Friday, Barbara

From: John_Hampp@fpl.com
Sent: Monday, December 04, 2006 8:39 AM
To: Friday, Barbara
Subject: REVISED DRAFT Title V Permit No.: 0850001-016-AC/0850001-017AV - FP&L - Martin Power Plant

Return Receipt

Your document:	REVISED DRAFT Title V Permit No.: 0850001-016-AC/0850001-017AV - FP&L - Martin Power Plant
was received by:	John Hampp/GC/FPL
at:	12/04/2006 08:39:09 AM

Friday, Barbara

To: craig_arcari@fpl.com; john.hampp@fpl.com; Graziani, Darrel; KKosky@Golder.com; Halpin, Mike

Cc: Heron, Teresa

Subject: REVISED DRAFT Title V Permit No.: 0850001-016-AC/0850001-017AV - FP&L - Martin Power Plant

Attachments: 0850001.017.AV.R_pdf[1].zip

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Thank you,

DEP, Bureau of Air Regulation

Friday, Barbara

To: Little.James@epamail.epa.gov

Cc: Heron, Teresa

Subject: REVISED DRAFT Title V Permit No.: 0850001-016-AC/0850001-017-AV - FP&L - Martin Power Plant

Attachments: RTTechnicalEvaluation.pdf; 2AV0170850001TABLE1.pdf; 2RTSOB017AV.pdf; 0850001016AC&017AVDraftRevisonCombinedIntent.pdf; 0850001017History 2006.pdf; R017AVPermit 2006DRAFT.pdf; R0850001Final Compliance Plan 2003.pdf; RAppendix.pdf; RAV0170850001TABLE2.pdf; RTModletter016ACLinero.pdf

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Thank you,

DEP, Bureau of Air Regulation

Friday, Barbara

From: System Administrator
To: Graziani, Darrel; Halpin, Mike
Sent: Friday, December 01, 2006 12:01 PM
Subject: Delivered:REVISED DRAFT Title V Permit No.: 0850001-016-AC/0850001-017AV - FP&L - Martin Power Plant

Your message

To: 'craig.arcari@fpl.com'; 'john.hampp@fpl.com'; Graziani, Darrel; 'KKosky@Golder.com'; Halpin, Mike
Cc: Heron, Teresa
Subject: REVISED DRAFT Title V Permit No.: 0850001-016-AC/0850001-017AV - FP&L - Martin Power Plant
Sent: 12/1/2006 12:00 PM

was delivered to the following recipient(s):

Graziani, Darrel on 12/1/2006 12:01 PM
Halpin, Mike on 12/1/2006 12:01 PM

Friday, Barbara

From: Exchange Administrator
Sent: Friday, December 01, 2006 12:02 PM
To: Friday, Barbara
Subject: Delivery Status Notification (Relay)

Attachments: ATT126819.txt; REVISED DRAFT Title V Permit No.: 0850001-016-AC/0850001-017AV - FP&L - Martin Power Plant

ATT126819.txt (364 B)   REVISED DRAFT Title V Permit N...

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.

craig.arcari@fpl.com
john.hampp@fpl.com

Friday, Barbara

From: Exchange Administrator
Sent: Friday, December 01, 2006 12:01 PM
To: Friday, Barbara
Subject: Delivery Status Notification (Relay)

Attachments: ATT126819.txt; REVISED DRAFT Title V Permit No.: 0850001-016-AC/0850001-017AV - FP&L - Martin Power Plant

ATT126819.txt (283 B)   REVISED DRAFT Title V Permit N...

This is an automatically generated Delivery Status Notification.

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

KKosky@Golder.com

Friday, Barbara

From: Halpin, Mike
To: Friday, Barbara
Sent: Friday, December 01, 2006 12:07 PM
Subject: Read: REVISED DRAFT Title V Permit No.: 0850001-016-AC/0850001-017AV - FP&L - Martin Power Plant

Your message

To: 'craig.arcari@fpl.com'; 'john.hampp@fpl.com'; Graziani, Darrel; 'KKosky@Golder.com'; Halpin, Mike
Cc: Heron, Teresa
Subject: REVISED DRAFT Title V Permit No.: 0850001-016-AC/0850001-017AV - FP&L - Martin Power Plant
Sent: 12/1/2006 12:00 PM

was read on 12/1/2006 12:07 PM.

Friday, Barbara

From: EPA Postmaster automated message [postmaster@epamail.epa.gov]
Sent: Friday, December 01, 2006 12:07 PM
To: Friday, Barbara
Subject: Delivery Notification: Message successfully forwarded

Attachments: ATT126821.txt; ATT126821.txt

ATT126821.txt (634 B) ATT126821.txt (2 KB)

This report relates to a message you sent with the following header fields:

```
  Message-id: <5280B20498F24C46A51A87E86A0C8F97038CC6@tlhexsmb5.floridadep.net>
  Date: Fri, 01 Dec 2006 12:00:26 -0500
  From: "Friday, Barbara" <Barbara.Friday@dep.state.fl.us>
  To: Little.James@epamail.epa.gov
  Subject: REVISED DRAFT Title V Permit No.:  0850001-016-AC/0850001-017-AV -
   FP&L - Martin Power Plant
```

Your message has been successfully relayed to the recipients

```
  Recipient address: little.james@mseive.epa.gov
  Original address: Little.James@epamail.epa.gov
  Reason: Message successfully relayed to a system that does not support receipts
  Diagnostic code: dns;mseive02.rtp.epa.gov (TCP|134.67.208.33|1391|134.67.221.150|25)
(mseive02.rtp.epa.gov ESMTP Postfix) smtp;250 Ok
  Remote system: dns;mseive02.rtp.epa.gov (TCP|134.67.208.33|1391|134.67.221.150|25)
(mseive02.rtp.epa.gov ESMTP Postfix)
```

on a remote system that does not support the generation of successful delivery receipts. This does NOT mean that your message has actually been placed in the recipients' mailboxes; merely that it has passed through a part of the message transport infrastructure. In the event of a nondelivery you should expect to receive a nondelivery notification; in the event of successful delivery, however, you are unlikely to receive a positive confirmation of delivery.

Friday, Barbara

From: Little.James@epamail.epa.gov
Sent: Friday, December 01, 2006 12:22 PM
To: Friday, Barbara
Subject: Re: REVISED DRAFT Title V Permit No.: 0850001-016-AC/0850001-017-AV - FP&L - Martin Power Plant

"Friday, Barbara" <Barbara.Friday@dep.state.fl.us>
12/01/2006 12:00 PM

To: James Little/R4/USEPA/US@EPA
cc: "Heron, Teresa" <Teresa.Heron@dep.state.fl.us>
Subject: REVISED DRAFT Title V Permit No.: 0850001-016-AC/0850001-017-AV - FP&L - Martin Power Plant

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Thank you,
DEP, Bureau of Air Regulation
[attachment "RTTechnicalEvaluation.pdf" deleted by James Little/R4/USEPA/US] [attachment "2AV0170850001TABLE1.pdf" deleted by James Little/R4/USEPA/US] [attachment "2RTSOB017AV.pdf" deleted by James Little/R4/USEPA/US] [attachment "0850001016AC& 017AVDraftRevisonCombinedIntent.pdf" deleted by James Little/R4/USEPA/US] [attachment "0850001017History 2006.pdf" deleted by James Little/R4/USEPA/US] [attachment

"R017AVPermit 2006DRAFT.pdf"
deleted by James Little/R4/USEPA/US] [attachment "R0850001Final Compliance Plan 2003.pdf"
deleted by James Little/R4/USEPA/US] [attachment "RAppendix.pdf" deleted by James
Little/R4/USEPA/US] [attachment "RAV0170850001TABLE2.pdf" deleted by James
Little/R4/USEPA/US] [attachment "RTModletter016ACLinero.pdf" deleted by James
Little/R4/USEPA/US]

Friday, Barbara

From: Craig_Arcari@fpl.com
Sent: Tuesday, December 05, 2006 9:12 AM
To: Friday, Barbara
Cc: craig.arcari@fpl.com; Graziani, Darrel; john.hampp@fpl.com; KKosky@Golder.com; Halpin, Mike; Heron, Teresa; willie_welch@fpl.com
Subject: Re: REVISED DRAFT Title V Permit No.: 0850001-016-AC/0850001-017AV - FP&L - Martin Power Plant

Attachments: 0850001.017.AV.R_pdf[1].zip

0850001.017.AV.R_pdf[1].zip (7...

Received.

-Craig W. Arcari
General Manager, Martin Power Plant

Office: 772 597 7106
Cell: 772 285 2648

"Friday, Barbara" <Barbara.Friday@dep.state.fl.us>
12/01/2006 12:00 PM

To: craig.arcari@fpl.com, john.hampp@fpl.com, "Graziani, Darrel" <Darrel.Graziani@dep.state.fl.us>, KKosky@Golder.com, "Halpin, Mike" <Mike.Halpin@dep.state.fl.us>
cc: "Heron, Teresa" <Teresa.Heron@dep.state.fl.us>
Subject: REVISED DRAFT Title V Permit No.: 0850001-016-AC/0850001-017AV - FP&L - Martin Power Plant

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Thank you,<?xml:namespace prefix = o ns = "urn:schemas-microsoft-com:office:office" />
DEP, Bureau of Air Regulation (See attached file: 0850001.017.AV.R_pdf[1].zip)

Friday, Barbara

From: Craig_Arcari@fpl.com
Sent: Tuesday, December 05, 2006 7:39 AM
To: Friday, Barbara
Subject: REVISED DRAFT Title V Permit No.: 0850001-016-AC/0850001-017AV - FP&L - Martin Power Plant

Return Receipt

Your document:	REVISED DRAFT Title V Permit No.: 0850001-016-AC/0850001-017AV - FP&L - Martin Power Plant
was received by:	Craig Arcari/PGBU/FPL
at:	12/05/2006 07:38:53 AM

FLORIDA POWER & LIGHT COMPANY, ENVIRONMENTAL SERVICES DEPT., P.O.BOX 14000, JUNO BEACH, FL 33408

FPL

Friday , September 22, 2006

Scott M Sheplak, Professional Engineer
Bureau of Air Regulation
Division of Air Resources Management Department of
Environmental Protection
2600 Blair Stone Road, MS#5505
Tallahassee, FL 32399-2400

Dear Mr. Seplak,

Florida Power & Light Company is providing comments to the Draft Martin Plant Title V Permit Modification and Construction Permit Modification (0850001-016-AC and 0850001-017-AV) in the attached document.

Should you have any questions, or need any additional information, please do not hesitate to contact me at either 561-691-2894 *(office)* or 561-676-1838 *(mobile)*.

Sincerely,

John C Hampp

John C. Hampp
Principal Specialist

Florida Power & Light Company
JES-JB
700 Universe Blvd.
Juno Beach, FL 33408
Email: john_hampp@fpl.com

FPL Comments Re: Martin Title V Technical Evaluation and Preliminary Determination

<u>Excess Emissions During Operational Switching from Natural Gas to Fuel Oil on Combined Cycle Units 8</u>

FPL disagrees with the department's conclusion that:

"The reverse situation does not require the same consideration of excess emissions. Operational switching from natural gas to fuel oil firing can be accomplished without a significant load reduction. Additionally, the fuel oil firing mode is characterized by greater allowable and actual emissions. The Department believes that any excess emissions from natural gas to fuel oil switching can be accommodated by the permitted limits for fuel oil firing."

FPL requests that the Department reconsider its conclusion and incorporate allowable excess emissions for operational switching from Natural Gas to Fuel Oil on Unit 8 combustion turbines. Although operational switching from gas to oil can be accomplished at higher loads, it does not allow the option of aborting the transfer. At lower loads, GE process control logic allows enough time to perform a pressure check of the fuel nozzles, which will provide us an early indication of transfer issues. The same check can be made at high loads, but without the ability to abort. Combustion instability in a burner can (eg. a plugged fuel oil nozzle) will cause a combustion issue, resulting in a CT trip requiring a subsequent restart. The restart of the CT will result in higher overall NOx than the shorter duration excess emissions from a CT load reduction to allow the switch from natural gas to fuel oil with the option of aborting and avoiding a unit trip and subsequent restart.

Martin Title V Permit Comments

Subsection A. Facility Description (Page 2)

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

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

The facility also includes one auxiliary boiler, two diesel generators (one unregulated), two storage oil tanks, a mechanical cooling tower, four natural gas fuel heaters.

FPL suggests the following description as a replacement:

The facility also includes one auxiliary boiler, four diesel generators (three unregulated), and a mechanical cooling tower.

FPL has previously notified the department of the following:
1) two diesel generators were added to service Combined Cycle Unit 8 in 2005
2) the two storage tanks contain low sulfur distillate which has a vapor pressure less than 3.5kPa and are not subject to NSPS Kb
3) The four natural gas heaters planned in the project were replaced with electric gas heaters during construction of the plant.

Subsection B. Summary of Emissions Unit ID Nos. and Brief Descriptions (Page3)
The following emission unit changes are recommended:

EU ID No. -013 Four gas-fired fuel heaters for Unit 8 (DELETE)
EU ID No. -014 Two distillate oil storage tanks for Unit 8 gas turbines (DELETE)
EU ID No. -015 Diesel Generators (for Units -001,-002, -011, -012,-017,and -018)

Section II Facility-wide (Page5)

The following Condition should be deleted from this section:

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

Test Methods & Procedures (page 26)

> *FROM:*
> *B.23 The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 as follows: U.S. EPA. Method 20 (40 CFR 60, Appendix A) shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen.*
>
> *TO:*
> *B.23 The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 as follows: U.S. EPA. Method 20* ***or US EPA Method 7E*** *(40 CFR 60, Appendix A) shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen.*

Test Methods & Procedures (page 28)

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

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

For each combustion turbine that operates with power augmentation for less than 200 hours during the previous federal fiscal year, the annual performance tests when operating with power augmentation for the current federal fiscal year of operation are not required.

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

For each combustion turbine that fires distillate oil for less than ***400*** *hours during the previous federal fiscal year, the annual performance tests when firing distillate oil for the current federal fiscal year of operation are not required.* ***Combustion turbines firing more than 400 hours will also be required to demonstrate compliance with PM standards.***

For each combustion turbine that operates with power augmentation for less than ***400*** *hours during the previous federal fiscal year, the annual performance tests when operating with power augmentation for the current federal fiscal year of operation are not required.*

Recordkeeping and Reporting Requirements (page 31)

FROM:
B.40. To determine compliance with the oil firing heat input limitation, the permittee shall maintain daily records of fuel oil consumption and hourly usage for each turbine and heating value for each fuel.

TO:
B.40. To determine compliance with the oil firing heat input ***curves****, the permittee shall maintain daily records of fuel oil consumption and hourly usage for each turbine and heating value for each fuel.*

Subsection C. This section addresses the following emissions unit.(page 36)

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

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

Subsection C. Emission Limitations and Standards.(page 37)

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

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

on oil. However, testing is required for permit renewal purposes ***if the unit operated on oil during the previous 5 years.****. [40 CFR 60.44c(c); and, Rule 62-297.310(7), F.A.C.]*

Subsection C. Reporting and Recordkeeping Requirements.(page 38)

Note: numbering for paragraphs need to be changed to sequential paragraphs beginning with "(a)" or should note that the unlisted paragraphs are "reserved".

Subsection E. Common Conditions (Page 43)

The following emission unit changes are recommended:

EU ID No. -013 Four gas-fired fuel heaters for Unit 8 (DELETE)
EU ID No. -014 Two distillate oil storage tanks for Unit 8 gas turbines (DELETE)
EU ID No. -015 Diesel Generators (for Units -001,-002. -011, -012,-017,and -018)

Subsection H. This section addresses the following emission units (page 51)

FROM:
Compliance assurance monitoring (CAM) does not apply since these emissions units have NOx CEMS which are used to demonstrate continuous compliance. The units have the following manufacturers' CEMs installed: (a) Thermo Environmental Instruments (Model 42CHL) for NOx, and (b) Servomex (Model 1420C) for O2.

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

Subsection H. Equipment (page 53)

FROM:

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

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

TO:

H.3. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain four General Electric Model PG7241FA gas turbine-electrical generator sets each with a generating capacity of 170 MW. Each gas turbine shall include dual-fuel capability. Ancillary equipment includes an inlet air filtration system, and an evaporative inlet air-cooling system. The gas turbines will utilize the DLN combustors to increase overall unit efficiency. Electic fuel heaters will preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas.

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

Subsection H. Excess Emissions (page 57)

FROM

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

TO:

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

FPL has provided comments in response to the technical evaluation and preliminary evaluation supporting the need for allowable excess emissions for the gas-to-oil fuel switch.

Subsection H. Emissions Performance Testing (page 59)

FROM:

H.20. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period.

TO:

H.20. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions. ***CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the CO and NOx standards.*** *Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period.*

Subsection H. Continuous Monitoring Requirements (page 60)

FROM:
(g) Data Exclusion. Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, and DLN tuning. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 16 and 18 of this section.

TO:
(g) Data Exclusion. Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, and DLN tuning. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. ***15*** *and* ***16*** *of this section.*

Subsection H. Continuous Monitoring Requirements (page 61) (H23)

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

TO:
{Permitting Note: The actual water-to-fuel ratio will vary depending on operating conditions and load.}

Subsection I. (Emission Unit No. 013, page 64)

Delete this section in its entirety. Electric Fuel Heaters were constructed in place of the originally specified Gas Fired Fuel Heaters.

Subsection J. Equipment (page 65)

FROM:
J.1. Cooling Tower: The permittee is authorized to install one new 18-cell mechanical draft cooling tower with the following design characteristics: a circulating water flow rate of 310,000 gpm; design hot/cold water temperatures of 104° F/90° F; a design air flow rate of 1,386,055 per cell;

TO:
J.1. Cooling Tower: The permittee is authorized to install one new ***22****-cell mechanical draft cooling tower with the following design characteristics: a circulating water flow rate of 310,000 gpm;*

Subsection K. (Emission Unit No. 014, page 66)

Delete this section in its entirety. The two fuel oil storage tanks will be used for storage of low sulfur distillate which has a vapor pressure less than 3.5kPa and are not subject to NSPS Kb.

Appendix I-1 List of Insignificant Emission Units and/or Activities (page 71)

Add the following emission unit/activity:

8 **Main Liquid Fuel** Two distallate fuel storage tanks.75" Vents to Atmosphere 2" Liquid Fuel Drain Tank Vent (235 gallon) 8" Vent with Filter for Unit 8 Liquid Fuel Storage Tank (2,100,000 gallon each)

Memorandum

Florida Department of Environmental Protection

TO:	Trina Vielhauer
THRU:	A.A. Linero
FROM:	Teresa Heron T.H.
DATE:	November 30, 2006
SUBJECT:	Re-issuance of DRAFT Title V Operation Permit Revision FP&L Martin Units 3, 4 and 8 DEP File Nos. 0850001-016-AC and 0850001-017-AV

With this action we are withdrawing and replacing a previously distributed DRAFT Revision of the FP&L Martin Power Plant Title V Operation Permit that was intended to incorporate the conditions of the PSD Permit for the recently constructed Combined Cycle Unit 8.

The re-issued package will replace the one we distributed on August 21, 2006. FP&L did not public notice the original package and had enough changes to justify re-issuance rather than to address them after public notice.

Some of the original and subsequent requests require changes to the unexpired PSD Permit for Unit 8. Others require establishment of new enforceable conditions related to Units 3 and 4 that were constructed in the early 1990's under PSD Permits that have long since expired. With respect to Unit 8, FP&L requests:

- Eight hours instead of six hours of excess emissions during the cold startup of the Unit 8 steam turbine-electrical generator (STG);
- Recognition of some diesel engines (for which individual permits were not required) in the Title V Permit;
- Changes to fuel oil storage tank conditions to reflect non-applicability of 40CFR60, Subpart Kb;
- Description of a 22-cell (instead of 18-cell) cooling tower; and
- Removal of gas heater references because they installed electric heaters instead.

Because the underlying Unit 8 PSD Permit has not expired, we are simultaneously issuing a modification of that permit to make the requested changes and reflecting those changes within the Title V Operation Permit Revision.

With respect to Units 3 and 4, FP&L requests:

- Operation of Combined Cycle Units 3 and 4 in the range of 90 to 100 percent of the permitted heat rate (in accordance with the rules) during the annual compliance tests rather than the 95-100% requirement under a DARM Guidance (since rescinded); and
- Recognition of power augmentation (PA) for Units 3 and 4.

We are addressing FP&L's requests regarding Units 3 and 4 in the PSD Permit Modification for Unit 8. There are some testing requirements or clarifications included in this action. The Draft PSD Permit Modification is being processed concurrently with the Title V Operation Permit Revision.

AAL/th

Attachments

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Telephone: (850) 488-0114 FAX: (850) 922-6979

Colleen M. Castille
Secretary

December 1, 2006

Electronically Sent – Received Receipt Requested

Mr. Craig Arcari, Plant General Manager
Martin Power Plant
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Re: Martin Power Plant - Intent to Issue Air Permits
DEP Files Nos. 0850001-016-AC and 0850001-017-AV
Facility ID: 0850001; ORIS Code: 0643

Dear Mr. Arcari:

Attached are copies of a Draft Air Construction Permit Modification and a DRAFT Title V Air Operation Permit Revision for the Martin Power Plant located in the western part of unincorporated Martin County, approximately seven miles north of Indiantown, on State Road 710, Martin County, Florida. The Department's Intent to Issue Permits, the Public Notice of Intent to Issue Air Permits (the Public Notice), Statement of Basis, and a Technical Evaluation are also included.

Electronic versions of the permits 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 at www.dep.state.fl.us/air/eproducts/ards/default.asp.

The Department hereby withdraws the Intent to Issue, the DRAFT Title V Operation Permit Revision, and the Draft Air Construction Permit Modification distributed on August 21, 2006 and replaces those documents with the ones enclosed.

The enclosed Public Notice must be published as soon as possible. Proof of publication, i.e., newspaper affidavit, must be provided to the Department'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 Department's proposed action to A. A. Linero, Program Administrator, at the above letterhead address. If you have any other questions, please contact Teresa Heron at 850/921-9529 or Mr. Linero at 850/921-9523.

Sincerely,

Trina L. Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

TLV/aal/th

Enclosures

In the Matter of an Application for a Construction Permit Modification
and a Title V Permit Revision by:

Florida Power & Light Company 700 Universe Boulevard Juno Beach, Florida 33408	DEP Files: 0850001-016-AC and 0850001-017-AV Related Files: PSD-FL-146C and PSD-FL-327B Facility: Martin Power Plant Location: Martin County

INTENT TO ISSUE AIR PERMITS

The Department of Environmental Protection (Department) gives notice of its intent to issue:

- An Air Construction Permit Modification primarily to establish certain startup, testing, and operational conditions for Martin Power Plant Combined Cycle Units 3, 4 and 8; and,
- A Title V Air Operation Permit Revision to incorporate Combined Cycle Unit 8 and the concurrent Air Construction Permit Modification.

Copies of the Draft Air Construction Permit Modification and the DRAFT Title V Air Operation Permit Revision are attached. The details are provided in the application file specified above. The reasons for issuance are stated below.

The applicant, Florida Power & Light Company, applied on March 3, 2006 for modification of conditions in two previously issued Air Construction (PSD) Permits and revision of the Title V Air Operation Permit for the Martin Power Plant. The facility is located in the western part of unincorporated Martin County, approximately seven miles north of Indiantown, on State Road 710.

The Department 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, 62-212, 62-213, and 62-214. This source is not exempt from construction and Title V permitting procedures. The Department has determined that an Air Construction Permit Modification is required to establish the startup, testing, and operational conditions for Martin Power Plant Combined Cycle Units 3, 4 and 8 and a Title V Air Operation Permit Revision is required to incorporate Combined Cycle Unit 8.

The Department intends to issue the Air Construction Permit Modification and the Title V Air Operation Permit Revision based on the belief that reasonable assurances have been provided to indicate that the construction activity and 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, 62-214, 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 PERMITS (Public Notice). The Public 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 Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax: 850/922-6979), 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 may result in the denial of the permits pursuant to Rule 62-110.106(11), F.A.C.

The Department will issue the Air Construction Permit Modification and the PROPOSED Title V Air Operation Permit Revision and subsequent FINAL Title V Air Operation Permit Revision, in accordance with the conditions of the attached Draft Air Construction Permit Modification and the DRAFT Title V Air Operation Permit Revision unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the Draft Air Construction Permit Modification issuance action for a period of 14 (fourteen) days from the date of publication of the Public Notice. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this Draft Air Construction Permit Modification, the Department shall revise the Draft Air Construction Permit Modification and require, if applicable, another Public Notice.

The Department will accept written comments concerning the DRAFT Title V Air Operation Permit Revision issuance action for a period of 30 (thirty) days from the date of publication of the Public Notice. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Title V Air Operation Permit Revision, the Department shall further revise the DRAFT Title V Air Operation Permit Revision 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, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2242; Fax: 850/245-2303).

Petitions filed by the permit applicant or any of the parties listed below must be filed within 14 (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 14 (fourteen) days of publication of the public notice or within 14 (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 Department for notice of agency action may file a petition within 14 (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 Department'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 Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the Department on the application(s) 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 permit revision. Any petition shall be based only on objections to the permit revision 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 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.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Trina L. Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE AIR PERMITS (including the combined Public Notice, Technical Evaluation and Preliminary Determination, Draft Air Construction Permit Modification, and the DRAFT Title V Air Operation Permit Revision) were sent electronically (with Received Receipt) before the close of business on 12/1/06 to the person(s) listed below.

Craig Arcari, Florida Power & Light Company: craig_arcari@fpl.com
John Hampp, Florida Power & Light Company: john_hampp@fpl.com
Darrel Graziani, P.E., Southeast District Office: darrel.graziani@dep.state.fl.us
Jim Little, U.S. EPA, Region 4: little.james@epamail.epa.gov
Kennard F. Kosky, P.E., Golder Associates, Inc.: kkosky@golder.com
Mike Halpin, P.E., Siting Office: mike.halpin@dep.state.fl.us

Clerk Stamp

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

Barbara J. Friday 12/1/06
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMITS

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft Air Construction Permit Modification No. 0850001-016-AC
DRAFT Title V Operation Permit Revision No. 0850001-017-AV
FPL Martin Power Plant - Martin County

The Department of Environmental Protection (permitting authority) gives notice of its intent to issue an Air Construction Permit Modification and a Title V Air Operation Permit Revision to the Florida Power & Light Company for the Martin Power Plant, located in the western part of unincorporated Martin County, approximately seven miles north of Indiantown, on State Road 710. The applicant's name and address are: Mr. Craig Arcari, Plant Manager, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, FL 33408.

This facility consists of two oil and natural gas fired conventional steam electric generating stations (Units 1 and 2) and three natural gas fueled combined-cycle units (Units 3, 4 and 8). Combined Cycle Unit 8 is a nominal 1,150 megawatt (MW) unit that recently began operation. It consists of four combustion turbine/heat recovery steam generator (CT/HRSG) sets and a nominal 470 MW steam turbine electric generator (STG). Pollutants from Unit 8 are controlled by use of inherently clean natural gas, Dry Low NO_X/CO combustors, and selective catalytic reduction (SCR).

All physical construction related to Combined Cycle Unit 8 is complete and the unit is in operation. A Modification of the current Unit 8 Air Construction/PSD Permit will be issued that will allow excess emissions from individual CT/HRSG sets for a period of eight rather than six hours during future cold startups of the 470 MW STG. Such cold startups of a STG are infrequent and typically years apart for baseloaded combined cycle units.

The Draft Air Construction/PSD Permit Modification addresses a request by FP&L to allow annual testing of Units 3 and 4 to be conducted at 90 to 100 percent of capacity rather than 95 to 100 percent. The request is consistent with the requirements in the original Air Construction/PSD Permit for Units 3 and 4. The Modification will also recognize a high power mode of operation known as power or steam augmentation. This is a feature included in the original design and actual construction of Units 3 and 4 within the permitted heat input and emission limits.

The DRAFT Title V Operation Permit Revision incorporates the conditions of the Unit 8 Air Construction/PSD Permit as well as the Draft Air Construction Permit Modification.

The Department will issue the Air Construction Permit Modification and the PROPOSED Title V Air Operation Permit Revision and subsequent FINAL Title V Air Operation Permit Revision, in accordance with the conditions of the Draft Air Construction Permit Modification and the DRAFT Title V Air Operation Permit Revision unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the Draft Air Construction Permit Modification issuance action for a period of 14 (fourteen) days from the date of publication of this Notice. Written comments should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this Draft Air Construction Permit, the Department shall issue a Revised Draft Air Construction Permit and require, if applicable, another Public Notice.

The Department will accept written comments concerning the DRAFT Title V Air Operation Permit Revision for a period of thirty (30) days from the date of publication of this Public Notice. 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 Department at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 or facsimile (850/922-6979). As part of his or her comments, any person may also request that the Department hold a public meeting on this permitting action. If the Department determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly (http://faw.dos.state.fl.us/) and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Department 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 Title V Air Operation Permit Revision, the Department shall issue a further revision of the DRAFT Title V Air Operation Permit Revision 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, 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 14 (fourteen) days of publication of the public notice or within 14 (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 Department for notice of agency action may file a petition within 14 (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 Department'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 Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the Department on the application(s) 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 permit revision. Any petition shall be based only on objections to the permit revision 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 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:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Southeast District Office
400 North Congress Avenue
West Palm Beach, Florida 33416-5425
Telephone: 561/681-6600
Fax: 561/681-6790

The complete project file includes the Statement of Basis, Draft Permits, the application(s), and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, South Permitting Section, at the above address, or call 850/488-0114, for additional information.

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Florida Power & Light Company
Martin Power Plant

Martin County

Modifications of Previous PSD Permit Conditions
Units 3, 4 and 8

Air Construction Permit No. 0850001-016-AC

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Permitting South

December 1, 2006

BACKGROUND

The applicant submitted an application to revise the facility's Title V Operation Permit to include the recently constructed Combined Cycle Unit 8 and to incorporate revisions to be made in a concurrent Air Construction Permit Modification. The requested Air Construction Permit Modification is primarily to establish certain startup, testing, and operational conditions for Martin Power Plant Combined Cycle Units 3, 4 and 8. This Technical Evaluation addresses their requests for a concurrent Air Construction Permit modification.

AIR CONSTRUCTION PERMIT MODIFICATION

Following are the requested changes by issuance of an Air Construction Permit Modification:

- FP&L requests that required annual compliance testing of Combined Cycle Units 3 and 4 be conducted within a range of 90 to 100 percent of the capacity (corrected for ambient conditions) rather than a range of 95 to 100 percent.
- FP&L requests recognition of a high power mode for Combined Cycle Units 3 and 4 known as power or steam augmentation that was included in the original design and construction.
- FP&L requests addition of EPA Test Methods 25, 25A for the determination of VOC emissions and EPA Test Method 7E for the determination of NO_X concentrations for Units 3 and 4.
- FP&L requests to change the word "limitation" to "curves" in the sentence "to determine compliance with the oil firing heat input limitation" in Units 3 and 4. This was not implemented.
- FP&L requests extension of the allowable excess emissions period from six to eight hours during the "cold" startup of the 470 MW steam turbine-electrical generator (STG) for Unit 8. The single Unit 8 STG operates with the steam raised by the four heat recovery steam generators (HRSGs). FP&L requests extension of startup to allow use of only two combustion turbines to start up the STG. The excess emissions are from low load operation of the CT/HRSG sets as they power and provide steam for the cold STG startup.
- FP&L requests excess emissions for a (1) one-hour duration when switching from natural gas to distillate fuel oil on Unit 8.
- FP&L requests deletion of references to gas-fired heaters since they installed electrical heaters to heat the fuel for Unit 8.
- FP&L requests deletion of references of the two 2,100,000 gallon distillate fuels storage vessels serving Unit 8, as regulated emissions units in the PSD Permit and transferring them to Appendix I, Insignificant Emissions Units in the Title V Operation Permit Revision.
- FP&L requests recognition of two diesel generators added to service combined cycle Unit 8 in the Title V Permit.
- FP&L requests recognition of the installation of 22-cell instead of 18-cell mechanical draft cooling tower serving Unit 8.

PERMIT NO. PSD-FL-146 FOR UNITS 3 AND 4

The following sections address the requested changes to conditions in the original PSD Permit and its subsequent revision applicable to Units 3 and 4.

Annual Testing of Units 3 and 4 at 90-100 percent of capacity

The original AC/PSD Permit issued in 1991 did not specify the rate at which Units 3 and 4 must be tested during annual compliance tests. The applicable regulation required that testing be conducted at capacity which was defined as 90 to 100 percent of the maximum operation rate allowed by the permit per Paragraph 62-297.310(2), F.A.C.

In 1996 the Department, at the request of FP&L, added a condition to the PSD Permit to reflect the Department's December 1995 Guidance DARM-EM-05, "Rate of Operation During Compliance Testing for Combustion Turbines". The guidance defined capacity as 95-100 percent of the manufacturer's rated heat input to the combustion turbine achievable for the average ambient (or conditioned) air temperature during the test. The guidance also required testing at capacity as re-defined.

The mentioned Guidance was subsequently rescinded. The Department will issue an AC/PSD Permit Modification that reflects the original rule definition of capacity and testing requirements. The exact language is in the attached Draft Air Construction Permit Modification.

The Department will include the wording that marks capacity to ambient or conditioned air. The additional wording accounts for the fact that capacity varies throughout the year with respect to temperature. For example the "Winter Rating" of such units could easily be 15 percent greater than the "Summer Rating". The change will also be reflected by revision of Condition B.3 of the Title V Operation Permit as discussed above.

Recognition of Power (Steam) Augmentation on Units 3 and 4

Combined Cycle Units 3 and 4 were permitted in 1991 with enforceable limitations on heat input, NO_X and CO. The concept of power augmentation was not specifically addressed in the original AC/PSD Permit.

Power augmentation involves the routing of some steam from the HRSG back to the expansion portion of the CT for purpose of additional power production from the electrical generator directly associated with the CT. Normally such steam is routed to the Steam Turbine Generator (STG). In certain applications, some steam is actually routed back to the CT combustors for NO_X control. In the present case, the CTs have Dry Low NO_X Combustors (DLN) and, except for rare use of fuel oil, do not require steam injection for NO_X control.

By letter dated February 1993 (during the construction of Units 3 and 4) FP&L advised the Department:

"With the completion of detailed engineering and shop testing, refinement of the information previously provided to DER as part of the certification process has occurred in two general areas. The first is the development of the peak mode of operation (i.e. power augmentation)."

The details submitted by FP&L in 1993 and 1994 are included as Attachment II to this Technical Evaluation. During the same time, the Department was in the process of modifying the relevant AC/PSD Permit. Apparently both FP&L and the Department did not at the time consider it necessary to revise the open AC/PSD Permit to recognize power augmentation as a distinct mode of operation.

By letter dated August 2, 1994 FP&L submitted a description of the goals for the Unit 3 and 4 testing program. The manner by which testing would be conducted while practicing power augmentation was described and is given in the previously referenced Attachment II.

It is clear that the unit must comply with the same emission limits during power augmentation as required under the normal mode for natural gas operation. It is also clear that power augmentation is practiced sparingly.

For clarification purposes, the Department will add a provision in the AC/PSD Permit Modification to recognize this mode of operation. The exact language is given in the attached Draft Air Construction Permit Modification. For reference, this mode is already recognized in the current Title V Operation Permit and no changes are required within the present Title V Operation Permit Revision.

Additional Approved Test Methods for Combined Cycle Units 3 and 4

Method 7E is an approved test method for determination of NO_X concentrations. The Department will allow its use in conjunction with other approved EPA Methods to determine both NO_X concentrations and mass emissions.

Methods 25 and 25A are approved test methods for Total Hydrocarbons. The applicant may use these methods in lieu of the previously approved Method 18 to determine VOC emissions and may, as needed, use certain provisions of Method 18 to subtract non-VOC fractions (e.g. methane) from the values obtained by Methods 25 or 25A.

NO_X emissions data collected during the annual NO_X continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the required annual performance test. The new conditions are shown in the attached draft air construction permit modification.

Testing Conditions Related to Power Augmentation at Units 3 and 4

This permit also specifies that testing is required in the power augmentation mode for any unit that operated more than 400 hours in the power augmentation mode during the previous federal fiscal year. The units have CEMS for NO_X emissions and the units are subject to the same NO_X limitations under power augmentation as they are under normal operation. The exact language is shown in the attached Draft Air Construction Permit Modification.

Compliance with the Oil Firing Heat Input Limitation

FP&L requested that Condition No. 14 of the original PSD Permit (PSD-FL-146) for Units 3 and 4 be modified as follows:

14. To determine compliance with the oil firing heat input ~~limitation~~ curves, the permittee shall maintain daily records of fuel oil consumption and hourly usage for each turbine and heating value for each fuel. All records shall be maintained for a minimum of five (5) years after the date of each record and shall be made available to representatives of the Department upon request.

According to FP&L, "the distillate fuel piping and other subsequent systems were removed and these units are currently not capable of burning distillate fuel oil. Testing on oil was never done as these units have never operated on distillate fuel oil and are currently incapable of doing so."

Condition 14 relates back to Condition 1 of the original PSD Permit that includes limits on heat input as follows:

1. The maximum heat input to each CT shall neither exceed 1966 MMBtu/hr while firing natural gas, nor 1846 MMBtu/hr while firing fuel oil (@40 °F). For coal derived gas firing the maximum heat input to each CT shall not exceed 2100 MMBtu (@75 °F). These heat input limitations are subject to change. Any changes shall be provided at least 90 days before commercial operation for each fuel available to the site which a unit is capable of firing, at which time this condition may be modified to reflect those parameters. Each combined cycle unit's fuel consumption shall be continuously determined and recorded.

The Department does not consider it necessary to make the requested change in Condition 14. Because the units are "currently incapable" of firing fuel oil, the Department believes that enabling this capability will require a specific permit. At that time, conditions similar to No. 1 can be considered and specified in terms of a different heat input limitation or characteristic curve.

At this time, the Department has no information regarding plans to enable fuel oil firing and has not received characteristic heat input/temperature curves. No changes will be made at this time on Condition 14.

PSD PERMIT FOR UNIT 8 NO. PSD-FL-327

The following sections address the requested changes to conditions in the original PSD Permit and its subsequent revision applicable to Units 3 and 4.

Cold Start-up of Combined Cycle Unit 8 STG

The Department conducted a full determination of best available control technology (BACT) during the original permitting of Unit 8 in 2003 and required use of inherently clean fuels, installation of DLN combustors and a selective catalytic reduction (SCR) system.

A cold startup of a STG that is part of a four-on-one combined cycle unit is an uncommon event and indicates that there has been a prolonged shutdown of about 1,000 MW of typically baseloaded capacity. A cold STG startup might occur at intervals between one and ten years.

A longer period of excess emissions for the cold startup of the STG provides greater flexibility to the operator in the manner by which different CT/HRSG sets are blended in and out within the allowable excess emissions period. According to the applicant, the longer period allows for use of only two CTs to start up the STG (and HRSGs). This is a lower emitting scenario because less CTs operate in the higher emitting (non DLN) modes.

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

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

The FP&L analysis is included as Attachment I to this Statement of Basis. The rationale provided is acceptable to the Department. The exact changes to the original language in the PSD Permit for Unit 8 are indicated in the attached Draft Air Construction Permit Modification.

<u>Excess Emissions during Operational Switching from Natural Gas to Fuel Oil on Combined Cycle Unit 8</u>

The Department previously recognized the need for excess emissions considerations for switching from fuel oil to natural gas during operation of the combustion turbines. The Air Construction/PSD Permit for Combined Cycle Unit 8 provides that for <u>fuel oil-to-gas</u> fuel switching, excess emissions shall not exceed one (1) hour in any 24-hour period.

The excess emissions are at least partially caused by the need to reduce load to less than 50 percent of capacity at which level the dry low NO_X/CO features of the GE 7FA combustion turbines are not fully employed.

Operational switching from <u>natural gas to fuel oil</u> firing <u>can</u> be accomplished without a significant load reduction. However, FP&L requests the Department consider the possibility that FP&L may want to make the switch at low load instead of high load, thus requiring as much time as a fuel oil to natural gas switch. According to FP&L:

"Although operational switching from gas to oil can be accomplished at higher loads, it does not allow the option of aborting the transfer. At lower loads, GE process control logic allows enough time to perform a pressure check of the fuel nozzles, which will provide us an early indication of transfer issues. The same check can be made at high loads, but without the ability to abort. Combustion instability in a burner can (e.g. a plugged fuel oil nozzle) will cause a combustion issue, resulting in a CT trip requiring subsequent restart. The restart of the CT will result in higher overall NO_X than the shorter duration excess emissions from a CT load reduction to allow the switch from natural gas to fuel oil with the option of aborting and avoiding a unit trip and subsequent restart."

The described scenario describes infrequent switches as it is much more economical to operate the units on natural gas than fuel oil. As discussed in a previous section above, Units 3 and 4 have never operated on fuel oil while Unit 8 has that capability. The Department will modify the condition as indicated in the attached Draft Air Construction Permit Modification to allow FP&L to conduct its fuel switches in the manner they have described.

Deletion of References to Gas-fired Heaters

Gas-fired heaters to heat natural gas used by the combustion turbines were not installed. Instead FP&L installed electrical heaters and requested removal of the references to the gas-fired heaters. The Department will remove those references as requested. The changes are shown in the attached Draft Air Construction Permit Modification.

Final Design and as-Constructed Description of the Mechanical Cooling Tower

FP&L requested that the PSD Permit be modified to reflect that the as-constructed cooling tower has 22 instead of 18 cells. The changes are shown in the attached Draft Air Construction Permit Modification.

40CFR60, Subpart Kb Requirements

FP&L requested removal of references to the two 2,100,000 gallon distillate fuel storage vessels as regulated emissions units. FP&L requested transferring them to Appendix I, Insignificant Emissions Units.

The Department agrees that these large storage vessels are no longer subject to 40 CFR 60, NSPS Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.

Section 60.110b(c) exempts all vessels with greater than 151 m^3 (40,000 gallons) storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa). Information collected by the Department indicates that the true vapor pressure of typical low sulfur (less than 0.05% S) is less than 1 kPa.

The Department will clarify non-applicability of Subpart Kb. However the Department will keep the emissions unit designation. The tanks were part of a project that was subject to PSD for VOC. The use of 0.05% sulfur fuel is part of the BACT requirement. The condition will be modified consistent with some of the more recent permits (such as West County) that are not subject to Subpart Kb, but are subject to PSD for VOC and the maintenance of records is required. The changes are indicated in the attached Draft Air Construction Permit Modification.

Attachment I

Cold Start-up of the Steam Turbine/Generator on a Four-on-One Combined Cycle

The following scenario is specific to Manatee Unit 3, but also applies to Martin Unit 8 and Turkey Point Unit 5. All three units have "four-on-one" combined cycles that consist of: 4 General Electric 7FA combustion turbine-electrical generators (CTs); four duct-fired heat recovery steam generators (HRSGs); and a single steam turbine-electrical generator (STG).

Although a cold steam start-up is a complex procedure done infrequently, actual operating experience now shows that the six hours originally permitted by the PSD and AC permits is inadequate to successfully, and smoothly, execute a cold Steam Turbine start. The Steam Turbine Start Up process has CTs sequentially started so that the respective HRSG is able to provide a sufficient quantity of steam at the appropriate temperature, pressure, and flow to maintain accurate Steam Turbine speed control and warm the STG slowly. This requires that the CT's be run at low loads, during which time the full Dry Low NO_X (DLN) features are not fully enabled.

Typically, one CT is started ahead of the others, and a second CT is started somewhat later. When the steam conditions from the second CT/HRSG match the pressure and temperature of the first HRSG, it is "blended" by means of valving operations with the first CT/HRSG steam and the start-up progresses. Later, a third CT/HRSG combination is started, warmed up, and "blended". This is done in order to "unblend" the first CT/HRSG as it approaches the 6-hour excess emissions window. That is, the steam from the first CT's HRSG is routed by means of valving operations from the Main Steam Turbine Header to the condenser. The first CT's load is then ramped up to a point where the SCR can be placed into service and render the CT in compliance with its normally permitted emissions. Afterward, it is "re-blended" with the other two starting units.

This process of "unblending" one CT while ensuring the other CT's have been sequentially started up, and in the right configuration to provide steam of adequate temperature, pressure, and quantity to be "blended" to the steam turbine has proven to be challenging. During the "unblending" and "blending" valving operations, CT HRSG's temperatures, pressure and drum levels become very difficult to control.

Any HRSG instability can trip the CT's which would require a new restart and potentially more excess emissions, either from a restart of the CTs, or more typically, the start-up must be postponed until the next calendar day as insufficient start-up time remains in the current 24-hour period. Postponing the start-up until the next day necessitates that the needed generation is supplied from elsewhere. In the case of Manatee Unit 3 (or Martin Unit 8 or Turkey Point Unit 5), alternate residual fuel oil-fired units are greater emitters.

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

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

A two CT start-up with 8-hours of excess emissions versus a three CT start-up with 6-hours of excess emissions allows: greater operational flexibility; a simplified start-up process; less risk from unintended CT trips associated with blending/unblending operations; and a modest net reduction in NOx mass emissions over the duration of the start-up.

Table 1. PMT UNIT 3 COLD TURBINE S/U JUNE 12, 2005. NOx emissions in pounds from CEM data

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

Source: FP&L

Attachment II

Power Augmentation on Combined Cycle Units 3 and 4 (2/1993 and 8/1994)

Power Augmentation

Units 3 & 4 at Martin utilize advanced combustion turbines (CT's). The term "advanced" refers to a very high firing temperature design. The higher firing temperature requires use of exotic materials coupled with very sophisticated internal cooling techniques. This design approach results in a machine which operates very close to its true maximum capability in normal operation (e.g., base load).

Conventional power generation combustion turbines have two ratings, base and peak loads. Conventional units operate at a base load firing temperature of 1900° F to 2100° F and have reasonable design margins. Peak load is a temporary operating mode which is accomplished by simply raising the firing temperature by 50° F to 100° F in the conventional combustion turbine.

Peak load operation for Units 3 & 4 cannot be accomplished by simply raising the firing temperature since these units operate at 2350° F. To obtain a peak load rating for these units, steam is injected into the combustion turbine at temperatures lower than the combustion gases.

The lower temperature steam allows overfiring of the CT without exceeding 2350° F. Furthermore, the additional mass flow contributed by the steam produces more power from the turbine. GE refers to this peaking mode of operation as "power augmentation". When operating in this mode, emission limits will remain within the already permitted levels.

Operating in this mode has economic and environmental benefits. Economically, the additional power supply is at a very desirable incremental heat rate, thus lowering fuel costs. Environmentally, the use of this peaking mode displaces other higher emission units in the FPL system. Therefore, the benefits accrue to both the environment and FPL customers.

Martin Units 3 & 4 are designed to use the power augmentation mode sparingly. The auxiliary equipment necessary to support power augmentation in limited in capacity. For example, the water treatment plant and demineralizer can support continuous power augmentation for only 48 hours at a time. On a consistent daily use basis, Units 3 & 4 would only be able to run two hours per day in the power augmentation mode. FPL expects to use this peak mode of operation approximately 228 hours per year. This estimate is based on several assumptions that cannot be verified without actual plant operational data and yearly weather patterns.

III. Steam Power Augmentation Testing of CT operation for both physical performance and compliance with permitted emission limits for NOx, CO and VOC will be conducted with steam augmentation occurring from zero up to maximum steam injection levels. Based on these operation tests, adjustments will be made to the control constants and fuel split schedules as discussed above to maintain emissions at permitted levels and to control combustor stability and dynamics.

Month, day, 2007

Electronically Sent – Received Receipt Requested

Mr. Craig Arcari, Plant General Manager
Martin Power Plant
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Re: DEP File No. 0850001-016-AC
PSD-FL-146C and PSD-FL-327B
Combined Cycle Units 3, 4 and 8

Dear Mr. Arcari:

The Florida Department of Environmental Protection ("the Department") reviewed your application to make some minor modifications to the PSD Permits related to Combined Cycle Units 3, 4 and 8 in conjunction with issuance of a Title V Operation Permit Renewal that incorporates the recently constructed Unit 8. The changes primarily address startup, testing, and as-built equipment descriptions.

The PSD Permit for Unit 8 has not yet expired. Therefore the changes requested will be addressed as an Air Construction Permit Modification and will also address the requests related to Units 3 and 4 to make them enforceable so they can be included in the requested Title V Operation Permit Renewal.

The Department addressed each request in its Technical Evaluation dated December 1, 2006. Following are the new conditions and changes to previous conditions applicable to Units 3, 4 and 8.

NEW CONDITIONS APPLICABLE TO COMBINED CYCLE UNITS 3 AND 4

The following condition supersedes Specific Condition No. 1 of PSD-FL-146 as previously modified on September 6, 1996.

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

   Operation During Testing. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. Permitted capacity and operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.

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

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

[Rule 62-4.160(2), Rule 62-297.310(2), and Rule 62-210.200(PTE), F.A.C.; PSD-FL-146 and PSD-FL-146A (0850001-002 and 0850001-003-AC issued 9/6/96); Specific Condition No. 1. Rescission of Guidance DARM-EM-05; and Applicant Request dated April 5, 2006, Permit No. 0850001-016-AC.]

The following condition supersedes Specific Condition No. 10 of PSD-FL-146 as previously modified on September 6, 1996.

10. <u>Compliance Test Methods</u>: Tests shall be conducted using EPA reference methods, or equivalent, in accordance with 40 CFR 60 Appendix A.

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

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

** EPA Method 18 may be conducted to account for the non-regulated methane fraction of the measured VOC emissions.

The stack test for each turbine shall be performed within 10% of the maximum heat rate input for the tested operating temperature. See Specific Condition No.1 of PSD-FL-146C for utilization of ambient temperature versus heat input curves during compliance testing.

Initial (I) compliance tests shall be performed on each Combustion Turbine using both fuels (based on information provided by the applicant, initial testing using distillate oil has not been done). It is not necessary to plan the firing of a fuel solely to complete the initial compliance test; instead, the initial test may be postponed until such time as the untested fuel is ready for service.

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

For each combustion turbine that fires distillate oil for less than 400 hours during the previous federal fiscal year, the annual performance tests when firing distillate oil for the current federal fiscal year of operation are not required. Combustion turbines firing more than 400 hours on oil will also be required to demonstrate compliance with PM standards.

For each combustion turbine that operates with power augmentation for less than 400 hours during the previous federal fiscal year, the annual performance tests when operating with power augmentation for the current federal fiscal year of operation are not required. During power augmentation each unit shall comply with the emissions limits stated in Specific Condition No. 4 of PSD-FL-146.

[40 CFR Appendix A; Rule 62-204.800, F.A.C. and Rule 62-297.310(7)(a)4., F.A.C.; PSD-FL-146, Specific Condition No. 10; and applicant request letter dated April 5, 2006.]

MODIFICATIONS OF AIR CONSTRUCTION/PSD PERMIT 327 - COMBINED CYCLE UNIT 8

Specific conditions listed in Section III, Part A, No. 3, and No. 16, the entire Part B, and Part D, No. 1 are hereby modified; new Specific Condition No. 5 is added to Part D as shown below. Double-underline denotes additions and strikethrough (~~strikethrough~~) indicates deletions.

Section III, Part A - Combined Cycle Gas Turbines (EU 011, 012, 017 and 018)

Specific Condition No. 3 is modified as follows:

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

Specific Condition No. 16.a is modified as follows:

Steam Turbine/HRSG System Cold Startup: For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed ~~six~~ eight 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.}*

Specific Condition No. 16.d is modified as follows:

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

The rest of Specific Condition 16 is unchanged.

Section III, Part B. Gas-Fired Fuel Heaters (EU 013)

This Part is deleted since FP&L installed Electrical Heaters to heat the fuel.

Section III, Part C. Cooling Tower (EU 020)

Specific Condition No. 1 is modified as follows:

Cooling Tower: The permittee installed one new 22-cell mechanical draft cooling tower with the following design characteristics: a circulating water flow rate of 310,000 gpm; design hot/cold water temperatures of 104° F/90° F; a design air flow rate of 1,386,055 per cell; a liquid-to-gas air flow ratio of 1.4; and drift eliminators with a drift rate of no more than 0.001 percent. ~~The permittee shall submit the final design details within 60 days of selecting the vendor.~~ [Application; Design]

(No other changes were made to Section III, Part C)

Section III, Part D. Distillate Oil Storage Tank (EU 014)

Specific Condition No. 1 is modified as follows:

NSPS Subpart Kb Applicability: The distillate oil tanks are not subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb. ~~except for the record keeping requirements specified below.~~

[40 CFR 60.110b(a) and (c) and Rule 62-204.800(7)(b), F.A.C.]

A new condition, Specific Condition No. 5, is added to Section III, Part D as follows:

Fuel Oil Records: The permittee shall keep readily accessible records showing the maximum true vapor pressure of the stored liquid. The maximum true vapor pressure shall be less than 3.5 kPa. Compliance with this condition may be demonstrated by using the information from the respective MSDS for the low or ultralow sulfur fuel oil stored in the tanks.
[62-4.070(3) F.A.C.]

{Permitting Note: An evaluation of several Material Safety Data Sheets (MSDS) by the Department demonstrated that the vapor pressure is much less than 3.5 kPa for low sulfur fuel oil and for ultralow sulfur fuel oil.}

(No other changes were made to Section III, Part D)

A copy of this letter shall be filed with the referenced permit and shall become part of the permit. Any party to this permitting decision (order) has the right to seek judicial review of it under Section 120.68 of the Florida Statutes, by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Joseph Kahn, Director
Division of Air Resource Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this PERMIT MODIFICATION was sent electronically (with Received Receipt) before the close of business on ________________ to the person(s) listed below:

Craig Arcari, Florida Power & Light Company (Craig_Arcari@fpl.com)
John Hampp, Florida Power & Light Company (John_Hampp@fpl.com)
Darrel Graziani, P.E., Southeast District Office (Darrel.Graziani@dep.state.fl.us)
Jim Little, U.S. EPA, Region 4 (Little.James@epamail.epa.com)
Kennard F. Kosky, P.E., Golder Associates, Inc. (kkosky@golder.com)
Mike Halpin, P.E., Power Plant Siting Office (Mike.Halpin@dep.state.fl.us)

Clerk Stamp

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

________________________ __________
(Clerk) (Date)

STATEMENT OF BASIS

Title V Permit Revision No. 0850001-017-AV
Federal Acid Rain Program ORIS Code **6043**

Florida Power and Light Company
Martin Power Plant
Martin County

These permitting actions are issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

EXISTING FACILITY

This facility is owned by Florida Power & Light Company (FP&L) and is known as the Martin Power Plant, near Indiantown in Martin County, Florida. It consists of:

- Two 863 megawatts (MW) residual fuel oil and natural gas fired conventional steam electric generating units (Units 1 and 2), that started up in 1980/81 and are equipped with multicyclones and Low NO_X burners;
- Two nominal 500 MW natural gas fueled combined cycle units (Units 3 and 4), that started up in 1994 and are equipped with Dry Low NO_X (DLN) combustors;
- One nominal 1,150 MW natural gas-fueled combined cycle unit (Unit 8), that started up in 2005 and is equipped with DLN combustors and selective catalytic reduction (SCR) systems for nitrogen oxides control; and
- Ancillary equipment including an auxiliary steam boiler, gas heaters, diesel generators, fuel oil storage tanks, and mechanical cooling towers.

PRESENT AUTHORITY TO OPERATE FACILITY

With the exception of Unit 8, the facility operates under Title V Operation Permit 0850001-013-AV effective January 1, 2004 and expires on December 31, 2008. Combined Cycle Unit 8 operates under the authority of Air Construction/PSD Permit No. 0850001-010-AC (PSD-FL-327). The Unit 8 Air Construction/PSD Permit authorized construction of two combustion turbine electrical generators (CTs) along with four duct-fired heat recovery steam generators (HRSGs), a single steam turbine-electrical generator (STG) and ancillary equipment. The Unit 8 project incorporated the new construction along with two previously constructed Simple Cycle CTs (Units 8A and 8B) into a single Combined Cycle Unit 8. The mentioned construction permit was issued April 16, 2003 and expires on December 31, 2006.

PURPOSE OF REVISION TO TITLE V OPERATION PERMIT

The primary purpose of the present application is to revise the facility's Title V Operation Permit to include the recently constructed Combined Cycle Unit 8 and to incorporate the revisions in the concurrent Air Construction Permit Modification.

CONCURRENT AIR CONSTRUCTION PERMITTING ACTIONS

FP&L requested a concurrent Air Construction Permit Modification primarily to establish certain startup, testing, and operational conditions for Martin Power Plant Combined Cycle Units 3, 4 and 8. The Department evaluated each of these requests in the separate Technical Evaluation dated December 1, 2006 that supports the concurrent Air Construction Permit modification.

A Modification of the current Unit 8 Air Construction Permit will be issued that will allow excess emissions from individual CT/HRSG sets for a period of eight rather than six hours during future cold startups of the 470 MW STG. Such cold startups of a STG are infrequent and typically years apart for baseloaded combined cycle units.

The Draft Air Construction Permit Modification also addresses a request by FP&L to allow annual testing of Units 3 and 4 to be conducted at 90 to 100 percent of capacity rather than 95 to 100 percent. The request is consistent with the requirements in the original Air Construction/PSD Permit for Units 3 and 4. The Modification will also recognize a high power mode of operation known as power or steam augmentation. This is a feature included in the original design and actual construction of Units 3 and 4 within the permitted heat input and emission limits.

This DRAFT Title V Operation Permit Revision incorporates the conditions of the Unit 8 Air Construction Permit as well as the conditions in the Draft Air Construction Permit Modification.

REVISIONS TO TITLE V OPERATION PERMIT 0850001-013-AV

The changes are shown below (~~strikethrough~~) or double-underlined.

Section II. Facility - Wide Conditions

FP&L requests deletion of Section II, Specific Condition No. 11 that states:

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

The Department notes that the condition is verbatim from the original air construction permits issued in 1977 for the two 863 megawatt units. The Department will move the condition to Section III, Subpart A, related to Units 1 and 2 so that it is not applicable to units constructed thereafter. The condition reference is A.48 in the attached Draft Title V Operation Permit Revision.

Section III. Emissions Units and Conditions

Subsection B. Specific Condition 3. Subsection B contains the conditions applicable to Combined Cycle Units 3 and 4. Changes to Specific Condition 3 are needed to allow annual testing in the range of 90 to 100 percent of capacity. The rationale is given in the Technical Evaluation in support of the Draft air construction permit modification where the underlying enforceable conditions are being changed. The condition has been rewritten to accurately state the Department's rule and the concurrent air construction permit modification. Specific Condition B.3 is modified as follows:

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

Operation During Testing. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted c~~C~~apacity is defined as ~~95~~ 90 to 100 percent of the ~~manufacturer's rated heat input achievable for the average ambient (or conditioned) air temperature during the test~~ maximum operation rate allowed by the permit. Permitted capacity and operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.

If it is impractical to test at permitted capacity, ~~then the units~~ an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.

~~In such cases~~, If tested at less than capacity, the entire heat input versus inlet temperature curves will be adjusted by the increment equal to the difference between the design heat input value and ~~105~~ 110 percent of the value reached during the test. Data, curves, and calculations necessary to demonstrate the heat input rate correction at both design and test conditions shall be submitted to the Department with the compliance test report.

[Rule 62-4.160(2), Rule 62-297.310(2), and Rule 62-210.200(PTE), F.A.C.; PSD-FL-146 and PSD-FL-146A (0850001-002 and 0850001-003-AC issued 9/6/96); Specific Condition No. 1. Rescission of Guidance DARM-EM-05; and Applicant Request dated April 5, 2006, Permit No. 0850001-016-AC]

Subsection B. Specific Condition 27. Subsection B, Specific Condition 27 relates to annual testing. The condition is being revised to reflect certain changes authorized through the concurrent Air Construction Permit Modification. These include use of EPA Methods 25 and 25A and 7E to determine VOC and NO_X emissions during all conditions (including power augmentation). Specific Condition B. 27 is reorganized and modified as follows:

B.27. ~~It is not necessary to plan the firing of a fuel solely to complete the initial compliance test; instead, the initial test may be postponed until such time as the untested fuel is ready for service~~.

Compliance Test Methods. Tests shall be conducted using EPA reference methods, or equivalent, in accordance with ~~the July 1, 1996 version of~~ 40 CFR 60 Appendix A.

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

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

** EPA Method 18 may be conducted to account for the non-regulated methane fraction of the measured VOC emissions.

The stack test for each turbine shall be performed within 10% of the maximum heat rate input for the tested operating temperature. See Specific Condition B.3 for utilization of ambient temperature versus heat input curves during compliance testing. ~~Annual (A) compliance tests shall be performed on each combustion turbine with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests shall be conducted using EPA reference methods, or equivalent, in accordance with the July 1, 1996 version of 40 CFR 60 Appendix A.~~

Initial (I) compliance tests shall be performed on each Combustion Turbine using both fuels. (Note: Based on information provided in the Title V Permit Application, initial testing using distillate oil has not been done). ~~See Specific Condition B.3 for utilization of ambient temperature versus heat input curves during compliance testing.~~ It is not necessary to plan the firing of a fuel solely to complete the initial compliance test; instead, the initial test may be postponed until such time as the untested fuel is ready for service.

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

For each combustion turbine that fires distillate oil for less than 400 hours during the previous federal fiscal year, the annual performance tests when firing distillate oil for the current federal fiscal year of operation are not required. Combustion turbines firing more than 400 hours on oil will also be required to demonstrate compliance with PM standards.

For each combustion turbine that operates with power augmentation for less than 400 hours during the previous federal fiscal year, the annual performance tests when operating with power augmentation for the current federal fiscal year of operation are not required. During power augmentation each unit shall comply with the emission limits stated in Specific Condition No. B.6.

[40 CFR Appendix A; Rule 62-204.800, F.A.C. and Rule 62-297.310(7)(a)4., F.A.C.; PSD-FL-146, Specific Condition No. 10; and applicant request letter dated July 28, 1998 and April 5, 2006.]

Subsections F and G. Subsections F and G comprise the Specific Conditions applicable to Units 8A and 8B when they operated as Simple Cycle Units. These Subsections will be marked "reserved" and the Specific Conditions are deleted in their entirety. The operation of Units 8A and 8B will be fully addressed in Subsection H that describes the operation of the recently constructed and tested Combined Cycle Unit 8.

Subsections H, I and J. New Subsections H, I and J include all of the Specific Conditions applicable to the new Combined Cycle Unit 8 (including ancillary equipment) authorized under AC/PSD Permit No. 0850001-010-AC (PSD-FL-327) and any modification thereto.

All conditions of PSD-FL-327 including the present AC/PSD Permit Modification are transferred verbatim except for obsolete construction conditions. Please refer to the new Subsections H, I, and J in the attached DRAFT Title V Operation Permit Revision.

Section IV - Acid Rain Part

Section IV is updated to reflect the Combined Cycle Unit 8 operation system. This involves adding Units 8C and 8D. Previously permitted Units 8A and 8B that, together with Units 8C and 8D, comprise Unit 8 were added during the previously issued Title V Operation permit.

Compliance Plan CP-1

The revised Compliance Plan CP-1 addresses test requirements applicable to Combined Cycle Unit 8 when the individual combustion turbines operate and are tested in high power modes known as peaking and power augmentation. The revised Compliance Plan CP-1 replaces the previous CP-1 that addressed similar incomplete testing of simple cycle Units 8A and 8B (that now comprise part of Unit 8).

Additional Applicable Requirements

No changes were requested by the applicant with respect to the incorporation of new applicable requirements. However, the Department proposes to incorporate in this permit the recent promulgation or modifications of Federal regulations related to combustion turbines.

40CFR60, Subpart GG. The Department is clarifying the applicability of 40CFR Part60, Subpart GG – Standards of Performance for Stationary Gas Turbines. In the previous permits, 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 clarifies 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).

40CFR63, Subpart YYYY. This subpart is the MACT for combustion turbines. By electronic communication dated October 26, 2004, the Department previously determined that the combustion turbines that comprise Combined Cycle Unit 8 qualify as existing units for purposes of the 40CFR63, Subpart YYYY. Existing combustion turbines are not required to meet the notification requirements or the emission limitations of Subpart YYYY.

40CFR63, Subparts DDDDD and ZZZZ. The Department includes these subparts since there are emission units at this facility subject to 40 CFR 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, or Institutional Boilers or Process Heaters and 40 CFR 63, Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE), adopted by reference in Rule 62-204.800(11), F.A.C. These requirements are added as new Appendices DDDDD and ZZZZ (part of the permit).

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

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

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

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

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

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

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Additional Appendices and Attachments listed on Placard Page are part of this Permit

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

DRAFT Permit Revision No. 0850001-017-AV
Facility ID No. 0850001
SIC Nos.: 49, 4911
Project: Title V Air Operation Permit Revision

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

This Title V air operation permit revision is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit revision.

Referenced attachments made a part of this permit revision:

Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix U-1, List of Unregulated Emissions Units and/or Activities
APPENDIX TV-6, TITLE V CONDITIONS (version dated 02/12/02)
APPENDIX SS-1, STACK SAMPLING FACILITIES (version dated 10/27/96)
Phase II Acid Rain Part Renewal Application received July 3, 2003
NSPS Custom Fuel Monitoring Schedule dated October 14, 1997
Appendix CP-1, Compliance Plan dated August 29, 2003 (updated August 21, 2006)
Appendix A, NSPS Subpart A, General Provisions
Appendix A-1, NESHAP Subpart A, General Provisions
Appendix Da, NSPS Subpart Da Requirements for Duct Burners
Appendix GG, NSPS Subpart GG Requirements for Gas Turbines
Appendix SC, Standard Conditions
Appendix BD, Best Available Control Technology Determination
Appendix Dc: NSPS Requirements for Small Steam Generating Units, 40 CFR 60, Subpart Dc
Appendix DDDDD: NESHAP Subpart DDDDD, Requirements for Industrial, Commercial, and Institutional Boilers and Process Heaters
Appendix GG: NSPS Requirements for Gas Turbines, 40 CFR 60, Subpart GG
Appendix ZZZZ: NESHAP Subpart ZZZZ, Requirements for Stationary Reciprocating Internal Combustion Engines
FIGURE 1, Summary Report- Gaseous and Opacity Excess Emissions and Monitoring System Performance Report

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

Joseph Kahn, Director
Division of Air Resource Management

JK/tlv/aal/th

Section I. Facility Information

Subsection A. Facility Description

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

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

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

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

This facility also includes one auxiliary boiler, four diesel generators (three unregulated), two storage oil tanks, a mechanical cooling tower, and four electrical heaters. Also included in this permit is an additional unregulated emissions unit identified as facility-wide particulate matter (PM) and volatile organic compounds (VOC) emissions.

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

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

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

Unregulated Emissions Units and/or Activities

-015	Diesel Generator (for Units -001, 002, 011, 012, 017 and 018)
-016	Facility-wide Fugitive Emissions for PM and VOCs

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

Subsection C. Relevant Documents

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

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

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

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

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

Section II. Facility-wide Conditions

The following conditions apply facility-wide:

1. Appendix TV-6, Title V Conditions, is a part of this permit.

   {Permitting note: Appendix TV-6, Title V Conditions is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided one copy when requested or otherwise appropriate.}

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

3. Prevention of Accidental Releases (Section 112(r) of CAA).

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

   RMP Reporting Center
   P.O. Box 1515
   Lanham-Seabrook, Maryland 20703-1515
   Telephone: 301/429-5018

   and,

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

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

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

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

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

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

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

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

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

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

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

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

{Note: This condition implements the requirements of Rules 62-296.320(4)(c)1., 3., & 4., F.A.C. (see Condition 57. of Appendix TV-6, Title V Conditions).}

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

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

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

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

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

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

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

    {Permitting Note: This condition implements the requirements of Rules 62-213.440(3)(a)2. & 3., F.A.C. (see Condition 51. of Appendix TV-6, Title V Conditions).}

13. 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.]

14. Compliance Plan. Appendix CP-1, Compliance Plan, is a part of this permit. Emissions units 011, 012, 017 and 018 have not, to date, been operated under the gas firing with peaking, and/or gas firing with power augmentation modes. Therefore, a compliance plan is included to cover initial testing requirements for these alternate methods of operation for emissions of CO and NO_x. Please see Specific Conditions **H.9**, **H.18** and **H.19.** [Rule 62-213.440(2), F.A.C.]

Section III. Emissions Units and Conditions.

Subsection A. This section addresses the following emissions units.

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

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

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

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

The following conditions apply to the emissions units listed above:

General

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

Essential Potential to Emit (PTE) Parameters

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

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

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

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

Emission Limitations and Standards

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

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

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

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

A.6. [Reserved.]

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

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

A.9. Sulfur Dioxide.

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

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

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

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

A.10. Nitrogen Oxides.

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

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

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

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

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

where:

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

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

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

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

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

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

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

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

<u>Excess Emissions</u>

A.12. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. [40 CFR 60.11(d)]

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

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

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

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

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

2. <u>Sulfur dioxide.</u> Excess emissions for affected facilities are defined as:

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

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

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

Test Methods and Procedures

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

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

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

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

A.18. Compliance.

(b) The owner or operator shall determine compliance with the particulate matter, SO_2, and NOx standards in 40 CFR 60.42, 60.43, and 60.44 as follows:

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

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

Where,

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

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

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

F_d = factor as determined from Method 19.

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

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

ii. The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration (%O_2). The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of all the individual O_2 sample concentrations at each traverse point.

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

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

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

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

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

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

   i. The sampling site and location shall be the same as for the SO_2 sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

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

   iii. The NOx emission rate shall be computed for each pair of NOx and O_2 samples. The NOx emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

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

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

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

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

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

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

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

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

   where:

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

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

   %CO2 = carbon dioxide concentration, percent dry basis.

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

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

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

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

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

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

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

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

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

4. For Method 6, Method 6C may be used. Method 6A may also be used whenever Methods 6 and 3B data are specified to determine the SO_2 emission rate, under the conditions in 40 CFR 60.46(d)(1).

5. For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O_2 concentration (%O_2) for the emission rate correction factor.

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

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

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

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

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

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

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

Continuous Monitoring Requirements

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

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

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

A.26. The owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under 40 CFR 60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under 40 CFR 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under 40 CFR 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under 40 CFR 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in 40 CFR 60.13(c), that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine opacity compliance. [40 CFR 60.11(e)(5)]

A.27. Owners and operators of all continuous emission monitoring systems (CEMS) installed in accordance with the provisions of this part shall check the zero (or low-level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in Appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified. For continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments except that for systems using automatic zero adjustments. The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

{1}Not applicable.

where:

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

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

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

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

[40 CFR 60.45(c)]

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

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

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

where:

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

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

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

where:

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

[40 CFR 60.45(e)]

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

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

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

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

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

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

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

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

SI Units:

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

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

English Units:

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

SI Units:

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

English Units:

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

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

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

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

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

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

where:

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

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

n = the number of fuels being burned in combination.

[40 CFR 60.45(f)]

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

Recordkeeping and Reporting Requirements

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

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

[40 CFR 60.7(a)(4)]

A.37. The owner or operator subject to the provisions of 40 CFR 60 shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or, any periods during which a continuous monitoring system or monitoring device is inoperative. [40 CFR 60.7(b)]

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

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

[40 CFR 60.7(c)(1), (2), (3), and (4)]

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

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.

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

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

A.40. (1)Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

i. For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

ii. The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and

iii. The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in 40 CFR 60.7(e)(2).

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in 40 CFR 60.7(e)(1) and (e)(2).

[40 CFR 60.7(e)(1)]

A.41. The owner or operator subject to the provisions of 40 CFR 60 shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and, all other information required by 40 CFR 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least 5 (five) years following the date of such measurements, maintenance, reports, and records.
[40 CFR 60.7(f); Rule 62-213.440(1)(b)2.b., F.A.C.]

A.42. Records shall be kept of each delivery of "on-specification" used oil with a statement of the origin of the used oil and the quantity delivered/stored for firing. In addition, monthly records shall be kept of the quantity of "on-specification" used oil fired in these emissions units. The above records shall be maintained in a form suitable for inspection, retained for a minimum of five years, and be made available upon request. See Specific Conditions **A.11.**, **A.21.**, and **A.43.**
[Rule 62-213.440(1)(b)2.b., F.A.C.; and 40 CFR 279.61 and 761.20(e)]

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

A.44. Until such time when the Environmental Protection Agency (EPA) promulgates final rules regarding fuel sampling and test methods, the Department will accept the current fuel sampling and analysis program, provided that daily as fired fuel oil samples are composited and analyzed for sulfur content on a monthly basis to demonstrate compliance with fuel oil sulfur content limits.

Quarterly reports containing the results of the monthly fuel oil sampling and analysis shall be submitted to the Department no later than thirty (30) days after the end of each quarter.

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

A.45. 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

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

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

A.48. Please be advised that the Department does not condone nor authorize the permittee to by-pass waste materials from either air or wastewater facilities at any time that would result in a violation of the rules and regulations of the Department. In case of breakdown or lack of proper functioning of the facility causing or likely to cause discharge of improperly treated sewage or air emissions, it shall be the duty of the owner of the facility to promptly notify the Department. In addition to notifying this Department, the permittee shall notify the local County Health Officer. The owner of the impaired facility causing the violation shall be responsible for any and all damages which may result. If violations of State standards occur, enforcement actions may be initiated.
[AC43-4037; and AC43-4038]

Subsection B. This section addresses the following emissions units.

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

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

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

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

The following conditions apply to the emissions units listed above:

General

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

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

Essential Potential to Emit (PTE) Parameters

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

{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.}

Operation During Testing. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. Permitted capacity and operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.

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

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

[Rule 62-4.160(2), Rule 62-297.310(2), and Rule 62-210.200(PTE), F.A.C.; PSD-FL-146 and PSD-FL-146A (0850001-002 and 0850001-003-AC issued 9/6/96); Specific Condition No. 1. Rescission of Guidance DARM-EM-05; and Applicant Request dated April 5, 2006, Permit No. 0850001-016-AC.]

B.4. Methods of Operation.

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

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

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

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

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

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

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

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

Emission Limitations and Standards

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

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

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

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

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

[b] Exclusive of background concentrations.

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

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

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

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

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

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

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

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

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

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

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

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

Excess Emissions

B.12. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

B.13. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized. [Rule 62-210.700(2), F.A.C.]

B.14. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

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

B.16. Reserved.

<u>Monitoring of Operations</u>

B.17. At all times, including periods of startup, shutdown and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. [40 CFR 60.11(d)]

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

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

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

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

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

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

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

(1) Monitoring of fuel nitrogen content shall not be required if NG is the only fuel being fired in the gas turbines.

(2) Sulfur Monitoring

a. Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternative method. The reference methods are ASTM D1072-80, ASTM D3031-81, ASTM D3246-81, and ASTM D4084-82, as referenced in 40 CFR 60.335(b)(2), or the latest edition(s).

b. This custom fuel monitoring schedule shall become effective on the date this permit becomes valid. Effective the date of this custom schedule, sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333, then sulfur monitoring shall be conducted once per quarter for six quarters. If monitoring data is provided by the applicant which demonstrates consistent compliance with the requirements herein the applicant may begin monitoring as per the requirements of 2(c).

c. c. If after the monitoring required in item 2(b) above, or herein, the sulfur content of the fuel shows little variability and, calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333, sample analysis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.

d. d. Should any sulfur analysis as required in items 2(b) or 2(c) above indicate noncompliance with 40 CFR 60.333, the owner or operator shall notify the Department of such excess emissions and the custom schedule shall be re-examined by the Environmental Protection Agency. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

(3) If there is a change in fuel supply, the owner or operator must notify the Department of such change for re-examination of this custom schedule. A substantial change in fuel quality shall be considered as a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

(4) Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of five years, and be available for inspection by personnel of federal, state, and local air pollution control agencies.

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

Test Methods and Procedures

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

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

B.22. The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with the permitted NO_X standard at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer. This specific condition does **not apply** if only natural gas is fired in the turbine. [40 CFR 60.335(c)(2)]

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

U.S. EPA. Method 20 or Method 7 (40 CFR 60, Appendix A) shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NO_X emissions shall be determined at each of the load conditions specified in 40 CFR 60.335(c)(2). See Specific Condition **B.20.** that describes the approved Custom Fuel Monitoring Schedule for Natural Gas for this facility. After initial testing, subsequent annual NO_X compliance tests for NO_X limits that are more stringent than 40 CFR 60, Subpart GG, shall not require an ISO correction or testing at four load points; rather, the testing shall be done at capacity (see Specific Condition **B.3.**). However, when testing shows that NO_X

emissions exceed the standard when operating at capacity, the permittee shall recalibrate the NO_X emission control system using emission testing at four load points.
[40 CFR 60.335(c)(3); and applicant request letter dated July 29, 1998]

B.24. The owner or operator shall determine compliance with the sulfur content standard of 0.5 percent, by weight, as follows: ASTM D 2880-96 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-90(94)E-1, D 3031-81(86), D 4084-94, or D 3246-92 shall be used for the sulfur content of gaseous fuels (incorporated by reference-see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator. See specific condition B.20 that describes the approved Custom Fuel Monitoring Schedule for Natural Gas for this facility.
[40 CFR 60.335(d)]

B.25. To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in 40 CFR 60.335 (a) and 40 CFR 60.335(d) of 40 CFR 60.335 to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency. See Specific Condition **B.20** that describes the approved Custom Fuel Monitoring Schedule for Natural Gas for this facility. [40 CFR 60.335(e)]

B.26. The owner or operator shall provide, or cause to be provided, stack sampling and performance testing facilities as follows:
(1) Sampling ports adequate for test methods applicable to such facilities.
(2) Safe sampling platform(s).
(3) Safe access to sampling platform(s).
(4) Utilities for sampling and testing equipment.
[40 CFR 60.8; PSD-FL-146, Specific Condition No. 21]

B.27. Compliance Test Methods: Tests shall be conducted using EPA reference methods, or equivalent, in accordance with 40 CFR 60 Appendix A.

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

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

** EPA Method 18 may be conducted to account for the non-regulated methane fraction of the measured VOC emissions.

The stack test for each turbine shall be performed within 10% of the maximum heat rate input for the tested operating temperature. See Specific Condition No.1 of PSD-FL-146C for utilization of ambient temperature versus heat input curves during compliance testing.

Initial (I) compliance tests shall be performed on each Combustion Turbine using both fuels (based on information provided by the applicant, initial testing using distillate oil has not been done). It is not necessary to plan the firing of a fuel solely to complete the initial compliance test; instead, the initial test may be postponed until such time as the untested fuel is ready for service.

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

For each combustion turbine that fires distillate oil for less than 400 hours during the previous federal fiscal year, the annual performance tests when firing distillate oil for the current federal fiscal year of operation are not required. Combustion turbines firing more than 400 hours on oil will also be required to demonstrate compliance with PM standards.

For each combustion turbine that operates with power augmentation for less than 400 hours during the previous federal fiscal year, the annual performance tests when operating with power augmentation for the current federal fiscal year of operation are not required. During power augmentation each unit shall comply with the emissions limits stated in Specific Condition No.4 of PSD-FL-146.
[40 CFR Appendix A; Rule 62-204.800, F.A.C. and Rule 62-297.310(7)(a)4., F.A.C.; PSD-FL-146, Specific Condition No. 10; and applicant request letter dated April 5, 2006.]

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

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

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

Continuous Monitoring Requirements

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

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

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

(c) A malfunction means any sudden and unavoidable failure of air pollution equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

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

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

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

B.33. If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, Appendix B, of 40 CFR 60 before the performance test required under 40 CFR 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under 40 CFR 60.8 or within 30 days thereafter in accordance with the applicable performance specification in Appendix B of 40 CFR 60. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act. [40 CFR 60.13(c)]

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

B.35. Owners and operators of all continuous emission monitoring systems (CEMS) installed in accordance with the provisions of this part shall check the zero (or low-level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in Appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified. For continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments except that for systems using automatic zero adjustments. The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

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

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

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

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

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

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

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

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

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

Recordkeeping and Reporting Requirements

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

B.41. The permittee shall have required sampling tests of the emissions performed within 60 after achieving the maximum turbine firing rate, but not later than 180 days from the start of operations. Thirty (30) days notice prior to the initial sampling test and fifteen (15) days notice before subsequent annual testing shall be provided to the Southeast District Office. Written reports of the tests shall be submitted to the Southeast District Office within 45 days of test completion.
[PSD-FL-146, Specific Condition No. 17]

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

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

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

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

Nitrogen oxides. Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with the permitted nitrogen oxide standard by the initial performance test required in 40 CFR 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the initial performance test. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

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

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

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

[40 CFR 60.7(a)(4)]

B.45. The owner or operator subject to the provisions of 40 CFR 60 shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or, any periods during which a continuous monitoring system or monitoring device is inoperative. [40 CFR 60.7(b)]

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

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

[40 CFR 60.7(c)(1), (2), (3), and (4)]

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

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.

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

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

B.48. Reporting Frequency Reduction.

(1) Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

i. For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

ii. The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and

iii. The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in 40 CFR 60.7(e)(2).

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the non complying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in 40 CFR 60.7(e)(1) and (e)(2).

[40 CFR 60.7(e)(1)]

B.49. The owner or operator subject to the provisions of 40 CFR 60 shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and, all other information required by 40 CFR 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least 5 (five) years following the date of such measurements, maintenance, reports, and records.
[40 CFR 60.7(f); Rule 62-213.440(1)(b)2.b., F.A.C.]

Miscellaneous

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

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

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

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

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

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

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

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

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

Subsection C. This section addresses the following emissions unit.

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

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

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

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

The following conditions apply to the emissions unit listed above:

General

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

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

Essential Potential to Emit (PTE) Parameters

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

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

Emission Limitations and Standards

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

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

C.5. Visible Emissions. Visible emissions shall not exceed twenty (20) percent opacity (6-minute average), except for one six-minute period per hour of not more than twenty seven (27) percent opacity. This standard applies at all times, except during periods of startup, shutdown, or malfunction. [40 CFR 60.43c(c) & (d)]

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

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

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

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

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

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

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

Test Methods and Procedures

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

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

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

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

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

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

Where

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

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

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

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

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

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

Recordkeeping and Reporting Requirements

C.17. (a) Reserved.

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

(c) Reserved.

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

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

(1) Calendar dates covered in the reporting period.

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

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

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

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

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

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

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

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

(1) For distillate oil:

i. The name of the oil supplier; and

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

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

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

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

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

[40 CFR 60.48c]

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

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

[40 CFR 60.7(a)(4)]

C.19. The owner or operator subject to the provisions of 40 CFR 60 shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or, any periods during which a continuous monitoring system or monitoring device is inoperative. [40 CFR 60.7(b)]

C.20. Reporting Frequency Reduction.

(1) Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

i. For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

ii. The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and

iii. The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in 40 CFR 60.7(e)(2).

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in 40 CFR 60.7(e)(1) and (e)(2). **Note:** As long as the auxiliary boiler operates only during startup and shutdown and for

periodic maintenance testing, requirements under this specific condition are not applicable. See Specific Condition **C.3.**

[40 CFR 60.7(e)(1)]

C.21. The owner or operator subject to the provisions of 40 CFR 60 shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and, all other information required by 40 CFR 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least 5 (five) years following the date of such measurements, maintenance, reports, and records.
[40 CFR 60.7(f); Rule 62-213.440(1)(b)2.b., F.A.C.]

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

Subsection D. This section addresses the following emissions unit.

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

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

NESHAP and NSPS Applicability

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

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

Essential Potential to Emit (PTE) Parameters

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

Emission Limitations and Standards

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

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

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

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

Test Methods and Procedures

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

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

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

Subsection E. Common Conditions.

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

The following conditions apply to the emissions units listed above:

Test Methods and Procedures

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

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

E.2. Applicable Test Procedures.

(a) Required Sampling Time.

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

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

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

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

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

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

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

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

TABLE 297.310-1
CALIBRATION SCHEDULE

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

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

E.3. Determination of Process Variables.

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

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

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

E.4. The permittee shall comply with the requirements contained in APPENDIX SS-1, Stack Sampling Facilities, attached to this permit. [Rule 62-297.310(6), F.A.C.]

E.5. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

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

a. Did not operate; or

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

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

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

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

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

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

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

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

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

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

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

Recordkeeping and Reporting Requirements

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

E.7. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

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

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

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.

10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

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

Subsection F. Reserved.

PSD-FL-286 for the simple cycle units is superseded by PSD-FL-327 for the "4-on-1" combined cycle combustion turbine system. Refer to Subsections H, I and J.

Subsection G. Reserved.

PSD-FL-286 for the simple cycle units is superseded by PSD-FL-327 for the "4-on-1" combined cycle combustion turbine system. Refer to Subsections H, I and J.

Subsection H. This section addresses the following emissions units.

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

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

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

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

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

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

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

The following conditions apply to the emission units listed above:

Applicable Standards and Regulations

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

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

Equipment

H.3. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain four General Electric Model PG7241FA gas turbine-electrical generator sets each with a generating capacity of 170 MW. Each gas turbine shall include a modern automated gas turbine control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system, an evaporative inlet air-cooling system, and a bypass stack for simple cycle operation. The gas turbines will utilize DLN combustors. Electric fuel heaters will preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas.

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

H.4. Gas Turbine NOx Controls

(a) *DLN Combustion*: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NOx emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the simple cycle permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

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

(c) *(SCR) System*: The permittee shall install, tune, operate, and maintain a selective catalytic reduction (SCR) system to control NOx emissions from each gas turbine during combined cycle operation when firing either natural gas or distillate oil. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NOx emissions and ammonia slip.

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

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

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

Performance Restrictions

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

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

H.8. Methods of Operation: Subject to the restrictions and requirements of this permit, the gas turbines may operate under the following methods of operation.

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

(b) *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Each gas turbine shall fire no more than 500 hours of distillate oil during any consecutive 12 months.

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

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

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

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

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

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

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

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

Emissions Limitations and Standards

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

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

a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 10. Compliance with the 24-hour CO CEMS standards shall be determined separately for each method of operation based on the hours of operation for each method. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

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

c. The fuel specifications established in Condition No. H.8 of this section combined with the efficient combustion design and operation of each gas turbine represents the Best Available Control Technology (BACT) determination for PM/PM_{10} 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: PM_{10} emissions for* *gas firing are estimated at 9 lb/hour for simple cycle operation, 11 lb/hour for combined cycle operation, and 17 lb/hour for combined cycle operation with duct burning. PM_{10} emissions for oil firing are estimated at 17 lb/hour for simple cycle operation and 37 lb/hour for combined cycle operation.}*

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

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

f. Subject to the requirements of Condition No. H.21 of this section, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027.

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

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

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

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

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

Excess Emissions

H.12. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

H.13. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

H.14. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

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

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

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

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

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

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

H.16. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

Emissions Performance Testing

H.17. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

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

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

H.18. Special Compliance Determinations: The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. Each gas turbine shall be stack tested to demonstrate compliance with the emission standards for CO, NOx, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated for each unit configuration (i.e., simple cycle and combined cycle operation), but not later than 180 days after startup of each unit configuration. Each unit shall be tested when firing natural gas and distillate oil. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the CO and NOx standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NOx mass rate emissions standards. CO and NOx emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. CO and VOC emissions tests performed during simple cycle operation may be used to satisfy the test requirements for similar operation in combined cycle mode. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

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

H.20. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the CO and NOx standards. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period.

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

[Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

H.21. Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

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

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

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

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis.

[Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

Continuous Monitoring Requirements

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

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

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

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

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

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

(f) *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. {Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NOx emissions depending on the use of alternate methods of operation}. [Rule 62-212.400(BACT), F.A.C.]

(g) *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, and DLN tuning. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 15 and 16 of this section. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

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

{Permitting Note: Compliance with these requirements ensure compliance with the other applicable CEM system requirements such as: NSPS Subparts Da and GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.}
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

H.23. Water Injection Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a monitoring system to continuously measure and record the water-to-fuel ratio when firing distillate oil. The permittee shall document the water-to-fuel ratio required to meet permitted emissions levels over the range of load conditions allowed by this permit. The NOx CEMS is used to demonstrate compliance with the NOx emissions standards. During NOx CEMS downtimes or malfunctions, the permittee shall monitor the water-to-fuel ratio and operate at a level that is consistent with the documented flow rate for the gas turbine load condition.

{Permitting Note: The actual water-to-fuel ratio will vary depending on operating conditions and load.}

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

H.24. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NOx emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NOx monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load condition.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

Records and Reports

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

H.26. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each gas turbine for the previous month

of operation: fuel consumption, hours of operation, hours of power augmentation, hours of peaking, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

H.27. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

(a) Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

(b) Compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

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

H.28. Malfunction Notification: Within one working day of a malfunction that causes emissions in excess of a standard (subject to the specified averaging periods), the permittee shall notify the Compliance Authority. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports summarizing the malfunctions. [Rule 62-210.700, F.A.C.]

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

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

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

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

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

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

Subsection I. This section addresses the following emissions units.

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

Emission Unit ID	Emission Unit Description
020	22-cell mechanical draft cooling tower

Equipment

I.1. Cooling Tower: The permittee is authorized to install one new 22-cell mechanical draft cooling tower with the following design characteristics: a circulating water flow rate of 310,000 gpm; design hot/cold water temperatures of 104° F/90° F; a design air flow rate of 1,386,055 per cell; a liquid-to-gas air flow ratio of 1.4; and drift eliminators with a drift rate of no more than 0.001 percent. [Application; Design]

Emissions and Performance Requirements

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

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

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

General

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

Subsection J. This section addresses the following emissions units.

This section of the permit addresses the following emissions units.

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

NSPS Applicability

J.1. NSPS Subpart Kb Applicability: The distillate oil tanks are not subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb.

[40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]

Equipment Specifications

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

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

Emissions and Performance Requirements

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

Notification, Reporting and Records

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

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

J.5. Fuel Oil Records: The permittee shall keep readily accessible records showing the maximum true vapor pressure of the stored liquid. The maximum true vapor pressure shall be less than 3.5 kPa. Compliance with this condition may be demonstrated by using the information from the respective MSDS for the low or ultralow sulfur fuel oil stored in the tanks.
[62-4.070(3) F.A.C.]

{Permitting Note: An evaluation of several Material Safety Data Sheets (MSDS) by the Department demonstrated that the vapor pressure is much less than 3.5 kPa for low sulfur fuel oil and for ultralow sulfur fuel oil.}

General

J.6. Common Conditions: These emissions units are also subject to applicable requirements of the conditions contained in **Subsection E. Common Conditions** and all applicable requirements of the attached **Appendices,** made part of the permit.

Section IV. This section is the Acid Rain Part.

Operated by: Florida Power and Light Company

ORIS code: 6043

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

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

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

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

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

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

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

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

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

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

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

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

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

(3) Allowances shall be accounted for under the Federal Acid Rain Program.

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

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

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

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

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

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

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

	Brief Description of Emissions Units and/or Activities
1	**Chemical Feed Skid**, consisting of: Ammonia Feed Tanks Vent Hydrazine Feed Tanks Vent H. P. Phosphate Feed Tanks Vent I. P. Phosphate Feed Tanks Vent
2	**Fire Protection Equipment** with: .75" Vents to Atmosphere Diesel Engine Exhaust 2" Diesel Day Tank Vent CT Lube Seal Trip, and Hydraulic Oil 3" Bearing Drain Enlargement Exhausters Vent to Atmosphere **Auxiliary Buildings H.V.A.C.** Vent/Exhaust System for, Switchgear Rooms Chemical Storage Room Water Chemistry Lab Fume Hoods
3	**Main Liquid Fuel** .75" Vents to Atmosphere 2" Liquid Fuel Drain Tank Vent (235 gallon) 8" Vent with Filter for Units 3 and 4 Liquid Fuel Storage Tank (2,000,000 gallon)
4	**Auxiliary Steam, Chemical Feed, Chlorine and Gas Purging,** comprised of: Ash Pit Potable Water Bleach Tank 2" Vent (2,000 gallons)

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

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

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

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

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

APPENDICES

CONTENTS

APPENDIX A

NSPS Subpart A, Identification of General Provisions

Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

NESHAP Subpart A, Identification of General Provisions

Emissions units subject to a National Emissions Standards for Hazardous Air Pollutants for Source Category of 40 CFR 63 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 63.1 Applicability.

§ 63.2 Definitions.

§ 63.3 Units and abbreviations.

§ 63.4 Prohibit activities and circumvention .

§ 63.5 Preconstruction review and notification requirements.

§ 63.6 Compliance with standards and maintenance requirements.

§ 63.7 Performance testing requirements.

§ 63.8 Monitoring Requirements.

§ 63.9 Notification Requirements

§ 63.10 Recordkeeping and reporting requirements.

§ 63.11 Control device requirements.

§ 63.12 State authority and delegations.

§ 63.13 Addresses of State air pollution control agencies and EPA Regional Offices.

§ 63.14 Incorporation by reference.

§ 63.15 Availability of information and confidentiality.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

APPENDIX BD

FINAL BACT DETERMINATION

OVERVIEW

The project added an 1150 MW "4-on-1" combined cycle gas turbine system to the existing FPL Martin Power Plant. PSD-significant emissions increases required determinations of the Best Available Control Technology (BACT) for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2), and volatile organic compounds (VOC).

BACT CONTROL TECHNOLOGIES

The Department reviewed available control technologies for each pollutant resulting in a PSD-significant increase. The Department's technical review and rationale for the BACT determinations are presented in the "Technical Evaluation and Preliminary Determination" as revised prior to the siting hearing. The following summarizes the control technologies upon which the Department's final BACT determinations are based.

BACT for CO and VOC Emissions

Good Combustion and Operating Practices: BACT for CO and VOC emissions is the efficient combustion of fuels at high temperatures associated with good combustion design and operating practices. General Electric's dual-fuel combustors have demonstrated very low CO and VOC emissions while simultaneously reducing NOx emissions for gas and oil firing.

BACT for NOx Emissions

DLN Combustion: When firing natural gas under simple cycle mode, BACT for NOx emissions is the operation of General Electric's dry low-NOx (DLN) combustion system. The efficient fuel combustion and thorough mixing of the gas stream reduces hot and cold spots surrounding the combustion zone. The full lean premix combustion results in NOx emissions less than 9 ppmvd when firing natural gas. The Speedtronic™ control system continuously monitors performance parameters and adjusts for efficient operation. The control system also provides for quick automated startups, lean pre-mix combustion performance, and controlled shutdowns.

Wet Injection: When firing distillate oil under simple cycle mode, BACT for NOx emissions is the operation of General Electric's dual-fuel combustor with wet injection designed to reduce the flame temperature and lower NOx emissions.

SCR: When firing natural gas or distillate oil in combined cycle mode, BACT for NOx emissions is the operation of the selective catalytic reduction (SCR) system in conjunction with DLN combustion and wet injection. Ammonia injected into the exhaust gas stream combines with NOx in a reduction action across a catalyst bed to form nitrogen and water. The catalyst bed is located after the HRSG, which reduces exhaust temperatures to the appropriate operating range of the catalyst material. The SCR system will achieve about a 70% reduction with an initial ammonia slip of no more than 5 ppmvd.

BACT for PM, SAM, and SO_2 Emissions

Fuel Specifications: BACT for PM, SAM, and SO_2 emissions is the use of natural gas as the primary fuel (≤ 2.0 grains of sulfur per 100 standard cubic feet of natural gas) and restricted use of very low sulfur distillate oil (≤ 0.05% sulfur by weight). These fuels are readily combustible and contain little ash, sulfur, or other contaminants.

BACT STANDARDS

The following summarizes the final Best Available Control Technology determinations for this project in accordance with Rule 62-212.400(BACT), F.A.C.

Gas-Fired Fuel Heaters: BACT for emissions of CO, NOx, PM/PM_{10}, SAM, SO_2, and VOC from the gas-fired fuel heaters is the efficient combustion of natural gas and the following visible emissions criteria, "If visible emissions are greater than 5% opacity, the permittee shall investigate the cause, take appropriate corrective actions, and document the incident. This condition does not impose any initial or periodic testing." This condition is similar to that for the previously permitted gas-fired fuel heaters under Permit No. PSD-FL-286.

Cooling Tower: BACT for emissions of PM/PM_{10} from the cooling tower is a design drift rate of no more than 0.001 percent of the circulating water flow rate.

FINAL BACT DETERMINATION

Gas Turbines/HRSG Systems

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]	Oil	Simple or Combined Cycle	14.4	64.7	15.0, 24-hr
	Gas	Simple Cycle	7.4	27.5	8.0, 24-hr
		Simple Cycle w/PA.	12.0	45.0	12.0, 24-hr
		Combined Cycle, Normal	7.4	27.5	10.0, 24-hr
		Combined Cycle, All Modes	NA	NA	
NOx [b]	Oil	Simple Cycle	42.0	319.2	42.0, 3-hr
		Combined Cycle w/SCR	10.0	76.0	10.0, 24-hr
	Gas	Simple Cycle	9.0	58.7	9.0, 24-hr
		Simple Cycle w/PA	12.0	76.2	12.0, 24-hr
		Simple Cycle w/Peaking	15.0	95.3	15.0, 24-hr
		Combined Cycle w/SCR, Normal	2.5	16.3	2.5, 24-hr
		Combined Cycle w/SCR and DB	2.5	23.6	
		Combined Cycle w/SCR, All Modes	NA	NA	
PM/PM_{10} [c]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
		Simple or Combined Cycle	Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
VOC [e]	Oil	Simple or Combined Cycle	2.5	6.0	NA
	Gas	Simple or Normal Combined Cycle	1.3	2.8	NA
		Combined Cycle, w/DB and/or PA	4.0	10.5	NA
Ammonia [f]	Oil/Gas	Combined Cycle w/SCR	5.0	NA	NA

a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 10. Compliance with the 24-hour CO CEMS standards shall be determined separately for each method of operation based on the hours of operation for each method. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

b. Compliance with the NOx standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 7E or 20. NOx mass emission rates are defined as oxides of nitrogen expressed as NO_2. Compliance with the 24-hour NOx CEMS standards during simple cycle operation shall be determined separately for each method of operation based on the hours of operation for each method. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

c. The fuel specifications established above combined with the efficient combustion design and operation of each gas turbine represents the Best Available Control Technology (BACT) determination for PM/PM_{10} 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. PM10* *emissions for oil firing are estimated at 17 lb/hour for simple cycle operation and 37 lb/hour for combined cycle operation.}*

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent the Best Available Control Technology (BACT) determination for these pollutants. *{Permitting Note: SO_2 emissions for gas firing are estimated at 9.8 lb/hour for simple and combined cycle operation and 12.8 lb/hour for combined cycle operation with duct burning. SO_2 emissions for oil firing are estimated at 99 lb/hour for simple and combined cycle operation. SAM emissions are estimated to be less than 10% of the SO_2 emissions.}*

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

f. Subject to the following testing requirements, each SCR system shall be designed and operated for an initial ammonia slip target of no more than 5.0 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.

Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5.0 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 less 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 less 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.]

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

APPENDIX CF

CITATION FORMAT AND DEFINITIONS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001"identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7]

Means: Title 40, Part 60, Section 7

DEFINITIONS [RULE 62-210.200, F.A.C.]

(119) Excess Emissions - Emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, soot blowing, load changing or malfunction.

(179) Malfunction - Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

(258) Shutdown - The cessation of the operation of an emissions unit for any purpose.

(275) Startup - The commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

E.U. ID No.	Brief Description
-011	Combined Cycle Combustion Turbine (8A)
-012	Combined Cycle Combustion Turbine (8B)
-017	Combined Cycle Combustion Turbine (8C)
-018	Combined Cycle Combustion Turbine (8D)

These emissions units have not to date been operated in the high power modes (HPMs) of peaking or power augmentation. Therefore, this compliance plan is included to cover initial testing requirements for these HPMs for emissions of CO and NO_x. Please see Specific Conditions **H.9, H.18 and H.19.**

CP.1. Test Notification. The permittee shall notify the Department in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests.

[Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.7, 60.8; and 0850001-008-AC, Specific Condition 17. (Facility Information)]

CP.2. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

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

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

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

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

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

NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

The HRSG duct burners are part of the Unit 8 gas turbine/HRSG systems, which are regulated as Emissions Units 011, 012, 017, and 018.

§ 60.40a Applicability and Designation of Affected Facility.

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

§ 60.41a Definitions.

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

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

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

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

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

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

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

§ 60.42a Standard for Particulate Matter.

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

§ 60.43a Standard for Sulfur Dioxide.

In accordance with § 60.43a(b)(2), sulfur dioxide emissions shall not exceed 0.20 lb/MMBtu heat input from the combustion of gaseous fuel for uncontrolled sources. Natural gas is the primary fuel for the gas turbines with very low sulfur distillate oil (≤ 0.05% sulfur by weight) as a backup fuel. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum SO_2 emissions are expected to be less than 0.05 lb/MMBtu heat input from firing distillate oil in the gas turbine and natural gas in the duct burners. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

§ 60.44a Standard for Nitrogen Oxides.

In accordance with § 60.44a(d)(1), nitrogen oxides (expressed as NO_2) from a gas turbine/HRSG system with duct burners shall not exceed 1.6 pounds per megawatt-hour gross energy output. The permittee shall demonstrate compliance with this requirement based upon an initial test. Thereafter, compliance with the BACT standards of the PSD permit will demonstrate compliance with the NSPS Subpart Da limit. After investigation, if there is good reason to believe that this standard is being violated, the Department may require subsequent compliance testing in accordance with Rule 62-297.310(7)(b), F.A.C.

§ 60.46a Compliance Provisions.

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

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

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

Where:

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

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

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

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

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

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

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

§ 60.47a Emission Monitoring.

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

§ 60.48a Compliance Determination Procedures and Methods.

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

§ 60.49a Reporting requirements.

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

The Unit 8 gas turbines are regulated as Emissions Units 011, 012, 017, and 018.

The Unit 3 and 4 gas turbines are regulated as Emissions Units 003, 004, 005 and 006.

Updated 4/27/06

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

Subpart GG-Standards of Performance for Stationary Gas Turbines

§ 60.330 Applicability and designation of affected facility.

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

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

§ 60.331 Definitions.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(o) Garrison facility means any permanent military installation.

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

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

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

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

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

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

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

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

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

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

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

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

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

§ 60.332 Standard for nitrogen oxides.

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

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

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

where:

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

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

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

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

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

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

Fuel-bound nitrogen (% by weight)	F (NO_X% by volume)

$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N-0.1)
$N > 0.25$	0.005

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

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

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

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

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

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

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

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

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

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

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

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

§ 60.333 Standard for sulfur dioxide.

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

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

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

§ 60.334 Monitoring of operations.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(1) Nitrogen oxides.

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

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

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

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

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

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

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

(iii) For turbines using NO_X and diluent CEMS:

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

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

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

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

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

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

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

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

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

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

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

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

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

Sec. 60.335 Test methods and procedures.

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

(1) EPA Method 20,

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

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

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

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

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

(A) [Reserved]

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

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

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

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

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

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

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

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

Where:

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

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

backup fuels, separate performance testing is required for each fuel. Notwithstanding theserequirements, performance testing is not required for any emergency
fuel (as defined in Sec. 60.331).

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

(4) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with Sec. 60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522-00 (incorporated by reference, see Sec. 60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable Sec. 60.332 NO_X emission limit.

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

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

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

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

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

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

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

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

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

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

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

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

(ii) For gaseous fuels, ASTM D1072-80, 90 (Reapproved 1994); D3246-81, 92, 96; D4468-85 (Reapproved 2000); or D6667-01 (all of which are incorporated by reference, see Sec. 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

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

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

PSD-FL-327 Permit Monitoring of Operations

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

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

PSD-FL-327 Permit Test Methods and Procedures

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

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

STANDARD CONDITIONS

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

EMISSIONS AND CONTROLS

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

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

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

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

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

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

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

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

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

TESTING REQUIREMENTS

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

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

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

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

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

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

    c. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

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

14. Determination of Process Variables

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

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

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

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

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

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

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

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

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

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

RECORDS AND REPORTS

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

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

NESHAPS Requirements for Industrial, Commercial, and Institutional Boilers and Process Heaters

The auxiliary boiler is subject to the applicable requirements of this 40 CFR 63, Subpart DDDDD. The provisions of this Subpart may be provided in full upon request.

Source: Federal Register Dated 9/12/04

Tables to Subpart DDDDD of Part 63

Table 1 to Subpart DDDDD of Part 63--Emission Limits and Work Practice Standards
Table 2 to Subpart DDDDD of Part 63--Operating Limits for Boilers and Process Heaters With Particulate Matter Emission Limits
Table 3 to Subpart DDDDD of Part 63--Operating Limits for Boilers and Process Heaters With Mercury Emission Limits and Boilers and Process Heaters That Choose to Comply With the Alternative Total Selected Metals Emission Limits
Table 4 to Subpart DDDDD of Part 63--Operating Limits for Boilers and Process Heaters With Hydrogen Chloride Emission Limits
Table 5 to Subpart DDDDD of Part 63--Performance Testing Requirements
Table 6 to Subpart DDDDD of Part 63--Fuel Analysis Requirements
Table 7 to Subpart DDDDD of Part 63--Establishing Operating Limits
Table 8 to Subpart DDDDD of Part 63--Demonstrating Continuous Compliance
Table 9 to Subpart DDDDD of Part 63--Reporting Requirements
Table 10 to Subpart DDDDD of Part 63--Applicability of General Provisions to Subpart DDDDD (See Appendix B)

Appendices to Subpart DDDDD

Appendix A to Subpart DDDDD--Methodology and Criteria for Demonstrating Eligibility for the Health-Based Compliance Alternatives Specified for the Large Solid Fuel Subcategory
Appendix B to Subpart DDDDD--Applicability of General Provisions to Subpart DDDDD

NESHAPS REQUIREMENTS FOR STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES

The diesel emergency generator (EU 009) is subject to the applicable requirements of this 40 CFR 63, Subpart ZZZZ. The provisions of this Subpart may be provided in full upon request.

Source: Federal Register dated 6/15/04; Effective Date 8/16/04

What This Subpart Covers
63.6580 The purpose of subpart ZZZZ
63.6585 Subject to this subpart
63.6590 Parts of my plant does this subpart cover
63.6595 Compliance with this subpart

Emission Limitations
63.6600 Emission limitations and operating limitations

General Compliance Requirements
63.6605 General requirements for complying with this subpart

Testing and Initial Compliance Requirements
63.6610 Dates to conduct the initial performance tests or other initial compliance demonstrations
63.6615 Subsequent performance tests
63.6620 Performance tests and other procedures
63.6625 Monitoring, installation, operation, and maintenance requirements
63.6630 Initial compliance with the emission limitations and operating limitations

Continuous Compliance Requirements
63.6635 Monitoring and collecting data to demonstrate continuous compliance
63.6640 Continuous compliance with the emission limitations and operating limitations

Notification, Reports, and Records
63.6645 Notifications
63.6650 Reports
63.6655 Records
63.6660 Records form and retention

Other Requirements and Information
63.6665 General Provisions
63.6670 implementation and enforcement
63.6675 Definitions

Tables to Subpart ZZZZ of Part 63
Table 1a to Subpart ZZZZ of Part 63--Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE
Table 1b to Subpart ZZZZ of Part 63--Operating Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE
Table 2a to Subpart ZZZZ of Part 63--Emission Limitations for New and Reconstructed Lean Burn and Compression Ignition Stationary RICE

Table 2b to Subpart ZZZZ of Part 63--Operating Limitations for New and Reconstructed Lean Burn and Compression Ignition Stationary RICE
Table 3 to Subpart ZZZZ of Part 63--Subsequent Performance Tests
Table 4 to Subpart ZZZZ of Part 63--Requirements for Performance Tests
Table 5 to Subpart ZZZZ of Part 63--Initial Compliance with Emission Limitations and Operating Limitations
Table 6 to Subpart ZZZZ of Part 63--Continuous Compliance with Emission Limitations and Operating Limitations
Table 7 to Subpart ZZZZ of Part 63--Requirements for Reports
Table 8 to Subpart ZZZZ of Part 63--Applicability of General Provisions to Subpart ZZZZ- See Appendix A to Subpart ZZZZ

Appendix A to Subpart ZZZZ of Part 63- Applicability of General Provisions to Subpart ZZZZ

Appendix H-1. Permit History

Florida Power & Light Company — Permit No. **0850001-017-AV**

Martin Plant

Permit History (for tracking purposes):

E.U. ID No	Description	Permit No.	Issue Date	Expiration Date	Revised Date(s)
-001	Fossil Fuel Fired Steam Generator Unit 1	AC-73044 AC43-4037 AO43-170568	3/20/73 6/30/77 2/23/90	11/29/94	2/16/93
-002	Fossil Fuel Fired Steam Generator Unit 2	AC-73045 AC43-4038 AO43-170567	3/20/73 6/30/77 2/20/90	11/29/94	2/16/93
-003 -004 -005 -006 -007 -009	PSD Construction Permit for Combined Cycle Combustion Turbines Units 3A, 3B, 4A 4B and associated support equipment Auxiliary Boiler Diesel Generator Permit modifications (PSD-FL-146A) to include DARM guidance, flexibility in VOC testing and revision of a CEM issue. Power Plant Siting Project No.	PSD-FL-146 0850001-001-AC 0850001-002-AC 0850001-003-AC (PSD-FL-146A) PA89-27	6/05/91 Withdrawn 9/06/96 9/06/96 2/20/91		7/19/93 9/16/94 9/06/96 10/14/97 7/20/99 9/28/94
001 thru -009	Initial Title V Permit	0850001-004-AV (Initial Title V Permit)	1/01/99	12/31/03	
003-006	PSD-FL-146B Permit Modification: Construction/Installation of Inlet Foggers	0850001-005-AC PSD-FL-146B	7/20/99		
	Appendix I-1 List of Insignificant Units	0850001-006-AV (Administrative Permit Correction)	7/26/00	12/31/03	
003-006	Inclusion of the Inlet Foggers project in Title V. Combined Cycle Combustion Turbines Units 3A, 3B, 4A and 4B.	0850001-007-AV (Title V Revision)	7/26/00	12/31/03	
-011 -012 -013	PSD Construction Permit for Simple Cycle Combustion Turbines Units 8A and 8B, two Natural Gas Heaters and support equipment.	0850001-008-AC PSD-FL-286	8/16/00	12/01/03	
-011 & 012	Modification request. Simple-Cycle Combustion Turbines Units 8A and 8 B.	0850001-009-AV	Withdrawn		
011 & 012 013 & 014 017 & 018	PSD Construction for Combined Cycle Turbine System ("4-on-1"). Units 8A thru 8D and associated equipment.	0850001-010-AC (PSD-FL-327)	4/16/03	12/30/06	
-011 & 012	Permit modification. Simple-Cycle Combustion Turbines Units 8A and 8 B.	0850001-011-AC PSD-FL-286A	3/20/03	12/01/03	
-011 -012 -013	Incorporation in the Title V permit: Simple-Cycle Combustion Turbines Units 8A and 8B, two Natural Gas Heaters and support equipment.	0850001-012-AV (Title V Permit Revision)	6/20/03	12/31/03	
001thru -013 015 & 016	Facility wide. Permit renewal.	0850001-013-AV (Title V Permit Renewal)	12/18/03	12/31/08	

Permit History (for tracking purposes):

E.U. ID No	Description	Permit No.	Issue Date	Expiration Date	Revised Date(s)
003-006	Combined Cycle Combustion Turbines Units 3A, 3B, 4A and 4B. Request to modify annual performance tests.	0850001-014-AV	Withdrawn		
011 & 012 017 & 018	Startup and Excess Emissions revisions Unit 8 Combined Cycle Turbine System ("4-on-1")	0850001-015-AC PSD-FL-327A Permit Modification	7/5/2005	7/5/2010	
003-006	To revise test performance conditions of Combined Cycle Units 3A, 3B, 4A and 4B. To revise excess emissions period for Unit 8.	0850001-016-AC PSD-FL-146C and PSD-FL-327B Permit Modification	Pending		
011 & 012 013 & 014 017 & 018 & 019	Incorporation of Unit 8 Combined Cycle Turbine System ("4-on-1") and associated equipment. Inclusion of AC Permits Mod. 0850001-015-AC (PSD-FL-327A) and 0850001-016-AC (PSD-FL-327B).	0850001-017-AV (Title V Permit Revision of 0850001-013-AV)	Pending	12/31/2008	

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

Table 1-1, Air Pollutant Standards and Terms

Permit No. **0850001-017-AV**
Facility ID No. **0850001**

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

E.U. ID No(s)	Brief Description	Pollutant Name	Fuel(s)	Hours/Year	Allowable Emissions Standard(s)	Allowable Emissions lbs/hour	Allowable Emissions TPY	Equivalent Emissions* lbs/hour	Equivalent Emissions* TPY	Regulatory Citations	See Permit Conditions
-001	Fossil Fuel Fired	PM	Oil	8760	0.1 lb/MMBtu			865	3788.7	40 CFR 60.42	**A.5**
-002	Steam Generators		Gas	8760	0.1 lb/MMBtu						
		SO2	Oil	8760	0.8 lb/MMBtu			16920	30309	40 CFR 60.43	**A.9**
		NOx	Oil	8760	0.3 lb/MMBtu			2595	11366.1	40 CFR 60.44	**A.10**
			Gas	8760	0.2 lb/MMBtu			1808	7919.04		
		VE	Oil	8760	Not > 20%						**A.8**
-003	Combined Cycle	PM/PM10	Oil	2000		60.6	100			Rule 62-212.410, F.A.C.	**B.6**
-004	Combustion Turbines		Gas	8760		18					
-005	Units 3 and 4	SO2	Oil	2000	0.5% sulfur	920	568			40 CFR 60.333	**B.6**
-006			Gas	8760		91.5					
		NOx	Oil	2000	65 ppmvd @ 15% O2	461	3108			40 CFR 60.332	**B.6**
			Gas	8760	25 ppmvd @ 15% O2	177					
		VOC	Oil	2000	6 ppmvd	11	57			Rule 62-210.200 (39), F.A.C.	**B.6**
			Gas	8760	1.6 ppmvd	3					
		CO	Oil	2000	33 ppmvd	105.8	871			Rule 62-210.200 (39), F.A.C.	**B.6**
			Gas	8760	30 ppmvd	94.3					
		PB	Oil	2000		0.015	0.015			Rule 62-210.200 (39), F.A.C.	**B.6**
			Gas	8760		Negligible					
		SAM	Oil	2000		113	70			Rule 62-210.200 (39), F.A.C.	**B.7**
			Gas	8760		11.2					
		H114	Oil	2000		0.0052	0.34			Rule 62-210.200 (39), F.A.C.	**B.7**
			Gas	8760		0.021					
		FL	Oil	2000		0.055	0.055			Rule 62-210.200 (39), F.A.C.	**B.7**
		H021	Oil	2000		0.004	0.004			Rule 62-210.200 (39), F.A.C.	**B.7**
		VE	Oil	2000	Not > 20%					Rule 62-210.200 (39), F.A.C.	**B.8**
			Gas	8760	Not > 10%						
-007	Auxiliary	VE	Oil	8760	Not > 20%					40 CFR 60.43c	**C.5**
	Boiler	NOx	Gas/Oil	8760	0.3 lb/MMBtu			4.88	21.37	Rule 62-210.200 (39), F.A.C.	**C.10**
		SO2	Gas/Oil	8760	0.3% Sulfur in Oil					Rule 62-210.200 (39), F.A.C.	**C.8**
-009	Diesel Generator	NOx	Oil	400	15 gm./hp-hr.					Rule 62-210.200 (39), F.A.C.	**D.2**
	(for -003 to -006)	SO2	Oil	400	0.3% Sulfur in Oil					Rule 62-210.200 (39), F.A.C.	**D.3**

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

COMBINED CYCLE UNIT 8

Each gas turbine shall fire no more than 500 hours of distillate oil during any consecutive 12 months.
After demonstrating initial compliance in combined cycle mode, the combined group of four gas turbines shall operate in simple cycle for no more than an average of 1000 hours per gas turbine during any consecutive 12 months.
Continuous Emissions Monitoring System (CEMS): Block Average , ppmvd @ 15% O2

Table 1-1, Air Pollutant Standards and Terms Permit No. **0850001-017-AV**

E.U. ID No(s).	Brief Description	Pollutant	Fuel	Mode	Stack Test, 3-Run Average ppmvd@15%O2	lb/hr	CEMS ppmvd	Equivalent Emissions lbs/hours	TPY	Regulatory Citations	See Permit Conditions
-011 -012 -017 -018	Combined Cycle Combustion Turbine Unit 8	CO	Oil	Simple or Combined Cycle	14.4	64.7	15.0, 24-hr			Rule 62-210.200 (39), F.A.C.	**H.9**
			Gas	Simple Cycle	7.4	27.5	8.0, 24-hr				
				Simple Cycle w/PA	12	45	12.0, 24-hr				
				Combined Cycle, Normal	7.4	27.5					
				Combined Cycle, All Modes	NA	NA	10.0, 24-hr				
		NOx	Oil	Simple Cycle	42	319.2	42, 3-hr			Rule 62-210.200 (39), F.A.C.	**H.9**
				Combined Cycle w/SCR	10	76	10.0, 24-hr				
			Gas	Simple Cycle	9	58.7	9.0, 24-hr				
				Simple Cycle w/PA	12	76.2	12.0, 24-hr				
				Simple Cycle w/Peaking	15	95.3	15.0, 24-hr				
				Combined Cycle w/SCR, Normal	2.5	16.3					
				Combined Cycle w/SCR and DB	2.5	23.6					
				Combined Cycle w/SCR, All Modes	NA	NA	2.5, 24-hr				
		PM/PM_{10}	Oil/Gas	Simple or Combined	Fuel Specifications					Rule 62-210.200 (39), F.A.C.	**H.9**
				Simple or Combined	Visible emissions shall not exceed 10% opacity for each 6-minute block average.						
		SAM/SO_2	Oil/Gas	Simple or Combined	Fuel Specifications					Rule 62-210.200 (39), F.A.C.	**H.9**
		VOC	Oil	Simple or Combined Cycle	2.5	6	NA			Rule 62-210.200 (39), F.A.C.	**H.9**
			Gas	Simple or Normal Combined Cycle	1.3	2.8	NA				
				Combined Cycle, w/DB and/or PA	4	10.5	NA				
		Ammonia	Oil/Gas	Combined Cycle w/SCR	5	NA	NA			Rule 62-210.200 (39), F.A.C.	**H.9**

Table 2-1, Compliance Requirements

Florida Power & Light Company **Martin Plant**			Permit No. **0850001-017-AV** Facility ID No. **0850001**				
This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.							
E.U. ID Nos.	**Brief Description**						
-001	Fossil Fuel Fired Steam Generator						
-002	Fossil Fuel Fired Steam Generator						
Pollutant Name or parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date **	Min. Compliance Test Duration	CMS*	See Permit Conditions
VE	Oil	DEP Method 9	Annual	1-Oct	1 Hour		**A.15**
PM	Oil	EPA Method 5	Annual	1-Oct	3 Hours		**A.18**
	Gas	EPA Method 5	Annual	1-Oct	3 Hours		**A.18**
SO2	Oil	EPA Method 6C	Annual	1-Oct		Yes	**A.18**
	Gas	EPA Method 6C	Annual	1-Oct		Yes	**A.18**
NOx	Oil	EPA Method 7E	Annual	1-Oct		Yes	**A.18**
	Gas	EPA Method 7E	Annual	1-Oct		Yes	**A.18**
CO2 (Diluent Gas)						Yes	**A.23**
Volumetric Flow						Yes	**A.23**
Opacity						Yes	**A.23**
E.U. ID Nos.	**Brief Description**						
-003	Combustion Turbine with HRSG						
-004	Combustion Turbine with HRSG						
-005	Combustion Turbine with HRSG						
-006	Combustion Turbine with HRSG						
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date **	Min. Compliance Test Duration	CMS*	See Permit Conditions
VE	Oil	DEP Method 9	Annual	1-Oct	1 Hour		**B.27**
	Gas	DEP Method 9	Annual	1-Oct	1 Hour		**B.27**
PM/PM10	Oil	EPA Method 5 or 17	Annual	1-Oct	3 Hours		**B.27**
SO2 (Sulfur Content of Fuel)	Oil	ASTM D 2880-96	Daily				**B.24**
	Gas	ASTM D 1072-90(94)E-1 or D 3031--81(86) or D 4084-94 or D 3246-92	Annual	1-Oct			**B.24**
NOx	Oil	EPA Method 20	Annual	1-Oct		Yes	**B.27**
	Gas	EPA Method 20	Annual	1-Oct		Yes	**B.27**
CO	Oil	EPA Method 10	Annual	1-Oct			**B.27**
	Gas	EPA Method 10	Annual	1-Oct			**B.27**
CO2						Yes	

Table 2-1, Compliance Requirements

Florida Power & Light Company **Martin Plant**			Permit No. **0850001-017-AV** Facility ID No. **0850001**				
E.U. ID No.	**Brief Description**						
-007	Auxiliary Boiler						
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date **	Min. Compliance Test Duration	CMS*	See Permit Conditions
VE	Oil	DEP Method 9	Annual	1-Oct	1 Hour		**C.13**
SO2	Oil Gas	ASTM D 2880-96 ASTM D 1072-90(94)E-1	Daily Annual	 1-Oct			**C.11**
E.U. ID No.	**Brief Description**						
-009	Diesel Generator						
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date **	Min. Compliance Test Duration	CMS*	See Permit Conditions
SO2	Oil	Verification by vendor receipts	On delivery				**D.4**
E.U. ID No.	**Brief Description**						
-011 -012 -017 -018	Combined Cycle Unit 8 with SCR System "4-on-1"						
Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date **	Min. Compliance Test Duration	CMS*	See Permit Conditions
PM/PM10	Oil Gas	Fuel Specifications Visible Emissions	 Annual				**H.19**
SO2	Oil Gas	Verification by vendor receipts ASTM D 2880-71 (oil) D4084-82, D3246-81(gas)	On delivery				**H.19**
NOx	Oil Gas	EPA Method 7E and 20	Annual			Yes	**H.19, H.21, H.24**
VOC	Oil Gas	EPA Method 25 or 25A	Renewal				**H.19**
CO	Oil Gas	EPA Method 10	Annual			Yes	**H.19, H.21, H.24**
VE	Oil Gas	EPA Method 9	Annual				**H.19**
Ammonia***		EPA Method CTM-027	Annual				**H.19, H.23, H.26**

Notes:
*CMS [=] Continuous Monitoring System
*Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.
*** Additional Ammonia Slip Testing: Refer to Specific Condition H. 23