Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

P.E. Certification Statement

Permittee:
FP&L-Manatee Power Plant

DRAFT Permit No.: 0810010-011-AV

Project Type: Title V Air Operation Permit Revision
Inclusion of Unit #3 Combined Cycle Unit

I HEREBY CERTIFY *that the engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).*

Scott M. Sheplak, P.E. Date: 02/01/06
Registration Number: 48866

Permitting Authority:
Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: 850/921-9532
Fax: 850/921-9533

SMS/TH

Department of Environmental Protection

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Governor

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

Colleen M. Castille
Secretary

February 1, 2006

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

Re: Title V Air Operation Permit Revision
DRAFT Permit Project No.: 0810010-011-AV
Manatee Plant

Dear Mr. Plotkin:

One copy of the DRAFT Permit for the revision of a Title V Air Operation Permit for the Manatee Plant located at 19050 State Road 62, Parrish, Manatte County, is enclosed. The permitting authority's "INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION" and the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION" are also included.

An electronic version of the DRAFT Permit will be posted on the Division of Air Resource Management's world wide web site for the United States Environmental Protection Agency (USEPA) Region 4 office's review. The web site address is:

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

The "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION" must be published as soon as possible. Proof of publication, i.e., newspaper affidavit, must be provided to the permitting authority's office within 7 (seven) days of publication pursuant to Rule 62-110.106(5), F.A.C. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Please submit any written comments you wish to have considered concerning the permitting authority's proposed action to the Program Administratror, Permitting South Section, at the above letterhead address. If you have any questions, please contact Ms. Teresa Heron, Review Engineer at 850-921-9529.

Sincerely,

Trina L. Vielhauer, Chief
Bureau of Air Regulation

TLV/AAL/SMS/TH

Enclosures

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

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature] ☐ Agent ☐ Addressee

B. Received by (Printed Name) SHARI E. DRIDGE C. Date of Delivery 2-4-06

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

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

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7005 1160 0004 3034 3175

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

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Mr. Paul Plotkin, Manatee Plant General Managr.

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Total Postage & Fees	$

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Sent To
Mr. Paul Plotkin, Plant General Manager
Street, Apt. No.; or PO Box No. 19050 State Road 62
City, State, ZIP+4 Parrish, Florida 34219-9220

PS Form 3800, June 2002 See Reverse for Instructions

In the Matter of an
Application for Permit Revision by:

Florida Power & Light Corporation
19050 State Road 62
Parrish, FL 34291-9220
_____/

DRAFT Permit Project No.: 0810010-011-AV
Revision to Title V Air Operation Permit No.: 0810010-009-AV
Manateee Plant
Manatee County

INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION

The Department gives notice of its intent to issue a Title V Air Operation Permit Revision (copy of DRAFT Permit attached) for the Title V source detailed in the application specified above, for the reasons stated below. This is a revision to Title V Air Operation Permit No. 0810010-009-AV.

The applicant, Florida Power & Light Company, applied on October 31, 2005 to the permitting authority for a Title V Air Operation Permit Revision for their Manatee Power Plant located at 19050 State Road 62, Parrish, Manatee County, Florida, 34319-9220.

This permit revision is to to incorporate the construction permit of the new combined cycle gas-fired combustion turbine, identified as Unit 3, that was issued on April 11, 2003. Unit 3 adds 1,150 MW to the existing facility 1,600 MW for a total of 2,750 MW power output for the entire facility.

The permitting authority has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210 and 62-213. This source is not exempt from Title V permitting procedures. The permitting authority has determined that a Title V Air Operation Permit Revision is required to commence or continue operations at the described facility.

The permitting authority intends to issue this Title V Air Operation Permit Revision based on the belief that reasonable assurances have been provided to indicate that operation of the source will not adversely impact air quality, and the source will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-256, 62-257, 62-281, 62-296, and 62-297, F.A.C.

Pursuant to Sections 403.815 and 403.087, F.S., and Rules 62-110.106 and 62-210.350(3), F.A.C., you (the applicant) are required to publish at your own expense the enclosed "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION." The notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the permitting authority at the address or telephone number listed below. The applicant shall provide proof of publication to the Florida Department of Environmental Protection, Bureau of Air Regulation (FDEP)within 7 (seven) days of publication pursuant to Rule 62-110.106(5), F.A.C. The Permitting Authority's mailing address is: Florida Department of Environmental Protection, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, Mail Station #5505. Telephone (850) 488-0114; Fax (850) 921-9533. Failure to publish the notice and provide proof of publication may result in the denial of the permit revision pursuant to Rule 62-110.106(11), F.A.C.

The permitting authority will issue the PROPOSED Permit, and subsequent FINAL Permit, in accordance with the conditions of the attached DRAFT Permit unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The permitting authority will accept written comments concerning the proposed permit revision issuance action for a period of 30 (thirty) days from the date of publication of the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION." Written comments should be provided to the permitting authority office. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Permit, the permitting authority shall issue a Revised DRAFT Permit and require, if applicable, another Public Notice.

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 at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Telephone: (850) 245-2242, Fax: 850) 245-2303. Petitions filed by the permit revision applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, 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 fourteen 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;

(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 permitting authority's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the permitting authority 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.

Finally, pursuant to 42 United States Code (U.S.C.) Section 7661d(b)(2), any person may petition the Administrator of the EPA within 60 (sixty) days of the expiration of the Administrator's 45 (forty-five) day review period as established at 42 U.S.C. Section 7661d(b)(1), to object to issuance of any Title V permit. Any petition shall be based only on objections to the Title V permit that were raised with reasonable specificity during the 30 (thirty) day public comment period provided in this notice, unless the petitioner demonstrates to the Administrator of the EPA that it was impracticable to raise such objections within the comment period or unless the grounds for such objection arose after the comment period. Filing of a petition with the Administrator of the EPA does not stay the effective date of any Title V permit properly issued pursuant to the provisions of Chapter 62-213, F.A.C. Petitions filed with the Administrator of EPA must meet the requirements of 42 U.S.C. Section 7661d(b)(2) and must be filed with the Administrator of the EPA at: U.S. EPA, 401 M Street, S.W., Washington, D.C. 20460.

Executed in Tallahassee, Florida.

Florida Department of Environmental Protection

Trina L. Vielhauer, Chief

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION (including the PUBLIC NOTICE and the DRAFT Permit package) and all copies were sent by certified mail or electronically (with Received Receipt) before the close of business on 2/2/06 to the person(s) listed:

Mr. Paul Plotkin, R.O

In addition, the undersigned duly designated deputy agency clerk hereby certifies that copies of this INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION (including the PUBLIC NOTICE and the DRAFT Permit) were sent by U.S. mail or electronically (with Received Receipt) on the same date to the person(s) listed or as otherwise noted:

Mr. Kennard F. Kosky, P.E.

In addition, the undersigned duly designated deputy agency clerk hereby certifies that copies of this INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION (including the DRAFT Permit package) were sent by U.S. mail or electronically (with Received Receipt) on the same date to the person(s) listed:

Ms. Mara Nasca, FDEP-SWD Office
Barbara Friday, BAR [barbara.friday@dep.state.fl.us] (for posting with Region 4 , U.S. EPA

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 Friday 2/6/06

(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
DRAFT Permit Project No.: 0810010-011-AV
Revision to Title V Air Operation Permit No.: 0810010-009-AV
Manatee Power Plant
Manatee County

The Department gives notice of its intent to issue a Title V Air Operation Permit Revision to Florida Power & Light Company for their Manatee Power Plant located at Parrish, Manatee County, Florida, This is a revision to Title V Air Operation Permit No. 0810010-009-AV. The applicant for this project is Florida Power & Light Company; 700 Universe Blvd, Juno Beach, Florida, 33408. The applicant's responsible official is Mr. Paul Plotkin, Plant Manager.

This permit revision is to to incorporate the construction permit of the new combined cycle gas-fired combustion turbine, identified as Unit 3, that was issued on April 11, 2003. Unit 3 adds 1,150 MW to the existing facility 1,600 MW for a total of 2,750 MW power output for the entire facility.

The permitting authority will issue the PROPOSED Permit, and subsequent FINAL Permit, in accordance with the conditions of the DRAFT Permit unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Permitting Authority will accept written comments concerning the DRAFT Permit for a period of thirty (30) days from the date of publication of the "PUBLIC NOTICE OF INTENT TO ISSUE TITLE V AIR OPERATION PERMIT REVISION." Written comments must be post-marked and all facsimile comments must be received by the close of business (5:00 pm), on or before the end of this 30-day period, by the Permitting Authority at, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, Mail Station #5505 or fascimile (850) 921-9533. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location on the Department's official web site for notices at http://tlhora6.dep.state.fl.us/onw and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the DRAFT Permit, the Permitting Authority shall issue a Revised DRAFT Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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 of the Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department of Environmental Protection at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Telephone: (850) 245-2242, Fax: 850) 245-2303. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of the notice of intent, 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 fourteen 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 applicable 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 of the Florida Administrative Code (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; 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 petitioner's substantial rights will be affected by the agency determination;

(c) A statement of how and when the 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 state;

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

(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 permitting authority's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the permitting authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation is not available for this proceeding.

In addition to the above, pursuant to 42 United States Code (U.S.C.) Section 7661d(b)(2), any person may petition the Administrator of the EPA within 60 (sixty) days of the expiration of the Administrator's 45 (forty-five) day review period as established at 42 U.S.C. Section 7661d(b)(1), to object to issuance of any Title V permit. Any petition shall be based only on objections to the Title V permit that were raised with reasonable specificity during the 30 (thirty) day public comment period provided in this notice, unless the petitioner demonstrates to the Administrator of the EPA that it was impracticable to raise such objections within the comment period or unless the grounds for such objection arose after the comment period. Filing of a petition with the Administrator of the EPA does not stay the effective date of any Title V permit properly issued pursuant to the provisions of Chapter 62-213, F.A.C. Petitions filed with the Administrator of EPA must meet the requirements of 42 U.S.C. Section 7661d(b)(2) and must be filed with the Administrator of the EPA at: U.S. EPA, 401 M Street, S.W., Washington, D.C. 20460.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Permitting Authority:
Florida Department of Environmental Protection, Bureau of Air Regulation
111 South Magnolia Drive, Suite
Tallahassee, Florida, 32301
Telephone: (850) 488-0114
Fax: (850) 921-9529

Affected District/Local Program:
Florida Department of Environmental Protection Southwest District Office
13051 N. Telecom Parkway
Temple Terrace, Florida 33637-0926
Telephone: (813) 632-7600
Fax: (813) 744-6084

The complete project file includes the DRAFT Permit, the application, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact Scott Sheplak, P.E., at the above address, or call (850) 921-9532, for additional information.

STATEMENT OF BASIS

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

Title V Air Operation Permit Revision
DRAFT Permit Project No.: 0810010-011-AV

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

The subject of this permit is for the revision of the Title V Air Operation Permit No. 0810010-009-AV to incorporate the 1,150 MW combined cycle project, identified as Unit 3.

This facility consists of two Fossil Fuel-Fired Steam Electric Generators designated as Manatee Unit No. 1 and Unit No. 2 and a new "4-on-1" Gas-Fired Combined Cycle Combustion Turbine Electrical Generator designated as Manatee Unit 3. A description of these emissions units follows:

Unit 1 and Unit 2: Fossil Fuel Steam Generators:

Description: Fossil fuel fired steam generators Unit 1 and Unit 2 are each nominal 800 megawatt (900 MW gross capacity) electric steam generators. Each emissions unit consists of a boiler which drives a turbine generator. The maximum heat input for each boiler is 8650 mmBtu per hour when firing fuel oil (or combinations of authorized fuels). The maximum heat input for each boiler is 5670 mmBtu per hour when firing natural gas alone.

Fuel: The emissions units are fired on a variable combination of natural gas, No. 6 fuel oil, No. 2 fuel oil, propane, and used oil from FPL operations. Propane is utilized primarily for ignition of the main fuel.

Controls: Emissions are controlled with multiple cyclones, a flue gas recirculation system and staged combustion. The twin register low-NOx burners (ABB Combustion Services, Ltd.) are dual fuel with mechanical atomization for oil firing.

Stack Parameters: Each unit is equipped with a 499 foot stack.

During the renewal of this Title V permit in December 2003 (No. 0810010-009-AV), an agreement between FPL and FDEP was incorporated into the permit, the "Agreement for the Purpose of Ensuring Compliance with Ambient Air Quality Standards for Ozone" dated September 19, 2002. Since then, on July 2005, the Department issued a construction permit authorizing the installation of reburn technology for Units 1 and Unit 2 to reduce NOx emissions in accordance with this Agreement.

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

Compliance Assurance Monitoring (CAM) does not apply to the mechanical dust collectors installed within the steam generators because a mechanical dust collector: is inherent process equipment contained entirely within the flue gas ductwork; is a passive method of particle separation from the flue gas stream; is a device to recover unburned carbon and ash from the flue gas stream; and has no moving parts, no control inputs, nor any controllable parameters.

Unit 3: Gas-Fired "4 on 1" Combined Cycle Combustion Turbine Electrical Generators:

Description: Emissions units (E.U.) 006, 007, 008, and 009 each consist of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, a gas-fired heat recovery steam generator (HRSG), a bypass stack, a HRSG stack, and associated support equipment. In addition, the project also includes a single steam turbine-electrical generator that serves all four gas turbine/HRSG systems. Associated equipment (E.U. 010) consists of a hot water/electrical heater, the gas-fired heaters originally proposed in the PSD construction permit, were never installed.

Fuel: The combustion turbine units are fired exclusively with natural gas.

Capacity: Each of the four gas turbine-electrical generator sets has a nominal generating capacity of 170 MW for gas firing. Exhaust from each gas turbine passes through a separate heat recovery steam generator (HRSG). Steam from each HRSG is delivered to the single steam turbine-electrical generator, which has a nominal capacity of 470 MW. The total nominal generating capacity of the "4 on 1" combined cycle unit is 1150 MW. At a compressor inlet air temperature of 59° F, each gas turbine heat input is approximately 1600 MMBtu (LHV) per hour.

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

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

Stack Parameters: For simple cycle operation each gas turbine has a bypass stack that is 80 feet tall and 22 feet diameter. For combined cycle operation, each heat recovery steam generator has a HRSG stack that is 120 feet tall stack and 19.0 feet diameter.

These emissions units are regulated under Acid Rain, Phase II (the facility holds ORIS code 6042).

Compliance Assurance Monitoring (CAM) does not apply since these emissions units have NO_X CEMs which are used to demonstrate continuous compliance.

No changes were requested by the applicant with respect to the incorporation of new applicable requirements. However, the Department proposes to incorporate the recent 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). These requirements are added as new Appendix GG (part of the permit).

On March 5, 2004, EPA promulgated 40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. The facility is subject to applicable requirements of 40 CFR 63 NESAHP, Subpart YYYY because it is a major source of HAPs. These requirements are added as new Appendix YYYY (part of the permit).

Specific Condition B.4 is revised as follows to reflect the installation of the hot water/electric heaters instead of the gas-fired fuel heaters originally proposed:

> **B.4.** Gas Turbine Units 3A throughout 3D: The permittee is authorized to install, tune, operate, and maintain four new General Electric Model PG7241FA gas turbine-electrical generator sets each with a nominal capacity of 170 MW (EU 006, 007, 008 and 009). Each gas turbine shall include the Speedtronic™ automated gas turbine control system . Ancillary equipment includes an inlet air filtration system, an evaporative inlet air cooling system, and a bypass stack for simple cycle operation The gas turbines will utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to approximately 290° F before combustion to increase overall unit efficiency. ~~Gas-fired fuel heaters (EU 010)~~ Hot water/electric heaters will preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas. [Application; Design]

Specific Condition B.21. is revised to indicate that performance test are still required after major replacement or repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. Initial performance tests were already conducted in 2005. This condition is revised as follows:

> **B.21**. Special ~~Initial~~ Compliance Determinations: **The Department may require the permittee to conduct additional tests after major replacement or repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc.** Each gas turbine shall be stack tested to demonstrate ~~initial~~ compliance with the emission standards for CO, NO_X, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated for each unit configuration (i.e., simple cycle an combined cycle operation), but not later than 180 days after ~~the initial~~ startup of each unit configuration. Each unit shall be tested under all operating scenarios as required in Specific Condition No. B.10. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the ~~initial~~ CO and NOx standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may also be used to demonstrate compliance with the CO and NO_X mass emissions standards. CO and NOx emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. ~~Initial~~ CO and VOC emissions tests performed during simple cycle operation may be used to satisfy the ~~initial~~ test requirement for similar operation in combined cycle mode. ~~The Department may require the permittee to conduct additional tests after major replacement or repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc.~~
> [Rule 62-297.310(7)(a)1., F.A.C.]

The Department also includes Tables 1-2, Summary of Air Pollutants Emissions Standards and Table 2-2, Summary of Compliance Requirements and modified Table 3, Summary of Reporting Requirements to incorporate the information for Unit 3.

In addition to the above, the placard page and Section I, Facility Information of Title V permit No. 0810010-009-AV are also modified to include the Appendices of the air construction permit, (PSD-FL-328), the project description and the relevant documents of Unit 3.

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

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

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

Title V Air Operation Permit Revision

DRAFT Permit No. 0810010-011-AV

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

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

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

Compliance Authority:

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

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

Table of Contents

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

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

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

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

Referenced attachments made a part of this permit:
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix TV-5, Title V Conditions (version dated 3/28/05)
Appendix SS-1, Stack Sampling Facilities (version dated 10/07/96)
Table 297.310-1, Calibration Schedule (version dated 10/07/96)
Phase II Acid Rain Application/Compliance Plan received 5/27/03
Alternate Sampling Procedure: ASP Number 97-B-01
Order Granting Reduced Sampling Frequency, OGC Case Nos. 83-0580 and 83-0581, Order dated 4/24/84
Agreement for the Purpose of Ensuring Compliance with Ambient Air Quality Standards for Ozone dated 9/19/02
Appendix A, NSPS Subpart A, General Provisions
Appendix A-1, NESHAP Subpart A, General Provisions
Appendix Da, NSPS Subpart Da Requirements for Duct Burners
Appendix GG, NSPS Subpart GG Requirements for Gas Turbines
FIGURE 1 – Summary Report- Gaseous and Opacity Excess Emissions and Monitoring System Performance Report
Appendix YYYY, NESHAP Subpart YYYY, Requirements for Gas Turbines

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

Michael G. Cooke, Director
Division of Air Resource Management

MGC/TLV/SMS/TH

Section I. Facility Information.

Subsection A. Facility Description.

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

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

Combined Cycle Gas Turbines, Unit 3: This Unit consist of four nominal 170 megawatt General Electric Model PG7241(FA) gas-fired turbine-electrical generator sets with evaporative inlet cooling systems; an automated gas turbine control system, an inlet air filtration system, four supplementary-fired heat recovery steam generators (HRSG's) with SCR reactors; four nominal gas fired 550 mmBtu/hour (LHV) gas-fired duct burners located within each of the four HRSG's; four 80 feet bypass stack, four 120 feet exhaust stacks; and a common nominal 470 MW steam-electrical generator.

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

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

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

E.U. ID No.	Brief Description
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2
Unregulated Emissions Units and/or Activities	
003	Emergency Diesel Generator, Miscellaneous Mobile Equipment and Internal Combustion Engines
004	Painting of Plant Equipment and Non-halogenated Solvent Cleaning Operations

E.U. ID No.	Brief Description: "4 on 1" Combined Cycle Unit 3
006	Unit No.3A gas turbine (nominal 170 MW) with heat recovery steam generator.
007	Unit No.3B gas turbine (nominal 170 MW) with heat recovery steam generator
008	Unit No.3C gas turbine (nominal 170 MW) with heat recovery steam generator
009	Unit No.3D gas turbine (nominal 170 MW) with heat recovery steam generator
010	Other Emissions Unit includes an ammonia storage tank

Please reference the Permit No., Facility ID No., and appropriate Emissions Units ID Nos. on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

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

These documents are provided to the permittee for information purposes only:
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements
Table 3-1, Summary of Reporting Requirements
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix H-1, Permit History/ID Number Changes
Statement of Basis

These documents and all their related correspondence are on file with the permitting authority:
Initial Title V Air Operation Permit 0810010-001-AV effective January 1, 1999
Title V Air Operation Permit Administrative Correction 0810010-003-AV effective January 1, 1999
Title V Air Operation Permit Administrative Correction 0810010-004-AV effective January 1, 1999
Title V Air Operation Permit Revision 0810010-008-AV effective December 3, 2002
Title V Air Operation Permit Renewal 0810010-009-AC effective January 1,2004
Title V Air Operation Permit Revision 0810010-011-AV: Pending.

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

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

2. Not Federally Enforceable. General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. The permittee shall not cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

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

4. Prevention of Accidental Releases (Section 112(r) of CAA).
a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable. Any Risk Management Plans, original submittals, revisions or updated to submittals, should be sent to:

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

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

8. General Pollutant Emission Limiting Standards. Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic

solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. The following requirements are "not federally enforceable: The owner or operator shall:

a. Tightly cover or close all VOC or OS containers when they are not in use.
b. Tightly cover all open tanks which contain VOC or OS when they are not in use.
c. Maintain all pipes, valves, fittings, etc., which handle VOC or OS in good operating condition.
d. Immediately confine and clean up VOC or OS spills and make sure wastes are placed in closed containers for reuse, recycling or proper disposal.

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

9. Emissions of Unconfined Particulate Matter. Pursuant to Rules 296.320(4)(c)1., 3., & 4., F.A.C., reasonable precautions to prevent emissions of unconfined particulate matter at this facility include the following requirements (see Condition 57. of APPENDIX TV-5, TITLE V CONDITIONS): The following requirements are not federally enforceable: Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include:

a. The facility shall construct temporary sandblasting enclosures when necessary, in order to perform sandblasting on fixed plant equipment.
b. Maintenance of paved areas as needed.
c. Regular mowing of grass and care of vegetation.
d. Limiting access to plant property by unnecessary vehicles.
e. Bagged chemical products are stored in concrete block buildings until they are used.
f. Spills of powdered chemical products are cleaned up as soon as practicable.

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

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

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

{Permitting Note: This condition implements the requirements of Rules 62-213.440(3)(a)2. & 3., F.A.C. (see Condition 51. of APPENDIX TV-5, TITLE V CONDITIONS).}

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

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

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

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air and EPCRA Enforcement Branch
Air Enforcement Section
61 Forsyth Street
Atlanta, GA 30303-8960
Phone: 404/562-9155
Fax: 404/562-9163

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

15. The permittee shall comply with the terms of the attached "AGREEMENT FOR THE PURPOSE OF ENSURING COMPLIANCE WITH AMBIENT AIR QUALITY STANDARDS FOR OZONE" dated 9/19/02.
{Permitting note: FPL will need to obtain a non-PSD air construction permit from the Department prior to the reburn construction project described in the above Agreement.}

Section III. Emissions Units and Conditions.

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

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

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

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

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

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

Essential Potential to Emit (PTE) Parameters

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

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

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

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

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

A.3. Methods of Operation - Fuels.

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

When available, the Department strongly encourages the permittee to fire natural gas as a clean-burning alternative to fuel oil.

[Rule 62-213.410, F.A.C.; Permit No. 0810010-007-AC]

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

Emission Limitations and Standards

{Permitting Note: Unless otherwise specified, the averaging times for Specific Conditions A.5.-A.10. are based on the specified averaging time of the applicable test method. The attached Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

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

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

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

Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess emissions allowed by this condition.
[Rule 62-210.700(3), F.A.C., Note: these units have operational continuous opacity monitors.]

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

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

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

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

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

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

Excess Emissions

A.11. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

A.12. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

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

Monitoring of Operations

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

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

A.16. Determination of Process Variables.

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

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

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

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

A.17. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

1. [Reserved.]

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid fuel for more than 400 hours other than during startup.

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

   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: 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.

6-8. [Reserved.]

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

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

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

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

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

a. only gaseous fuel(s); or

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

c. only liquid fuel(s) for less than 400 hours per year.

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

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

a. only gaseous fuel(s); or

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

c. only liquid fuel(s) for less than 400 hours per year.

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

Test Methods and Procedures

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

A.20. Visible emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C. See specific condition **A.21** of this permit. VE testing shall be conducted in accordance with the requirements of specific condition **A.27** of this permit.
[Rule 62-296.405(1)(e)1., F.A.C.]

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

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

2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent

opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:

a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.

b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

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

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

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

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

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

performed by FPL prior to transferring oil to the Manatee plant. Reports of percent sulfur content of these analyses shall be maintained at the power plant facility.

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

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

A.25. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

A.26. Operating Rate During Testing. Testing of emissions shall be conducted with each emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

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

Testing may be conducted while firing No. 6 fuel oil at less than 90 percent of the maximum allowable rate; however, subsequent emissions unit operation is limited as described in specific condition **A.26** of this permit.
[Rules 62-4.070(3) and 62-213.440 F.A.C., AO 41-204804 Specific Condition 5, AO 41-219341 Specific Condition 5]

A.28. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the separate test runs unless otherwise specified in a particular test method or applicable rule.

[Rule 62-297.310(3), F.A.C.]

A.29. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

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 (attached to this permit).
(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

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

A.31. Testing While Injecting Additives. The owner or operator shall conduct emission tests while injecting additives consistent with normal operating practices.
[Rule 62-213.440, F.A.C., applicant agreement with EPA on March 3, 1998]

Record Keeping and Reporting Requirements

A.32. Excess Emissions - Malfunctions. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department's Southwest District, Air Section, in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department's Southwest District, Air Section. [Rule 62-210.700(6), F.A.C.]
{Permitting Note: In the event of excess emissions as noted above, Manatee Plant agrees to provide an informational notification to the office of the Director of the Manatee County Environmental Management Department}

A.33. Excess Emissions - Reports. Submit to the Department's Southwest District, Air Section, a written report of emissions in excess of emission limiting standards for opacity and sulfur dioxide as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years. [Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]
{Permitting Note: In addition to the quarterly report submitted to the Compliance Authority noted above, Manatee Plant agrees to provide an informational copy to the office of the Director of the Manatee County Environmental Management Department}

A.34. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department's Southwest District, Air Section, on the results of each such test.
(b) The required test report shall be filed with the Department's Southwest District, Air Section, as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department's Southwest District, Air Section, to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

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

19. The detailed calculations for one run that relate the collected data to the calculated emission rate.

20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.

21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.
[Rules 62-213.440 and 62-297.310(8), F.A.C.]

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

A.36. COMS for Periodic Monitoring. The owner or operator is required to install continuous opacity monitoring systems (COMS) pursuant to 40 CFR Part 75. The owner or operator shall maintain and operate COMS and shall make and maintain records of opacity measured by the COMS, for purposes of periodic monitoring.
[Rule 62-213.440, F.A.C., and applicant agreement with EPA on March 3, 1998]

Miscellaneous Conditions

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

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

   On-specification used oil shall meet the following specifications: [40 CFR 279, Subpart B.]
   Arsenic shall not exceed 5.0 ppm;
   Cadmium shall not exceed 2.0 ppm;
   Chromium shall not exceed 10.0 ppm;
   Lead shall not exceed 100.0 ppm;
   Total halogens shall not exceed 1000 ppm;
   Flash point shall not be less than 100 degrees F.

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

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

d. PCB Concentration of 2 to less than 50 ppm: On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall be burned only at normal source operating

temperatures. On-specification used oil with a PCB concentration of 2 to less than 50 ppm shall not be burned during periods of startup or shutdown.

e. Testing Required: The owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:

Arsenic, cadmium, chromium, lead, total halogens, flash point, PCBs.

Testing (sampling, extraction and analysis) shall be performed using approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods), latest edition.

Split samples of the used oil shall be retained for three months after analysis for further testing if necessary.
[AO 41-204804 Specific Condition 9, and AO 41-219341 Specific Condition 9]

f. Record Keeping Required: The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department: [40 CFR 279.61 and 761.20(e)].

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

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

The owner or operator shall submit, with the Annual Operation Report form, the analytical results and the total amount of on-specification used oil burned during the previous calendar year.

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

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

A.39. Initial Compliance Tests for Gas Firing: When firing 100% natural gas, the permittee shall conduct initial compliance tests to determine the emissions of particulate matter and level of opacity from Units 1 and 2. Test results shall demonstrate compliance with the applicable standards. A transmissometer calibrated in accordance with Rule 62-297.520, F.A.C., may also be used to demonstrate compliance with the visible emissions standard. Initial tests shall be conducted within 60

days after completing shakedown for each unit, but not later than 180 days after first fire on natural gas. [Rule 62-296.405(1)(e)1, F.A.C.; Permit No. 0810010-007-AC]

A.40. PSD Applicability Report: Before August 1st of each year, the permittee shall submit a report to the Bureau of Air Regulation and the Compliance Authority summarizing actual annual emissions for the previous calendar year. The reports shall be used to verify the permittee's predictions of future representative actual annual emissions. The reports shall be submitted for five separate years that are representative of normal post-change operations after completing construction of the natural gas project. The reports shall begin during the first year that natural gas is fired and continue for five years. Reports are subject to the following conditions.

a. The Department determines the "past actual emissions" for Units 1 and 2 as follows:

Pollutant	Past Actual Emissions Two-Year Average Tons per Year	Future Representative Actual Annual Emissions Calculation Methods
Carbon Monoxide (CO)	18,987	AOR (oil); Initial/Annual Performance Tests (gas)
Nitrogen Oxides (NOx)	8762	CEMS; Acid Rain Reporting
Particulate Matter (PM)	2384	AOR (oil); Initial Performance Test (gas)
Sulfur Dioxide (SO_2)	31,753	CEMS; Acid Rain Reporting
Volatile Organic Compounds (VOC)	149	AOR (oil); Initial Performance Test (gas)

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

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

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

determination of the Best Available Control Technology (BACT) for each PSD-significant pollutant.

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

Section III. Emissions Units and Conditions.

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

Emissions Unit 006 through 009: Units No. 3A through 3D

Description: Emissions units 006, 007, 008, and 009 each consist of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, a gas-fired heat recovery steam generator (HRSG), a bypass stack, a HRSG stack, and associated support equipment. In addition, the project also includes a single steam turbine-electrical generator that serves all four gas turbine/HRSG systems.

Fuel: The units are fired exclusively with natural gas.

Capacity: Each of the four gas turbine-electrical generator sets has a nominal generating capacity of 170 MW for gas firing. Exhaust from each gas turbine passes through a separate heat recovery steam generator (HRSG). Steam from each HRSG is delivered to the single steam turbine-electrical generator, which has a nominal capacity of 470 MW. The total nominal generating capacity of the "4 on 1" combined cycle unit is 1150 MW. At a compressor inlet air temperature of 59° F, each gas turbine heat input is approximately 1600 MMBtu (LHV) per hour.

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

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

Stack Parameters: For simple cycle operation each gas turbine has a bypass stack that is 80 feet tall and 22 feet diameter. For combined cycle operation, each heat recovery steam generator has a HRSG stack that is 120 feet tall stack and 19.0 feet diameter. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack parameters change. The following summarizes the exhaust characteristics:

			Simple Cycle Operation		Combined Cycle Operation	
Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp.	Exhaust Temp.	Flow Rate ACFM	Exhaust Temp., °F	Flow Rate ACFM
Gas	1600 MMBtu/hour	59° F	1116° F	2,389,500	202° F	1,004,200

Applicable Standards and Regulations

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

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

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

Equipment

B.4. Gas Turbine Units 3A throughout 3D: The permittee is authorized to tune, operate, and maintain four new General Electric Model PG7241FA gas turbine-electrical generator sets each with a nominal capacity of 170 MW (EU 006, 007, 008 and 009). Each gas turbine shall include the Speedtronic™ automated gas turbine control system . Ancillary equipment includes an inlet air filtration system, an evaporative inlet air cooling system, and a bypass stack for simple cycle operation The gas turbines will utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to approximately 290° F before combustion to increase overall unit efficiency. Hot water/electric heaters will preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas. [Application; Design]

B.5. Gas Turbine Controls:

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

- Selective Catalytic Reduction (SCR) System: The permittee shall tune, maintain and operate a SCR system to control NOx emissions from each turbine during a combined cycle operation mode. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancilliary equipment. The SCR system shall be operated to achieve the permitted levels for NOx emissions and ammonia slip. *{Permitting Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions of 40 CFR 68}*

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

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

Performance Restrictions

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

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

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

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

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

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

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

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

   (1) Prior to demonstrating compliance in combined cycle mode, each gas turbine shall operate in simple cycle mode for no more than 3390 hours during any consecutive 12 months.

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

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

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

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

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

Emissions Standards

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

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hour	ppmvd @ 15% O_2
CO[a]	Gas	Simple Cycle	7.4	27.5	8.0, 24-hr
		Simple Cycle w/PA	12.0	45.0	12.0, 24-hr
		Combined Cycle, Normal Operation	7.4	27.5	10.0, 24-hr
		Combined Cycle, All Modes	NA	NA	10.0, 24-hr
NOx[b]	Gas	Simple Cycle	9.0	58.7	9.0, 24-hr
		Simple Cycle w/PA	12.0	76.2	12.0, 24-hr
		Simple Cycle w/PK	15.0	95.3	15.0, 24-hr
		Combined Cycle w/SCR	2.5	16.3	2.5, 24-hr
		Combined Cycle w/SCR and DB	2.5	23.6	2.5, 24-hr
		Combined Cycle w/SCR, All Modes	N/A	N/A	2.5, 24-hr
PM/PM10[c]	Gas	Simple or Combined Cycle	Fuel Specifications		
		Simple or Combined Cycle	Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2[d]	Gas	Simple or Combined Cycle	Fuel Specifications		
VOC[e]	Gas	Simple or Normal Combined Cycle	1.3	2.8	NA
VOC[e]	Gas	Combined Cycle, w/DB and/or PA	4.0	10.5	NA
Ammonia[f]	Gas	Combined Cycle w/SCR	5	NA	NA

Notes:

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

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

b. Compliance with the NOX standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 7E or 20. NOX mass emission rates are defined as oxides of nitrogen expressed as NO2. Compliance with the 24-hr NOX CEMS standards during simple cycle operation shall be determined separately for each method of operation based on the hours of operation for each method . {Permitting Note: A 24-hr compliance average may be based on as little as 1-hr of CEMS data or as much as 24-hr of CEMS data .}

c. The fuel specifications established in Condition No. B.9 of this subsection combined with the efficient combustion design and operation of each gas turbine represents the Best Available Control Technology (BACT) determination for PM/PM10 emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9. {Permitting Note: PM10 emissions for gas firing are estimated at 9 lb/hour for simple cycle operation, 11 lb/hour for combined cycle operation, and 17 lb/hour for combined cycle operation with duct burning.}

d. The fuel sulfur specifications in Condition No.B.9 of this subsection effectively limit the potential emissions of SAM and SO2 from the gas turbines and represent the Best Available Control Technology (BACT) determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 27 of this section. {Permitting Note: SO2 emissions for gas firing are estimated at 9.8 lb/hour for simple and combined cycle operation and 12.8 lb/hour for combined cycle operation with duct burning. SAM emissions are estimated to be less than 10% of the SO2 emissions.}

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

f. Subject to the requirements of Condition No. B.24 of this section, each SCR system shall be designed and operated for an initial ammonia slip target of less that 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027.

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

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

B.11. Duct Burners: The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60, which are summarized in Appendix Da. {Permitting Note: During duct firing, compliance with the limits of this permit also demonstrates compliance with the standards of NSPS 40 CFR 60, Subpart Da for duct burners.}

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

Excess Emissions

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

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

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

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

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

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

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

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

B.17. Work Practice Standard and Load Restriction:

a. *Simple Cycle Work Practice BACT*: Each unit will be operated according to manufacturer specifications and control systems. The CT control system is designed to reach Mode 5Q (i.e.

five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire.

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

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

B.18. Initial Steam Blows: Prior to completing the conversion from simple cycle to combined cycle operation, the permittee is authorized to operate each gas turbine at loads below 50% for the purpose of cleaning the HRSG piping system and piping connecting the HRSG to the steam turbine. Prior to conducting any steam blows, the permittee shall submit a proposed schedule. On the first day of conducting steam blows, the permittee shall notify the Compliance Authority that the process has begun. The permittee shall complete this process within 90 days of conducting the initial steam blow. For good cause, the permittee may request that the Compliance Authority extend the steam blow period. During the steam blows, the following conditions apply:

a. The permittee shall take all precautions to minimize the extent and duration of excess emissions.

b. Each gas turbine shall fire only natural gas and each CEMS shall be on line and functioning properly.

c. CO and NO_X emissions may exceed the BACT limits specified in this permit; however, NO_X emissions shall not exceed the NSPS Subpart GG limit of 110 ppmvd corrected to 15% oxygen based on a 24-hour block average. If the NSPS standard is exceeded, the permittee shall notify the Compliance Authority within one working day of the incident.

Within 30 days of completing the initial steam blows, the permittee shall submit a report to the Bureau of Air Regulation and the Compliance Authority summarizing the daily emissions resulting from each steam blow. {Permitting Note: It is estimated that steam blows will occur intermittently over a 30-day period for each gas turbine/HRSG system followed by a similar 60-day period of intermittent steam blows for the common piping system serving the four interconnected combined cycle units. It is not expected that steam blows would occur every day during these periods. This condition only applies if simple cycle operation begins prior to combined cycle operation and NSPS compliance tests for simple cycle operation have been performed} [Application; Design; Rules 62-212.400(BACT) and 62-210.700(5), F.A.C.]

B.19. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

Emissions Performance Testing

B.20. Test Methods: Required tests shall be performed in accordance with the following reference methods.

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

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

B.21. Special Compliance Determinations: The Department may require the permittee to conduct additional tests after major replacement or repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. Each gas turbine shall be stack tested to demonstrate compliance with the emission standards for CO, NO_X, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated for each unit configuration (i.e., simple cycle an combined cycle operation), but not later than 180 days after the startup of each unit configuration. Each unit shall be tested under all operating scenarios as required in Specific Condition No. B.10. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the CO and NOx standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may also be used to demonstrate compliance with the CO and NO_X mass emissions standards. CO and NOx emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. CO and VOC emissions tests performed during simple cycle operation may be used to satisfy the test requirement for similar operation in combined cycle mode.
[Rule 62-297.310(7)(a)1., F.A.C.]

B.22. Continuous Compliance: The permittee shall demonstrate continuous compliance with the CO and NO_X emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds. [Rule 62-212.400 (BACT), F.A.C.]

B.23. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia slip. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. *{Permitting Note: After initial compliance with the VOC standards are demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.}*
[Rules 62-212.400 (BACT) and 62-297.310(7)(a)4., F.A.C.]

B.24. Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

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

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

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

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

Continuous Monitoring Requirements

B.25. CEM Systems: The permittee shall calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO_X from each gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NOx standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

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

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

c. *Diluent Monitors*. The oxygen (O2) content or carbon dioxide (CO2) content of the flue gas shall also be monitored at the location where CO and NOx are monitored to correct the measured emissions rates to 15% oxygen. If a CO2 monitor is installed, the oxygen content of the flue gas

shall be calculated by the CEMS using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR Part 75.

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

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

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

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

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

or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department.

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

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

B.26. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall calibrate, maintain and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

Records, Reports And Notification

B.27. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

B.28. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following in a written or electronic log for each gas turbine for the previous month of operation: consumption of each fuel, the hours of operation, the hours of power augmentation, the hours of peaking, the hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

B.29. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur specification of this permit by maintaining records of the sulfur content of the natural gas being supplied based on the vendor's analysis for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 (or more recent versions) in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

B.30. Malfunction Notification: Within one working day of a malfunction that causes emissions in excess of a standard (subject to the specified averaging periods), the permittee shall notify the Compliance Authority. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports report of the malfunctions.

B.31. Semiannual NSPS Excess Emissions Report: Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Compliance Authority summarizing emissions in excess of an NSPS standard. In accordance with 40 CFR 60.7(d), the permittee shall submit the NSPS excess emissions report identified as Figure 1 and summarized in Appendix XS. For purposes of

reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NO_X emission standard identified in Appendix GG; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NO_X or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO_2 emissions in excess of the NSPS standards except during startup or shutdown. [40 CFR 60.7]

B.32. Quarterly Excess Emission Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of excess emissions. The information shall be summarized for simple/combined cycle startups, simple/combined cycle shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

Section IV. This section is the Acid Rain Part.

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

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

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

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

A.1. The Phase II permit application(s) submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of these Phase II acid rain unit(s) must comply with the standard requirements and special provisions set forth in the application(s) listed below:
a. DEP Form No. 62-210.900(1)(a), dated 7/1/95, received 5/27/03.
[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

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

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

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

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

1. No permit revision shall be required for increase in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.
2. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.
3. Allowances shall be accounted for under the Federal Acid Rain Program.

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

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

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

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

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

E.U. ID No.	Brief Description of Emissions Units and/or Activity
003	Emergency Diesel Generator, Miscellaneous Mobile Equipment and Internal Combustion Engines
004	Painting of Plant Equipment and Non-halogenated Solvent Cleaning Operations

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

Florida Power & Light Company
Manatee Plant

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

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

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

Brief Description of Emissions Units and/or Activities

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

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

Florida Power & Light Company
Manatee Plant

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

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

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

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

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

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

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

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

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

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

Notes:

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

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

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

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

			Allowable Emissions*			Equivalent Emissions			
Pollutant	**Fuel(s)**	**Hours per Year**	**Standard(s)**	**lb/hour**	**TPY**	**lb/hour**	**TPY**	**Regulatory Citations**	**See Permit Condition(s)**
NOx	Natural. Gas	8760	2.5 ppmvd@15%O_2	16.3 23.6			71.4 103.37	Rule 62-212.400, F.A.C.	B.9 and B.10
CO	Natural. Gas	8760	7.4 10 ppmvd@15%O_2	27.5 37.2			120.5 162.7	Rule 62-212.400, F.A.C.	B.9 and B.10
VOC	Natural. Gas	8760	1.3 4 ppmvd@15%O_2	2.8 10.5			12.3	Rule 62-212.400, F.A.C.	B.9 and B.10
VE	Natural. Gas	8760	10 % opacity				15.1	Rule 62-212.400, F.A.C.	B.9 and B.10
NH_3	Natural. Gas	8760	5 ppmvd@15%O_2	11.3			49.4	Rule 62-212.400, F.A.C.	B.9 and B.10
PM/PM_{10}	Natural. Gas	8760	Fuel Specifications					Rule 62-212.400, F.A.C.	B.9 and B.10
SAM/SO_2	Natural. Gas	8760	Fuel Specifications					Rule 62-212.400, F.A.C.	B.9 and B.10

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

Simple Cycle Operation Mode:

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

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

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

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

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

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

Notes:

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

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

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

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

Pollutant or Parameter	Fuel[3]	Compliance Reference Method	Testing Frequency	Frequency Base Date[1]	Minimum Compliance Stack Test Duration	CMS[2]	See Permit Condition(s)
NO_x	N.G.	CEMS. 24-hour block average Method 7E or 20 for lb/hr 3-run average	Annual	June	3 hours	Yes	B.10, B20, B-22
CO	N.G.	CEMS. 24-hour block average Method 10 for lb/hr 3-run average	Annual	June	3 hours	Yes	B.10, B20, B-22
PM	N.G.	Visible Emissions (VE) subrogate	Annual	June			B.9, B.10, B-20,
VOC	N.G.	EPA Method 25A. Optionally Method 18.	Initial	June	3 hours		B.10, B.20, B-23
VE	N.G.	Method 9	Annual	June	6 minutes block average	Yes	B.10, B.20
SO_2/SAM	N.G.	Fuel Specifications	As received	June			B. 9, B.10, B.20, B.27.
NH3	N.G.	CTM-027	Initial	June			B.2-, B.20

Notes:

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

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

Table 3-1, Summary of Reporting Requirements

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

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

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

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

Table 3-1, Summary of Reporting Requirements

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

Table 3-1, Summary of Reporting Requirements

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

Table 3-1, Summary of Reporting Requirements

Unit 3 Compliance Test Report Content See Specific Conditions B.23, B.27, B.28, and B.29	Operating data Monitoring of Capacity Fuel records	Fifth day of each calendar month and/or upon Department request	Rule 62-212.400, F.A.C. Rule 62-4.070(3), F.A.C	B.23, B.27, B.28, B.29.
Notification of startup (for any emission unit or facility which has a valid operating permit which has been shut down more than one year) Contents: 1. Startup date 2. Anticipated emission rates or pollutants released 3. Changes to processes or control devices which will result in changes to emission rates, and 4. Any other conditions which may differ from the valid outstanding operation permit	As occurs	At least 60 days prior to intended startup; or, if an emergency, as soon as possible after the startup date is ascertained	Rule 62-210.300(5), F.A.C.	TV-5 No. 19
Report Type/Content	**Frequency**	**Deadline**	**Regulatory Citations**	**See Permit Condition(s)**
Fuel Analysis Report Content: For each fuel received in the preceding month: 1. Heating value 2. Density or specific gravity 3. Percent sulfur content by weight	Monthly	15th day following each calendar month	Rule 62-4.070(3), F.A.C.; Rule 62-213.440, F.A.C.	A.35
Used Oil Report Monthly content: Analytical results and the total amount of on-specification used oil burned during the previous calendar month Annual content: Analytical results and the total amount of on-specification used oil burned during the previous calendar year	Monthly and annually	Within 30 days of the end each calendar month in which used oil is burned during the previous calendar month; and March 1 with AOR	40 CFR 279 and 761; Rule 62-4.070(3), F.A.C.; Rule 62-213.440, F.A.C.	A.37.g

Table 3-1, Summary of Reporting Requirements

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

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

Table 3-1, Summary of Reporting Requirements

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

Appendix H-1: Permit History

Florida Power & Light Company
Manatee Plant

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

E.U. ID No.	Description	Permit No.	Effective Date	Expiration Date	Project Type [1]
All	Facility	0810010-001-AV	01/01/1999	12/31/2003	Initial
001, 002	Fossil Fuel Steam Generators 1 & 2	0810010-002-A0	05/27/1997	05/27/2002	Burn Boiler Cleaner & Propane
All	Facility	0810010-003-AV	01/01/1999	12/31/2003	Administration Correction
All	Facility	0810010-004-AV	01/01/1999	12/31/2003	Administration Correction
001, 002	Fossil Fuel Steam Generators 1 & 2	0810010-005-AC	12/23/1999	12/23/2000	AC (modification.)
006-009	Combined Cycle Unit 3a to 3D	0810010-006-AC	04/15/2003	12/31/2006	AC to install Combined Cycle Unit 3
001, 002	Fossil Fuel Steam Generators 1 & 2	0810010-007-AC	08/12/2002	07/01/2003	AC modification
001, 002	Fossil Fuel Steam Generators 1 & 2	0810010-008-AV	12/03/2002	12/31/2003	AV Revision
All	Facility	0810010-009-AV	01/01/2004[2]	12/31/2008	AV Renewal
001,002	Fossil Fuel Steam Generators 1 & 2	0810010-010-AC	07/05/2005	07/05/2010	AC (mod.) to allow reburn technology
006 to 009	Combined Cycle (CC) Unit 3a to 3D	0810010-011-AV	Pending	12/31/2008	AV Revision to incorporate CC Unit 3

[1] Project Type: Title V Permit (AV) - Initial, Revision, Renewal, or Administrative Correction; Air Construction Permit (AC): New, Modification; Extension (only for an AC); or, Withdrawn or Denied.
[2] ARMS day 55 from the date of posting the PROPOSED Permit for EPA review (see confirmation e-mail from Tallahassee) or the date that EPA confirms resolvement of any objections.

NESHAP REQUIREMENTS FOR GAS TURBINES

Applicability of NESHAP Subpart YYYY

The Manatee Power Plant is an existing major source of hazardous air pollutant emissions. As such, the proposed new combustion turbines are subject to NESHAP Subpart YYYY, which became final on March 5, 2004. According to the final rule, each unit is considered a "new lean premix gas-fired stationary combustion turbine". Therefore, each new combustion turbine is subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @ 15% O_2). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show continuous compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

Staying of the Rule

On August 18, 2004, EPA stayed the effectiveness of 40 CFR 63, Subpart YYYY for lean premix gas turbines. Following is the change in 40 CFR 63 that stays effectiveness:

§ 63.6095(d) Stay of standards for gas-fired subcategories.

If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

Requirements

The applicable requirements in Subpart YYYY at this time:

§ 63.6145 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you start up your new or reconstructed stationary combustion turbine before March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after March 5, 2004.

(c) As specified in § 63.9(b), if you start up your new or reconstructed stationary combustion turbine on or after March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.

(d) If you are required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with § 63.6090(b), your notification must include the information in § 63.9(b)(2)(i) through (v) and a statement that your new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine).

(e) If you are required to conduct an initial performance test, you must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in § 63.7(b)(1).

(f) If you are required to comply with the emission limitation for formaldehyde, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

[Rules 62-4.070(3) and 62-204.800, F.A.C.; Subparts A and YYYY in 40 CFR 63]

Friday, Barbara 2/1/06

To: 'Kosky, Ken'; Nasca, Mara

Cc: Heron, Teresa

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

Attachments: 0810010-011-AV-D.zip

Attached for your records is a zip file for the subject DRAFT Title V Permit Revision.

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

Friday, Barbara

From: System Administrator
To: Nasca, Mara
Sent: Thursday, February 02, 2006 10:50 AM
Subject: Delivered:DRAFT Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant

Your message

To:	'Kosky, Ken'; Nasca, Mara
Cc:	Heron, Teresa
Subject:	DRAFT Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant
Sent:	2/2/2006 10:49 AM

was delivered to the following recipient(s):

Nasca, Mara on 2/2/2006 10:50 AM

Friday, Barbara

From: Exchange Administrator
Sent: Thursday, February 02, 2006 10:50 AM
To: Friday, Barbara
Subject: Delivery Status Notification (Relay)

Attachments: ATT741315.txt; DRAFT Title V Permit Revision No.: 0810010-011-AV - Florida Power & Light Company - Manatee Power Plant


ATT741315.txt
(283 B)


DRAFT Title V
Permit Revision ...

This is an automatically generated Delivery Status Notification.

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

KKosky@GOLDER.com