Friday, Barbara

To: Kozlov, Leonard; Jerome.guidry@att.net

Cc: Heron, Teresa

Subject: FINAL Title V Permit Renewal No.: 0970043-013-AV - Kissimmee Utility Authority - Cane Island Power Park

Attached for your records is a zip file which contains the FINAL Title V Permit Renewal and associated documents.

If I may be of further assistance, please feel free to contact me.

Barbara J. Friday
Planner II
Bureau of Air Regulation
(850)921-9524
Barbara.Friday@dep.state.fl.us

Memorandum

Florida Department of
Environmental Protection

TO: Michael G. Cooke

THRU: Trina L. Vielhauer
Al Linero

FROM: Teresa Heron

DATE: December 16, 2004

SUBJECT: FINAL Title V Permit No.: 0970043-013-AV
Kissimmee Utility Authority (KUA)

Attached is the final permit package for the Title V Permit Renewal for this facility. No comments were received from the USEPA in response to the Proposed Title V permit.

We recommend your approval and signature of the attached final Title V Permit Renewal.

AAL/th

Attachments

NOTICE OF FINAL PERMIT RENEWAL

In the Matter of an
Application for Permit Renewal by:

Mr. A. K. Ben Sharma, P.E.
Vice President of Power Supply
Kissimmee Utility Authority
P.O. Box 423219
Kissimmee, FL 34742-3219

Osceola County
FINAL Permit Renewal No. **0970043-013-AV**
Combustion Turbines Units 001-002 and 003
410 MW Power Plant
Cane Island Power Park

Enclosed is FINAL Title V Permit Renewal Number **0970043-013-AV** for the operation of the Cane Island Power Park, located at 6075 Old Tampa Highway, Intercession City, Osceola County, issued pursuant to Chapter 403, Florida Statutes (F.S.).

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

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

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

Executed in Tallahassee, Florida.

Trina L. Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT RENEWAL (including the FINAL permit renewal) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 12/27/04 to the person(s) listed or as otherwise noted:

Mr. A. K. Ben Sharma, P.E.*
Mr. Jerome Guidry, P.E., Perigee Technical Services
Mr. Len Kozlov, Central District Office
U.S.EPA, Region 4 (INTERNET E-mail Memorandum)

12/27/04 cc: Teresa Heron
Reading File

Clerk Stamp

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

Barbara J. Friday 12/27/04
(Clerk) (Date)

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OFFICIAL USE

Mr. A.K. Ben Sharma, P.E., Vice President

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Sent To Mr. A.K. Ben Sharma, P.E., Vice President

Street, Apt. No.; or PO Box No. P.O. Box 423219

City, State, ZIP+4 Kissimmee, Florida 34742-3219

PS Form 3800, June 2002 See Reverse for Instructions

SENDER: COMPLETE THIS SECTION

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

1. Article Addressed to:

Mr. A.K. Ben Sharma, P.E.
Vice President of Power Supply
Kissimmee Utility Authority
P.O. Box 423219
Kissimmee, Florida 34742-3219

COMPLETE THIS SECTION ON DELIVERY

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☐ Agent
☐ Addressee

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Sid Mance

C. Date of Delivery

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☐ Insured Mail ☐ C.O.D.

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2. Article Number
(Transfer from service label) 7004 1350 0000 1910 2973

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

FINAL PERMIT RENEWAL DETERMINATION

I. Comment(s).

No comments were received from Region 4, U.S.EPA, concerning the PROPOSED Title V Permit Renewal that was posted on the Department's web-site on November 8, 2004.

II. Conclusion.

The permitting authority hereby issues the FINAL Title V Permit Renewal **0970043-013-AV** with no changes.

STATEMENT OF BASIS

Kissimmee Utility Authority
Cane Island Power Park
Osceola County

Facility ID No. 0970043

FINAL Title V Permit Renewal No. **0970043-013-AV**

Title V Permit Renewal

This Title V air operation permit renewal is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to perform the work and 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.

This facility consists of three fossil fuel-fired combustion turbine electric generating units a cooling tower, three distillate oil storage tanks and ancillary equipment.

Emissions Unit 001 is a 40 MW General Electric Model LM-6000PA simple-cycle combustion turbine with an electrical generator set. Emission Unit 002 is a General Electric Model PG7111(EA) combustion turbine with electrical generator set and an unfired heat recovery steam generator (HRSG) with a steam-electric generator. Emissions Unit 002 produces 80 MW during simple-cycle operation and 120 MW during combined-cycle operation. Each combustion turbine fires natural gas as the primary fuel with very low sulfur distillate oil (≤ 0.05% sulfur by weight) as a backup fuel. Both units have simple-cycle stacks. Unit 002 also has a separate HRSG stack for combined-cycle operation.

Emissions Unit 003 is a nominal 167 MW stationary gas combustion turbine-electrical generator burning natural gas with very low sulfur fuel oil as backup; a supplemental gas-fired heat recovery steam generator to raise sufficient steam to achieve 250 MW in combined-cycle operation; an 80-90 MW steam electric generator; a 44 mmBtu/hr heat input duct burner; a selective catalytic reduction unit and ancillary equipment; ammonia storage; a 130-foot stack; and a 100-foot bypass stack for simple-cycle operation.

Support facilities for Unit 003 include a cooling tower, water and wastewater facilities, water storage tanks, storm water detention pond, 230 KV transmission line, and a 1.0 million gallon storage tank for back-up distillate fuel oil. NOx emissions are controlled by Dry Low NO_X (DLN) combustors and wet injection under simple-cycle operation. NOx emissions are controlled by DLN and wet injection and selective catalytic reduction (SCR) when operating in combined-cycle mode. Inherently clean fuels and good combustion practices are employed to control all pollutants. Because a continuous emissions monitoring system (CEMS) is used to demonstrate compliance for NO_X, a compliance assurance monitoring (CAM) plan is not required for the SCR system. Site Certification for this Unit 003 was approved on November 22, 1999.

Emissions Unit 004, 007, and 008 are storage tanks for the very low sulfur back-up fuel oil. Emissions Unit 005 is the duct burner for Emissions Unit 003 and Emission Unit 006 is the cooling tower.

Based on the Title V Air Permit Revision Application received on October 17, 2001, this facility is a major source of hazardous air pollutants (HAPs). It holds ORIS code **7238** under the federal Acid Rain Program.

The Initial Title V Operation Permit for this facility was issued on June 1, 1999. It addressed Emissions Units 001, 002 and their fuel storage and ancillary equipment. The most recent Title V Operation Permit Revision was issued on November 17, 2003 and recognized the construction of Emissions Unit 003, its storage tank, cooling tower, and ancillary equipment as authorized by Permit PSD-FL-254.

The purpose of the present permit is to renew the Title V Operation Permit which will expire on December 31, 2004. No changes were requested by the applicant with respect to the Operation Permit Revision issued in 2003. However the Department proposes a number of changes related to promulgation or modifications of Federal regulations related to combustion turbines.

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 include clearer compliance methods for modern combustion turbines compared with those in existence at the time the original rule was promulgated (1977).

On March 5, 2004, EPA promulgated 40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. The facility is subject to Subpart YYYY because it is a major source of HAPs. The rule imposes no requirements on the existing combustion turbines at this facility unless they are reconstructed in the future.

Therefore, Specific Conditions C.16 and C.17 are added to Subsection C. Common Conditions:

C.16. Appendix GG. These gas combustion turbines are each subject to 40 CFR 60 - Subpart GG, New Stationary Source Performance Standards (NSPS) for Stationary Gas Turbines (attached as Appendix GG).

[Rule 62-204. 800 (7) F.A.C and 40 CFR 60, Subpart GG, NSPS-Gas Combustion Turbines]

C.17. Appendix YYYY. This facility is subject to 40 CFR 63 - Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (attached as Appendix YYYY) since it is a major source of hazardous air pollutants. However, all stationary combustion turbines at this facility are existing units (construction was commenced before January 14, 2003).

[Rule 62-204.800 (11) F.A.C and 40 CFR 63, Subpart A, General Provisions and Subpart YYYY, NESHAP-Combustion Turbines]

The permitting note related to potential-to-emit/capacity/heat input was not included for the three units, all of which were permitted under the rules for the Prevention of Significant Deterioration (Specific Conditions A.1, B.1, and E.2). Information kept on site, internal operating procedures, historical data from the EPA Air Markets Website, and Department's standards for equipment and accuracy ensure units continue to operate within their permitted heat input limits. [(Rule 62-297.310(5), F.A.C. incorporated as Specific Condition C.4)]

Following is an example of the permit note that the Department proposes to remove from each of the mentioned conditions:

> ~~{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each emission unit for the purposes of confirming that emissions testing is conducted within 95 to 100 percent of the emission unit's rated capacity (or to limit future operation to 105 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability}~~

Specific conditions No. A.9 and B.9 are being corrected to clarify that fuel sampling and analysis is required by Subpart GG to insure compliance with the sulfur dioxide emission limits. Fuel sampling and analysis is not an alternative to be used in lieu of a SO_2 continuous emissions monitoring system (CEMS).

Therefore, these two conditions (**A.9** and **B.9**) are revised as follows:

> Sulfur Dioxide - Sulfur Content. ~~**The permittee elected to use fuel sampling and analysis in lieu of installing a continuous monitoring system for SO_2 as required by the NSPS.**~~ ~~This protocol is allowed because the emissions unit does not have an operating flue gas desulfurization device~~. The permittee shall demonstrate compliance with the SO_2 limit by EPA test method 8 or fuel sampling and analysis. The permittee shall demonstrate compliance with the gaseous fuel sulfur limit via record keeping. Excess emissions shall be reported if the fuel being fired in the gas turbine exceeds 0.05% sulfur, by weight.
>
> [AC 49-205703 (PSD-FL-182) and 40 CFR 60, Subpart GG]

In addition to the above change, the standard language is updated in Section II. Facility-wide Conditions and Appendix I, List of Insignificant Emissions Units and/or Activities. Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Kissimmee Utility Authority
Cane Island Power Park
Facility ID No. **0970043**
Osceola County

Title V Air Operation Permit Renewal

FINAL Permit No. **0970043-013-AV**

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

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

Telephone: 850/488-0114
Fax: 850/922-6979

Table of Contents

Department of Environmental Protection

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

Jeb Bush
Governor

Colleen M. Castille
Secretary

Permittee:
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, FL 34742

FINAL Permit No. 0970043-013-AV
Facility ID No. 0970043
SIC No.: 49
Project: Title V Air Operation Permit Renewal

This permit renewal is for the operation of the Kissimmee Utility Authority's Cane Island Power Park. This facility is located at 6075 Old Tampa Highway, Intercession City, Osceola County. The UTM coordinates are Zone 17, 449.8 East, and 3127.9 North. The Latitude is 28° 16' 40" North and the Longitude is 81° 31' 01" West.

This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to perform the work and 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. The facility holds ORIS code **7238** under Phase II of the federal Acid Rain Program.

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
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements
Appendix TV-4, Title V Conditions (version dated 02/12/02)
Appendix SS-1, Stack Sampling Facilities (version dated 10/07/96)
Appendix GG, 40 CFR 60 - NSPS Subpart GG for Stationary Gas Turbines
Appendix YYYY, 40 CFR 63 NESHAP - Subpart YYYY for Combustion Turbines
Table 297.310-1, Calibration Schedule (version dated 10/07/96)
Figure 1 - Summary Report-Gaseous And Opacity Excess Emission And Monitoring System Performance Report (version dated 7/96)
Alternate Sampling Procedure, ASP No. 97-B-01
BACT Determination dated April 7, 1993
Order extending permits dated March 18, 1999

Effective Date: January 1, 2005
Renewal Application Due Date: July 5, 2009
Expiration Date: December 31, 2009

Michael G. Cooke

Michael G. Cooke, Director
Division of Air Resource Management

"More Protection, Less Process"

Printed on recycled paper.

Section I. Facility Information.

Subsection A. Facility Description.

This facility is an electric power generating plant and consists of:

Simple-Cycle Combustion Turbine Unit 1 (Emissions Unit 001), rated at 40 MW,

Combined-Cycle Combustion Turbine Unit 2 (Emissions Unit 002), rated at 120 MW, and

Combined-Cycle Combustion Turbine Unit 3 (Emissions Unit 003), rated at 250 MW, with duct burner (Emissions Unit 005).

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

Based on the Title V permit renewal application received June 30, 2004, this facility is a major source of hazardous air pollutants (HAPs).

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

E.U. ID No.	Brief Description
001	Simple-Cycle Combustion Turbine (Unit 001), rated at 40 MW, 367 mmBtu/hr for natural gas and 372 mmBtu/hr for number 2 fuel oil, capable of burning natural gas and number 2 fuel oil, with emissions exhausted through a 65 ft. stack .
002	Combined-Cycle Combustion Turbine (Unit 002), rated at 120 MW, 869 mmBtu/hr for natural gas and 928 mmBtu/hr for number 2 fuel oil, capable of burning natural gas and number 2 fuel oil, with emissions exhausted through a 75 ft. stack .
003 005	Combined-Cycle Combustion Turbine (Unit 003), with duct burner (Unit 005).
004	Fuel Storage Tank (one million gallon)(Unit 004).

Unregulated Emissions Units and/or Activities	
007	Distillate Fuel Oil Tank No. 2 (700,000 gal. capacity)
008	Distillate Fuel Oil Tank No. 1 (300,000 gal. capacity)
006	Cooling Tower

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

Subsection C. Relevant Documents.

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

<u>These documents are provided to the permittee for information purposes only:</u>
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix H-1, Permit History/ID Number Changes
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements

<u>These documents are on file with the permitting authority:</u>
Initial Title V Permit Application received June 14, 1996 and subsequent applications for revisions received on June 6, 2000, October 17, 2001 and July 15, 2002 (withdrawn).
Acid Rain Phase II Part Application renewal signed by the Designated Representative on June 28, 2004.
Title V Permit Renewal Application received on June 30, 2004.
DRAFT Title V Permit Renewal clerked on September 23, 2004.
PROPOSED Title V Permit Renewal posted on November 8, 2004.

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. APPENDIX TV-4, TITLE V CONDITIONS, is a part of this permit.
{Permitting note: APPENDIX TV-4, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided 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.
[Rules 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 updates to submittals, should be sent to:

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

and,

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

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. [Reserved.]

8. Not federally enforceable. 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. {Permitting Note: No vapor emissions control devices or systems are deemed necessary nor ordered by the Department as of the issuance date of this permit.}
[Rule 62-296.320(1)(a), F.A.C.]

9. Emissions of Unconfined Particulate Matter. Pursuant to Rules 62-296.320(4)(c)1., 3. & 4., F.A.C., reasonable precautions to prevent emissions of unconfined particulate matter at this facility include the following requirements (see Condition 57. of APPENDIX TV-4, TITLE V CONDITIONS.

The following techniques will be used to prevent unconfined particulate matter emissions on as needed basis:

a. Maintenance of paved areas shall be performed as needed.
b. Worker and site vehicle movements shall be conducted on paved roads.
c. Delivery vehicle movements shall be conducted on paved roads.
d. Fuel oil delivery by truck shall be conducted on paved roads.

[Rule 62-296.320(4)(c)2., F.A.C.; and proposed by applicant in the initial Title V permit application received June 14, 1996.]

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

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.
[Rules 62-213.440(3) and 62-213.900, F.A.C.]

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

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

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

Telephone: 407/894-7555
Fax: 407/897-2966

13. EPA Compliance Authority. 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 & EPCRA Enforcement Branch
Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303-8960

Telephone: 404/562-9155
Fax: 404/562-9163 or 404/562-9164

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.]

Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
001	Simple-Cycle Combustion Turbine (Unit 001), rated at 40 MW, 367 mmBtu/hr for natural gas and 372 mmBtu/hr for number 2 fuel oil, capable of burning any combination of natural gas and number 2 fuel oil, with emissions exhausted through a 65 ft. stack.

This emissions unit is regulated under Acid Rain, Phase II; Rule 62-210.300, F.A.C., Permits Required; and is subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines (attached as Appendix GG). This unit underwent a BACT Determination dated April 7, 1993. BACT Limits were incorporated into the subsequent air construction/PSD permits including AC 49-205703 (PSD-FL-182) issued on April 9, 1993. Since this unit is located at a major source for hazardous air pollutants, this unit is also subject to 40 CFR 63, Subpart YYYY, National Emissions Standards for Hazardous Air Pollutants for Combustion Turbines (attached as Appendix YYYY). See Specific Conditions **C.16** and **C.17**.

{Permitting Note. Fossil fuel fired combustion turbine Unit 001 is a 40 MW GE Model LM6000PA. NO_x emissions are controlled by low-NO_x combustors, and by water injection, whereas SO_2 and H_2SO_4 emissions are controlled by firing .05% S oil, for only limited time periods. Unit 001 began commercial operation in 1994.}

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

<u>Essential Potential to Emit (PTE) Parameters</u>

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

Unit No.	mmBtu/hr Heat Input	Fuel Type
001	367*	Natural Gas
	372*	Fuel Oil

*Based on 101.3 kilopascals pressure, 288 Kelvin and 60% relative humidity (ISO standard day conditions), and lower heating value of the fuel fired.

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; AC 49-205703 (PSD-FL-182); 0970043-007-AC (modification of PSD-FL-182A)]

A.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **C.8.**
[Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation - Fuels. The only fuels allowed to be fired are pipeline-quality natural gas and low sulfur No. 2 distillate oil. The sulfur content of the No. 2 distillate oil shall not exceed 0.05% sulfur by weight. Operation of Unit No. 1 shall not exceed 5000 hours during any consecutive 12 months. Of the total allowable hours of operation, Unit No. 1 shall fire distillate oil for no more than:

a. 800 hours during any consecutive 12 months if natural gas is available, or
b. 1000 during any consecutive 12 months if natural gas is unavailable.

{Permitting Note: The limitations of specific conditions A.3 and A.6 are more stringent than the NSPS sulfur dioxide limitation and thus assure compliance with 40 CFR 60.333 and 60.334} [Rule 62-213.410, F.A.C., AC 49-205703 (PSD-FL-182); 0970043-007-AC (PSD-FL-182A); 0970043-009-AV, Revised on 10/13/00]

Emission Limitations and Standards

{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions **A.4.** through **A.5.** are based on the specified averaging time of the applicable test method.}

A.4. Visible Emissions. Visible emissions shall not exceed 10 percent opacity, except for during startup, shutdown or periods of part load operation, at which time visible emissions shall not exceed 20 percent opacity.
[AC 49-205703 (PSD-FL-182)]

A.5. The maximum allowable emissions from Unit 001 shall not exceed the emission limitations listed below.

	Emission Limits			
Pollutant	**Gas**	**Number 2 Fuel Oil**	**Equivalent Emissions Tons/Year** [a, b]	**Basis**
NO_x [c]	25 ppmvd at 15% oxygen on a dry basis	42 ppmvd at 15% oxygen on a dry basis	105.5 [c]	BACT
SO_2	nil	20 lb/hr	10.0	BACT
PM	0.0245lb/mmBtu	0.0323 lb/mmBtu	24.0	BACT
H_2SO_4	nil	2.2 lb/hr	1.1	BACT
VOC	1.4 lb/hr	3 lb/hr	4.3	BACT
CO	30 ppmvd	63 ppmvd	118.0	BACT
Opacity	10% (see A.4.)	10% (see A.4.)		BACT
Be [d]	nil	2.5 E-6 lb/MMBtu	< 1	BACT
As [d]	nil	4.2 E-6 lb/MMBtu	< 1	AC 49-205703
Hg [d]	nil	3.1 E-6 lb/MMBtu	< 1	AC 49-205703
Pb [d]	nil	2.8 E-5 lb/MMBtu	< 1	AC 49-205703

a. Tons per year based on 4000 hrs/yr for natural gas firing, 1000 hrs/yr for number 2 fuel oil firing.
b. Based on 372 mmBtu/hr for number 2 fuel oil and 367 mmBtu/hr for natural gas.
c. Original permit PSD-FL-182 limited NOx emissions to 25 ppmvd for gas firing to be reduced to 15 ppmvd. Project No. 0970043-007-AC (12/21/99) modified the PSD permit establishing the final NO_x emission limit as 25 ppmvd when firing natural gas with a corresponding reduction in hours of operation (5000 hours per year) and a combined NOx emissions cap (366.1 TPY) with Unit No. 2.
d. Limits based upon an approved emission factor, which is subject to change in the future.

[AC49-205703 (PSD-FL-182); 0970043-007-AC; 0970043-009-AV, Revised on 10/13/00]

Test Methods and Procedures

A.6. Annual Compliance Tests. Emission testing for visible emissions and NO_x shall be performed annually, in accordance with specific condition **A.8.**, with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests shall be conducted using the following EPA reference methods in accordance with 40 CFR 60, Appendix A:

a. Method 9 for VE;
b. Method 20 for NO_x.

Annual compliance with the NO_x standard may be determined by using data collected as part of the annual Relative Accuracy Test Audit (RATA) testing as described in 40 CFR 60 Appendix B. Performance Specification 2. Section 7.1.2. instead of performing Methods 7E and 20 as separate tests. EPA Method 10 will be conducted simultaneously with the NO_x/ O_2 RATA tests. The 20-30 minute tests conducted for the RATA testing will be strung together in a manner that fulfills additional requirements of EPA Methods 10 and 20 as to test run time (3 one hour runs) and O_2 stratification investigation. The collected data will be bias corrected to comply with the RATA test requirements, but will not be bias corrected for compliance with NSPS so as to meet the requirements of methods 10 and 20 (the NSPS test methods). No less than eight test points will be used for the RATA testing which will comply with both the RATA test requirements and the NSPS test requirements. The NO_x span for methods 20 and 7E should not exceed 50 ppm instead of a span of 300 ppm as required by Subpart GG. Mass emissions of NO_x and CO shall be determined pursuant to the procedures in 40 CFR 60, Appendix A. Method 19 or 40 CFR 75, Appendix F. If the unit is not operating because of scheduled maintenance outages and emergency repairs, it will be tested within thirty days of returning to service.
Note: Measured NO_x emissions will be ISO corrected for comparison with NSPS, but will not be ISO corrected for comparison with the BACT standard.
[Rules 62-297.401 and 62-213.440, F.A.C., and AC 49-205703 (PSD-FL-182)]

A.7. Testing for PM, CO, VOC. Particulate matter tests shall be conducted using EPA test methods 5 or 17. Alternatively, the opacity emissions test may be used unless the 10% opacity limit is exceeded. Carbon monoxide tests shall be conducted using EPA test method 10. VOC tests shall be conducted using EPA test method 25A.
[Rule 62-297.401, F.A.C., and AC 49-205703 (PSD-FL-182).]

A.8. Additional Test Requirements. Test results shall be the average of three valid runs. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity, which is defined as 95-100 percent of the maximum heat input rate allowed by this permit, achievable for the average ambient air temperature during the test. If it is impracticable to test at permitted capacity, the emissions unit may be tested at less than permitted capacity. In such cases, subsequent operation is limited by adjusting downward the entire heat input vs. inlet temperature curve by the increment equal to the difference between the maximum permitted heat input value and 105 percent of the value reached during the test. 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. Data, curves, and calculations necessary to demonstrate the heat input rate correction at both design and test conditions shall be submitted to the Department with the compliance test report.
[AC 49-205703 (PSD-FL-182).]

A.9. Sulfur Dioxide - Sulfur Content. The permittee shall demonstrate compliance with the SO_2 limit by EPA test method 8 or fuel sampling and analysis. The permittee shall demonstrate compliance with the gaseous fuel sulfur limit via record keeping. Excess emissions shall be reported if the fuel being fired in the gas turbine exceeds 0.05% sulfur, by weight. [AC 49-205703 (PSD-FL-182).]

A.10. Fuel Sampling & Analysis - Sulfur/Nitrogen and Lower Heating Value. The following fuel sampling and analysis program shall be used to demonstrate compliance with the sulfur dioxide standard:

a. Determine and record the as-fired fuel sulfur content, percent by weight, for liquid fuels using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest editions, to analyze a representative sample of the blended fuel following each fuel delivery. ASTM D3246-81, or its latest edition, shall be used for sulfur content of gaseous fuel.

b. Record daily the amount of each fuel fired, density of each fuel, heating value, nitrogen content and the percent sulfur content by weight of fuel oil as specified in 40 CFR 60.334.

[Rule 62-213.440, F.A.C.; and AC 49-205703 (PSD-FL-182).]

Monitoring of Operations

A.11. Continuous Monitoring Required. A continuous monitoring system shall be maintained to record fuel consumption. A continuous monitoring system shall be maintained to record emissions of nitrogen oxides in accordance with the requirements of 40 CFR 75. Data collected from this system shall be used for periodic monitoring purposes. While water injection is being utilized for NO_x control, water to fuel ratio and fuel bound nitrogen is not required to be continuously monitored as long as the permittee will report excess emissions using the data collected by the continuous monitoring system in accordance with the following conditions:

1. Each NO_x CEMS must be capable of calculating NO_x emissions concentrations corrected to 15% O2 and ISO conditions.
2. Monitor data availability shall be no less than 95 percent on a quarterly basis.
3. NO_x CEMS should provide at least 4 data points for each hour and calculate a one-hour average.

To implement condition 1, Kissimmee Utility Authority (KUA) shall use ambient data (temperature, relative humidity, pressure) to correct excess emissions data to ISO conditions if requested by the Department. If monitor availability drops below 95% on a quarterly basis as prescribed in condition 2, KUA shall use water to fuel ratio and fuel-bound nitrogen data to monitor excess emissions in subsequent quarters until the minimum CEMS monitor availability is above 95%. The use of CEMS to monitor excess emissions is more stringent than the surrogate parameter monitoring in 40 CFR 60.334 since the CEMS directly measures NO_x emissions. The CEMS also provides monitoring when no water injection is used to control NOx emissions (i.e., when firing natural gas, dry low NO_x burners are used).
[AC 49-205703 (PSD-FL-182).]

A.12. Excess Emissions by CEMS. The CEMS shall be used to determine periods of excess emissions as per 40 CFR 60.334. Excess emissions are defined for this emissions unit as any 60-minute period during which the average emissions exceed the emission limits of specific condition **A.5.** of this permit. Periods of startup, shutdown and malfunction shall be monitored, recorded and reported with excess emissions following the format and requirements of 40 CFR 60.7.

[AC 49-205703 (PSD-FL-182).]

Recordkeeping and Reporting Requirements

A.13. Excess Emission Reports. Semi-annual excess emission reports shall be submitted to the DEP's Central District Office. These reports shall be postmarked by the 30th day following the end of each calendar half. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.
[AC 49-205703 (PSD-FL-182)]

A.14. Natural Gas Sulfur Content Records Required. The owner or operator shall receive and maintain records of sulfur content of natural gas provided by the natural gas supplier, as per 40 CFR 60.334. The records shall report total sulfur content in terms of grains of sulfur per hundred cubic feet (standard conditions).
[AC 49-205703 (PSD-FL-182)]

A.15. Additional Reports Required. The owner or operator shall report the following with the Annual Operating Report (AOR) by March 1 of each calendar year: sulfur and nitrogen contents, by weight, and lower heating value of the fuel oil being fired, annual fuel consumption of number 2 fuel oil and natural gas, hours of operation per fuel usage and air emission limits. As it may become available, the permittee shall also provide the Department with information regarding documented enhancements to the LM6000PA, dual-fuel class, combustion turbine machine, which have demonstrated in the field the ability to achieve a continuous NO_X emission rate of 15 ppmvd while firing natural gas.
[Rule 62-210.370(3), F.A.C.; and AC49-205703 (PSD-FL-182); 0970043-007-AC; 0970043-009-AV, Revised on 10/13/00]

Other Specific Conditions

A.16. Maintain Capability to install an SCR. This emissions unit is permitted for maximum NO_x emission levels of 15 (gas)/42 (oil) ppmv. The Department will revise permitted emission levels for NO_x if the manufacturer achieves an even lower NO_x emission, pursuant to F.A.C. Rule 62-4.080. The permittee shall maintain capability for future installation of a selective catalytic reduction (SCR) system. This is required in the event that the permittee is unable to comply with the permitted NO_x levels and the Department requires an SCR to be installed. In the event an SCR system is required to be installed, the emission limitations shall be established at the time of installation by stack test results and through a revised determination of BACT.
[AC 49-205703 (PSD-FL-182)]

A.17. This emissions unit is also subject to conditions **C.1.** through **C.17.**, contained in **Subsection C., Common Conditions.**

A.18. This emissions unit is also subject to conditions **D.1.** through **D.6.**, contained in **Subsection D., NSPS Common Conditions.**

Subsection B. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
002	Combined-Cycle Combustion Turbine (Unit 002), rated at 120 MW, 869 mmBtu/hr for natural gas and 928 mmBtu/hr for number 2 fuel oil, capable of burning any combination of natural gas and number 2 fuel oil, with emissions exhausted through a 75 ft. stack.

This emissions unit is regulated under Acid Rain, Phase II; Rule 62-210.300, F.A.C., Permits Required; and, is subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. The affected facility to which this subpart applies is the combined-cycle gas turbine, Unit 2. This unit underwent a BACT Determination dated April 7, 1993. BACT limits were incorporated into the subsequent air construction/PSD permits including AC 49-205703 (PSD-FL-182) issued on April 9, 1993. Since this unit is located at a major source for hazardous air pollutants, this unit is also subject to 40 CFR 63, Subpart YYYY, National Emissions Standards for Hazardous Air Pollutants for Combustion Turbines (attached as Appendix YYYY). See Specific Conditions **C.16** and **C.17**.

{Permitting Notes: Fossil fuel fired combustion turbine Unit 002 is a General Electric Model PG7111EA. NO_x emissions are controlled by low-NO_x combustors, and by water injection, whereas SO_2 and H_2SO_4 emissions are controlled by firing 0.05%, by weight, sulfur oil for only limited time periods. Exhaust is vented through the heat recovery steam generator that is not equipped with duct burners and then through a 75 ft. stack. The turbine exhaust may also be vented through a bypass stack for simple-cycle operation when the HRSG or steam turbine is down for maintenance and/or repair. The turbine began commercial operation in 1995.}

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	mmBtu/hr Heat Input	Fuel Type
002	869*	Natural Gas
	928*	No. 2 Fuel Oil

* Based on 101.3 kilopascals pressure, 288 Kelvin and 60% relative humidity (ISO standard day conditions), and lower heating value of the fuel fired.

[Rules 62-4.160(2), 62-210.200(PTE), F.A.C.; and AC 49-205703 (PSD-FL-182)]

B.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **C.8.** [Rule 62-297.310(2), F.A.C.]

B.3. Methods of Operation.

a. Fuels: The only fuel(s) allowed to be burned are natural gas and number 2 fuel oil (0.05%), except that firing of number 2 fuel oil is limited to no more than 1000 hours per year if natural gas is unavailable, or no more than 800 hours per year if gas is available. The sulfur content of the fuel oil shall not exceed 0.05%, by weight. {Permitting Note: The limitations of specific conditions A.3 and A.6 are more stringent than the NSPS sulfur dioxide limitation and thus assure compliance with 40 CFR 60.333 and 60.334}

b. Inlet Air Fogging: The permittee is authorized to install and operate a high pressure, direct water spray fogging system. The proposed equipment will inject up to 26 gpm from spray nozzles to provide evaporative cooling of the compressor inlet air to Unit 2. Based on an inlet air mass flow rate of 2,077,077 pounds per hour, the inlet air fogging system shall be designed to achieve a

25° F cooling reduction from an ambient temperature of 95° F to cooled compressor inlet air temperature of 70° F. {Permitting Note: The inlet air fogging system will typically operate during periods of peak power demand and high ambient temperatures. Fogging provides evaporative cooling of the inlet air to the compressor, which allows a higher mass flow rate with a corresponding increase in power production of up to 8 MW depending on initial ambient conditions. The increased power production is realized by firing additional fuel, which results in increased actual emissions. However, there are no increases in the maximum heat input rates, power production, or emissions levels, which are established under the coldest expected ambient temperatures. Fogging simply allows performance of the combustion turbine at a lower temperature than the existing ambient conditions.}
[Rule 62-213.410, F.A.C.; AC 49-205703 (PSD-FL-182); 0970043-008-AC (PSD-FL-182I); and 0970043-009-AV, Revised on 10/13/00]

Emission Limitations and Standards

{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions **B.4.** through **B.5.** are based on the specified averaging time of the applicable test method.}

B.4. Visible Emissions. Visible emissions shall not exceed 10 percent opacity, except for during startup, shutdown or periods of part load operation, at which time visible emissions shall not exceed 20 percent opacity.
[AC 49-205703 (PSD-FL-182)]

B.5. The maximum allowable emissions from Unit 2 shall not exceed the emission limitations listed below.

Pollutant	**Emission Limits**			**Basis**
	Gas	**Number 2 Fuel Oil**	**Equivalent Emissions Tons/Year** [a, b]	
NO_x [c]	15 ppmvd at 15% oxygen on a dry basis	42 ppmvd at 15% oxygen on a dry basis	290.6	BACT
SO_2	nil	52 lb/hr	26	BACT
PM	0.010 lb/mmBtu	0.0162 lb/mmBtu	41.2	BACT
H_2SO_4	nil	5.72 lb/hr	2.86	BACT
VOC	2 lb/hr	5 lb/hr	10.26	BACT
CO	20 ppmvd	20 ppmvd	242	BACT
Opacity	10% (see B.4.)	10% (see B.4.)		BACT
Be [d]	nil	2.5e-6 lb/mmBtu	< 1	BACT
As [d]	nil	4.2e-6 lb/mmBtu	< 1	AC 49-205703
Hg [d]	nil	3.0e-6 lb/mmBtu	< 1	AC 49-205703
Pb [d]	nil	2.8e-5 lb/mmBtu	< 1	AC 49-205703

a. Tons per year based on 7760 hrs/yr for natural gas firing, 1000 hrs/yr for number 2 fuel oil firing.
b. Based on 928 mmBtu/hr for number 2 fuel oil and 869 mmBtu/hr for natural gas.
c. NO_x emission limits were permitted to be 25 ppmvd while firing natural gas until 1/1/98 via original application.
d. Limits based upon an approved emission factor, which is subject to change in the future.

B.6. Annual Compliance Tests. Emission testing for visible emissions and NO_x shall be performed annually, in accordance with specific condition **B.8.**, with the fuel(s) used for more than

400 hours in the preceding 12-month period. Tests shall be conducted using the following EPA reference methods in accordance with 40 CFR 60, Appendix A:

a. Method 9 for VE;
b. Method 20 for NO_x.

Annual compliance with the NO_x standard may be determined by using data collected as part of the annual Relative Accuracy Test Audit (RATA) testing as described in 40 CFR 60 Appendix B. Performance Specification 2. Section 7.1.2. instead of performing Methods 7E and 20 as separate tests. EPA Method 10 will be conducted simultaneously with the NO_x/ O_2 RATA tests. The 20-30 minute tests conducted for the RATA testing will be strung together in a manner that fulfills additional requirements of EPA Methods 10 and 20 as to test run time (3 one hour runs) and O_2 stratification investigation. The collected data will be bias corrected to comply with the RATA test requirements, but will not be bias corrected for compliance with NSPS so as to meet the requirements of methods 10 and 20 (the NSPS test methods). No less than eight test points will be used for the RATA testing which will comply with both the RATA test requirements and the NSPS test requirements. The NO_x span for methods 20 and 7E should not exceed 50 ppm instead of a span of 300 ppm as required by Subpart GG. Mass emissions of NO_x and CO shall be determined pursuant to the procedures in 40 CFR 60, Appendix A. Method 19 or 40 CFR 75, Appendix F. If the unit is not operating because of scheduled maintenance outages and emergency repairs, it will be tested within thirty days of returning to service.
Note: Measured NO_x emissions will be ISO corrected for comparison with NSPS, but will not be ISO corrected for comparison with the BACT standard.
[Rules 62-297.401 and 62-213.440, F.A.C.; and AC 49-205703 (PSD-FL-182)]

B.7. Testing for PM, CO, VOC. Particulate matter tests shall be conducted using EPA test methods 5 or 17. Alternatively, the opacity emissions test may be used unless the 10% opacity limit is exceeded. Carbon monoxide tests shall be conducted using EPA test method 10. VOC tests shall be conducted using EPA test method 25A.
[Rule 62-297.401, F.A.C.; and AC 49-205703 (PSD-FL-182)]

B.8. Additional Test Requirements. Test results shall be the average of three valid runs. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity, which is defined as 95-100 percent of the maximum heat input rate allowed by this permit, achievable for the average ambient air temperature during the test. If it is impracticable to test at permitted capacity, the emissions unit may be tested at less than permitted capacity. In such cases, subsequent operation is limited by adjusting downward the entire heat input vs. inlet temperature curve by the increment equal to the difference between the maximum permitted heat input value and 105 percent of the value reached during the test. 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. Data, curves, and calculations necessary to demonstrate the heat input rate correction at both design and test conditions shall be submitted to the Dept. with the compliance test report.
[AC 49-205703 (PSD-FL-182)]

B.9. The permittee shall demonstrate compliance with the SO_2 limit by EPA test method 8 or fuel sampling and analysis. The permittee shall demonstrate compliance with the gaseous fuel sulfur limit via record keeping. Excess emissions shall be reported if the fuel being fired in the gas turbine exceeds 0.05% sulfur by weight.
[AC 49-205703 (PSD-FL-182)]

B.10. Fuel Sampling & Analysis - Sulfur/Nitrogen and Lower Heating Value. The following fuel sampling and analysis program shall be used to demonstrate compliance with the sulfur dioxide standard:

a. Determine and record the as-fired fuel sulfur content, percent by weight, for liquid fuels using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest editions, to analyze a representative sample of the blended fuel following each fuel delivery. ASTM D3246-81, or its latest edition, shall be used for sulfur content of gaseous fuel.

b. Record daily the amount of each fuel fired, density of each fuel, heating value, nitrogen content and the percent sulfur content by weight of fuel oil as specified in 40 CFR 60.334.

[Rule 62-213.440, F.A.C.; and AC 49-205703 (PSD-FL-182)]

Monitoring of Operations

B.11 Continuous Monitoring Required. A continuous monitoring system shall be maintained to record fuel consumption. A continuous monitoring system shall be maintained to record emissions of nitrogen oxides in accordance with the requirements of 40 CFR 75. Data collected from this system shall be used for periodic monitoring purposes. While water injection is being utilized for NO_x control, water to fuel ratio and fuel bound nitrogen is not required to be continuously monitored as long as the permittee will report excess emissions using the data collected by the continuous monitoring system in accordance with the following conditions:

1. Each NO_x CEMS must be capable of calculating NO_x emissions concentrations corrected to 15% O2 and ISO conditions.
2. Monitor data availability shall be no less than 95 percent on a quarterly basis.
3. NO_x CEMS should provide at least 4 data points for each hour and calculate a one-hour average.

To implement condition 1, KUA shall use ambient data (temperature, relative humidity, pressure) to correct excess emissions data to ISO conditions if requested by the Department. If monitor availability drops below 95% on a quarterly basis as prescribed in condition 2, KUA shall use water to fuel ratio and fuel-bound nitrogen data to monitor excess emissions in subsequent quarters until the minimum CEMS monitor availability is above 95%. The use of CEMS to monitor excess emissions is more stringent than the surrogate parameter monitoring in 40 CFR 60.334 since the CEMS directly measures NO_x emissions. The CEMS also provides monitoring when no water injection is used to control NOx emissions (i.e., when firing natural gas, dry low NO_x burners are used).

[AC 49-205703 (PSD-FL-182)]

B.12. Excess Emissions by CEMS. The CEMS shall be used to determine periods of excess emissions as per 40 CFR 60.334. Excess emissions are defined for this emissions unit as any 60-minute period during which the average emissions exceed the emission limits of specific condition **B.5.** of this permit. Excess emissions from the combustion turbine caused entirely or in part by the operation of the inlet air fogging system shall also be prohibited. Periods of startup, shutdown and malfunction shall be monitored, recorded and reported with excess emissions following the format and requirements of 40 CFR 60.7.

[AC49-205703 (PSD-FL-182); 0970043-008-AC (PSD-FL-182I); and 0970043-009-AV, Revised on 10/13/00]

Recordkeeping and Reporting Requirements

B.13. Excess Emission Reports. Semi-annual excess emission reports shall be submitted to the DEP's Central District Office. These reports shall be postmarked by the 30th day following the

last day of June and the last day of December. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.
[AC 49-205703 (PSD-FL-182)]

B.14. Natural Gas Sulfur Content Records Required. The owner or operator shall receive and maintain records of sulfur content of natural gas provided by the natural gas supplier, as per 40 CFR 60.334. The records shall report total sulfur content in terms of grains of sulfur per hundred cubic feet (standard conditions).
[AC 49-205703 (PSD-FL-182)]

B.15. Additional Reports Required. The owner or operator shall report the following with the Annual Operating Report (AOR) by March 1 of each calendar year: sulfur and nitrogen contents, by weight, and lower heating value of the fuel oil being fired, annual fuel consumption of number 2 fuel oil and natural gas, hours of operation per fuel usage and air emission limits.
[Rule 62-210.370(3), F.A.C.; and AC 49-205703 (PSD-FL-182)]

Other Conditions

B.16. Maintain Capability to install an SCR. This emissions unit is permitted for maximum NO_x emission levels of 15 (gas)/42 (oil) ppmv. The Department will revise permitted emission levels for NO_x if the manufacturer achieves an even lower NO_x emission, pursuant to F.A.C. Rule 62-4.080. The permittee shall maintain capability for future installation of a selective catalytic reduction (SCR) system. This is required in the event that the permittee is unable to comply with the permitted NO_x levels and the Department requires an SCR to be installed. In the event an SCR system is required to be installed, the emission limitations shall be established at the time of installation by stack test results and through a revised determination of BACT.
[AC 49-205703 (PSD-FL-182)]

B.17. This emissions unit is also subject to conditions **C.1.** through **C.17,** contained in **Subsection C., Common Conditions.**

B.18. This emissions unit is also subject to conditions **D.1.** through **D.6.,** contained in **Subsection D., NSPS Common Conditions.**

Subsection C. Common Conditions.

E.U. ID No.	Brief Description
001	Simple-Cycle Combustion Turbine (Unit 001), rated at 40 MW, 367 mmBtu/hr for natural gas and 372 mmBtu/hr for number 2 fuel oil, capable of burning any combination of natural gas and number 2 fuel oil, with emissions exhausted through a 65 ft. stack. GE Model LM6000PA.
002	Combined-Cycle Combustion Turbine (Unit 002), rated at 120 MW, 869 mmBtu/hr for natural gas and 928 mmBtu/hr for number 2 fuel oil, capable of burning any combination of natural gas and number 2 fuel oil, with emissions exhausted through a 75 ft. stack. GE Model PG7111EA.
003 005	Combined-Cycle Combustion Turbine (Unit 003), with duct burner (Unit 005), rated at 250 MW, 1696 mmBtu/hr for natural gas and 1910 mmBtu/hr for number 2 fuel oil, and capable of burning any combination of natural gas and number 2 fuel oil. Emissions are exhausted through a 100 ft. stack for simple-cycle operation, and a 130 ft. stack for combined-cycle operation. GE Model MS7241FA.

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

Essential Potential to Emit (PTE) Parameters

C.1. Restricted Operation. Unit No. 1 shall operate no more than 5000 hours during any consecutive 12 months. Operation of Unit No. 2 is not restricted (8,760 hours/year). In addition, the combined NOx emissions of Unit Nos. 1 and 2 shall not exceed 366.1 tons during any consecutive 12 months. Compliance with this requirement shall be demonstrated each month with NOx emissions data collected from the installed CEMS. Records shall be maintained on site demonstrating compliance with this cap for each consecutive 12-month period. Additionally, the annual submittal of each Annual Operating Report shall include such data and calculations. {Permitting Note: Revised by Project No. 0970043-009-AV on 10/13/00 to incorporate previous Project No. 0970043-007-AC that modified original permit PSD-FL-182. This action set a final NOx limit for Unit No. 1 of 25 ppmvd with a corresponding reduction in annual hours of operation from 8760 to 5000 and established the NOx emissions cap.}
[Rule 62-210.200(PTE), F.A.C.; 0970043-007-AC (PSD-FL-182A); 0970043-009-AV, Revised on 10/13/00.]

Emission Limitations and Standards

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

Excess Emissions

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

C.2. 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.]

C.3. 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

C.4. 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.; and PSD-FL-254, Specific Condition 50.]

C.5. Visible Emissions. The test method for visible emissions for emissions units 001 (Unit 1), 002 (Unit 2), and 003 (Unit 3) shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C.
[Rules 62-204.800 and 62-297.401, F.A.C.]

C.6. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

C.7. 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.]

C.8. Operating Rate During Testing. Testing of emissions shall be conducted with each emissions unit operation at permitted capacity, which is defined as 95 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 105 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.
[Rule 62-297.310(2), F.A.C.]

C.9. Applicable Test Procedures.

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

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

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

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

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

(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.]

C.10. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

Recordkeeping and Reporting Requirements

C.11. Excess Emissions - Notification. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Central 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 semi-annual report, if requested by the Central District Air Section.
[Rule 62-210.700(6), F.A.C.]

C.12. Excess Emissions - Report. Submit to the Central District Air Section a written report of emissions in excess of emission limiting standards as set forth in this permit, for each semi-annual period. 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.
[Rule 62-213.440, F.A.C.; and AC 49-205703 (PSD-FL-182)]

C.13. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Central District Air Section on the results of each such test.
(b) The required test report shall be filed with the Central 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 Central 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.]

C.14. Frequency of Compliance Tests.

The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a. Did not operate; or

b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.

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

a. Visible emissions, if there is an applicable standard;

b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

c. Each NESHAP pollutant, if there is an applicable emission standard.

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

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

(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

(d) 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.]

C.15. 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.]

C.16. Appendix GG. These gas combustion turbines are each subject to 40 CFR 60 - Subpart GG, New Stationary Source Performance Standards (NSPS) for Stationary Gas Turbines (attached as Appendix GG).

[Rule 62-204. 800 (7) F.A.C and 40 CFR 60, Subpart GG, NSPS-Gas Combustion Turbines]

C.17. Appendix YYYY. This facility is subject 40 CFR 63 - Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (attached as Appendix YYYY) since it is a major source of hazardous air pollutants. However, all stationary combustion turbines at this facility are existing units (construction was commenced before January 14, 2003).

[Rule 62-204.800 (11) F.A.C and 40 CFR 63, Subpart A, General Provisions and Subpart YYYY, NESHAP-Combustion Turbines]

Subsection D. NSPS Common Conditions.

E.U. ID No.	Brief Description
001	Simple-Cycle Combustion Turbine Unit 1, rated at 40 MW, 367 mmBtu/hr for natural gas and 372 mmBtu/hr for number 2 fuel oil, capable of burning any combination of natural gas and number 2 fuel oil, with emissions exhausted through a 65 ft. stack. GE Model LM6000 PA
002	Combined-Cycle Combustion Turbine Unit 2, rated at 120 MW, 869 mmBtu/hr for natural gas and 928 mmBtu/hr for number 2 fuel oil, capable of burning any combination of natural gas and number 2 fuel oil, with emissions exhausted through a 75 ft. stack. GE Model PG7111EA
003 005	Combined-Cycle Combustion Turbine Unit 003 with duct burner (Unit 005), rated at 250 MW, 1696 mmBtu/hr for natural gas and 1910 mmBtu/hr for number 2 fuel oil, and capable of burning any combination of natural gas and number 2 fuel oil. Emissions are exhausted through a 100 ft. stack for simple-cycle operation, and a 130 ft. stack for combined-cycle operation. GE Model MS7241FA

The emissions units above are subject to the following conditions from 40 CFR 60 Subpart A, General Provisions. The affected units to which this subpart applies are the simple-cycle combustion turbine, Unit 001, the combined-cycle combustion turbine, Unit 002, and the combined-cycle combustion turbine, Unit 003.

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

D.1. Pursuant to 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 as follows:

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

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

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
(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]

(f) The 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 five years following the date of such measurements, maintenance, reports, and records.
[40 CFR 60.7 and Rule 62-213.440(1)(b)2.b., F.A.C.]

D.2. Pursuant to 40 CFR 60.8 Performance Tests.

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart.
(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.
(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]

D.3. Pursuant to 40 CFR 60.11 Compliance With Standards And Maintenance Requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined in accordance with performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.
(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Reference 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)(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 opacity compliance.
[40 CFR 60.11]

D.4. Pursuant to 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]

D.5. Pursuant to 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.
(c) If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he/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 continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments except that for systems using automatic zero adjustments. The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.
(2) Unless otherwise approved by the Administrator, the following procedures shall be followed for continuous monitoring systems measuring opacity of emissions. Minimum procedures shall include a method for producing a simulated zero opacity condition and an

upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photo detector assembly.
(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) When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.
(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 recorder during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non-reduced form (e.g., ppm pollutant and percent O2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).
[40 CFR 60.13]

D.6. Pursuant to 40 CFR 60.17 Incorporations by Reference.

The materials listed below are incorporated by reference in the corresponding sections noted. [Note: The remainder of this section has not been reproduced in this permit for brevity. See 40 CFR 60.17 for materials incorporated by reference.]
[40 CFR 60.17]

Subsection E. This section addresses the following emissions units.

E.U. ID Nos.	Brief Description
003 and 005	These units are comprised of a combined-cycle combustion turbine plant that includes (a) a stationary gas turbine (Unit 003), (b) a supplementary gas-fired heat recovery steam generator (HRSG) with duct burner (Unit 005), and (c) a steam turbine. The plant is rated at 250 MW, 1696 mmBtu/hr for natural gas and 1910 mmBtu/hr for number 2 fuel oil, and capable of burning any combination of natural gas and number 2 fuel oil. Emissions are exhausted through a 100 ft. stack for simple-cycle operation, and a 130 ft. stack for combined-cycle operation. Emission Unit 003 is a General Electric Model MS7241FA

This combustion turbine is regulated under Phase II of the federal Acid Rain Program; Rule 62-210.300, F.A.C., Permits Required; and, is subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines (attached as Appendix GG). The HRSG equipped with a natural gas fired 44 mmBTU/hr duct burner (HHV) and 80-90 MW steam electrical generator shall comply with all applicable provisions of 40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial Commercial-Institutional Steam Generating Units Which Construction is Commenced After September June 9, 1989, adopted by reference in Rule 62-204.800(7), F.A.C. Since this unit is located at a major source for hazardous air pollutants, this unit is also subject to 40 CFR 63, Subpart YYYY, National Emissions Standards for Hazardous Air Pollutants for Combustion Turbines (attached as Appendix YYYY). See Specific Conditions **C.16** and **C.17**.

Simple-cycle control technology includes (a) dry low nitrogen oxides (NOx) (DLN) combustors to control NOx emissions during periods of natural gas use, and (b) a water injection system to control NOx emissions during periods of distillate fuel oil use.

Combined-cycle control technology includes (a) a selective catalytic reduction system (SCR) to control NOx emissions, (b) DLN combustors to control NOx emissions during periods of natural gas use, and (c) a water injection system to control NOx emissions during periods of distillate fuel oil use. Because a continuous emissions monitoring system (CEMS) is used to demonstrate compliance for NO_X, a compliance assurance monitoring (CAM) plan is not required for the SCR system.

This turbine was permitted on November 22, 1999 and began commercial operation in 2001.

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

Essential Potential to Emit (PTE) Parameters

E.1. Combustion Turbine Capacity. The maximum heat input rates, based on the lower heating value (LHV) of each fuel to this Unit at ambient conditions of 19°F temperature, 55% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,696 million Btu per hour (mmBtu/hr) when firing natural gas, and not exceed 1,910 mmBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions were required to be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing by the permittee.

[Rule 62-210.200, F.A.C. (Definitions - Potential Emissions); and PSD-FL-254, Specific Condition 10.]

E.2. Heat Recovery Steam Generator equipped with Duct Burner. The maximum heat input rate of the natural gas fired duct burner shall not exceed 44 mmBtu/hour (HHV).

[Rule 62-210.200 F.A.C. (Definitions - Potential Emissions), Rule 62-4.160(2) F.A.C., and PSD-FL-254, Specific Condition 11.]

E.3. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **C.8.**
[Rule 62-297.310(2), F.A.C.]

Methods of Operation

E.4. Operating Procedures. Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment.
[Rule 62-4.070(3), F.A.C.; and PSD-FL-254, Specific Condition 14.]

E.5. Circumvention. The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly.
[Rule 62-210.650, F.A.C.; and PSD-FL-254, Specific Condition 15.]

E.5.1. Maximum allowable hours of operation for the 250 MW Combined-Cycle Unit are 8760 hours per year while firing natural gas. Fuel oil firing of the combustion turbine is permitted for a maximum of 720 hours per year.
[Rule 62-210.200, F.A.C. (Definitions - Potential Emissions); PSD-FL-254, Specific condition 16.]

E.5.2. Simple-Cycle Operation. The plant may be operated in simple-cycle mode. Different limits apply depending upon whether simple-cycle operation is of an intermittent nature (e.g., caused by maintenance of equipment following the combustion turbine, or temporary electrical demand fluctuations), or long-term electrical demand situations.
[PSD-FL-254, Specific Condition 17.]

E.6. Fuels. Only pipeline natural gas or a maximum of 0.05 percent, by weight, sulfur fuel oil (No. 2 or superior grade of distillate fuel oil) shall be fired in this unit.
[Rule 62-210.200, F.A.C. (Definitions - Potential Emissions); and PSD-FL-254, Specific Condition 9.]

Control Technology

E.7. Dry Low NO_X (DLN) combustors are installed on the stationary combustion turbine to comply with the simple-cycle NO_X emissions limits listed in Specific Condition **E.13.**
[Rules 62-4.070 and 62-212.400, F.A.C.; and PSD-FL-254, Specific Condition 18.]

E.8. A water injection system is installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions.
[Rules 62-4.070 and 62-212.400, F.A.C.; and PSD-FL-254, Specific Condition 19.]

E.9. A selective catalytic reduction (SCR) system is installed to comply with the combined-cycle NO_X limit listed in Specific Condition **E.13.**
[PSD-FL-254, Specific Condition 20.]

E.10. These units are designed to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions **E.13.** through **E.17.**
[Rules 62-4.070 and 62-204.800, F.A.C.; 40 CFR60.40a(b); and PSD-FL-254, Specific Condition 21.]

E.11. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems prior to their installation. DLN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize simple-cycle NO_X emissions and CO emissions.
[Rules 62-4.070 and 62-210.650 F.A.C.; and PSD-FL-254, Specific Condition 22.]

E.12. Drift eliminators are installed on the cooling tower to reduce PM/PM_{10} emissions.
[PSD-FL-254, Specific Condition 23.]

<u>**Emission Limitations and Standards**</u>

{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions **E.13.** through **E.17.** are based on the specified averaging time of the applicable test method.}

E.13. <u>Nitrogen Oxides.</u>

A. *Combined-Cycle Operation*

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on gas (fuel oil) and the duct burner on or off, shall not exceed 3.5 (15) ppmvd @15% O_2 on a 3-hr block average. Compliance shall be determined by the continuous emission monitor (CEMS). Emissions of NO_X calculated as NO_2 in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 26 (108) pounds per hour (lb/hr) with the duct burner on or off to be demonstrated by *initial* stack test.
- The concentration of ammonia in the exhaust gas from each combustion turbine shall not exceed 5 ppmvd @15% O_2. The compliance procedures are described in Specific Condition **E.21.** [Rules 62-212.400 and 62-4.070, F.A.C.]
- When NO_X monitoring data are not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

B. *Intermittent Simple-Cycle Operation*

The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on gas (fuel oil) shall not exceed 12 (42) ppmvd at 15% O_2 (24-hr block average). Emissions of NO_X in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 86 (310) pounds per hour (lb/hr). [Rule 62-212.400, F.A.C.]

- Notwithstanding the applicable NO_X limit during simple-cycle operation, reasonable measures shall be implemented to maintain the concentration of NO_X in the exhaust gas at 9 ppmvd at 15% O_2 or lower. Any tuning of the combustors for Dry Low NO_X operation while

firing gas shall result in initial subsequent NO_X concentrations of **9** ppmvd @15% O_2 or lower.
[Rules 62-212.400 and 62-4.070, F.A.C.]

- When NO_X monitoring data are not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

C. *Continuous Simple-Cycle Operation*

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on gas (fuel oil) shall not exceed 9 (42) ppmvd at 15% O_2 (24-hr block average). Emissions of NO_X in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 65 (310) pounds per hour (lb/hr). [Rules 62-212.400, F.A.C.]
- Notwithstanding the applicable NO_X limit during simple-cycle operation, reasonable measures shall be implemented to maintain the concentration of NO_X in the exhaust gas at 9 ppmvd at 15% O_2 or lower. Any tuning of the combustors for Dry Low NO_X operation while firing gas shall result in initial subsequent NO_X concentrations of 9 ppmvd @15% O_2 or lower. [Rules 62-212.400 and 62-4.070, F.A.C.]
- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

[PSD-FL-254, Specific Condition 24.]

E.14. Carbon Monoxide. Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on gas (fuel oil) shall neither exceed 12 (20) ppm, nor exceed 43 (71) lb/hr, with the duct burner off, and neither exceed 20 (30) ppm, nor exceed 71 (108) lb/hr, with the duct burner on, to be demonstrated by stack test using EPA Method 10.
[Rule 62-212.400, F.A.C.; and PSD-FL-254, Specific Condition 25.]

E.15. Volatile Organic Compounds. Emissions of VOC in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on gas (fuel oil) shall neither exceed 1.4 (10) ppm, nor exceed 3 (21.4) lb/hr, with the duct burner off, and neither exceed 4 (10) ppm, nor exceed 8.5 (21.4) lb/hr, with the duct burner on, to be demonstrated by *initial* stack test using EPA Method 18, 25 or 25A. No annual testing is required.
[Rule 62-212.400, F.A.C.; and PSD-FL-254, Specific Condition 26.]

E.16. Sulfur Dioxide. SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content less than 20 grains per 100 standard cubic foot), or by firing No. 2 or superior grade distillate fuel oil with a maximum 0.05 percent sulfur, by weight, for 720 hours per year. Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Conditions **E.32.** and **E.33.** will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the duct burner or the combustion turbine. Emissions of SO_2 shall not exceed 38.1 tons per year.
[40 CFR 60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C. to avoid PSD Review; and PSD-FL-254, Specific Condition 27.]

E.17. Visible Emissions. VE emissions shall serve as a surrogate for PM/PM_{10} emissions from the combustion turbine operating with or without the duct burner, and shall not exceed 10 percent opacity from the stack in use.
[Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.; and PSD-FL-254, Specific Condition 28.]

Excess Emissions

E.18. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period. During any calendar day in which a start-up or shutdown occurs with natural gas as the exclusively fired fuel, an alternative NO_X limit of 86 lb/hr (310 lb/hr if fuel oil is fired during the calendar day) on the basis of a 24-hour average shall apply.
[Rule 62-210.700, F.A.C.; and PSD-FL-254, Specific Condition 29., as modified on November 26, 2002.]

E.19. Excess emissions 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 pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 24-hr average for NO_X.
[PSD-FL-254, Specific Condition 30.]

E.20. Excess Emissions Report. If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Central District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition **E.13.**
[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7 (1998 version); and PSD-FL-254, Specific Condition 31.]

Compliance Determination

E.21. Selective Catalytic Reduction System (SCR) Compliance Procedures.

- An *initial* stack emission test for nitrogen oxides and ammonia from the CGT/HRGS pair was conducted: 1) for natural gas firing, and 2) for distillate fuel oil firing. The ammonia injection rate necessary to comply with the NO_X standard was established during the initial performance tests.
- The SCR equipment shall operate at all times that the combustion turbine is operating in combined-cycle operation mode. The permittee shall, whenever possible, operate the facility in a manner so as to optimize the effectiveness of the SCR unit, while minimizing ammonia slip to below the emission limit.
- The permittee shall operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system of the CGT/HRSG set. It shall be maintained and calibrated according to the manufacture's specifications. During the stack test, the permittee at each load condition shall determine the minimum ammonia flow rate required to meet the emissions limitations. During NO_X CEM downtimes or

malfunctions, the permittee shall operate at greater or equal to 100% of the ammonia injection rate determined during the stack test.

[PSD-FL-254, Specific Condition 52.]

E.22. Compliance with the allowable emission limiting standards shall be determined annually as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C. [PSD-FL-254, Specific Condition 32.]

E.23. Annual compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on these units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources".
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources".
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Tests must be conducted with the duct burner on and with the duct burner off.
- EPA Method 26A (modified) for ammonia sample collection.
- EPA Draft Method 206 for ion chromatographic analysis for ammonia.

[PSD-FL-254, Specific Condition 33.]

E.24. Continuous compliance with the NO_X emission limits. Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system on a 3-hr average basis (a 24-hour block average shall be used to demonstrate compliance with the NO_x limits when operating under Intermittent Simple-Cycle Operation or Continuous Simple-Cycle Operation). Based on CEMS data, a separate compliance determination is conducted at the end of each 3-hr period and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous 3-hr period. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700, F.A.C. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. These excess emissions periods shall be reported as required in Specific Condition **E.20.**
[Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75; and PSD-FL-254, Specific Condition 34.]

E.25. Compliance with the SO_2 and PM/PM_{10} emission limits. Notwithstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR 60.335 or 40 CFR 75 are used when determination of fuel sulfur content is made. Analysis may be performed by the owner or

operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1998 version).
[PSD-FL-254, Specific Condition 35.]

E.26. Compliance with CO emission limit. An *initial* test for CO, was conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the annual RATA testing for the NO_X CEMS required pursuant to 40 CFR 75. As an alternative to annual testing in a given year, periodic tuning data shall be provided to demonstrate compliance in the year the tuning is conducted.
[PSD-FL-254, Specific Condition 36.]

E.26.1 Compliance with the VOC emission limit. An *initial* test was required to demonstrate compliance with the VOC emission limit. Subsequently, the CO emission limit and periodic tuning data shall be employed as surrogate and no annual testing is required.
[PSD-FL-254, Specific Condition 37.]

E.27. Testing procedures. Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.
[PSD-FL-254, Specific Condition 38.]

Monitoring of Operations

E.28. Continuous Monitoring System. The permittee shall calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the NO_X from these units. Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the permitted limits, listed in Specific Condition **E.13.** (other than those allowed for in Specific Condition **E.18.**) shall be reported to the DEP Central District Office within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternatively by facsimile within one working day).
[Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C.; 40 CFR 60.7 (1998 version); and PSD-FL-254, Specific Condition 44., as modified on November 26, 2002.]

E.29. CEMS for reporting excess emissions. The NO_X CEMS shall be used in lieu of the requirement for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998 version). Upon request from DEP, the CEMS emission rates for NO_X on the CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.
[EPA approval letter dated February 10, 1999; and PSD-FL-254, Specific Condition 45.]

E.30. CEMS in lieu of Water to Fuel Ratio. The NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998 version). Subject to EPA approval, the calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1998 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from DEP, the CEMS emission rates for NO_X on this Unit shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.
[EPA Approval dated February 10, 1999; and PSD-FL-254, Specific Condition 46.]

E.31. Continuous Monitoring System Reports. The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40 CFR 75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Emissions Monitoring Section Administrator and EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.
[PSD-FL-254, Specific Condition 47.]

E.32. Natural Gas Monitoring Schedule. A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75, and certified by the USEPA.

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

[PSD-FL-254, Specific Condition 48.]

E.33. Fuel Oil Monitoring Schedule. The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 fuel oil received at this facility an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).
[PSD-FL-254, Specific Condition 49.]

Recordkeeping and Reporting Requirements

E.34. Semi-Annual Reports. Semi-annual excess emission reports, in accordance with 40 CFR 60.7(a)(7)(c), shall be submitted to the DEP's Central District Office.
[PSD-FL-254, Specific Condition 14, in Section II.]

E.35. Test Notification. The DEP's Central District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).
[PSD-FL-254, Specific Condition 39.]

E.36. Special Compliance Tests. The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.
[PSD-FL-254, Specific Condition 40.]

E.37. Test Results. Compliance test results shall be submitted to the DEP's Central District office no later than 45 days after completion of the last test run.
[Rule 62-297.310(8), F.A.C.; and PSD-FL-254, Specific Condition 41.]

E.38. Records. All measurements, records, and other data required to be maintained by KUA shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.
[PSD-FL-254, Specific Condition 42.]

E.39. Compliance Test Reports. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.
[PSD-FL-254, Specific Condition 43.]

E.40. Subpart Dc Requirements. The permittee shall comply with all applicable requirements of 40 CFR 60, Subpart Dc.
[PSD-FL-254, Specific Condition 51.]

Other Specific Conditions

E.41. This emissions unit is also subject to conditions **C.1.** through **C.17.**, contained in **Subsection C., Common Conditions.**

E.42. This emissions unit is also subject to conditions **D.1.** through **D.6.**, contained in **Subsection D., NSPS Common Conditions.**

Subsection F. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
004	- Fuel Storage Tank

This fuel storage unit, consisting of a 1.0 million gallon distillate fuel oil storage tank (Unit 004), shall comply with all applicable provisions of 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C.
[PSD-FL-254, Specific Condition 5.]

The following conditions apply to the emissions unit listed above:

Essential Potential to Emit (PTE) Parameters

F.1. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year.
[Rules 62-4.160(2) and 62-210.200, F.A.C., Definitions - (PTE).]

Recordkeeping Requirements

F.2. The permittee shall maintain records on site for storage vessel identification number 004 to include the date of construction, the material storage capacity, and type of material stored for the life of this storage vessel.
[40 CFR 60.116b(b).]

Section IV. This section is the Acid Rain Part.

Operated by: Kissimmee Utility Authority
ORIS code: **7238**

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

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

E.U. ID No.	Brief Description
001	Simple-Cycle Combustion Turbine (Unit 001)
002	Combined-Cycle Combustion Turbine (Unit 002)
003	Combined-Cycle Combustion Turbine (Unit 003)

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

a. DEP Form No. 62-210.900(1)(a). signed by the Designated Representative on June 25, 2004.

[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	2005	2006	2007	2008	2009
001	1	SO_2 allowances to be determined by USEPA	0*	0*	0*	0*	0*
002	2	SO_2 allowances to be determined by USEPA	0*	0*	0*	0*	0*
003	3	SO_2 allowances to be determined by USEPA	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 USEPA.

A.3. Fast-Track Revisions of Acid Rain Parts. Those Acid Rain sources making a change described at Rule 62- 214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, F.A.C., Fast-Track Revisions of Acid Rain Parts.
[Rules 62-213.413 and 62-214.370(4), F.A.C.]

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

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

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, or that meet the criteria specified in Rule 62-210.300(3)(b)1., F.A.C., Generic Emissions Unit Exemption, are exempt from the permitting requirements of Chapters 62-210, 62-212 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.

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

Brief Description of Emissions Units and/or Activities
Natural Gas Fuel Gas Heater.

Appendix H-1, Permit History/ID Number Changes

Permit History (for tracking purposes):

E.U. ID No.	Description	Permit No.	Issue Date	Expiration Date	Extended Date[1, 2]
Unit 1	Simple-Cycle Comb. Turbine, Unit 1	AC49-205703 PSD-FL-182	4/9/93	11/1/96	9/16/94, 5/8/95
	To burn very low sulfur oil up to 800 hrs	0970043-004-AC	5/19/97		
	To allow NOx CEM compliance	970043-003-AC	8/15/97		
	Extension of time to lower NOx limit from 25 to 15 ppmvd	0970043-005-AC	12/17/98		
	Set NOx limit for Unit 1 at 25 ppmvd, reduce Unit 1 to 5000 hr/yr, establish NOx cap for Units 1 and 2	0970043-007-AC	12/21/99		
Unit 2	Combined-Cycle Gas Turbine, Unit 2	AC49-205703 PSD-FL-182	4/9/93	11/1/96	9/16/94, 5/8/95
	To burn very low sulfur oil up to 800 hrs	0970043-004-AC	5/19/97		
	To allow NOx CEM compliance	0970043-003-AC	8/15/97		
	Set NOx limit for Unit 1 at 25 ppmvd, reduce Unit 1 to 5000 hr/yr, establish NOx cap for Units 1 and 2	0970043-007-AC	12/21/99		
	Added inlet air fogging for Unit 2	0970043-008-AC (PSD-FL-182I)	10/13/00		
	Added inlet air fogging for Unit 2 in initial Title V permit	0970043-009-AV	10/13/00	12/31/04	
Unit 3	Combined-Cycle Gas Turbine, Unit 3 To modify excess emission condition	PSD-FL-254 PA 98-38 0970043-011-AC 0970043-012-AV	 11/22/99 11/27/02 Withdrawn	12/31/02	
All Title V	Unit 1, Unit 2 and Unit 3 Initial Title V Revision to add Unit 2 foggers Revision to add Unit 3 Withdrawn request Renewal	 0970043-002-AV 0970043-009-AV 0970043-010-AV 0970043-012-AV 0970043-013-AV	 06/01/99 10/13/00 11/17/03 Withdrawn 01/01/2005	 12/31/04 12/31/04 12/31/04 12/31/09	

ID Number Changes (for tracking purposes):
From: **Facility ID No.:** 30ORL490043
To: **Facility ID No.:** 0970043

Notes:
1 - AO permit(s) automatic extension(s) in Rule 62-210.300(2)(a)3.a., F.A.C., effective 03/21/96.
2 - AC permit(s) automatic extension(s) in Rule 62-213.420(1)(a)4., F.A.C., effective 03/20/96.
{Rule 62-213.420(1)(b)2., F.A.C., effective 03/20/96, allows Title V Sources to operate under existing valid permits}

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 'exempt emissions units'.

E.U. ID No.	Brief Description of Emissions Units and/or Activity
007	Distillate Fuel Oil Tank No. 2 (700,000 gal. capacity)
008	Distillate Fuel Oil Tank No. 1 (300,000 gal. capacity)
006	Cooling Tower

Table 1-1, 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.

E.U. ID	Brief Description
001	Simple-Cycle Gas Turbine, Unit 1, rated at 40 MW.

			Allowable Emissions[a]			Equivalent			
Pollutant	Fuel(s)	Hours	Standard(s)	lb/hr	TPY	lb/hr	TPY	Regulatory	See Permit
VE	No 2 Oil Nat Gas	5000	10 % opacity					AC 49-205703	A.4.
SO_2	No 2 Oil Nat Gas	1000	0.05% S by weight, fuel oil	20			10	AC 49-205703	A.9., A.10., A.13.
NO_x**	No. 2 Fuel Oil	1000	42 ppmvd at 15% oxygen on a dry	63			31.5	AC 49-205703	A.5., C.1
NO_x**	Natural Gas	5000	25 ppmvd at 15% oxygen dry basis	37			74.0	AC 49-205703	A.5., C.1
PM	No. 2 Fuel Oil	1000	0.0323 lb/MMBtu			12.0	6.0	AC 49-205703	A.5., A.7.
PM	Natural Gas	5000	0.0245 lb/MMBtu			9	18.0	AC 49-205703	A.5., A.7.
VOC	No. 2 Fuel Oil	1000	3 lb/hour	3			1.5	AC 49-205703	A.5., A.7.
VOC	Natural Gas	5000	1.4 lb/hour	1.4			2.8	AC 49-205703	A.5., A.7.
CO	No. 2 Fuel Oil	1000	63 ppmvd at 15% oxygen on a dry	76			38.	AC 49-205703	A.5., A.7.
CO	Natural Gas	5000	30 ppmvd at 15% oxygen on a dry	40			80.0	AC 49-205703	A.5., A.7.
Hg	No. 2 Fuel Oil	1000	3.1 E-6 lb/mmBtu			<1	<1	AC 49-205703	A.5.
As	No. 2 Fuel Oil	1000	4.2 E-6 lb/mmBtu			<1	<1	AC 49-205703	A.5.
Be	No. 2 Fuel Oil	1000	2.5 E-6 lb/mmBtu			<1	<1	AC 49-205703	A.5.
Pb	No. 2 Fuel Oil	1000	2.8 E-5 lb/mmBtu			<1	<1	AC 49-205703	A.5.

Notes for EU 001:

a No. 2 fuel oil firing is limited to 1000 hours per year. Total operation is limited to 5000 hours per year.

1 The "Equivalent Emissions" listed are for informational purposes only. They are based upon 4000 hours per year of gas operation and 1000 hours per year of #2 oil operation. [Rule 62-213.205, F.A.C.]

* Firing of number 2 fuel oil is limited to no more than 1000 hours per year to the unit for any reason.

**{Permitting Note: Emissions Units 001 and 002 have a combined NOx emissions cap of 366.1 during any consecutive 12 months. Last revised by Project No. 0970043-009-AV on 10/13/00.}

E.U. ID	Brief Description
002	Combined-Cycle Gas Turbine, Unit 2, rated at 120 MW.

			Allowable Emissions[a]			Equivalent			
Pollutant	Fuel(s)	Hours	Standard(s)	lb/hr	TPY	lb/hr	TPY	Regulatory	See Permit
VE	No 2 Oil Nat Gas	8760	10 % opacity					AC 49-205703	A.4.
SO_2	No 2 Oil Nat Gas	1000	0.05% S by weight, fuel oil	52			26	AC 49-205703	A.9., A.10., A.13.
NO_x	No. 2 Fuel Oil	1000	42 ppmvd at 15% oxygen on a dry	170			85.0	AC 49-205703	A.15.
NO_x	Natural Gas	8760	15 ppmvd at 15% oxygen on a dry	53			205.6	AC 49-205703	A.15.
PM	No. 2 Fuel Oil	1000	0.0162 lb/MMBtu			15.0	7.5	AC 49-205703	A.5., A.7.
PM	Natural Gas	8760	0.0100 lb/MMBtu			8.7	33.7	AC 49-205703	A.5., A.7.
VOC	No. 2 Fuel Oil	1000	5.0 lb/hour	5			2.5	AC 49-205703	A.5., A.7.
VOC	Natural Gas	8760	2.0 lb/hour	2			7.76	AC 49-205703	A.5., A.7.
CO	No. 2 Fuel Oil	1000	20 ppmvd at 15% oxygen on a dry	65			32.5	AC 49-205703	A.5., A.7.
CO	Natural Gas	8760	20 ppmvd at 15% oxygen on a dry	54			209.5	AC 49-205703	A.5., A.7.
Hg	No. 2 Fuel Oil	1000	3.0e-6 lb/mmBtu			<1	<1	AC 49-205703	A.5.
As	No. 2 Fuel Oil	1000	4.2e-6 lb/mmBtu			<1	<1	AC 49-205703	A.5.
Be	No. 2 Fuel Oil	1000	2.5e-6 lb/mmBtu			<1	<1	AC 49-205703	A.5.
Pb	No. 2 Fuel Oil	1000	2.8e-5 lb/mmBtu			<1	<1	AC 49-205703	A.5.

Notes for EU 002:

a lb/hour and TPY values based on using number 2 fuel oil for 1000 hours per year; for natural gas using 7760 hours per year.

1 The "Equivalent Emissions" listed are for informational purposes only. They are based upon 7760 hours per year of gas operation and 1000 hours per year of #2 oil operation. [Rule 62-213.205, F.A.C.]

* Firing of number 2 fuel oil is limited to no more than 1000 hours per year to the unit for any reason.

{Permitting Note: Emissions Units 001 and 002 have a combined NOx emissions cap of 366.1 during any consecutive 12 months. Last revised by Project No. 0970043-009-AV on 10/13/00.}

E.U. ID	Brief Description
003	Combined-Cycle Gas Turbine, Unit 3, with HRSG and duct burner, rated at 250 MW.

			Allowable Emissions			Equivalent			
Pollutant	Fuel(s)	Hours	Standard(s)	lb/hr	TPY	lb/hr	TPY	Regulatory	See Permit
VE	No 2 Oil or Nat Gas		≤ 10 percent opacity					PSD-FL-254	**E.17.**
SO_2	No. 2 Fuel Oil	720	Maximum .0005 sulfur by weight		38.1				**E.16.**
	Natural Gas	8760	20 grains per 100 scf						
NO_x	No. 2 Fuel Oil	720	15 ppmvd	108					**E.13.**
	Natural Gas		3.5 ppmvd	26					
VOC	No. 2 Fuel Oil	720							
	(duct burner off)		10 ppm	21.4					**E.15.**
	(duct burner on)		10 ppm	21.4					**E.15.**
VOC	Natural Gas								
	(duct burner off)		1.4 ppm	3					**E.15.**
	(duct burner on)		4 ppm	8.5					**E.15.**
CO	No. 2 Fuel Oil	720							
	(duct burner off)		20 ppm	71					**E.14.**
	(duct burner on)		30 ppm	108					**E.14.**
CO	Natural Gas								
	(duct burner off)		12 ppm	43					**E.14.**
	(duct burner on)		20 ppm	71					**E.14.**

Table 2-1, 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	Simple-Cycle Combustion Turbine, Unit 1, rated at 40 MW.

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date[1]	Minimum Compliance Test Duration	CMS[2]	See Permit Condition(s)
VE	No 2 Fuel Oil, Nat. Gas	EPA Method 9	Annual	August 1st	1 hour	No	A.6.
SO_2	"	Method 8 for Fuel oil firing only; Fuel Sampling & Analysis	As Fired			Yes*	A.9, A.10.
NO_x	"	EPA Test Method 20	Annual	August 1st	3 hours	Yes	A.6.
PM	"	EPA Test Methods 5 or 17	Only if 10% Opacity is exceeded		3 hours	No	A.7.
VOC	"	EPA Test Method 25A	Initial Compliance			No	A.7.
CO	"	EPA Test Method 10	Annual			No	A.7.
Hg	No.2 oil	EPA Method 101 or fuel sampling	Initial Compliance			No	A.5.
As	No.2 oil	Fuel sampling	Initial Compliance			No	A.5.
Be	No.2 oil	EPA Method 104 or fuel sampling	Initial Compliance			No	A.5.
Pb	No.2 oil	Fuel sampling	Initial Compliance			No	A.5.

Notes for EU 001:

* Continuous monitoring of fuel consumption required.
[1] Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.
[2] CMS = continuous monitoring system
See also Section C for general testing requirements

{Permitting Note: Emissions Units 001 and 002 have a combined NOx emissions cap of 366.1 during any consecutive 12 months. Compliance must be demonstrated monthly by CEMS data. Last revised by Project No. 0970043-009-AV on 10/13/00.}

Emissions Unit	Brief Description
002	Combined-Cycle Combustion Turbine, Unit 2, rated at 120 MW.

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date[1]	Minimum Compliance Test Duration	CMS[2]	See Permit Condition(s)
VE	No 2 Fuel Oil, Nat. Gas	EPA Method 9	Annual	August 1st	1 hour	No	B.6.
SO_2	"	Method 8 for Fuel oil firing only; Fuel Sampling & Analysis	As Fired			Yes*	B.9, B.10.
NO_x	"	EPA Test Method 20	Annual	August 1st	3 hours	Yes	B.6.
PM	"	EPA Test Methods 5 or 17	Only if 10% Opacity is exceeded		3 hours	No	B.7.
VOC	"	EPA Test Method 25A	Initial Compliance			No	B.7.
CO	"	EPA Test Method 10	Annual			No	B.7.
Hg	No.2 oil	EPA Method 101 or fuel sampling	Initial Compliance			No	B.5.
As	No.2 oil	Fuel sampling	Initial Compliance			No	B.5.
Be	No.2 oil	EPA Method 104 or fuel sampling	Initial Compliance			No	B.5.
Pb	No.2 oil	Fuel sampling	Initial Compliance			No	B.5.

Notes for EU 002:

* Continuous monitoring of fuel consumption required.
[1] Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.
[2] CMS = continuous monitoring system
See also Section F for general testing requirements.

{Permitting Note: Emissions Units 001 and 002 have a combined NOx emissions cap of 366.1 during any consecutive 12 months. Compliance must be demonstrated monthly by CEMS data. Last revised by Project No. 0970043-009-AV on 10/13/00.}

Emissions Unit	Brief Description
003	Combined-Cycle Combustion Turbine, Unit 3, rated at 250 MW.

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date[1]	Minimum Compliance Test Duration	CMS	See Permit Condition(s)
VE	No 2 Fuel Oil, Nat. Gas	EPA Method 9	Annual	August 1st	1 hour		**E.23.**
SO_2	"	Fuel Sampling & Analysis	Daily				**E.16., E.25, E.32., E.33.**
NO_x	"	EPA Test Method 20	Annual	August 1st	3 hours	Yes	**E.23.**
CO	"	EPA Test Method 10	Annual				**E.23.**

NESHAP REQUIREMENTS FOR GAS TURBINES

The Kissimmee Utilities Authority Cane Island Facility is an existing major source of hazardous air pollutant emissions. As such, it is an "affected source" with respect to 40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Permits promulgated on March 5, 2004.

According to the applicable rule at 40 CFR 63.6090(b)(4), "Existing combustion turbines in all subcategories do not have to meet the requirements of this subpart and of Subpart A of this part. No initial notification is necessary for any existing stationary combustion turbine, even if a new or reconstructed turbine in the same category would require an initial notification".

Thus Subpart YYYY imposes no additional requirements on this facility unless the units are reconstructed or new units are added.

APPENDIX YYYY

NESHAP REQUIREMENTS FOR GAS TURBINES

The Kissimmee Utilities Authority Cane Island Facility is an existing major source of hazardous air pollutant emissions. As such, it is an "affected source" with respect to 40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Permits promulgated on March 5, 2004.

According to the applicable rule at 40 CFR 63.6090(b)(4), "Existing combustion turbines in all subcategories do not have to meet the requirements of this subpart and of Subpart A of this part. No initial notification is necessary for any existing stationary combustion turbine, even if a new or reconstructed turbine in the same category would require an initial notification".

Thus Subpart YYYY imposes no additional requirements on this facility unless the units are reconstructed or new units are added.

Updated 7/8/04

Source [44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987; 65 FR 61759, Oct. 17, 2000; 69 FR 41346, July 8, 2004]

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.

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(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)
$N \le 0.015$	0
$0.015 < N \le 0.1$	0.04(N)
$0.1 < N \le 0.25$	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 NO_X emissions, the owner or operator may, 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 or local permitting authority approval of a petition for an alternative procedure of continuously monitoring compliance with the applicable NO_X emission limit under Sec. 60.332, that approved procedure may continue to be used, even if it deviates from paragraph (a) of this section.

(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 NO_X emissions may elect to use a NO_X CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. An acceptable alternative to installing a CEMS is described in paragraph (f) of this section.

(f) The owner or operator of a new turbine who elects not to install a CEMS under paragraph (e) of this section, may instead 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 the lean premixed (low-NO_X) combustion 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 required 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 turbines required under paragraph (f) of this section to monitor combustion parameters or parameters that document proper operation of the NO_X 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 calendar quarter.

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 is required under Sec. 60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NO_X 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.

Best Available Control Technology (BACT) Determination
Kissimmee Utility Authority
Osceola County
PSD-FL-182

The applicant proposes to install two combustion turbine generators at their facility near Intercession City, Osceola County. These generator systems will consist of: 1) one nominal 80 megawatt (MW) General Electric PG7111EA combined cycle combustion turbine (CCCT), with exhaust through a heat recovery steam generator (HRSG), which will be used to power a nominal 40 MW steam turbine and 2) a 40 MW General Electric LM6000 simple cycle combustion turbine (SCCT).

The PG7111EA combustion turbine will be capable of operating on a combined and a simple cycle mode. The LM6000 will operate on a simple cycle mode. The applicant has requested to burn natural gas or fuel oil No. 2, with a 0.05 percent sulfur content, on a continuous basis (8,760 hrs/year). The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the facility based on 100 percent capacity factor, ISO conditions, and type of fuel fired to be as follows:

Pollutant	Emissions (TPY) Oil		Gas		PSD Significant Emission Rate (TPY)
	PG7111EA	LM6000	PG7111EA	LM6000	
NO_x	744.6	275.9	429.2	157.7	40
SO_2	227.8	87.6	nil	nil	40
PM/PM_{10}	65.7	52.6	30.7	39.4	25/15
CO	284.7	332.9	236.5	175.2	100
VOC	21.9	13.1	8.8	6.1	40
H_2SO_4	25.1	9.6	nil	nil	7
Be	0.0099	0.0035	---	---	0.0004
Hg	0.012	0.005	---	---	0.1
Pb	0.044	0.141	---	---	0.6

Florida Administrative Code (F.A.C.) Rule 17-2.500(2) (f) (3) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

Date of Receipt of a BACT Application

June 2, 1992

BACT Determination Requested by the Applicant

Pollutant	Proposed Limits
NO_x	25 ppmvd @ 15% O_2 (natural gas burning) 42 ppmvd @ 15% O_2 (for oil firing) PG7111(EA) Control Technology: Low NO_x Burners GE LM6000 Control Technology: Water Injection

- o Combustion Products (e.g., particulates). Controlled generally by good combustion of clean fuels.
- o Products of Incomplete Combustion (e.g., CO). Control is largely achieved by proper combustion techniques.
- o Acid Gases (e.g., NO_x). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulates, sulfur dioxide, fluorides, sulfuric acid mist, etc,), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

BACT POLLUTANT ANALYSIS

COMBUSTION PRODUCTS

Particulate Matter (PM/PM_{10})

The design of this system ensures that particulate emissions will be minimized by combustion control and the use of clean fuels. The particulate emissions from the combustion turbines when burning natural gas and fuel oil will not exceed 15 lbs/hr (oil) and 7 lbs/hr (gas) for the PG7111 and 12 lbs/hr (oil) and 9 lbs/hr (gas) for the LM6000. The Department accepts the applicant's proposed control for particulate matter and heavy metals.

Lead, Mercury, Beryllium (Pb, Hg, Be)

The Department agrees with the applicant's rationale that there are no feasible methods to control lead, mercury, and beryllium; except by limiting the inherent quality of the fuel.

Although the emissions of these toxic pollutants could be controlled by particulate control devices, such as a baghouse or scrubber, the amount of emission reductions would not warrant the added expense. As this is the case, the Department does not believe that the BACT determination would be affected by the emissions of these pollutants.

ACID GASES

Nitrogen Oxides (NO_x)

The emissions of nitrogen oxides represent a significant proportion of the total emissions generated by this project, and need to be controlled if deemed appropriate. As such, the applicant presented an extensive analysis of the different available technologies for NO_x control.

The applicant has stated that BACT for nitrogen oxides will be met by using water injection and advanced combustor design to limit emissions to 25 ppmvd (corrected to 15% O_2) when burning natural gas and 42 ppmvd (corrected to 15% O_2) when burning fuel oil.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NO_x emission limit established to date for a combustion turbine is 4.5 ppmvd at 15% oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system.

Selective catalytic reduction is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NO_x with a new catalyst. As the catalyst ages, the maximum NO_x reduction will decrease to approximately 86 percent.

The effect of exhaust gas temperature on NO_x reduction depends on the specific catalyst formulation and reactor design. Generally, SCR units can be designed to achieve effective NO_x control over a 100-300°F operating window within the bounds of 450-800°F, although recently developed zeolite-based catalysts are claimed to be capable of operating at temperatures as high as 950°.

Most commercial SCR systems operate over a temperature range of about 600-750°F. At levels above and below this window, the specific catalyst formulation will not be effective and NO_x reduction will decrease. Operating at high temperatures can permanently damage the catalyst through sintering of surfaces.

Increased water vapor content in the exhaust gas (as would result from water or steam injection in the gas turbine combustor) can shift the operating temperature window of the SCR reactor to slightly higher levels.

As stated by the applicant, the exhaust temperatures of the proposed simple cycle CTs for this site are between 600°F to 800°F.

SCR has been judged to be technically infeasible for oil firing in some previous BACT determinations.

The latest information available now indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NO_x injection ratio. For natural gas firing operation, NO_x emissions can be controlled with up to a 90 percent efficiency using a 1 to 1 or greater ammonia injection ratio. By lowering the injection ratio for oil firing, testing has indicated that NO_x can be controlled with efficiencies ranging from 60 to 80 percent. When the injection ratio is lowered there is not a problem with ammonium bisulfate formation since essentially all of the ammonia is able to react with the nitrogen oxides present in the combustion gases. Based on this strategy SCR has been both proposed and established as BACT for oil fired combined cycle facilities with NO_x emission limits ranging from 11.7 to 25 ppmvd depending on the efficiency of control established.

The applicant has indicated that the total levelized annual operating cost to install SCR for this project at 100 percent capacity factor and burning natural gas is $2,944,000 for the PG7111EA and $1,589,000 for the LM6000. Taking into consideration the total annual cost, a cost/benefit analysis of using SCR can now be developed.

For the PG7111EA combined cycle combustion turbine, based on the information supplied by the applicant, it is estimated that the maximum annual NO_x emissions using low NO_x burner will be 372 tons/year (natural gas) and 700 tons/year (oil firing). Assuming that SCR would reduce the NO_x emissions by 80%, about 74 tons of NO_x (natural gas) and 140 tons of NO_x (oil) would be emitted annually. When this reduction (298 TPY natural gas and 560 TPY oil) is taken into consideration with the total levelized annual operating cost of $2,944,000 (natural gas) and $3,424,000 (oil firing); the cost per ton of controlling NO_x is $9,879 (natural gas) and $6,114 (oil), respectively. These calculated costs are higher than has previously been approved as BACT.

For the simple cycle combustion turbine, based on the information supplied by the applicant, it is estimated that the maximum annual NO_x emissions using water injection will be 145 tons/year (natural gas) and 250 tons/year (oil firing). Assuming that SCR would reduce the NO_x emissions by 80%, about 29 tons of NO_x (natural gas) and 50 tons of NO_x (oil firing) would be emitted annually. When this reduction (116 TPY natural gas and 200 TPY oil) is taken into consideration with the total levelized annual operating cost of $1,589,000 (natural gas) and $1,840,000 (oil firing); the cost per ton of controlling NO_x is $13,700 (natural gas) and $9,200 (oil), respectively. These calculated costs are higher than has previously been approved as BACT.

proposed the use of No. 2 fuel oil with a 0.05% sulfur by weight as BACT for this project. The Department accepts their proposal as BACT for this project.

BACT Determination by DER

NO_X Control

The information that the applicant presented and Department calculations indicates that the cost per ton of controlling NO_X for these turbines [$9,879 (gas) PG7111EA, $6,114 (oil) PG7111EA, $13,700 (gas) LM6000, and $9,200 (oil) LM6000] is high compared to other BACT determinations which require SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO_X control is not justifiable as BACT at this time.

A review of the permitting activities for combined cycle proposals across the nation indicates that SCR has been required and most recently proposed for installations with a variety of operating conditions (i.e., natural gas, fuel oil, and various capacity factors). Although, the cost and other concerns expressed by the applicant are valid, the Department, in this case, is willing to accept water injection and low NO_X burner design as BACT for this project for a limited time (up to 12/31/97).

It is the Department's understanding that General Electric is developing programs for the PG7111EA and the LM6000, using either steam/water injection or dry low NO_X combustor technology to achieve a NO_X emission control level of 9 ppm when firing natural gas. Therefore, the Department has determined that the following BACT will apply by 1/1/98.

a) For the combined cycle unit (PG7111EA), if the 15 (gas)/42 (oil) ppmv emission rates cannot be met by 1/1/98, SCR will be installed. Hence, the permittee shall install a duct module suitable for future installation of SCR equipment.
b) For the simple cycle unit (LM6000), the manufacturer will attempt to achieve a maximum NO_X emission level of 15 (gas)/42 (oil) ppmv by 1/1/98. Should this level of control not be achieved, the permittee must notify the Department of the expected compliance date by 1/1/97.
c) For both turbines (PG7111EA and LM6000), when the manufacturer achieves an even lower NO_X emission level than 15 (gas)/42 (oil) ppmv, this level may become a condition of this permit.

SO_2 Control

BACT for sulfur dioxide is the burning of fuel oil No. 2 with 0.05% sulfur content by weight.

injection technology or any other technology available, but no later than 1/1/98. Should this level of control not be achieved, the permitte shall install SCR.

40 MW SIMPLE CYCLE COMBUSTION TURBINE

Pollutant	Emission Standards/Limitations Oil[(a)]	Gas[(b)]	Method of Control
NO_x	42 ppmv	25 ppmv[(c)] 15 ppmv	Water Injection Dry Low NO_x Combustor
CO	76 lbs/hr	40 lbs/hr	Combustion
PM & PM10	12 lbs/hr	9 lbs/hr	Combustion
SO_2	20 lbs/hr	nil	No. 2 Fuel Oil (0.05% S)
H_2SO_4	2.2 lbs/hr	nil	No. 2 Fuel Oil (0.05% S)
VOC	3 lbs/hr	1.4 lbs/hr	Combustion
Hg	3.0×10^{-6} lb/MMBtu		Fuel Quality
Pb	2.8×10^{-5} lb/MMBtu		Fuel Quality
Be	2.5×10^{-6} lb/MMBtu		Fuel Quality

(a) No. 2 fuel oil with a maximum of 0.05% sulfur by weight.
(b) Natural gas/fuel oil 8260/500 hours per year. Natural gas/fuel oil 7760/1000 hours per year. Continuous firing of fuel oil (8760 hrs/yr) is not allowed unless natural gas is not available.
(c) Initial NO_x emission rates for natural gas firing shall not exceed 25 ppmvd at 15% oxygen on a dry basis. The permittee shall achieve NO_x emissions of 15 ppmvd at 15% oxygen at the earliest achievable date based on dry low NO_x combustor technology or any other technology available, but no later than 1/1/98. Should this level of control not be achieved when the compliance demonstration stack tests are performed, the permittee must provide the Department with the expected compliance dates which will be updated annually. After 1/1/98, if the compliance schedule has not been met, the Department may require SCR be installed since the exhaust temperature has an acceptable range for SCR installation.

Department of Environmental Protection

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

Jeb Bush
Governor

David B. Struhs
Secretary

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Mr. A.K. Sharma
Director of Power Supply
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741

ORDER EXTENDING PERMIT EXPIRATION DATE
Cane Island Power Park, **Facility ID No.:** 0970043

Section 403.0872(2)(b), Florida Statutes (F.S.), specifies that any facility which submits to the Department of Environmental Protection (Department) a timely and complete application for a Title V permit "is entitled to operate in compliance with its existing air permit pending the conclusion of proceedings associated with its application."

Section 403.0872(6), F.S., provides that a proposed Title V permit which is not objected to by the United States Environmental Protection Agency (EPA) "must become final no later than fifty-five (55) days after the date on which the proposed permit was mailed" to the EPA.

Pursuant to the Federal Acid Rain Program as defined in Rule 62-210.200, Florida Administrative Code (F.A.C.), all Acid Rain permitting must become effective on January 1 of a given year.

This facility, which will be permitted pursuant to Section 403.0872, F.S., (Title V permit) will be required to have a permit effective date subsequent to the final processing date of the facility's Title V permit.

To prevent misunderstanding and to assure that the above identified facility continues to comply with existing permit terms and conditions until its Title V permit becomes effective, it is necessary to extend the expiration date(s) of its existing valid permit(s) until the effective date of its Title V permit. Therefore, under the authority granted to the Department by Section 403.061(8), F.S., **IT IS ORDERED:**

1. The expiration date(s) of the existing valid permit(s) under which the above identified facility is currently operating is (are) hereby extended until the effective date of its permit issued pursuant to Section 403.0872, F.S., (Title V permit);

2. The facility shall comply with all terms and conditions of its existing valid permit(s) until the effective date of its Title V permit;

3. The facility will continue to comply with the requirements of Chapter 62-214, F.A.C., and the Federal Acid Rain Program, as defined in Rule 62-210.200, F.A.C., pending final issuance of its Title V permit.

PETITION FOR ADMINISTRATIVE REVIEW

The Department will take the action described in this Order unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/488-9730; Fax: 850/487-4938). Petitions filed by the permit applicant or any of the parties listed below must be filed within 14 days of receipt of this Order. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of the public notice or within 14 days of receipt of this Order, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the permitting authority for notice of agency action may file a petition within 14 days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the permitting authority's action is based must contain the following information:

(a) The name and address of each agency affected and each agency's file or identification number, if known;

(b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination;

(c) A statement of how and when each petitioner received notice of the agency action or proposed action;

(d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate;

(e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; and,

(f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and,

(g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the permitting authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this Order. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation will not be available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542, F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this Order.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000. The petition must specify the following information:

(a) The name, address, and telephone number of the petitioner;

(b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any;

(c) Each rule or portion of a rule from which a variance or waiver is requested;

(d) The citation to the statute underlying (implemented by) the rule identified in (c) above;

(e) The type of action requested;

(f) The specific facts that would justify a variance or waiver for the petitioner;

(g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and,

(h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2), F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

This Order constitutes final agency action unless a petition is filed in accordance with the above paragraphs.

RIGHT TO APPEAL

Any party to this Order has the right to seek judicial review of the Order 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 Office of General Counsel, 3900 Commonwealth Boulevard, MS35, Tallahassee, Florida 32399-3000; 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 days from the date the Notice of Agency Action is filed with the Clerk of the Department.

DONE AND ORDERED this 18th day of March, 1999, in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Howard L. Rhodes

HOWARD L. RHODES, Director
Division of Air Resources Management
Twin Towers Office Building
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
850/488-0114

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this order and all copies were sent by certified mail before the close of business on 3/18/99 to the person(s) listed:

Mr. D. D. Schultz, P.E., Black & Veatch
Mr. Timothy M. Hillman, Black & Veatch
Mr. Len Kozlov, CD

Clerk Stamp

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

Barbara J. Boutwell 3/18/99
(Clerk) (Date)

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In the matter of:	)	
	)	
Florida Electric Power Coordinating Group, Inc.,	)	ASP No. 97-B-01
	)	
Petitioner.	)	

ORDER ON REQUEST FOR ALTERNATE PROCEDURES AND REQUIREMENTS

Pursuant to Rule 62-297.620, Florida Administrative Code (F.A.C.), the Florida Electric Coordinating Group, Incorporated, (FCG) petitioned for approval to: (1) Exempt fossil fuel steam generators which burn liquid and/or solid fuel for less than 400 hours during the federal fiscal year from the requirement to conduct an annual particulate matter compliance test; and, (2) Exempt fossil fuel steam generators which burn liquid and/or solid fuel for less than 400 hours during the federal fiscal year from the requirement to conduct an annual particulate matter compliance test during the year prior to renewal of an operation permit. This Order is intended to clarify particulate testing requirements for those fossil fuel steam generators which primarily burn gaseous fuels including, but not necessarily limited to natural gas.

Having considered the provisions of Rule 62-296.405(1), F.A.C., Rule 62-297.310(7), F.A.C., and all supporting documentation, the following Findings of Fact, Conclusions of Law, and Order are entered:

FINDINGS OF FACT

1. The Florida Electric Power Coordinating Group, Incorporated, petitioned the Department to exempt those fossil fuel steam generators which have a heat input of more than 250 million Btu per hour and burn solid and/or liquid fuel less than 400 hours during the year from the requirement to conduct an annual particulate matter compliance test. [Exhibit 1]

2. Rule 62-296.405(1)(a), F.A.C., applies to those fossil fuel steam generators that are not subject to the federal standards of performance for new stationary sources (NSPS) in 40 CFR 60 and which have a heat input of more than 250 million Btu per hour.

3. Rule 62-296.405(1)(a), F.A.C., limits visible emissions from affected fossil fuel steam generators to, "20 percent opacity except for either one six-minute period per hour during which

not exceed 40 percent. The option selected shall be specified in the emissions unit's construction and operation permits. Emissions units governed by this visible emission limit shall test for particulate emission compliance annually and as otherwise required by Rule 62-297, F.A.C."

4. Rule 62-296.405(1)(a), F.A.C., further states, "Emissions units electing to test for particulate matter emission compliance quarterly shall be allowed visible emissions of 40 percent opacity. The results of such tests shall be submitted to the Department. Upon demonstration that the particulate standard has been regularly complied with, the Secretary, upon petition by the applicant, shall reduce the frequency of particulate testing to no less than once annually.

5. Rule 297.310(7)(a)1., F.A.C., states, "The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit."

6. Rule 297.310(7)(a)2., F.A.C., states, "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.

7. Rule 297.310(7)(a)3., F.A.C., further states, "In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal: a. Did not operate; or, b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours."

8. Rule 297.310(7)(a)4., F.A.C., states, "During each federal fiscal year (October 1 -- September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for: a. Visible emissions, if there is an applicable standard; b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant..."

9. Rule 297.310(7)(a)5., F.A.C., states. "An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours."

10. Rule 297.310(7)(a)6., F.A.C., states, "For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be

required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup."

11. Rule 297.310(7)(a)7., F.A.C., states, "For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to Rule 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup." [Note: The reference should be to Rule 62-296.405(1)(a), F.A.C., rather than Rule 62-296.405(2)(a), F.A.C.]

12. The fifth edition of the U. S. Environmental Protection Agency's Compilation of Air Pollutant Emission Factors, AP-42, that emissions of filterable particulate from gas-fired fossil fuel steam generators with a heat input of more than about 10 million Btu per hour may be expected to range from 0.001 to 0.006 pound per million Btu. [Exhibit 2]

13. Rule 62-296.405(1)(b), F.A.C. and the federal standards of performance for new stationary sources in 40 CFR 60.42, Subpart D, limit particulate emissions from uncontrolled fossil fuel fired steam generators with a heat input of more than 250 million Btu to 0.1 pound per million Btu.

CONCLUSIONS OF LAW

1. The Department has jurisdiction to consider the matter pursuant to Section 403.061, Florida Statutes (F.S.), and Rule 62-297.620, F.A.C.

2. Pursuant to Rule 62-297.310(7), F.A.C., the Department may require Petitioner to conduct compliance tests that identify the nature and quantity of pollutant emissions, if, after investigation, it is believed that any applicable emission standard or condition of the applicable permits is being violated.

3. There is reason to believe that a fossil fuel steam generator which does not burn liquid and/or solid fuel (other than during startup) for a total of more than 400 hours in a federal fiscal year and complies with all other applicable limits and permit conditions is in compliance with the applicable particulate mass emission limiting standard.

ORDER

Having considered the requirements of Rule 62-296.405, F.A.C., Rule 62-297.310, F.A.C., and supporting documentation, it is hereby ordered that:

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

2. For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup;

3. For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to Rule 62-296.405(1)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup;

4. 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 particulate matter emission compliance test results for any fossil fuel steam generator emissions unit that burned liquid and/or solid fuel for a total of no more than 400 hours during the year prior to renewal.

5. Pursuant to Rule 62-297.310(7), F.A.C., owners of affected fossil fuel steam generators may be required to conduct compliance tests that identify the nature and quantity of pollutant emissions, if, after investigation, it is believed that any applicable emission standard or condition of the applicable permits is being violated.

6. Pursuant to Rule 62-297.310(8), F.A.C., owners of affected fossil fuel steam generators shall submit the compliance test report to the District Director of the Department district office having jurisdiction over the emissions unit and, where applicable, the Air Program Administrator of the appropriate Department-approved local air program within 45 days of completion of the test.

PETITION FOR ADMINISTRATIVE REVIEW

The Department will take the action described in this Order unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 of the Florida Statutes, or a party requests mediation as an alternative remedy under section 120.573 before the deadline for filing a petition. Choosing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement. The procedures for petitioning for a hearing are set forth below, followed by the procedures for requesting mediation.

A person whose substantial interests are affected by the Department's proposed decision may petition for an administrative hearing in accordance with sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000. Petitions must be filed within 21 days of receipt of this Order. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition (or a request for mediation, as discussed below) within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 of the Florida Statutes, or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-5.207 of the Florida Administrative Code.

A petition must contain the following information:

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department File Number, and the county in which the project is proposed;

(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;

(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;

(d) A statement of the material facts disputed by each petitioner, if any;

(e) A statement of facts that the petitioner contends warrant reversal or modification of the Department's action or proposed action;

(f) A statement identifying the rules or statutes each petitioner contends require reversal or modification of the Department's action or proposed action; and,

(g) A statement of the relief sought by each petitioner, stating precisely the action each petitioner wants the Department to take with respect to the Department's action or proposed action in the notice of intent.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this Order. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A person whose substantial interests are affected by the Department's proposed decision, may elect to pursue mediation by asking all parties to the proceeding to agree to such mediation and by filing with the Department a request for mediation and the written agreement of all such parties to mediate the dispute. The request and agreement must be filed in (received by) the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, by the same deadline as set forth above for the filing of a petition.

A request for mediation must contain the following information:

(a) The name, address, and telephone number of the person requesting mediation and that person's representative, if any;

(b) A statement of the preliminary agency action;

(c) A statement of the relief sought; and

(d) Either an explanation of how the requester's substantial interests will be affected by the action or proposed action addressed in this notice of intent or a statement clearly identifying the petition for hearing that the requester has already filed, and incorporating it by reference.

The agreement to mediate must include the following:

(a) The names, addresses, and telephone numbers of any persons who may attend the mediation;

(b) The name, address, and telephone number of the mediator selected by the parties, or a provision for selecting a mediator within a specified time;

(c) The agreed allocation of the costs and fees associated with the mediation;

(d) The agreement of the parties on the confidentiality of discussions and documents introduced during mediation;

(e) The date, time, and place of the first mediation session, or a deadline for holding the first session, if no mediator has yet been chosen;

(f) The name of each party's representative who shall have authority to settle or recommend settlement; and

(g) The signatures of all parties or their authorized representatives.

As provided in section 120.573 of the Florida Statutes, the timely agreement of all parties to mediate will toll the time limitations imposed by sections 120.569 and 120.57 for requesting and holding an administrative hearing. Unless otherwise agreed by the parties, the mediation must be concluded within sixty days of the execution of the agreement. If mediation results in settlement of the administrative dispute, the Department must enter a final order incorporating the agreement of the parties. Persons whose substantial interests will be affected by such a modified final decision of the Department have a right to petition for a hearing only in accordance with the requirements for such petitions set forth above. If mediation terminates without settlement of the dispute, the Department shall notify all parties in writing that the administrative hearing processes under sections 120.569 and 120.57 remain available for disposition of the dispute, and the notice will specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under section 120.542 of the Florida Statutes. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000.

The petition must specify the following information:

(a) The name, address, and telephone number of the petitioner;

(b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any;

(c) Each rule or portion of a rule from which a variance or waiver is requested;

(d) The citation to the statute underlying (implemented by) the rule identified in (c) above;

(e) The type of action requested;

(f) The specific facts that would justify a variance or waiver for the petitioner;

(g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and

(h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver, when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in section 120.542(2) of the Florida Statutes, and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner. Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully each of those terms is defined in section 120.542(2) of the Florida Statutes, and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner. Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

This Order constitutes final agency action unless a petition is filed in accordance with the above paragraphs. Upon timely filing of a petition, this Order will not be effective until further Order of the Department.

RIGHT TO APPEAL

Any party to this Order has the right to seek judicial review of the Order 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 Office of General Counsel, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000; 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 days from the date the Notice of Agency Action is filed with the Clerk of the Department.

DONE AND ORDERED this 17 day of March, 1997 in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Howard L. Rhodes

HOWARD L. RHODES, Director
Division of Air Resources Management
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2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(904) 488-0114

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that a copy of the foregoing was mailed to Rich Piper, Chair, Florida Power Coordinating Group, Inc., 405 Reo Street, Suite 100, Tampa, Florida 33609-1004, on this 18th day of March 1997.

Clerk Stamp

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

[signature] 3-18-97
Clerk Date

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LORIDA ELECTRIC POWER COORDINATING GROUP, INC. (FCG)
05 REO STREET, SUITE 100 • (813) 289-5644 • FAX (813) 289-5646
AMPA, FLORIDA 33609-1004

January 28, 1997

Clair H. Fancy, P.E.
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32301

RECEIVED
JAN 28 1997
BUREAU OF
AIR REGULATION

RE: Comments Regarding Draft Title V Permits

Dear Mr. Fancy:

The Florida Electric Power Coordinating Group, Inc. (FCG), which is made up of 36 utilities owned by investors, municipalities, and cooperatives, has been following the implementation of Title V in Florida and recently submitted comments to you on draft Title V permit conditions by letter dated December 4, 1996. As indicated in that letter, representatives from the FCG would like to meet with you and other members of your air permitting staff to discuss some significant concerns that FCG member companies have regarding conditions that may be included in Title V permits issued by your office. While we will be discussing these issues with you and your staff in greater detail at that meeting, we would like to explain some of our concerns in this letter.

Primarily, the FCG members are concerned that the Title V permits may contain conditions that are much different in important respects than those conditions currently included in existing air permits. During the rulemaking workshops and seminars conducted by the Department to discuss the rules implementing the Title V permitting program, representations were made on several occasions that industry could expect to see permit conditions that were substantively similar to existing permit conditions and that primarily the format was changing. Representations were also made to industry that Title V did not impose additional substantive requirements beyond what was already required under the Department's rules. Based on the first draft Title V permit that we have reviewed, we are concerned that there may be some attempt to change the substantive requirements on existing facilities through the Title V permitting process, and we would like to discuss this with you at the meeting we have scheduled for January 30, 1997.

1. Federal Enforceability--The FCG has long been concerned about the designation of non-federally enforceable permit terms and conditions. We are concerned about this issue because the Department's first draft Title V permits have included language stating that *all* terms and conditions would become federally enforceable once the permit is issued. This approach is consistent with the Department's guidance memorandum dated September 13, 1996 (DARM-PER/V-18), but we understand that the Department may now intend to remove all references to

the federal enforceability of permit terms and conditions. We are also concerned about this approach because a Title V permit is generally federally enforceable and, without any designation of non-federally enforceable terms and conditions, the entire permit could be interpreted to be federally enforceable. As we stated in the December 4 letter as well as our letter dated October 11, 1996, all terms and conditions in a Title V permit do *not* become enforceable by the U.S. Environmental Protection Agency and citizens under the Clean Air Act simply by inclusion in a Title V permit. To make it clear which provisions in a Title V permit are not federally enforceable (which are being included because of state or local requirements only), it is very important to specifically designate those conditions as having no federally enforceable basis. Such a designation is actually required under the federal Title V rules, which provide that permitting agencies are to "specifically designate as not being federally enforceable under the Act any terms and conditions included in the permit that are not required under the Act or under any of its applicable requirements." 40 CFR § 70.6(b). We would like to discuss with you our concerns about this issue and to again specifically request that when Title V permits are issued by the Department, conditions having no federally enforceable basis clearly be identified as such.

2. PM Testing on Gas--The FCG understands that the Department may attempt to require annual particulate matter compliance testing while firing natural gas to determine compliance with the 0.1 lb/mmBtu emission limit established under Rule 62-296.405(1)(b), F.A.C. The FCG member companies feel strongly that compliance testing for particulate matter should not be required while firing natural gas. The Department has not historically required particulate matter compliance testing while firing natural gas, it is not required under the current permits for these units, and it should not be necessary since natural gas is such a clean fuel. Typically only *de minimis* amounts of particulate matter would be expected from the firing of natural gas, so compliance testing would not provide meaningful information to the Department, and the expense to conduct such tests is not justified. We understand that Department representatives suggested that industry could pursue an alternative test procedure under Rule 62-297.620, F.A.C., to allow a visible emissions test to be used in lieu of a stack test for determining compliance with the particulate matter limit. While certainly a visible emissions test would be preferable over a stack test, neither of these tests should be needed to demonstrate compliance with the particulate matter limit of 0.1 lb/mmBtu while burning natural gas. The FCG strongly urges that the Department reconsider its position on this issue and clarify that compliance testing for particulate matter while firing natural gas is not required.

3. Excess Emissions--By letter dated December 5, 1996, the U.S. Environmental Protection Agency (EPA) submitted a letter commenting on a draft Title V permit that had been issued by the Department and indicated some concern regarding excess emission provisions included in conditions that were quoted from Rule 62-210.700, F.A.C. Because the permit conditions cited simply quote the applicable provisions of the Department's rules regarding

excess emissions and because these rules have been approved as part of Florida's State Implementation Plan, the permit conditions are appropriate to be included in the permit. We understand that the Department intends to include as applicable requirements in Title V permit conditions the provisions of Rule 62-210.700, F.A.C. If the Department receives any further adverse comments regarding the excess emissions rule under 62-210.700, F.A.C., we would appreciate your contacting us. Because this issue is so important to us, we would like to discuss it with you in greater detail at our meeting on January 30.

4. Compliance Testing for Combustion Turbines--While the Department's November 22, 1995, guidance regarding the compliance testing requirements for combustion turbines clearly states that the use of heat input curves based on ambient temperatures and humidities is to be included as a permit condition *only* if requested by a permittee, we understand that the Department may intend to include this requirement in Title V permits for all combustion turbines. As we are sure you recall, the FCG worked over a period of several months with the Department on the development of the guidance memorandum and it was clearly understood by FCG members that the heat input curves would not be mandated but would remain voluntary for any existing combustion turbine. It was also understood by FCG members that the requirement to conduct testing at 95 to 100 percent of capacity would be required only if the permit applicant requested the use of heat input curves. We understand that the Department may be interpreting the requirement to use heat input curves and to test at 95 to 100 percent of permitted capacity to be mandatory for all combustion turbines. We would like to clarify this with you during our meeting. Also, we would like to confirm that, regardless of whether a combustion turbine uses heat input curves or tests at 95 to 100 percent of permitted capacity, it is necessary to test at four load points and correct to ISO only to determine compliance with the nitrogen oxides (NOx) standard under New Source Performance Standard Subpart GG under 40 CFR § 60.332 and not annually thereafter.

5. Test Methods--The FCG is concerned about the possibility of the Department requiring a full permit revision to authorize the use of an approved test method not specifically identified in a Title V permit, even though the Department may have separately approved the use of the particular test method for a unit (i.e., through a compliance test protocol). It is the FCG's position that language should be included in all Title V permits indicating that other test methods approved by the Department may be used. Further, a full permit revision (including public notice) should *not* be necessary when a test method not previously identified in the permit is approved for use by a unit. The Department's subsequent approval of test methods should simply be included in the next permit renewal cycle. The FCG understands that the Department planned to confirm this approach with the U.S. Environmental Protection Agency Region IV, and we would like to discuss this issue with you at the January 30 meeting to learn of the agency's response.

6. Quarterly Reports--The FCG understands that the Department may be interpreting the quarterly reporting requirements under Rule 62-296.405(1)(g), F.A.C., to apply regardless of whether continuous emissions monitors were required under the preceding Rule 62-296.405(1)(f), F.A.C. It is the FCG's position that quarterly reports are required under Rule 62-296.405(1)(g) only when continuous emissions monitors are required under the preceding paragraph (f). While this may not be entirely clear from the language of the rules, paragraphs (f) and (g) were originally included in a separate rule on "continuous emission monitoring requirements" where it was very clear that the requirements of paragraph (g) applied *only* if continuous emission monitoring was required under paragraph (f). Research indicates that Rule 17-2.710, F.A.C. (copy attached), where these provisions were originally located, was first transferred to Rule 17-297.500, F.A.C. (which later became Rule 62-297.500), later repealed in November of 1994, and ultimately replaced with what is now Rule 62-296.405(1)(f) and (g), F.A.C. To the extent that an emissions unit is not subject to Rule 62-296.405(1)(f) and is not required to install and operate continuous emissions monitors (e.g., oil- and gas-fired units), the quarterly reporting requirements of paragraph (g) should not apply.

7. Trivial Activities--As you may recall, in May of 1996, the FCG submitted to the Department a list of small, *de minimis* emissions units and activities that it considered to be "trivial," consistent with the list developed by EPA as part of the Title V "White Paper" and incorporated by reference by the Department in its March 15, 1996, guidance memorandum (DARM-PER/V-15-Revised). We never received a response from the Department and now understand that the Department may not have made a determination as to whether any of the emission units or activities on the list should qualify as "trivial." This is an important issue to the FCG because only "trivial" activities can be omitted from the Title V permit application and permit, and ultimately omitted from emission estimates in the annual air operation reports under Rule 62-210.370(3), F.A.C. The FCG remains hopeful that the Department will consider its request to determine that most, if not all, of the emission units and activities on the May, 1996, list to be "trivial." We would like to discuss a possible resolution of this issue with you and your staff at the January 30 meeting.

8. Permit Shield--The FCG continues to be concerned about the language in Conditions 5 and 20 of Appendix TV-1, Title V Conditions, which circumvents the permit shield provisions under Section 403.0872(15), Florida Statutes, and Rule 62-213.460, F.A.C. The FCG believes that these conditions should be deleted in their entirety. To the extent that the Department attempt to caveat the applicability of those conditions, the FCG believes that it is important to cite to not only the regulatory citation for the permit shield but the statutory citation as well.

Thank you again for considering the FCG's comments on the draft Title V permits. We very much appreciate the cooperation we have received from the Department throughout the

Title V implementation process, and we look forward to our meeting later this week. If you have any questions in the meantime, please call me at 561-625-7661.

Sincerely,

Rich Piper

Rich Piper, Chair
FCG Air Subcommittee

Enclosures

cc: Howard L. Rhodes, DEP
John Brown, DEP
Pat Comer, DEP OGC
Scott M. Sheplak, DEP
Edward Svec, DEP
FCG Air Subcommittee
Angela Morrison, HGSS

32601

AP-42
FIFTH EDITION
JANUARY 1995

COMPILATION OF AIR POLLUTANT EMISSION FACTORS

VOLUME I: STATIONARY POINT AND AREA SOURCES

Office Of Air Quality Planning And Standards
Office Of Air And Radiation
U. S. Environmental Protection Agency
Research Triangle Park, NC 27711

January 1995

Exhibit 2

1.4 Natural Gas Combustion

1.4.1 General[1-2]

Natural gas is one of the major fuels used throughout the country. It is used mainly for industrial process steam and heat production; for residential and commercial space heating; and for electric power generation. Natural gas consists of a high percentage of methane (generally above 80 percent) and varying amounts of ethane, propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium). Gas processing plants are required for the recovery of liquefiable constituents and removal of hydrogen sulfide before the gas is used (see Section 5.3, Natural Gas Processing). The average gross heating value of natural gas is approximately 8900 kilocalories per standard cubic meter (1000 British thermal units per standard cubic foot), usually varying from 8000 to 9800 kcal/scm (900 to 1100 Btu/scf).

1.4.2 Emissions And Controls[3-5]

Even though natural gas is considered to be a relatively clean-burning fuel, some emissions can result from combustion. For example, improper operating conditions, including poor air/fuel mixing, insufficient air, etc., may cause large amounts of smoke, carbon monoxide (CO), and organic compound emissions. Moreover, because a sulfur-containing mercaptan is added to natural gas to permit leak detection, small amounts of sulfur oxides will be produced in the combustion process.

Nitrogen oxides (NO_x) are the major pollutants of concern when burning natural gas. Nitrogen oxide emissions depend primarily on the peak temperature within the combustion chamber as well as the furnace-zone oxygen concentration, nitrogen concentration, and time of exposure at peak temperatures. Emission levels vary considerably with the type and size of combustor and with operating conditions (particularly combustion air temperature, load, and excess air level in boilers).

Currently, the two most prevalent NO_x control techniques being applied to natural gas-fired boilers (which result in characteristic changes in emission rates) are low NO_x burners and flue gas recirculation. Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses NO_x formation. The three most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners, staged fuel burners, and radiant fiber burners. Nitrogen oxide emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NO_x burners. Other combustion staging techniques which have been applied to natural gas-fired boilers include low excess air, reduced air preheat, and staged combustion (e. g., burners-out-of-service and overfire air). The degree of staging is a key operating parameter influencing NO_x emission rates for these systems.

In a flue gas recirculation (FGR) system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the gas is mixed with combustion air prior to being fed to the burner. The FGR system reduces NO_x emissions by two mechanisms. The recycled flue gas is made up of combustion products which act as inerts during combustion of the fuel/air mixture. This additional mass is heated in the combustion zone, thereby lowering the peak flame temperature and reducing the amount of NO_x formed. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. The amount of flue gas recirculated is a key operating parameter influencing NO_x emission rates for these systems. Flue gas recirculation is normally used in combination with low NO_x burners. When used in combination, these techniques are capable of reducing uncontrolled NO_x emissions by 60 to 90 percent.

Two post-combustion technologies that may be applied to natural gas-fired boilers to reduce NO_x emissions by further amounts are selective noncatalytic reduction and selective catalytic reduction. These systems inject ammonia (or urea) into combustion flue gases to reduce inlet NO_x emission rates by 40 to 70 percent.

Although not measured, all particulate matter (PM) from natural gas combustion has been estimated to be less than 1 micrometer in size. Particulate matter is composed of filterable and condensable fractions, based on the EPA sampling method. Filterable and condensable emission rates are of the same order of magnitude for boilers; for residential furnaces, most of the PM is in the form of condensable material.

The rates of CO and trace organic emissions from boilers and furnaces depend on the efficiency of natural gas combustion. These emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. In some cases, the addition of NO_x control systems such as FGR and low NO_x burners reduces combustion efficiency (due to lower combustion temperatures), resulting in higher CO and organic emissions relative to uncontrolled boilers.

Emission factors for natural gas combustion in boilers and furnaces are presented in Tables 1.4-1, 1.4-2, and 1.4-3.[6] For the purposes of developing emission factors, natural gas combustors have been organized into four general categories: utility/large industrial boilers, small industrial boilers, commercial boilers, and residential furnaces. Boilers and furnaces within these categories share the same general design and operating characteristics and hence have similar emission characteristics when combusting natural gas. The primary factor used to demarcate the individual combustor categories is heat input.

Table 1.4-1 (Metric And English Units). EMISSION FACTORS FOR PARTICULATE MATTER (PM) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (Size, 10^6 Btu/hr Heat Input) (SCC)[b]	Filterable PM[c]			Condensable PM[d]		
	kg/10^6 m^3	lb/10^6 ft^3	RATING	kg/10^6 m^3	lb/10^6 ft^3	RATING
Utility/large industrial boilers (> 100) (1-01-006-01, 1-01-006-04)	16 - 80	1 - 5	B	ND	ND	NA
Small industrial boilers (10 - 100) (1-02-006-02)	99	6.2	B	120	7.5	D
Commercial boilers (0.3 - < 10) (1-03-006-03)	72	4.5	C	120	7.5	C
Residential furnaces (<0.3) (No SCC)	2.8	0.18	C	180	11	D

[a] References 9-14. All factors represent uncontrolled emissions. Units are kg of pollutant/10^6 cubic meters natural gas fired and lb of pollutant/10^6 cubic feet natural gas fired. Based on an average natural gas higher heating value of 8270 kcal/m^3 (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. ND = no data. NA = not applicable.

[b] SCC = Source Classification Code.

[c] Filterable PM is that particulate matter collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Condensable PM is that particulate matter collected using EPA Method 202, (or equivalent). Total PM is the sum of the filterable PM and condensable PM. All PM emissions can be assumed to be less than 10 micrometers in aerodynamic equivalent diameter (PM-10).

Table 1.4-2 (Metric And English Units). EMISSION FACTORS FOR SULFUR DIOXIDE (SO_2), NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (Size, 10^6 Btu/hr Heat Input) (SCC)[b]	SO_2[c]			NO_x[d]			CO[e]		
	kg/10^6 m^3	lb/10^6 ft^3	RATING	kg/10^6 m^3	lb/10^6 ft^3	RATING	kg/10^6 m^3	lb/10^6 ft^3	RATING
Utility/large Industrial Boilers (> 100) (1-01-006-01, 1-01-006-04)									
Uncontrolled	9.6	0.6	A	8800	550[f]	A	640	40	A
Controlled - Low NO_x burners	9.6	0.6	A	1300	81[f]	D	ND	ND	NA
Controlled - Flue gas recirculation	9.6	0.6	A	850	53[f]	D	ND	ND	NA
Small Industrial Boilers (10 - 100) (1-02-006-02)									
Uncontrolled	9.6	0.6	A	2240	140	A	560	35	A
Controlled - Low NO_x burners	9.6	0.6	A	1300	81[f]	D	980	61	D
Controlled - Flue gas recirculation	9.6	0.6	A	480	30	C	590	37	C
Commercial Boilers (0.3 - < 10) (1-03-006-03)									
Uncontrolled	9.6	0.6	A	1600	100	B	330	21	C
Controlled - Low NO_x burners	9.6	0.6	A	270	17	C	425	27	C
Controlled - Flue gas recirculation	9.6	0.6	A	580	36	D	ND	ND	NA
Residential Furnaces (<0.3) (No SCC)									
Uncontrolled	9.6	0.6	A	1500	94	B	640	40	B

[a] Units are kg of pollutant/10^6 cubic meters natural gas fired and lb of pollutant/10^6 cubic feet natural gas fired. Based on an average natural gas fired higher heating value of 8270 kcal/m^3 (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. ND = no data. NA = not applicable.

[b] SCC = Source Classification Code.

[c] Reference 7. Based on average sulfur content of natural gas, 4600 g/10^6 Nm^3 (2000 gr/10^6 scf).

Table 1.4-2 (cont.).

[d] References 10,15-19. Expressed as NO_2. For tangentially fired units, use 4400 kg/10^6 m^3 (275 lb/10^6 ft^3). At reduced loads, multiply factor by load reduction coefficient in Figure 1.4-1. Note that NO_x emissions from controlled boilers will be reduced at low load conditions.

[e] References 9-10,16-18,20-21.

[f] Emission factors apply to packaged boilers only.

Table 1.4-3 (Metric And English Units). EMISSION FACTORS FOR CARBON DIOXIDE (CO_2) AND TOTAL ORGANIC COMPOUNDS (TOC) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (Size, 10^6 Btu/hr Heat Input) (SCC)[b]	CO_2[c]			TOC[d]		
	$kg/10^6\ m^3$	$lb/10^6\ ft^3$	RATING	$kg/10^6\ m^3$	$lb/10^6\ ft^3$	RATING
Utility/large industrial boilers (> 100) (1-01-006-01, 1-01-006-04)	ND[e]	ND	NA	28[f]	1.7[f]	C
Small industrial boilers (10 - 100) (1-02-006-02)	1.9 E+06	1.2 E+05	D	92[g]	5.8[g]	C
Commercial boilers (0.3 - < 10) (1-03-006-03)	1.9 E+06	1.2 E+05	C	128[h]	8.0[h]	C
Residential furnaces (No SCC)	2.0 E+06	1.3 E+05	D	180[h]	11[h]	D

[a] All factors represent uncontrolled emissions. Units are kg of pollutant/10^6 cubic meters and lb of pollutant/10^6 cubic feet. Based on an average natural gas higher heating value of 8270 kcal/m^3 (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values by multiplying the given factor by the ratio of the specified heating value to this average heating value. NA = not applicable.

[b] SCC = Source Classification Code.

[c] References 10,22-23.

[d] References 9-10,18.

[e] ND = no data.

[f] Reference 8: methane comprises 17% of organic compounds.

[g] Reference 8: methane comprises 52% of organic compounds.

[h] Reference 8: methane comprises 34% of organic compounds.

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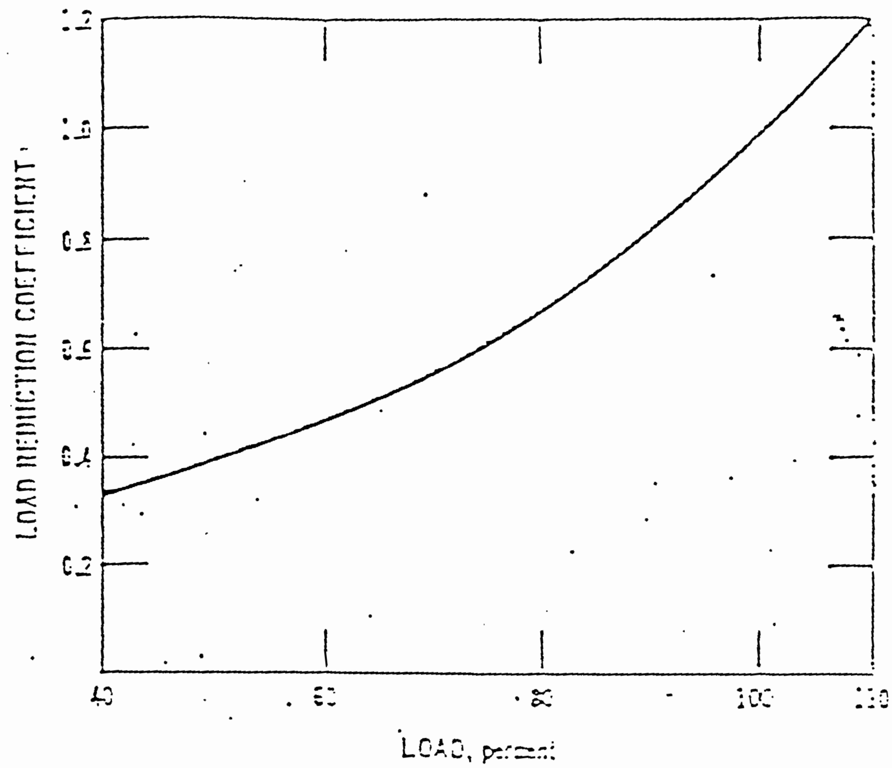

Figure 1.4-1. Load reduction coefficient as a function of boiler load. (Used to determine NO_x reductions at reduced loads in large boilers.)

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