory operations.
10. Equipment used for steam cleaning.
11. Belt or drum sanders having a total sanding surface of five square feet or less and other equipment used exclusively on wood or plastics or their products having a density of 20 pounds per cubic foot or more.
12. Equipment used exclusively for space heating, other than boilers.
13. Laboratory equipment used exclusively for chemical or physical analyses.
14. Brazing, soldering or welding equipment.
15. Laundry dryers, extractors, or tumblers for fabrics cleaned with only water solutions of bleach or detergents
16. One or more emergency generators located within a single facility provided:
    a. None of the emergency generators is subject to the Federal Acid Rain Program; and
    b. Total fuel consumption by all such emergency generators within the facility is limited to 32,000 gallons per year of diesel fuel, 4,000 gallons per year of gasoline, 4.4 million standard cubic feet per year of natural gas or propane, or an equivalent prorated amount if multiple fuels are used.

17. One or more heating units and general purpose internal combustion engines located within a single facility provided:
    a. None of the heating units or general purpose internal combustion engines is subject to the Federal Acid Rain Program; and
    b. Total fuel consumption by all such heating units and general purpose internal combustion engines within the facility is limited to 32,000 gallons per year of diesel fuel, 4,000 gallons per year of gasoline, 4.4 million standard cubic feet per year of natural gas or propane, or an equivalent prorated amount if multiple fuels are used.
18. Fire and safety equipment.
19. Surface coating operation within a single facility if the total quantity of coatings containing greater than 5.0 percent VOCs, by volume, used is 6.0 gallons per day or less, averaged monthly, provided the amount of coating used shall include any solvents and thinners used in the process including those used for cleanup.
20. Degreasing units using heavier-than-air vapors exclusively, except any such unit using or emitting any substance classified as a hazardous air pollutant.

TABLE 297.310-1 CALIBRATION SCHEDULE
(version dated 10/07/96)

[Note: This table is referenced in Rule 62-297.310, F.A.C.]

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent, or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass ref. 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, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of at least three readings Max. deviation between readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually 2. One Point: Semiannually	Spirometer or calibrated wet test or dry gas test meter	2%
	3. Check after each test series	Comparison check	5%

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BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

DEPARTMENT BACT DETERMINATION

Refer to the draft BACT document issued with initial Technical Evaluation for this project and to the Final Determination issued with the Final permit for the rationale regarding the following BACT determination.

POLLUTANT	CONTROL TECHNOLOGY	DEPARTMENT'S PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO_X	9 ppmvd @ 15% O_2 (simple cycle (SC) normal) 12 ppmvd @ 15% O_2 (simple cycle - PA) 15 ppmvd @ 15% O_2 (simple cycle – PK)
	SCR	2.5 ppmvd @ 15% O_2 (combined cycle (CC))
Particulate Matter	Natural Gas Combustion Controls	10 percent opacity. Fuel Specifications Control of Ammonia Slip (below)
Visible Emissions	As Above	10 Percent opacity
Carbon Monoxide	As Above	7.4/8.0 ppmvd @15% O_2 (full load/continuous SC) 12 ppmvd @15% O_2 (400 hours – SC/PA) 7.4/10.0 ppmvd @15% O_2 (full load/continuous CC)
Sulfur Oxides	As Above	2 grain sulfur/100 std cubic feet
Volatile Organic Compounds	As Above	1.3 ppmvd @ 15% O_2 4 ppmvd @ 15% O_2 (Duct Burner)
Ammonia	SCR Design	5 ppmvd @ 15% O_2 (Not a PSD Pollutant)
Gas Heaters	Low Sulfur Fuels	2 grain sulfur/100 std cubic feet

Note: "DB" means duct burning. "PA" means power augmentation. "PK" means peaking

BACT LIMIT COMPLIANCE REQUIREMENTS

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions (initial, annual)	Method 9
PM/PM_{10}	Fuel Specifications
VOC (initial)	Method 25A corrected by methane from Method 18
CTM-027 (initial, quarterly, annual)	Procedure for Collection and Analysis of Ammonia in Stationary Sources
SO_2/SAM	Record keeping for the sulfur content of fuels delivered to the site
CO (initial, CEMS)	Method 10; CO-CEMS (continuous 24 -hr block average)
NO_X (continuous 24-hr average) NO_X (PK or PA, 24 -hr average)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (initial)	Method 20 (can use RATA if at capacity) or Method 7E

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

Teresa Heron, Permit Engineer
A. A. Linero, P.E. Administrator ___AA Linero___
New Source Review Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

Trina L Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

April 11, 2003
Date

Approved By:

Howard L Rhodes

Howard L. Rhodes, Director
Division of Air Resources Management

4/11/03
Date

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 Activity**
003	Emergency Diesel Generator, Miscellaneous Mobile Equipment and Internal Combustion Engines
004	Painting of Plant Equipment and Non Halogenated Solvent Cleaning Operations

Table 1-1, Units 1 and 2 - Summary of Air Pollutant Emission Standards

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

Emissions Unit	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2

			Allowable Emissions			Equivalent Emissions[1]			
Pollutant	Fuel(s)	Hours per Year	Standard(s)	lb/hour	TPY	lb/hour	TPY	Regulatory Citations	See Permit Condition(s)
VE Steady State	Gas, Oil, Propane	8760	40% opacity					Rule 62-296.405(1)(a), F.A.C.	**A.5**
VE Soot Blowing or Load Change	Gas, Oil, Propane	8760	60 % opacity (>60% opacity for not more than 4, six-minute periods during 3 hours of excess emissions)					Rule 62-210.700(3), F.A.C.	**A.6**
PM Steady State	Gas/Oil, Propane	8760	0.1 lb/mmBtu			865, 865	3,789, 43*	Rule 62-296.405(1)(b), F.A.C.	**A.7**
PM Soot Blowing or Load Change	Gas/Oil, Propane	8760	0.3 lb/mmBtu			2,595, 2,595	1,421, 130*	Rule 62-210.700(3), F.A.C.	**A.8**

* The equivalent annual emissions for propane are based on the expected annual usage of propane reported by the applicant primarily as a startup fuel. Propane usage is not limited by this permit.

Table 1-1, Summary of Air Pollutant Emission Standards, Continued

Emissions Unit	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2

			Allowable Emissions			Equivalent Emissions[1]			
Pollutant	Fuels	Hours per Year	Standard(s)	lb/hour	TPY	lb/hour	TPY	Regulatory Citations	See Permit Condition(s)
SO_2	Oil, Propane	8760	1.1 lb/mmBtu			9,515 (oil)	41,676 (oil)	Rules 62-213.440 & 62-296.405(1)(c)1.g., F.A.C.	**A.9**
NO_x	Gas/Oil Propane	8760	0.30 lb/mmBtu			2,595 2,712	11,366 11,879	Rules 62-296.405(1)(d)2., F.A.C.	**A.10**

Notes:

[1] The "Equivalent Emissions" listed are for informational purposes only. Equivalent emissions are for each emissions unit.

Table 2-1, Unit 1 and 2 - Summary of Compliance Requirements

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

Emissions Unit	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2

Pollutant or Parameter	Fuels	Compliance Method	Testing Frequency	Frequency Base Date[1]	Minimum Compliance Test Duration	CMS[2]	See Permit Condition(s)
SO_2	Oil	Fuel sampling & analysis	As received			Yes	**A.9, A.15, A.23 & A.24**
NO_x	Gas, Oil, Propane	Continuous Emissions Monitor	Continuous			Yes	**A.10**
PM	Oil, Propane	Rule 62-296.405(1)(e)2	Annual	July	3 hours		**A.19, A.22, A.26 & A.27**
VE	Oil, Propane	DEP Method 9	Annual	July	1 hour	Yes	**A.18, A.20, A.21 & A.27**
On-spec. Used Oil		Record Keeping and Analysis	As fired				**A.37**

Notes:

[1] Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.
[2] CMS = continuous monitoring system

Table 1-2, Unit 3 - Summary of Air Pollutant Emission Standards

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

Emission Unit (EU) ID No.	Brief Description: "4 on 1" Combined Cycle Unit 3
005	Unit No.3A gas turbine (nominal 170 MW) with heat recovery steam generator
006	Unit No.3B gas turbine (nominal 170 MW) with heat recovery steam generator
007	Unit No.3C gas turbine (nominal 170 MW) with heat recovery steam generator
008	Unit No.3D gas turbine (nominal 170 MW) with heat recovery steam generator
010	Ammonia storage tank

Combined Cycle Operation Mode

			Allowable Emissions*			Equivalent Emissions[1]			
Pollutant	Fuel(s)	Hours per Year	Standard(s)	lb/hour	TPY	lb/hour	TPY	Regulatory Citations	See Permit Condition(s)
NOx	Natural. Gas	8760	2.5 ppmvd@15%O_2	16.3 23.6			71.4 103.37	Rule 62-212.400, F.A.C.	B.9 and B.10
CO	Natural. Gas	8760	7.4 10 ppmvd@15%O_2	27.5 37.2			120.5 162.7	Rule 62-212.400, F.A.C.	B.9 and B.10
VOC	Natural. Gas	8760	1.3 4.0 ppmvd@15%O_2	2.8 10.5			12.3	Rule 62-212.400, F.A.C.	B.9 and B.10
VE	Natural. Gas	8760	10 % opacity				15.1	Rule 62-212.400, F.A.C.	B.9 and B.10
NH_3	Natural. Gas	8760	5 ppmvd@15%O_2				49.4	Rule 62-212.400, F.A.C.	B.9 and B.10
PM/PM_{10}	Natural. Gas	8760	Fuel Specifications					Rule 62-212.400, F.A.C.	B.9 and B.10
SAM/SO_2	Natural. Gas	8760	Fuel Specifications					Rule 62-212.400, F.A.C.	B.9 and B.10

Table 1-2, Unit 3 - Summary of Air Pollutant Emission Standards

Simple Cycle Operation Mode:

After demonstrating initial compliance in combined cycle mode, the combined group of four gas turbines shall operate in simple cycle mode for no more than an average of 1,000 hours per unit during any consecutive 12 months.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hour	ppmvd @ 15% O_2
CO	Natural Gas	Simple Cycle	7.4	27.5	8.0, 24-hr
		Simple Cycle w/PA	12.0	45.0	12.0, 24-hr
NOx	Natural Gas	Simple Cycle	9.0	58.7	9.0, 24-hr
		Simple Cycle w/PA	12.0	76.2	12.0, 24-hr
		Simple Cycle w/PK	15.0	95.3	15.0, 24-hr
PM/PM_{10}	Natural Gas	Simple or Combined Cycle	Fuel Specifications		
		Simple or Combined Cycle	Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2	Natural Gas	Simple or Combined Cycle	Fuel Specifications		
VOC	Natural Gas	Simple or Normal Combined Cycle	1.3	2.8	NA

Table 2-2, Unit 3 - Summary of Compliance Requirements

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

Emission Unit (EU) ID No.	Brief Description: "4 on 1" Combined Cycle Unit 3
005	Unit No.3A gas turbine (nominal 170 MW) with heat recovery steam generator
006	Unit No.3B gas turbine (nominal 170 MW) with heat recovery steam generator
007	Unit No.3C gas turbine (nominal 170 MW) with heat recovery steam generator
008	Unit No.3D gas turbine (nominal 170 MW) with heat recovery steam generator
010	Ammonia storage tank

Pollutant or Parameter	Fuel[3]	Compliance Reference Method	Testing Frequency	Frequency Base Date[1]	Minimum Compliance Stack Test Duration	CMS[2]	See Permit Condition(s)
NO_x	N.G.	CEMS. 24-hour block average Method 7E or 20 for lb/hr 3-run average	Annual	June	3 hours	Yes	B.10, B.19, B.20, B-21
CO	N.G.	CEMS. 24-hour block average Method 10 for lb/hr 3-run average	Annual	June	3 hours	Yes	B.10, B.19, B-20, B-21, B.22
PM	N.G.	Visible Emissions (VE) subrogate	Annual	June			B.9, B.10, B-19
VOC	N.G.	EPA Method 25A. Optionally Method 18.	Initial	June	3 hours		B.10, B.19, B-20, B-21, B.22
VE	N.G.	Method 9	Annual	June	6 minutes block average		B.10, B.19
SO_2/SAM	N.G.	Fuel Specifications	As received	June			B. 9, B.10, B.19, B.28
NH_3	N.G.	CTM-027	Initial	June			B.2, B.19, B.23

Notes:

[1] Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.
[2] CMS = continuous monitoring system
[3] N.G: Natural Gas

__Simple Cycle Operation Mode__:
After demonstrating initial compliance in combined cycle mode, the combined group of four gas turbines shall operate in simple cycle mode for no more than an average of 1,000 hours per unit during any consecutive 12 months.

Table 3-1, Summary of Reporting Requirements

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.
The permittee shall hold at the facility, for 5 years from the date of the report, a copy of each report that is required to be submitted.
All reports shall be accompanied by a certification by a responsible official, pursuant to Rule 62-213.420(4), F.A.C.

Emissions Unit ARMS No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2

Emission Unit ARMS No.	Brief Description: "4 on 1" Combined Cycle Unit 3
005	Unit No.3A gas turbine (nominal 170 MW) with heat recovery steam generator
006	Unit No.3B gas turbine (nominal 170 MW) with heat recovery steam generator
007	Unit No.3C gas turbine (nominal 170 MW) with heat recovery steam generator
008	Unit No.3D gas turbine (nominal 170 MW) with heat recovery steam generator
010	Ammonia storage tank

Report Type/Content	Frequency	Deadline	Regulatory Citations	See Permit Condition(s)
Annual Statement of Compliance Content: As required by DEP Form 62-213.900(7), F.A.C.	Annually	March 1 (February 29 in Leap years)	Rule 62-213.440(3), F.A.C Rule 62-213.900, F.A.C.	Facility-wide No.11
Annual Operating Report Content: 1. Analytical results and the total amount of on-specification used oil burned during the previous calendar year 2. Information required by DEP Form 62-210.900(5), F.A.C.	Annually	March 1	Rule 62-210.370(3), F.A.C.	TV-5 No. 24; A.37.g Appendix SC, Condition 30
Major Source Annual Emissions Fee Form Content: As required by DEP Form 62-213.900(1), F.A.C.	Annually	March 1	Rule 62-213.205(1), F.A.C.	TV-5 No. 30

Table 3-1, Summary of Reporting Requirements

Deviation from Permit Requirements (report in accordance with the requirements of Rules 62-210.700(6) and 62-4.130, F.A.C.) Immediate Content: 1. Probable cause of such deviation. 2. Corrective and/or preventive measures taken. Quarterly Content (if requested by the Department): Full written report on malfunctions.	As occurs; **and** if requested quarterly	Immediately, per 62-4.130; **and** if requested by Department, at end of the quarter, per 62-210.700(6)	Rule 62-213.440(1)(b)3.b., F.A.C. Rule 62-210.700(6), F.A.C.; Rule 62-4.130, F.A.C.; 40 CFR 70.6(a)(3)(iii)(B)	TV-5 No. 44 TV-5 No. 9
Report Type/Content	**Frequency**	**Deadline**	**Regulatory Citations**	**See Permit Condition(s)**
Noncompliance with any Permit Condition or Limitation Content: 1. Description and cause of noncompliance. 2. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the noncompliance.	As occurs	Immediately [the same day, if during a workday (i.e., 8:00 a.m. -5:00 p.m.), or the first business day after the incident, excluding weekends and holidays.]	Rule 62-4.160, F.A.C.	TV-5 No. 12(8) TV-5 No. 10
Plant Operations-Problems (causing temporary non-compliance) 1. Cause of the problem. 2 . Steps being taken to correct the problem and to prevent its recurrence. 3. If applicable, intent toward reconstruction of equipment destroyed.	As occurs	Immediately [the same day, if during a workday (i.e., 8:00 a.m. -5:00 p.m.), or the first business day after the incident, excluding weekends and holidays.]	Rule 62-4.130, F.A.C.	TV-5 No. 9 TV- No. 10

Table 3-1, Summary of Reporting Requirements

Excess Emissions – Malfunctions (even if 2 hours or less in a 24-hr period.) Content: 1. Cause of the problem. 2. Steps being taken to correct the problem and to prevent its recurrence. 3. If applicable, intent toward reconstruction of equipment destroyed. Quarterly Content (if requested by the Department): Full written report on malfunctions.	As occurs; **and** if requested quarterly	Immediately, per 62-4.130; **and** if requested by Department, at end of the quarter, per 62-210.700(6)	Rule 62-210.700(6), F.A.C. Rule 62-4.130, F.A.C.	A.32 B.29, B.30, B.31.
Report Type/Content	**Frequency**	**Deadline**	**Regulatory Citations**	**See Permit Condition(s)**
Excess Emissions : Sulfur dioxide and opacity Content: Report of emissions in excess of emissions limiting standards, including explanation of nature and cause of excess emissions.	Quarterly	End of quarter	Rule 62-296.405(1), F.A.C. Rule 62-213.440, F.A.C.	A.33
Notification of implementation of operating changes (as defined in Rule 62-210.200, F.A.C.) Content: 1. Date on which change will occur. 2. Description of the change within the permitted source. 3. The pollutants emitted and any change in emissions; and 4. any term or condition becoming applicable or no longer applicable as a result of the change.	As occurs	7 days written notice prior to implementation	Rule 62-213.410, F.A.C. Rule 62.210.200, F.A.C.	TV-5 No. 33
Unit 1 and 2 Compliance Test Report Content: See specific condition A.34.	PM and Opacity Annually	As soon as practical, but no later than 45 days after the last sampling run of each test is done	Rule 62-297.310(8), F.A.C. Rule 62-213.440, F.A.C.	A.34

Table 3-1, Summary of Reporting Requirements

Unit 3 Compliance Test Report Content See Specific Conditions B.22, B.26, B.27, and B.28.	Operating data Monitoring of Capacity Fuel records	Fifth day of each calendar month and/or upon Department request	Rule 62-212.400, F.A.C. Rule 62-4.070(3), F.A.C	B.22, B.26, B.27, B.28
Notification of startup (for any emission unit or facility which has a valid operating permit which has been shut down more than one year) Contents: 1. Startup date. 2. Anticipated emission rates or pollutants released. 3. Changes to processes or control devices which will result in changes to emission rates, and 4. Any other conditions which may differ from the valid outstanding operation permit.	As occurs	At least 60 days prior to intended startup; or, if an emergency, as soon as possible after the startup date is ascertained	Rule 62-210.300(5), F.A.C.	TV-5 No. 19
Report Type/Content	**Frequency**	**Deadline**	**Regulatory Citations**	**See Permit Condition(s)**
Fuel Analysis Report Content: For each fuel received in the preceding month: 1. Heating value. 2. Density or specific gravity. 3. Percent sulfur content by weight.	Monthly	15th day following each calendar month	Rule 62-4.070(3), F.A.C. Rule 62-213.440, F.A.C.	A.35
Used Oil Report Monthly content: Analytical results and the total amount of on-specification used oil burned during the previous calendar month. Annual content: Analytical results and the total amount of on-specification used oil burned during the previous calendar year.	Monthly and annually	Within 30 days of the end each calendar month in which used oil is burned during the previous calendar month; and March 1 with AOR	40 CFR 279 and 761 Rule 62-4.070(3), F.A.C. Rule 62-213.440, F.A.C.	A.37.g

Table 3-1, Summary of Reporting Requirements

Risk Management Plan		When, and if, necessary	40 CFR 68	Facility-wide No. 4.
Construction Notifications Content: Updated proposed schedule of activities through the initial shakedown period and the firing of natural gas.	As necessary	Within 15 days of beginning construction	Rule 62-4.070(3), F.A.C. Permit No. 0810010-007-AC	A.38
PSD Applicability Report Content: Summary of actual emission for the previous calendar year.	Annually	Before August 1 each year	Rule 62-204.800, F.A.C. Rule 62-210.200(11), F.A.C. Rule 62-212.400, F.A.C. 40 CFR 52.21(b)(33)(ii)	A.40
Department Requested Information Content: Information required by law which is needed to determine compliance with the permit	If needed to determine compliance with permit Conditions	Within a reasonable time	Rule 62-4.160, F.A.C. Rule 62-213.440(1)(b), F.A.C.	TV-5 No. 12(15)

Report Type/Content	Frequency	Deadline	Regulatory Citations	See Permit Condition(s)
Monitoring Reports Content: Reports of any required monitoring and all instances of deviations from permit requirements.	Every 6 months		Rule 62-213.440(1)(b)3.a., F.A.C.	TV-5 No. 43

Table 3-1, Summary of Reporting Requirements

Acid Rain Reporting Requirements				
Report Type/Content	**Frequency**	**Deadline**	**Regulatory Citations**	**See Permit Condition(s)**
Acid Rain Excess Emissions Proposed Offset Plan Content: As required by 40 CFR 77 for an Acid Rain Unit that has excess emission in any calendar year.	Annually, if an exceedance occurred during the calendar year.	March 1 (February 29 in Leap years) following the calendar year in which the exceedance(s) occurred.	40 CFR 77	Phase II Acid Rain Part Application, Excess Emissions Requirements
Acid Rain Annual Compliance Certifications Content: As required by 40 CFR 72 Subpart I	Annually	March 1 (February 29 in Leap years) following the calendar year	40 CFR 72 Subpart I	Phase II Acid Rain Part Application, Recordkeeping and Reporting Requirements
Acid Rain Continuous Emission Monitoring Reports Content: As required by 40 CFR 75	See 40 CFR Part 75	See 40 CFR Part 75	40 CFR Part 75	Phase II Acid Rain Part Application, Recordkeeping and Reporting Requirements

Friday, Barbara

F.P. 10/30/06

To: paul_plotkin@fpl.com; KKosky@Golder.com; 'kevin_washington@fpl.com'; Nasca, Mara; Oven, Hamilton; Elihu46gl@aol.com

Cc: Heron, Teresa

Subject: FINAL Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant

Attachments: TV-6.pdf; 2FinalSOB0810010-011-AV.pdf; 297310-1.pdf; 0810010011FinalDetermination.pdf; 0810010011FinalPermitSignaturePage.pdf; Apdx H-0810010-011-AV.pdf; Appendices0810010-011-AV.pdf; Appendix U-0810010-011-AV.pdf; AppendixI-0810010-011-AV.pdf; ASPB9701.pdf; FIGURE1.pdf; FinalRevPermit0810010-011-AV.pdf; PMT 3 COLD ST STARTUPR1.pdf; SS-1.pdf; Table1Unit3Standards 0810010-011-AV.pdf; Table1Units12Standards0810010-011-AV.pdf; Table2Unit3Compliance 0810010-011-AV.pdf; Table2Units12 0810010-011-AV.pdf; Table3SummaryReports 0810010-011-AV.pdf

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The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

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The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,

DEP, Bureau of Air Regulation

Friday, Barbara

From:	System Administrator
To:	Nasca, Mara
Sent:	Monday, October 30, 2006 10:32 AM
Subject:	Delivered:FINAL Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant

Your message

To:	'paul_plotkin@fpl.com'; 'KKosky@Golder.com'; 'kevin_washington@fpl.com'; Nasca, Mara; Oven, Hamilton; 'Elihu46gl@aol.com'
Cc:	Heron, Teresa
Subject:	FINAL Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant
Sent:	10/30/2006 10:32 AM

was delivered to the following recipient(s):

Nasca, Mara on 10/30/2006 10:32 AM

Friday, Barbara

From:	System Administrator
To:	Oven, Hamilton
Sent:	Monday, October 30, 2006 10:32 AM
Subject:	Delivered:FINAL Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant

Your message

To:	'paul_plotkin@fpl.com'; 'KKosky@Golder.com'; 'kevin_washington@fpl.com'; Nasca, Mara; Oven, Hamilton; 'Elihu46gl@aol.com'
Cc:	Heron, Teresa
Subject:	FINAL Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant
Sent:	10/30/2006 10:32 AM

was delivered to the following recipient(s):

Oven, Hamilton on 10/30/2006 10:32 AM

Friday, Barbara

From:	Exchange Administrator
Sent:	Monday, October 30, 2006 10:32 AM
To:	Friday, Barbara
Subject:	Delivery Status Notification (Relay)
Attachments:	ATT33171.txt; FINAL Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant

ATT33171.txt (284 B) FINAL Title V Permit Revision ...

This is an automatically generated Delivery Status Notification.

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

KKosky@Golder.com

Friday, Barbara

From: Exchange Administrator
Sent: Monday, October 30, 2006 10:33 AM
To: Friday, Barbara
Subject: Delivery Status Notification (Relay)

Attachments: ATT33249.txt; FINAL Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant

ATT33249.txt (371 B) FINAL Title V Permit Revision ...

This is an automatically generated Delivery Status Notification.

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paul_plotkin@fpl.com
kevin_washington@fpl.com

Friday, Barbara

From:	Exchange Administrator
Sent:	Monday, October 30, 2006 10:36 AM
To:	Friday, Barbara
Subject:	Delivery Status Notification (Relay)
Attachments:	ATT34447.txt; FINAL Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant

ATT34447.txt (284 B) FINAL Title V Permit Revision ...

This is an automatically generated Delivery Status Notification.

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

Elihu46fl@aol.com

Friday, Barbara

From:	Paul_Plotkin@fpl.com
Sent:	Monday, October 30, 2006 5:42 PM
To:	Friday, Barbara
Subject:	FINAL Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant

Return Receipt

Your document:	FINAL Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant
was received by:	Paul Plotkin/PGBU/FPL
at:	10/30/2006 05:41:59 PM

Friday, Barbara

From: Nasca, Mara
Sent: Monday, October 30, 2006 7:24 PM
To: Friday, Barbara
Subject: Re: FINAL Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant

Thanks Barbara......have a great day!

Sent from my BlackBerry Wireless Handheld

----- Original Message -----
From: Friday, Barbara
To: 'paul_plotkin@fpl.com' <paul_plotkin@fpl.com>; 'KKosky@Golder.com' <KKosky@Golder.com>; 'kevin_washington@fpl.com' <kevin_washington@fpl.com>; Nasca, Mara; Oven, Hamilton; 'Elihu46gl@aol.com' <Elihu46gl@aol.com>
Cc: Heron, Teresa
Sent: Mon Oct 30 10:31:59 2006
Subject: FINAL Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant

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Thank you,

DEP, Bureau of Air Regulation

Friday, Barbara

From:	Nasca, Mara
To:	Friday, Barbara
Sent:	Monday, October 30, 2006 7:25 PM
Subject:	Read: FINAL Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant

Your message

To:	'paul_plotkin@fpl.com'; 'KKosky@Golder.com'; 'kevin_washington@fpl.com'; Nasca, Mara; Oven, Hamilton; 'Elihu46gl@aol.com'
Cc:	Heron, Teresa
Subject:	FINAL Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant
Sent:	10/30/2006 10:32 AM

was read on 10/30/2006 7:25 PM.

Friday, Barbara

From:	Nasca, Mara
To:	Friday, Barbara
Sent:	Tuesday, October 31, 2006 9:34 PM
Subject:	Read: RE: FINAL Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant

Your message

To:	Nasca, Mara
Subject:	RE: FINAL Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant
Sent:	10/31/2006 7:20 AM

was read on 10/31/2006 9:34 PM.