Gulf Power Company

Lansing Smith Electric Generating Plant

Facility ID No. 0050014
Bay County

Title V Air Operation Permit Revision

Permit Revision No. 0050014-022-AV
(2nd Revision to Permit No. 0050014-018-AV)

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Title V Air Operation Permit Revision

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Table of Contents

Section **Page Number**

Placard Page. 1

I. Facility Information.
- A. Facility Description. 2
- B. Summary of Emissions Units. 2
- C. Applicable Regulations. 3

II. Facility-wide Conditions. 4

III. Emissions Units and Conditions.
- A. Boilers Number 001 and 002 - Phase II, Acid Rain Units. 6
- B. Combustion Turbine No. 003 - Peaking Unit A & B. 16
- C. Gas Combustion Turbines No. 004 and 005 with HRSG and Duct Burner. Salt Water Cooling Tower No. 006. 19

IV. Acid Rain Part. 27
- Phase II Acid Rain Application/Compliance Plan.
- Phase II Acid Rain NO_X Compliance Plan.

V. Clean Air Interstate Rule Part. 39

VI. Appendices. 46
- Appendix A, Glossary.
- Appendix CAM, Compliance Assurance Monitoring Plan.
- Appendix I, List of Insignificant Emissions Units and/or Activities.
- Appendix ICE, Requirements for Internal Combustion Engines.
- Appendix 40 CFR 63, Subpart A, Standardized General Provisions.
- Appendix NESHAP Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.
- Appendix NSPS, Subpart A, Standardized General Provisions.
- Appendix NSPS, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units.
- Appendix NSPS Subpart GG, Standards of Performance for Stationary Gas Turbines.
- Appendix NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
- Appendix PA-1, Patrol Area.
- Appendix RR, Facility-wide Reporting Requirements.
- Appendix SO-1, Secretarial Order(s).
- Appendix TR, Facility-wide Testing Requirements.
- Appendix TV, Title V General Conditions.
- Appendix U, List of Unregulated Emissions Units and/or Activities.

Referenced Attachments. ..... At End
- Figure 1, Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance (40 CFR 60, July, 1996).
- Table H, Permit History.
- Table 1, Summary of Air Pollutant Standards and Terms.
- Table 2, Compliance Requirements.

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Permit No. 0050014-022-AV
Facility ID No. 0050014
Lansing Smith Electric Generating Plant
SIC Nos. 49, 4911
Title V Air Operation Permit Revision

The purpose of this permit is to revise the Title V air operation permit for the above referenced facility to incorporate a revised Phase II NO_X Averaging Plan. The existing Lansing Smith Electric Generating Plant is located in Bay County at 4300 County Road 2300, Southport, Florida 32409. UTM Coordinates are: Zone 16; 623.74 Kilometer (km) East and 3349.11 km North. Latitude is: 30° 16' 8.4566" North; and, Longitude is: 85° 42' 2.4149" West.

The Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213 and 62-214. The above named permittee is hereby authorized to operate the facility in accordance with the terms and conditions of this permit.

Effective Date: January 1, 2010
1st Revision Effective Date: November 3, 2012
2nd Revision Effective Date: December 27, 2012
Optional Renewal Application Due Date: May 20, 2013
Renewal Application Due Date: May 20, 2014
Expiration Date: December 31, 2014

Executed in Tallahassee, Florida

for Jeffery F. Koerner, Program Administrator
Office of Permitting and Compliance
Division of Air Resource Management

JFK/sa/tbc

Subsection A. Facility Description.

This facility consists of two coal fired steam generators (boilers), a Pratt & Whitney Twin-Pac combustion turbine peaking unit, and two gas-fired combined-cycle combustion turbine electrical generators with duct-fired heat recovery steam generators (HRSG). The two boilers are Acid Rain Phase II Units. The two combined-cycle combustion turbines are Acid Rain units. Pulverized coal is the primary fuel for the boilers. Distillate fuel oil is used to fire the combustion turbine and as a "back-up" fuel for the boilers. Natural gas is the only fuel allowed to be fired in the two combined-cycle combustion turbines. Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Subsection B. Summary of Emissions Units.

EU No.	Brief Description
Regulated Emissions Units	
001	Boiler Number 1 - 1,944.8 MMBtu/hour (Phase II Acid Rain Unit)
002	Boiler Number 2 - 2,246.2 MMBtu/hour (Phase II Acid Rain Unit)
003	Combustion Turbines A and B - 542 MMBtu/hour Peaking Unit (CAIR Unit)
004	170 MW Gas Combustion Turbine with HRSG and Duct Burner (Acid Rain Unit)
005	170 MW Gas Combustion Turbine with HRSG and Duct Burner (Acid Rain Unit)
006	Cooling Tower
010	Portable Welding Machine (See Appendix ICE)
011	Diesel Emergency Sump Pump (See Appendix ICE)
Unregulated Emissions Units and Activities (See Appendix U).	
007	Material Handling of Coal and Ash (See Appendix U)
008	Fugitive PM Sources - On-site Vehicles (See Appendix U)
009	General Purpose Internal Combustion Engines (See Appendix U)
010	Portable Welding machines, Miller - Bobcat250D
011	Diesel Emergency Sump Pump, PowerTech 6068TF275
012	Emergency Generator at CCCT, Kohler (350REOZDD)
013	Emergency Sump Pump, Gorman Rupp (Super TSERIES)
014	Emergency Generator, Taylor (TMC175)

Subsection C. Applicable Regulations.

Based on the Title V application, this facility is a potential major source of hazardous air pollutants (HAP). The existing facility is a Prevention of Significant Deterioration (PSD) major source of air pollutants in accordance with Rule 62-212.400, F.A.C. A summary of applicable regulations are shown in the following table.

Applicable Regulations	EU No(s).
Federal Rule Citations	
40 CFR 60, Subpart A, NSPS General Provisions	004, 005
40 CFR 60, Subpart Da, NSPS Standards of Performance for Electric Utility Steam Generating Units	004, 005
40 CFR 60, Subpart GG, Standards of Performance for Stationary Combustion Turbines	004, 005
40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	010, 011
40 CFR 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	009, 010, 011
40 CFR 75, Acid Rain Monitoring Provisions	001, 002, 004, 005
State Rule Citations	
62-204, F.A.C., Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference	001, 002, 003, 004, 005
62-210, F.A.C., Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms	001, 002, 003, 004, 005
62-212.400, F.A.C., Best Available Control Technology (BACT)	001, 002, 003, 004, 005
62-214, F.A.C., Requirements For Sources Subject To The Federal Acid Rain Program Federal Acid Rain Program, Phase II	001, 002, 004, 005
62-296, F.A.C., Emission Limiting Standards	001, 002, 003, 004, 005
62-296.470, F.A.C., Implementation of Federal Clean Air Interstate Rule	001, 002, 003, 004, 005
62-297, F.A.C., Stationary Sources - Emissions Monitoring	001, 002, 003, 004, 005

The following conditions apply facility-wide to all emission units and activities:

FW1. Appendices. The permittee shall comply with all documents identified in Section VI, Appendices, listed in the Table of Contents. Each document is an enforceable part of this permit unless otherwise indicated. [Rule 62-213.440, F.A.C.]

Emissions and Controls

FW2. Not federally Enforceable. 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. [Rule 62-296.320(2) and 62-210.200(Definitions), F.A.C.]

FW3. General Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed-necessary and ordered by the Department. Nothing is deemed necessary and ordered at this time. [Rule 62-296.320(1), F.A.C.]

FW4. 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% opacity. EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]

FW5. Unconfined Particulate Matter. No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity, including vehicular movement; transportation of materials; construction; alteration; demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling; without taking reasonable precautions to prevent such emissions. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include:

a. Grassing over each section of the ash landfill as it reaches its capacity.
b. Regular packing of the coal pile to reduce blowing dust and aid in the prevention of coal fires.
c. Application of a dust suppressant to the coal on the conveyor belts as necessary.
d. Chemical or water application to unpaved roads and/or unpaved yard areas.
e. Paving and maintenance of roads, parking areas, and yards.
f. Landscaping or planting of vegetation.
g. Confining abrasive blasting where possible.
h. Other techniques, as necessary.

[Rule 62-296.320(4)(c), F.A.C.; and, proposed by applicant in Title V air operation permit renewal application received May 18, 2009]

Annual Reports and Fees

See Appendix RR, Facility-wide Reporting Requirements for additional details.

FW6. 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 April 1st of each year. [Rule 62-210.370(3), F.A.C.]

FW7. Annual Emissions Fee Form and Fee. The annual Title V emissions fees are due (postmarked) by March 1st of each year. The completed form and calculated fee shall be submitted to: Major Air Pollution Source Annual Emissions Fee, P.O. Box 3070, Tallahassee, Florida 32315-3070. The forms are available for download by accessing the Title V Annual Emissions Fee On-line Information Center at the following Internet web site: http://www.dep.state.fl.us/air/emission/tvfee.htm. [Rule 62-213.205, F.A.C.]

FW8. Annual Statement of Compliance. The permittee shall submit an annual statement of compliance to the compliance authority at the address shown on the cover of this permit within 60 days after the end of each calendar year during which the Title V permit was effective. [Rules 62-213.440(3)(a)2. & 3. and (b), F.A.C.]

FW9. Prevention of Accidental Releases (Section 112(r) of CAA). If and when the facility becomes subject to 112(r), the permittee shall:

a. Submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center. Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to: RMP Reporting Center, Post Office Box 10162, Fairfax, VA 22038, Telephone: (703) 227-7650.

b. 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]

Other Requirements

FW10. Patrolling Requirements. Computer modeling results indicate modeled violations of the State of Florida's, and of the National, 24-hour sulfur dioxide ambient air quality standards within the property boundaries of this plant. In order to protect the general public, "No Trespassing" notices, combined with a regular patrol to ensure that public access is precluded in the areas described below (see Appendix PA-1, Patrol Area):

> Beginning from the point of origin[1, 2], proceed due north for a distance of approximately 330 meters until reaching the old fence line (point 1). From point 1, turn 90º to the west and proceed along the old fence line for a distance of 580 meters (point 2). From point 2, proceed due south for a distance of 175 meters (point 3). From point 3, proceed back to the point of origin to define the area.

[1] Point of origin: center of the common stack for Units 1 and 2.
[2] Set due North from the center of the stack as 0°. [Rules 62-204.220(1) & 62-204.240(1), F.A.C.]

FW11. Facility-wide NO_X Emissions Cap. In addition to individual (point source) emission limits and NO_X averaging plan requirements, the Lansing Smith facility shall be required to comply with a facility-wide NO_X emissions cap of 6,666 TPY. CEMS shall be the method of compliance. See facility-wide Condition **FW12.** for reporting and record-keeping requirements. [0050014-002-AC.]

FW12. CEMS for Reporting Facility-wide NO_X Emissions. The NO_X CEMS shall be used for ensuring compliance with the facility-wide cap. For the oil-fired peaking turbine (Emissions Unit EU-003), emissions shall be determined using fuel sampling and AP-42 emission factors. Monthly records shall be maintained of the facility-wide NO_X emissions and the owner/operator shall calculate the facility-wide cap on a monthly basis for each prior consecutive 12-month period. These records shall be made available to inspectors as necessary. Additionally, a summary shall be filed with each quarterly report as a means of demonstrating compliance with the facility-wide cap for each consecutive 12-month period. The monthly calculations for the coal-fired units shall consist of use of the monthly NO_X emission rate per MMBtu (as determined by CEMS using the appropriate fuel F factor) multiplied by the monthly fuel (MMBtu) usage as specified in specific condition **A.22.** and converted as appropriate to tons of NO_X for each unit. The sum of the monthly NO_X emissions from the coal units and the oil-fired peaking turbine shall then be added to the monthly NO_X emissions from the combined cycle unit, which will be calculated based upon the monthly average NO_X emission rate (lb/hr) multiplied by the number of valid operating hours for the same period. [Rule 62-4.070 and 62-204.800(7), F.A.C. to avoid PSD Review; and, 0050014-002-AC]

The specific conditions in this section apply to the following emissions units:

EU No.	Brief Description
001	Boiler Number 1 - 1,944.8 MMBtu/hour (Phase II Acid Rain Unit).
002	Boiler Number 2 - 2,246.2 MMBtu/hour (Phase II Acid Rain Unit).

Emission Unit No. 001 is a tangentially fired, dry bottom boiler that began commercial operation on May 12, 1965. Emission Unit No. 002 is a tangentially fired, dry bottom boiler that began commercial operation on April 9, 1967. Both Units are sharing a common stack that is 199 feet tall with a diameter of 18 feet and exit temperature of 260° F. The volumetric flow rate of Units 001 and 002 combined, at permitted capacity, is approximately 1,567,967 acfm. PM emissions from unit 001 are controlled by a hot side (Buell Model # BAL 2X34N333-4-3P) and a cold side (General Electric Model # BE1.2X21(12) 30-1.5-1.5-4.2P) electrostatic precipitator. PM emissions from unit 002 are controlled by a hot side (Buell Model # BAL 2X34N333-4-3P) and a cold side (GE-ESI Model # BE2.1X(2-12's)(12)-30-111-4.3P) electrostatic precipitator. Also, Low-NO_X burners and selective non-catalytic reduction (SNCR) control NO_X emissions.

{Permitting Notes: Based on the current Title V air operation permit, Units -001 and -002 are regulated under Rule 62-296.405, F.A.C. (Fossil Fuel Fired Steam Generators > 250 MMBtu/Hour Heat Input); have not undergone PSD Preconstruction Review; and are regulated under Phase II of the federal Acid Rain Program (40 CFR 75).}

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity. The maximum allowable heat input rate is as follows (see specific condition **A.23.**):

Unit No.	MMBtu/hr Heat Input	Fuel Type
001	1,944.8	Coal
	153	No. 2 Fuel Oil
	153	On-Specification Used Oil
002	2,246.2	Coal
	76	No. 2 Fuel Oil
	76	On-Specification Used Oil

[Rules 62-4.160(2), 62-210.200(PTE) & 62-296.405, F.A.C.; permits AC03-2023, AC03-2024 & 0050014-011 AC]

A.2. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation.

a. *Fuels.* The fuels that are allowed to be burned in these boilers are coal and/or new No. 2 fuel oil and/or on-specification used oil (see Specific Condition **A.42.**). Fuel oil is only used for periods of start-up and as needed for flame stabilization. Also, on-site generated "oil contaminated soil" is periodically combusted for energy recovery purposes.

b. Other.

1. Supplemental injection of "sodium carbonate" (at a rate of up to 420 pounds per hour) as necessary to maintain visible emissions below the applicable standards.
2. Supplemental injection of "GAM 60" for purposes of maintaining boiler tube temperatures.

[Rule 62-213.410, F.A.C.]

A.4. Hours of Operation. These emissions units may operate continuously (8,760 hours/year). [Rule 62-213.440 & 62-210.200(PTE), F.A.C.]

Control Technology

A.5. Selective Non-Catalytic Reduction (SNCR) System. The permittee is required to operate, and maintain a High Energy Reagent Technology (HERT) SNCR system for Units 1 and 2 to reduce emissions of NO_X in accordance with this permit and as described in the application, approved drawings, plans, and other documents on file with the Department. Based on the fuel used and the operating conditions recorded during the baseline testing authorized by air construction permit No. 0050014-012-AC, the designed target NO_X conversion efficiency for Unit 1 is 50% and the designed target NO_X conversion efficiency for Unit 2 is 30%. The designed target ammonia slip level is 5 part per million by volume (ppmv) based on a 24-hour average. [Design; Application No. 0050014-013-AC and Rule 62-4.080, F.A.C.]

{Permitting Note: Advanced Combustion Technology, Inc. designed the HERT SNCR system, which generally consists of the following:

- ***Urea Injection System**: Urea is delivered by truck and stored on site as a 50% aqueous solution in one 45,000 gallon tank. It is expected that the tank will be maintained at about 2/3 capacity to avoid the possibility of an overfill. This provides enough urea for about 5½ days of operation. The solution is maintained at a temperature of approximately 90° F by circulating through the SNCR system piping loop heating module. Using plant service water or other dilution water source, the metering module dilutes the reagent to a predetermined concentration (somewhat less than 30%) and precisely controls the flow of the diluted reagent to distribution modules located near the boiler injection point. The distribution modules provide the final control of diluted reagent and atomizing/cooling (plant) air being delivered to each injector. The diluted reagent is injected into the boiler via wall-mounted air atomizing lance installed in the upper levels of the boiler. At peak load, the urea injection rate is about 145 gallons per hour (gph) for Unit 1 and about 135 gph for Unit 2. This translates to an ammonia flow for Unit 1 of 391 lb/hr and for Unit 2 of 364 lb/hr, on a dry basis.*

- ***Ammonia Slip**: The SNCR is designed and guaranteed to have a maximum ammonia slip concentration of 5 ppmvd corrected to 3% O_2 (24 hour basis) in the duct cross-sectional area for all boiler loads. There are no provisions for continuously monitoring ammonia concentration in the flue gas. When ammonia measurements in the flue gas are required, a wet chemical method or other methods approved by EPA will be utilized. Although not required, more frequent tracking of ammonia slip will be monitored by measuring the amount of residual ammonia adsorbed by the fly ash. Fly ash samples will be measured periodically using an ion-specific electrode.}*

Emission Limitations and Standards

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

Unless otherwise specified, the averaging times for Specific Conditions **A.6. - A.11.** are based on the specified averaging time of the applicable test method.

A.6. Visible Emissions. Visible emissions shall not exceed 40 percent opacity. Because units 1 and 2 share a common stack, visible emissions violations from the stack will be attributed to both units unless opacity meter results show the specific unit causing the violation. [Rule 62-296.405(1)(a), F.A.C. and 62-213-440 F.A.C.]

A.7. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more. Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6)-minute periods, during the 3-hour period of excess

emissions allowed for boiler cleaning and load changes, at units which have installed continuous opacity monitors. [Rule 62-210.700(3), F.A.C.]
{Permitting Note: Load changes may be demonstrated by monitoring megawatt output.}

A.8. SO_2 Emissions. The sulfur content of the No. 2 fuel oil and the "on-specification" used oil shall not exceed 0.5 percent, by weight, as measured by applicable test methods. Sulfur dioxide emissions shall not exceed the following emissions limitations, as measured by applicable compliance methods:

Unit No.	Emissions Limit
001, alone	2.10 lbs./MMBtu
002, alone	2.70 lbs./MMBtu
001 and 002, combined	4.50 lbs./MMBtu

[Rules 62-204.220(1) & 62-204.240(1), F.A.C.]

A.9. NO_X Emissions Cap. The combined NO_X emissions from Units 1 and 2 shall not exceed 4,700 tons during any consecutive 12-month rolling total as determined by CEMS data reported to the EPA Acid Rain database (including the NO_X emissions and heat input rates). Within three working days of discovering an exceedance of the NO_X emissions cap, the permittee shall notify the Compliance Authority. [Permit No. 0050014-016-AC and Rule 62-4.080, F.A.C.] (See Facility-wide Conditions **FW11.** and **FW12.**)

{Permitting Note: No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly. For this project, proper operation of the air pollution control device means complying with the NO_X emissions cap. [Rule 62-210.650, F.A.C.]}

A.10. PM Emissions. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat. [Rule 62-296.405(1)(b), F.A.C.]

A.11. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. [Rule 62-210.700(3), F.A.C.]

Excess Emissions

Rule 62-210.700 (Excess Emissions), F.A.C. cannot vary any requirement of an NSPS, NESHAP or Acid Rain program provision.

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

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

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

Monitoring of Operations

A.15. CAM Plan. These emissions units are subject to the Compliance Assurance Monitoring (CAM) requirements contained in the attached Appendix CAM. Failure to adhere to the monitoring requirements specified does not necessarily indicate an exceedance of a specific emissions limitation; however, it may

constitute good reason to require compliance testing pursuant to Rule 62-297.310(7)(b), F.A.C. [40 CFR 64; Rules 62-204.800 and 62-213.440(1)(b)1.a., F.A.C.]

A.16. SNCR Urea Injection Rate Monitor. In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a flow meter to measure and record the urea injection rate for the SNCR system. [Rules 62-4.070(3) and 62-212.400(5)(c), F.A.C., and permit No. 0050014-013-AC]

Continuous Monitoring Requirements

{Permitting Note: In accordance with the federal Acid Rain Phase II requirements and Permit No. 0050014-013-AC, the following continuous monitors are installed on these units: SO_2, NO_X, Carbon Dioxide (CO_2), opacity, urea injection rate and stack gas flow.}

A.17. Opacity and CO_2 CEMS. These emissions units shall have installed, and shall maintain, continuous monitoring systems for monitoring opacity and CO_2. [Rule 62-296.405(1)(f)1., F.A.C. and Permit No. 0050014-016-AC]

A.18. NO_X CEMS. The Acid Rain NO_X CEMS shall be used to demonstrate compliance with the facility-wide NO_X emissions cap. (See Facility-wide conditions **FW11.**, **FW12.** and specific condition **A.9.**) [Permit No. 0050014-016-AC]

A.19. SO_2 CEMS. Those emissions units not having an operating flue gas desulfurization device may monitor sulfur dioxide emissions by fuel sampling and analysis according to methods approved by the EPA. The permittee elected to satisfy the monitoring requirements using SO_2 continuous emissions monitors. [Rule 62-296.405(1)(f)1.b., F.A.C.]

A.20. SO_2 Averaging Time. Continuous SO_2 emission monitoring 24-hour averages are required to demonstrate compliance with the standards of the Department (Specific Condition **A.8.**). A valid 24-hour average shall consist of no less than 18 hours of valid data capture per calendar day. In the event that valid data capture is interrupted, the permittee shall immediately initiate as-fired fuel sampling to demonstrate compliance with the SO_2 emissions standard. As-fired fuel sampling shall continue until such time as valid data capture is restored. In lieu of as-fired fuel sampling, the permittee may elect to demonstrate SO_2 emissions compliance by the temporary use of a spare SO_2 emissions monitor. The spare, previously calibrated, SO_2 emissions monitor must be installed and collecting data in the same time frame as required above for as-fired fuel sampling in order to maintain a quality control (QC) program. At a minimum, the QC program must include written procedures which shall describe in detail complete, step-by-step procedures and operations for each of the following activities:

a. Calibration of CEMS.
b. Calibration Drift (CD) determination and adjustment of CEMS.
c. Preventative maintenance of CEMS (including spare parts inventory).
d. Data recording, calculations and reporting.
e. Accuracy audit procedures including sampling and analysis methods.
f. Program of corrective action for malfunctioning CEMS.

[Rules 62-213.440, 62-204.800(7)(e)5., and 62-296.405(1)(f)1.b., F.A.C.; and, AO03-211310]

A.21. Continuous Monitor Performance Specifications. If continuous monitoring systems are required by rule or are elected by the permittee to be used for demonstrating compliance with the standards of the Department, they must be installed, maintained and calibrated, either:

a. In accordance with the EPA performance specifications listed below. These Performance Specifications are contained in 40 CFR 60, Appendix B, and are adopted by reference in Rule 62-204.800, F.A.C.
   (1) Performance Specification 1-Specifications and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources.

(2) Performance Specification 2-Specifications and Test Procedures for SO_2 Continuous Emission Monitoring Systems in Stationary Sources.
(3) Performance Specification 3-Specifications and Test Procedures for CO_2 Continuous Emission Monitoring Systems in Stationary Sources. Or,

b. In accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Excess emissions pursuant to Rule 62-210.700, F.A.C., shall be determined using the 40 CFR part 75 CEMS.

[Rule 62-297.520, F.A.C.; 40 CFR 75; and, Applicant request.]

Test Methods and Procedures

{Permitting Note: The attached Table 2, 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.22. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
17, 5, 5B or 5F	Method for Determining Particulate Matter Emissions (All PM is assumed to be PM_{10}.)
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 {Note: The method shall be based on a continuous sampling train.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography
19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.)
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25 and or 25A	Method for Determining Gaseous Organic Concentrations (Flame Ionization)
6, 6A, 6B or 6C	Determination of Sulfur Dioxide
CTM-027	Conditional EPA Test Method 027, Measurement of Ammonia Slip (or equivalent method)

The above methods are described in 40 CFR 60, Appendix A, and 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. [62-297.401, F.A.C., and Permit No. 0050014-016-AC]

A.23. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

A.24. Annual Compliance Tests Required. During each federal fiscal year (October 1st to September 30th), each Emission Units (EU -001 and EU -002) shall be tested to demonstrate compliance with the emissions standards for SO_2 and PM. [Rule 62-297.310(7), F.A.C. and Permit No. 0050014-016-AC]

A.25. Compliance Tests Prior To Renewal. Compliance tests shall be performed for PM, SO_2 and VE once every 5 years. The tests shall occur prior to obtaining a renewed operating permit to demonstrate compliance with the emission limits in Specific Conditions **A.6. - A.11.** [Rules 62-210.300(2)(a) and 62-297.310(7)(a), F.A.C.]

A.26. Testing While Injecting Additives. If supplemental additives are used greater than 50% of the time that the unit(s) are operated, the owner or operator shall conduct all emissions tests while injecting additives, consistent with normal operating practices approved by the Department. [Rule 62-213.440, F.A.C.]

A.27. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen-second intervals during the required period of observation.
2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:
   a. For the basic part of the standard (i.e., 20 percent opacity), the opacity shall be determined as specified above for a single-valued opacity standard.
   b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value. [Rules 62-297.310, and 62-297.401, F.A.C.]

A.28. Visible Emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C. The Permittee has elected to utilize a transmissometer (opacity meter) for demonstrating compliance with the visible emissions limit. As long as the transmissometer is calibrated, maintained, and operated in accordance with Performance Specification 1 of 40 CFR 60, Appendix B (see Specific Condition A.23.), the annual test for visible emissions is not required. [Rules 62-213.440 and 62-296.405(1)(e)1., F.A.C.]

{Permitting Note: A transmissometer used to demonstrate compliance should record sufficient data so as to be equivalent to a Method 9 test. Method 9 requires determining an average based on 24 readings at 15-second intervals, thus, a six-minute average. The transmissometers in use at this facility make a permanent recording every six-minutes based on an average of readings taken every 15 seconds. After the 6-minute average is recorded, the individual readings are erased and a new 6-minute average is determined based on the next set of 24 individual readings. This 6-minute block recording is consistent with the requirements of Method 9.}

A.29. Particulate Matter. The test methods for particulate matter emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone

wash shall be used with EPA Method 5 or 17. [Rules 62-213.440, 62-296.405(1)(e)2., 62-297.310, and 62-297.401, F.A.C.]

A.30. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedances of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards. [Rules 62-213.440, 62-296.405(1)(e)3., 62-297.310, 62-297.401, F.A.C.; and, AO03-211310]

{Permitting Note: The permittee has elected to demonstrate compliance with the SO_2 limits specified in condition A.8. by means of a continuous emissions monitoring system (CEMS). In addition to any other requirements associated with the operation and maintenance of these CEMS (i.e., Acid Rain requirements), operation of the CEMS shall be in accordance with the requirements listed below. The annual calibration RATA associated with these CEMS may be used in lieu of the required annual EPA Reference Method 6, as long as all of the requirements of Rule 62-297.310, F.A.C., are met (i.e., prior test notification, proper test result submittal, etc.).}

A.31. Fuel Sampling and Analysis. The following fuel sampling and analysis protocol shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance with the sulfur dioxide standard in the event that the SO_2 continuous emissions monitor is not able to capture valid data:

a. Determine and record the as-fired fuel sulfur content, percent by weight, for liquid fuels using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition, to analyze a representative sample of the blended fuel following each fuel delivery.
b. Determine and record the as-fired fuel sulfur content, percent by weight, for coal using ASTM D2013-72 and either ASTM D3177-75 or ASTM D4239-85, or the latest edition, to analyze a representative sample of the blended as-fired pulverized coal.
c. Determine and record the density (using ASTM D 1298-80, or the latest edition) and the calorific heat value in Btu per pound (using ASTM D 240-76, or the latest edition) of the fuel oil combusted.
d. Determine and record the calorific heat value in Btu per pound of the blended, as-fired pulverized coal using ASTM D2013-72 and either ASTM D2015-77 or D3286-(latest version), or the latest editions.
e. Record daily the amount of each fuel fired, the density of the fuel oil, the heating value of each fuel fired, and the percent sulfur content, by weight, of each fuel fired.
f. Utilize the information in a., b., c., d. and e., above, to calculate the SO_2 emission rate to ensure compliance at all times. [Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

A.32. Heat Input. Compliance with the heat input limitations specified in Specific Condition **A.1.** shall be demonstrated solely through the use of the composite fuel samples (see Specific Condition **A.31.c. & d.**) taken by on-site personnel (see Specific Condition **A.39.**) Records of the composite samples (typically taken daily as-fired for solid fuel and per shipment (after blending) for liquid fuel) shall be maintained on-site for a period of five years and shall be made available for Department inspection upon request. [Permit No. 0050014-011-AC]

{Permitting Note: The permittee and the Department agree that the CEMS used for the federal Acid Rain Program conservatively overestimates the heat input for this unit. The monitoring data for heat input is therefore not appropriate for purposes of compliance, including annual compliance certification.}

Recordkeeping and Reporting Requirements

A.33. Reporting Schedule. The following reports and notifications shall be submitted to the Compliance Authority:

Report	Reporting Deadline	Related Condition(s)
Excess Emissions	Quarterly	**A.35.**

A.34. Other Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements.

A.35. Excess Emission Reports. Submit to the Department a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years. [Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

A.36. Specific NO_X Reporting Requirement. The permittee shall prepare and submit reports for all required NO_X tests in accordance with the provisions of Rule 62-297.310(8), F.A.C. For each required test run, the report shall indicate the actual heat input rate (MMBtu/hour), the NO_X emission rate (lb/MMBtu) as recorded by the CEMS, and the urea injection rate (lb/hour). The report shall also include copies of the continuous monitoring records for the NO_X emissions. [Rule 62-297.310(8), F.A.C. and Permit No. 0050014-016-AC]

A.37. Annual NO_X Reports. In conjunction with each Annual Operating Report, the permittee shall submit an annual report summarizing the actual NO_X emissions from Units 1 and 2 as determined by the Acid Rain CEMS for each 12-month rolling total for the calendar year. The reports shall identify the date and duration of any periods when the CEMS was off line or unable to report valid data and shall describe how NO_X emissions were determined for these periods and included in the 12-month rolling total. Each report shall be submitted to the Compliance Authority in accordance with the deadline for the Annual Operating Report. The Compliance Authority may request this report at other times within the calendar year. [Rule 62-4.070(3), F.A.C. and Permit No. 0050014-016-AC]

A.38. Hours of Operation Log. For each emissions unit, the permittee shall maintain an operation log available for Department inspection that documents the total hours of annual operation, including a detailed account of the hours operated on each of the allowable fuels. [Rule 62-213.440]

A.39. Fuel Consumption Log. The owner or operator shall maintain daily records of fuel consumption and each analysis that provides the heating value and sulfur content for all fuels fired. These records must be of sufficient detail to determine compliance with the allowable sulfur dioxide emission limitations. [Rules 62-213.440 & 62-4.070(3), F.A.C.]

{Permitting Note: Daily records of fuel consumption are maintained on a 24-hour block (midnight to midnight) basis. Gulf Power will meet greater than a 95% daily sampling rate.}

A.40. CEMS Maintenance Log. A maintenance log of the continuous monitoring systems shall be kept showing:
a. Time out of service.
b. Calibration and adjustments.
[Rule 62-213.440, F.A.C.; and, AO03-211310, Specific Condition 8]

Miscellaneous Conditions

A.41. *Used Oil*. Burning of on-specification used oil is allowed in this emissions unit in accordance with all other conditions of this permit and the following conditions:

a. *On-specification Used Oil Emissions Limitations.* This emissions unit is permitted to burn on-specification used oil, which contains a Polychlorinated Biphenyl (PCB) concentration of less than 50 ppm. On-specification used oil is defined as used oil that meets the specifications of 40 CFR 279 - Standards for the Management of Used Oil, listed below. "Off-specification" used oil shall not be burned. Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil.

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
Flash point	100 degrees F minimum

b. *Quantity Limitation*. This emissions unit is permitted to burn "on-specification" used oil that is generated by Gulf Power Company, not to exceed 50,000 gallons per calendar year in each boiler (-001 & -002).

c. *PCB Limitation*. Used oil containing a PCB concentration of 50 or more ppm shall not be burned at this facility. Used oil shall not be blended to meet this requirement.

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

e. *Testing Requirements*. For each batch of used oil to be burned, the owner or operator must be able to demonstrate that the used oil qualifies as on-specification used oil and that the PCB content is less than 50 ppm. The requirements of this demonstration are governed by the following federal regulations:

Analysis of used oil fuel. A generator, transporter, processor/re-refiner, or burner may determine that used oil that is to be burned for energy recovery meets the fuel specifications of Sec. 279.11 by performing analyses or obtaining copies of analyses or other information documenting that the used oil fuel meets the specifications. [40 CFR 279.72(a)]

Testing of used oil fuel. Used oil to be burned for energy recovery is presumed to contain quantifiable levels (2 ppm) of PCB unless the marketer obtains analyses (testing) or other information that the used oil fuel does not contain quantifiable levels of PCBs.

(1) The person who first claims that a used oil fuel does not contain quantifiable level (2 ppm) PCB must obtain analyses or other information to support that claim.

(2) Testing to determine the PCB concentration in used oil may be conducted on individual samples, or in accordance with the testing procedures described in Sec. 761.60(g)(2). However, for purposes of this part, if any PCBs at a concentration of 50 ppm or greater have been added to the container or equipment, then the total container contents must be considered as having a PCB concentration of 50 ppm or greater for purposes of complying with the disposal requirements of this part.

(3) Other information documenting that the used oil fuel does not contain quantifiable levels (2 ppm) of PCBs may consist of either personal, special knowledge of the source and composition of the used oil, or a certification from the person generating the used oil claiming that the oil contains no detectable PCBs. [40 CFR 761.20(e)(2)]

When testing is required, the owner or operator shall sample and analyze each batch of used oil to be burned for the following parameters:

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

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

Additionally, the owner or operator shall sample and analyze each batch of used oil to be burned for the sulfur content (by weight), density and heat content in accordance with applicable test methods (see Specific Conditions **A.30.** and **A.31.**).

f. *Record Keeping Requirements*. The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department:
   (1) The gallons of on-specification used oil placed into inventory to be burned and the gallons of on-specification used oil burned each month, and
   (2) For each deposit of used oil, results of the analyses as required by the above conditions, or
   (3) Other information, besides testing, used to make a claim that the used oil meets the requirements of on-specification used oil or that the used oil contains less than 50 ppm of PCBs.

   [40 CFR 279.72(b), 40 CFR 279.74(b) and 40 CFR 761.20(e)]

g. *Reporting Requirements*. The owner or operator shall submit, with the Annual Operation Report form, the analytical results required above and the total amount of on-specification used oil placed into inventory to be burned and the total amount of on-specification used oil burned during the previous calendar year. [Rules 62-4.070(3) and 62-213.440, F.A.C.; and, 40 CFR 279 and 40 CFR 761, unless otherwise noted.]

A.42. Ambient Monitoring Requirements. Owners of fossil fuel steam generators shall monitor their emissions and the effects of the emissions on ambient concentrations of sulfur dioxide, in a manner, frequency, and locations approved, and deemed necessary and ordered by the Department. [Rule 62-296.405(1)(c)3., F.A.C.]

{Permitting Note: No ambient monitoring stations are deemed necessary nor ordered by the Department at this time.}

The specific conditions in this section apply to the following emissions unit:

EU No.	Brief Description
003	Combustion Turbines A & B, 542 MMBtu/hr Peaking Unit

Emissions unit number -003 is a Pratt and Whitney Twin-Pac combustion turbine-generator set consisting of two combustion turbines with separate stacks powering a common 40 MW electrical generator. The combustion turbines are designated as combustion turbine A and combustion turbine B. The Twin-Pac system has a maximum heat input of 542 million Btu per hour (MMBtu/hour) while being fueled by No. 2 fuel oil with a maximum sulfur content of 0.5%, by weight. Emissions from these combustion turbines are uncontrolled.

{Permitting notes: This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits required and 62-296.470 CAIR. These turbines are not subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. Each combustion turbine has its own stack. Stack heights = 33 feet, exit dimensions = 13'-7" x 10'-2", exit temperatures = 1,200 ºF, actual volumetric flow rate (total for both stacks) = 1,069,740 acfm. They began commercial operation on May 18, 1971.}

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. The maximum allowable heat input rate is as follows:

EU No.	MMBtu/hr Heat Input	Fuel Type
003	542	No. 2 Fuel Oil

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

B.2. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(2), F.A.C.]

B.3. Methods of Operation. Only new No. 2 fuel oil shall be fired in this combustion turbine engine. [Rule 62-213.410, F.A.C.; Applicant's request in Title V permit renewal application received May 18, 2009]

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

Emission Limitations and Standards

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

Unless otherwise specified, the averaging time(s) for Specific Conditions **B.5. - B.7.** are based on the specified averaging time of the applicable test method.

B.5. Visible Emissions. Visible emissions from each combustion turbine stack shall not be equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1., F.A.C. and AO03-249657]

B.6. Sulfur Dioxide - Sulfur Content. The sulfur content of the new No. 2 fuel oil shall not exceed 0.5 percent, by weight (see Specific Condition **B.11.)**. The permittee shall maintain a log available for Department inspection of the fuel sulfur content. [Rule 62-213.440, F.A.C. and AO03-249657]

B.7. Facility-wide NO_X Emissions Cap. In addition to the above requirements, emissions unit -003 is also subject to the facility-wide NO_X emissions cap of 6,666 tons per year. See Facility-wide Conditions **FW11.** and **FW12.**

Excess Emissions

Rule 62-210.700 (Excess Emissions), F.A.C. cannot vary any requirement of an NSPS, NESHAP or Acid Rain program provision.

B.8. Excess Emissions Allowed. Excess emissions from these emissions units resulting from startup, shutdown or 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.9. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. [Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

B.10. Sulfur Dioxide. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis provided by the vendor upon each fuel delivery. See Specific Conditions **B.6.** and **B.11.** [Rule 62-213.440, F.A.C.]

Test Methods and Procedures

{Permitting Note: The attached Table 2, 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.11. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
9	Visual Determination of the Opacity of Emissions from Stationary Sources
ASTM D2622-92 or ASTM D4294.90 ASTM D4057-88 and ASTM D129-91	The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either these methods or the latest edition.

The above methods are described in 40 CFR 60, Appendix A, and 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 62-213.440, 62-296.320(4)(b)4.9., 62-297.401 F.A.C. and 62-297.440, F.A.C.]

B.12. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

B.13. Annual Compliance Tests Required. During each federal fiscal year (October 1st to September 30th), this unit shall be tested to demonstrate compliance with the emissions standards for VE. [Rule 62-297.310(7), F.A.C.]

B.14. Compliance Tests Prior To Renewal. Compliance tests shall be performed for VE once every 5 years. The tests shall occur prior to obtaining a renewed operating permit to demonstrate compliance with the emission limits in Specific Condition **B.5.** [Rules 62-210.300(2)(a) and 62-297.310(7)(a), F.A.C.]

Recordkeeping and Reporting Requirements

B.15. Other Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements.

B.16. Hours of Operation Log. The permittee shall maintain an operation log available for Department inspection that documents the total hours of annual operation. [Rules 62-213.440 & 62-210.200(PTE), F.A.C.]

Miscellaneous Conditions

B.17. Periodic Monitoring Requirements. The owner or operator shall conduct testing for visible emissions, using EPA Method 9, while the combustion turbine is operating at 90-100 percent of its capacity, according to the following schedule: Upon exceeding 400 hours of operation on fuel oil, and every 150 hours of operation on fuel oil thereafter, in any given federal fiscal year (October 1 through September 30), the owner or operator shall conduct a visible emissions test on each of these combustion turbines while firing fuel oil. These tests shall be performed within 20 days of exceeding such operating hours. Regardless of the number of hours of operation on fuel oil, at least one compliance test shall be conducted on each combustion turbine every five years, coinciding with the term of this operation permit. [Rules 62-213.440(4) and 62-297.310(7), F.A.C.]

Subsection C. Emissions Units 004 & 005 and 006

The specific conditions in this section apply to the following emissions units:

EU No.	Brief Description
004	Combined Cycle Combustion Turbine Generator - *Facility Identification Unit No. 1 (CC-1)*
005	Combined Cycle Combustion Turbine Generator - *Facility Identification Unit No. 2 (CC-2)*
006	Salt Water Cooling Tower

Emission units 004 and 005 (collectively designated as Gulf Smith Unit 3) consist of a General Electric Model No. PG7241 (FA), combined-cycle combustion turbine with electrical generator set and General Electric OpFlex Peak enhancement package designed to expand the peak power production profile. Continuous Dynamics Monitoring (CDM) system installed to ensure that the combustion system parameters are kept at optimal performance. CDM is part of the remote dry low-NO_X (DLN) tuning service provided by General Electric.

The unit will achieve a nominal 566 megawatts, at annual average site conditions, with duct burners. These units are capable of a maximum of approximately 574 megawatts in combined cycle operation with power augmentation and evaporative cooling at 95 degrees F. The maximum heat input of the combustion turbines is a nominal 1,927 MMBtu/hr Lower Heat Value (LHV) at 65 degrees F each. The maximum heat input of the duct burners is a nominal 303 MMBtu/hr (LHV at 65 degrees F) each. The plant includes two 121-foot stacks; a small heater for the gas pipeline; and a 10-cell, mechanical draft salt water cooling tower. The cooling tower is not subject to a NESHAP because chromium-based chemical treatment is not used. Simple cycle operation is not a permitted activity. Support facilities for Unit 3 include water treatment and storage facilities. Emissions from Units -04 and -005 are controlled by Dry Low NO_X (DLN) combustors firing exclusively natural gas. Inherently clean fuels and good combustion practices are employed to control all pollutants. Emission unit -006 is a regulated salt water cooling tower for Smith units -004 and -005 and is equipped with drift eliminators.

{Permitting notes: These units began commercial operation during January of 2002. Units -004 and -005 are regulated under Acid Rain, Phase II. In addition, these CT's are regulated under: NSPS - 40 CFR 60, Subpart GG (Standards of Performance for Stationary Gas Turbines), which is adopted and incorporated by reference in Rule 62-204.800(7)(b), F.A.C.; a BACT determination (PSD-FL-269), dated July 28, 2000; Air Construction Permit No. 0050014-002-AC, issued July 28, 2000; and, Air Construction Permit revision project No. 0050014-003-AC. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not required to demonstrate compliance with non-NSPS permit standard(s). Stack heights = 121 feet, exit diameters = 16.8 feet, exit temperatures = 186 ºF, actual volumetric flow rates = 981,334 acfm.}

Essential Potential to Emit (PTE) Parameters

C.1. Permitted Capacity. The maximum allowable heat input rate is as follows:

a. *Combustion Turbine Capacity.* The maximum heat input rate, based on the lower heating value (LHV) of the fuel at ambient conditions of 65°F temperature, 100% load, and 14.7 psi pressure shall not exceed 1,927 million Btu per hour (MMBtu/hr) for each combustion turbine when firing natural gas. The maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing annual compliance testing.

b. *Heat Recovery Steam Generator equipped with Duct Burner*. The maximum heat input rate of each natural gas fired duct burner shall not exceed 303 MMBtu/hour (LHV).

[Rules 62-4.160(2) & 62-210.200(PTE), F.A.C.; and, 0050014-002-AC & 0050014-003-AC].

C.2. Emissions Unit Operating Rate Limitation After Testing. See the related testing provisions in Appendix TR, Facility-wide Testing Requirements. [Rule 62-297.310(2), F.A.C. and 0050014-002-AC]

C.3. Methods of Operation-Fuel. Pipeline natural gas is the only fuel allowed to be fired in the two combined-cycle combustion turbines. [Rule 62-213.410, F.A.C.; Applicant's request in Title V permit renewal application received May 18, 2009; and, 0050014-002-AC]

*{Permitting Note: For the purposes of Subsection C. of this permit, "pipeline natural gas" means natural gas with a sulfur content of less than 2.0 grains per dry standard cubic foot that is provided by the natural gas pipeline transmission company. (See Specific Condition **C.10.**)}*

C.4. Hours of Operation. Maximum allowable hours of operation for the 566 MW Combined Cycle Plant are 8,760 hours per year while firing natural gas. Combined operation in steam power augmentation mode plus OpFlex Peak mode is limited to1,000 hours per year per unit. [Rule 62-210.200 F.A.C. (Definitions-Potential Emissions) and 0050014-002-C and No. 0050014-019-AC]

Control Technology

C.5. NO_X Control. Dry Low NO_X (DLN) combustors shall be maintained on the stationary combustion turbine and Low NO_X burners shall be maintained in the duct burner arrangement to comply with the NO_X emissions limits listed in Specific Condition **C.9.** DLN systems shall each be maintained as per manufacturer's recommendation. [Rules 62-4.070 and 62-204.800(7), F.A.C. to avoid PSD Review; and, 0050014-002-AC]

C.6. PM Control. Drift eliminators shall be maintained on the cooling tower to reduce PM/PM_{10} emissions. [0050014-002-AC]

Emission Limitations and Standards

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

Unless otherwise specified, the averaging times for Specific Conditions **C.7. - C.12.** are based on the specified averaging time of the applicable test method.

C.7. Emissions Summary.

a. The following table is a summary of the BACT determination and is followed by the applicable specific conditions. Values are corrected to 15% O_2 on a dry basis. These limits, or their equivalent in terms of lb/hr or NSPS units, as well as the applicable averaging times, are followed by the applicable specific conditions.

Emission Unit	NO_X (1)	CO BACT	SO_2/SAM BACT	VOC BACT	PM/Visibility (% Opacity)	Technology and Comments
C.T.'s: With Duct Burners	82.9 lb/hr	16 ppm @ 15% O_2	2 gr/100 scf natural gas (3)	4 ppm @ 15% O_2	10%	Dry Low NO_X Combustors Natural Gas, Good Combustion
DB	0.1 Ib/MMBtu					
Steam Power Augmentation	113.3 lb/hr	23 ppm @ 15% O_2	2 gr/100 scf natural gas (3)	6 ppm @ 15% O_2	10%	Unit limited to 1000 hours per year of operation
OpFlex Peak Enhancement	113.3 lb/hr	23 ppm @ 15% O_2	2 grains per 100 scf of natural gas	NA[e]	10%	Continuous Dynamics Monitoring system
Cooling Tower	---				18.2 lb/hr (2)	Drift Eliminators

(1) NO_X limits not determined by BACT.
(2) Listed for informational purposes only.
(3) See Fuel Monitoring Schedule in Specific Condition **C.15.**

b. In addition to the above conditions that were established by permit 0050014-002-AC, emissions units -004 and -005 are also independently subject to all of the emission standards and requirements of 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines included with permit as Appendix NSPS subpart GG. Particularly the NO_X emission standard contained in 40 CFR 60.332(a)(1), which must be corrected to ISO conditions. [Rules 62-212.400, 62-204.800(7)(b) (Subpart GG and Da), 62-210.200 (Definitions-Potential Emissions) F.A.C.; 40 CFR 60 Subpart GG; and, permit No. 0050014-002-AC]

c. The Opflex peaking mode will be used to displace some of the steam power augmentation mode and is subject to the same emissions standards and initial Best Available Control Technology (BACT) determinations. [Permit No. 0050014-019-AC]

d. Emissions of NO_X in the stack exhaust gas with the combustion turbine operating in the Opflex peaking mode with or without duct firing shall not exceed 113.3 lb/hour based on a 30-day rolling average of data collected by the continuous emissions monitor system (CEMS) and prorated daily as necessary based upon hours of operation per operating mode. [Permit No. 0050014-019-AC]

e. Compliance with the CO emissions standard shall be demonstrated by stack testing accordance with Method 10, promulgated by the Environmental Protection Agency (EPA). [Permit No. 0050014-019-AC] *{Permitting Note: For informational purposes, the CO limit equates to 116.6 lb/hour. Compliance with the CO limit also provides reasonable assurance that VOC emissions are very low (<6 ppmvd @ 15% O_2)}*

f. Emissions of SO_2 and SAM shall be minimized by the firing of natural gas meeting this fuel sulfur specification. Compliance with this requirement may be demonstrated with data collected from the natural gas pipeline transmission company in conjunction with the current NSPS Custom Fuel Monitoring Schedule specified in the Title V air operation permit. [Permit No. 0050014-019-AC]

g. Compliance with the visible emissions standard shall be determined by EPA Method 9. [Permit No. 0050014-019-AC]

C.8. Visible Emissions. VE emissions shall serve as a surrogate for PM/PM_{10} emissions from the combustion turbine operating with or without steam augmentation and/or the duct burner and shall not exceed 10 percent opacity from the stack in use. PM/PM_{10} emissions (for information only) are up to 43 lb/hr. [Rules 62-4.070, 62-212.400, & 62-204.800(7), F.A.C.; and, 0050014-002-AC]

C.9. NO_X Emissions.

a. Emissions of NO_X in the stack exhaust gas, with the combustion turbine operating and the duct burner on shall not exceed 82.9 lb/hr (30 day rolling average). Emissions of NO_X in the stack exhaust gas, with the combustion turbine operating with steam augmentation and the duct burner on shall not exceed 113.3 lb/hr (30 day rolling average). Compliance will be determined by the continuous emission monitor system (CEMS) and prorated daily as necessary based upon hours of operation per operating mode. Emissions of NO_X in the stack exhaust gas with the combustion turbine operating with the duct burner on shall not exceed 82.9 lb/hr and 113.3 lb/hr with steam augmentation to be demonstrated by initial stack test.

b. Emissions of NO_X from the duct burner shall not exceed 0.1 lb/MMBtu, which is more stringent than the NSPS.

c. When NO_X monitoring data is not available, substitution for missing CEMS data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time. Heat input for these periods shall be determined by fuel sampling and measurement.

d. **Facility-wide NO_X emissions cap**: In addition to individual (point source) emission limits and NO_X averaging plan requirements, the Lansing Smith facility shall be required to comply with a facility-wide NO_X emissions cap of 6,666 TPY. CEMS shall be the method of compliance for reporting and record-keeping requirements. (See specific condition **FW11.**)

[Rules 62-4.070 and 62-204.800(7), F.A.C. to avoid PSD Review; and, 0050014-002-AC]

C.10. Sulfur Dioxide. SO_2 emissions shall be limited by firing natural gas with a total sulfur content less than 2 grains per 100 standard cubic foot as determined and provided by the natural gas pipeline transmission company. Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Condition **C.15.** will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the duct burner or the combustion turbine. {For informational purposes, annual SO_2 emissions will be up to 105 TPY} [40 CFR 60 Subpart GG; Rules 62-4.070, 62-212.400, & 62-204.800(7), F.A.C.; and, 0050014-003-AC]

C.11. Carbon Monoxide. Emissions of CO in the stack exhaust gas with the combustion turbine operating and duct burner on shall exceed neither 16 ppm nor 23 ppm (@ 15%O_2) with steam augmentation to be demonstrated annually by stack testing using EPA Method 10. {For informational purposes, this equates to 78.7 lb/hr and 116.6 lb/hr respectively} [Rule 62-212.400, F.A.C. and 0050014-002-AC]

C.12. Volatile Organic Compounds. Emissions of VOC in the stack exhaust gas with the combustion turbine operating and duct burner on shall exceed neither 4 ppm nor 6 ppm (@ 15%O_2) with steam augmentation to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. {For informational purposes, this equates to 10.2 lb/hr and 16.8 lb/hr respectively} [Rule 62-212.400, F.A.C. and 0050014-002-AC]

Excess Emissions

Rule 62-210.700 (Excess Emissions), F.A.C. cannot vary any requirement of an NSPS, NESHAP or Acid Rain program provision.

C.13. Excess Emissions Prohibited. 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. Such preventable emissions shall be included in the calculation of the 30-day rolling averages compiled by the continuous NO_X emissions monitor. [Rule 62-210.700(4), F.A.C. and 0050014-002-AC]

Monitoring of Operations

C.14. CAM Plan. These emissions units are subject to the Compliance Assurance Monitoring (CAM) requirements contained in the attached Appendix CAM. Failure to adhere to the monitoring requirements specified does not necessarily indicate an exceedance of a specific emissions limitation; however, it may constitute good reason to require compliance testing pursuant to Rule 62-297.310(7)(b), F.A.C. [40 CFR 64; Rules 62-204.800 and 62-213.440(1)(b)1.a., F.A.C.]

C.15. Natural Gas Monitoring Schedule. A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met (monitoring of nitrogen content is not required):

a. The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.
b. The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas pursuant to 40 CFR 75.11(d)(2).
c. Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.
d. This custom fuel monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

Gulf Power shall notify DEP of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than 1 grain per 100 cubic foot of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined. [0050014-002-AC]

Continuous Monitoring Requirements

C.16. NO_X CEMS. The permittee shall maintain and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from these units. Periods when NO_X emissions are above the standards, listed in Specific Conditions **C.7.** and **C.9.**, shall be reported to the DEP Northwest District Office within one working day (verbally) followed up by a written explanation postmarked not later than three (3) working days (alternatively by facsimile within one working day). [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C.; 40 CFR 60.7 (1998 version); and, 0050014-002-AC]

C.17. NO_X CEMS Requirements for Continuous Compliance. Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 30 day rolling average. Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. A valid operating day shall consist of at least one valid operating hour. These excess emissions periods shall be reported as required. Continuous compliance with the 0.1 lb/MMBtu limit for the duct burners will be demonstrated through continuous compliance with the combined duct burner and CT emission limits. [Rule 62-4.070 and 62-204.800(7), F.A.C. to avoid PSD Review; and 0050014-002-AC]

{Permitting Note: The requirements for the NO_X CEMS which are installed and maintained in accordance with 40 CFR 75 are at least as stringent as the requirements of 40 CFR 60, and are an acceptable alternative.}

C.18. CEMS for reporting excess emissions. The NO_X CEMS shall be used in lieu of the requirement for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998 version). Upon request from DEP, the CEMS emission rates for NO_X on the CT's shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332. [0050014-002-AC]

Test Methods and Procedures

{Permitting Note: The attached Table 2, 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.19. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
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 {Note: The method shall be based on a continuous sampling train.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25 and or 25A	Method for Determining Gaseous Organic Concentrations (Flame Ionization)

The above methods are described in 40 CFR 60, Appendix A, and 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. [Rule 62-297.401, F.A.C. and Permit No. 0050014-002-AC]

C.20. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

C.21. Annual Compliance Tests Required. During each federal fiscal year (October 1st to September 30th), EU -004 and -005 shall be tested to demonstrate compliance with the emissions standards for CO, VE and NO_X. Annual compliance with the applicable NO_X emissions standards shall also be demonstrated with valid data collected by the required CEM systems during the required annual RATA at permitted capacity. Continuous compliance shall be demonstrated as specified in Specific Condition **C.17.** [Rule 62-297.310(7), F.A.C. and Permit No. 0050014-002-AC]

C.22. Compliance Tests Prior To Renewal. Compliance tests shall be performed for CO and VE once every 5 years while operating in the OpFlex peaking mode. The tests shall occur prior to obtaining a renewed operating permit to demonstrate compliance with the emission limits in Specific Conditions **C.9. - C.12.** [Rules 62-210.300(2)(a), 62-297.310(7)(a), F.A.C. and 0050014-019-AC]

Additional Compliance Test Requirements

C.23. Compliance with the SO_2 and PM/PM_{10} emission limits. Not withstanding the requirements of Rule 62-297.310(7), F.A.C., the use of pipeline natural gas is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule, or natural gas supplier data may be submitted, or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR 60.335 or 40 CFR 75 are used when determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1998 version). [BACT and 0050014-002-AC]

C.24. Compliance with CO emission limit. Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the annual RATA testing for the NO_X CEMS required pursuant to 40 CFR 75. As an alternative to annual testing in a given year, periodic tuning data may be provided to demonstrate compliance in the year the tuning is conducted. [0050014-002-AC]

C.25. Compliance with the VOC emission limit. An initial test was required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit and periodic tuning data will be employed as surrogate and no annual testing is required. [0050014-002-AC]

C.26. Tests After Substantial Modifications. All performance tests required for initial startup shall also be conducted after any substantial modification and appropriate shakedown period of air pollution control equipment including the replacement of dry low-NO_X combustors. Shakedown periods shall not exceed 100 days after re-starting the combustion turbine. [0050014-002-AC]

Recordkeeping and Reporting Requirements

C.27. Reporting Schedule. The following reports and notifications shall be submitted to the Compliance Authority:

Report	Reporting Deadline	Related Condition(s)
Excess Emissions	Quarterly	**C.29.**
Excess Emissions - Malfunctions	Quarterly (if requested)	**C.30.**

C.28. Other Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements.

C.29. Quarterly Reports. Quarterly excess emission reports, in accordance with 40 CFR 60.7(a)(7)(c) (1998 version), shall be submitted to the DEP Northwest District Office. [0050014-002-AC]

C.30. Operational Records. To demonstrate compliance with the operational restriction on hours, the permittee shall maintain records of the hours of operation of each combustion turbine when operating in OpFlex Peaking mode and steam power augmentation mode. [Rule 62-4.070(3), F.A.C. and 0050014-019-AC]

C.31. Actual Emissions Reporting. This permit is based on an analysis that compared baseline actual emissions with projected actual emissions and avoided the requirements of subsection 62-212.400(4) through (12), F.A.C. for several pollutants. Therefore, pursuant to Rule 62-212.300(1)(e), F.A.C., the permittee is subject to the following monitoring, reporting and recordkeeping provisions.

a. The permittee shall monitor the emissions of any PSD pollutant that the Department identifies could increase as a result of the construction or modification and that is emitted by any emissions unit that could be affected; and, using the most reliable information available, calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change. Emissions shall be computed in accordance with the provisions in Rule 62-210.370, F.A.C., which are provided in Appendix C of this permit.

b. The permittee shall report to the Department within 60 days after the end of each calendar year during the 5-year period setting out the unit's annual emissions during the calendar year that preceded submission of the report. The report shall contain the following:

   1) The name, address and telephone number of the owner or operator of the major stationary source;

   2) The annual emissions calculations pursuant to the provisions of 62-210.370, F.A.C., which are provided in Appendix C of this permit;

   3) If the emissions differ from the preconstruction projection, an explanation as to why there is a difference; and

   4) Any other information that the owner or operator wishes to include in the report.

c. The information required to be documented and maintained pursuant to subparagraphs 62-212.300(1)(e)1 and 2, F.A.C., shall be submitted to the Department, which shall make it available for review to the general public.

For this project, the permit requires the annual reporting of actual NOx emissions for the following units: EU 004 and EU 005 Combined Cycle Combustion Turbine and Generator Sets.

[Application 0050014-019-AC; and Rules 62-212.300(1)(e) and 62-210.370, F.A.C.]

C.32. Excess Emissions Report. If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP Northwest District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels (in terms of applicable averaging periods) exceed the permitted standards listed in Specific Conditions **C.7. - C.12.** [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7 (1998 version); and, 0050014-002-AC]

{Permitting Note: This condition does not relieve the permittee from complying with the more stringent requirements of Rules 62-4.130, 62-4.160 and 62-210.700(6), F.A.C. for "immediately" reporting excess emissions due to malfunctions (see condition RR2 of Appendix RR, Facility-wide Reporting Requirements).}

Other Requirements

C.33. Federal Rule Requirements. In addition to the specific conditions listed above, this emissions unit is also subject to the applicable requirements contained in 40 CFR 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, attached to this permit as Appendix NSPS, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units. [0050014-002-AC]

Operated by: Gulf Power Company
Plant: Lansing Smith Electric Generating Plant
ORIS Code: 0643

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

E.U. ID No.	Brief Description
001	Boiler Number 1 - 1,944.8 MMBtu/hour (Phase II Acid Rain Unit)
002	Boiler Number 2 - 2,246.2 MMBtu/hour (Phase II Acid Rain Unit)
004	170 MW Gas Combustion Turbine with HRSG and Duct Burner (Acid Rain Unit)
005	170 MW Gas Combustion Turbine with HRSG and Duct Burner (Acid Rain Unit)

A.1. The Phase II Acid Rain 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), dated 10/01/12, received 10/01/12.
b. DEP Form No. 62-210.900(1)(a)4, dated 05/05/09, received 05/26/09.
c. DEP Form 62-210.900(1)(a)1, dated 9/24/12, received 10/01/12.
[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

A.2. Nitrogen oxide (NO_X) requirements for each Acid Rain Phase II unit are as follows:

E.U. ID #	EPA ID	NO_X Limit
001	**ID No. 1 Boiler 1**	Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves four NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the years 2013, 2014, 2015, 2016 and 2017. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.62** lb/MMBtu. In addition, this unit shall not have an annual heat input **greater than 13,246,415** MMBtu.
002	**ID No. 2 Boiler 2**	Pursuant to 40 CFR 76.11, the Florida Department of Environmental Protection approves four NO_X emissions averaging plans for this unit. Each plan is effective for one calendar year for the years 2013, 2014, 2015, 2016 and 2017. Under each plan, this unit's NO_X emissions shall not exceed the annual average alternative contemporaneous emission limitation of **0.44** lb/MMBtu. In addition, this unit shall not have an annual heat input **greater than 14,354,271** MMBtu.

Also, see Additional Requirements a. and b., below.

Additional Requirements

a. Under the plan (NO_X Phase II averaging plan), the actual Btu-weighted annual average NO_X emission rate for the units in the plan shall be less than or equal to the Btu-weighted annual average NO_X emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then this unit shall be deemed to be in compliance for that year with its alternative contemporaneous annual emission limitation and annual heat input limit.
b. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and requirements covering excess emissions.

A.3. Sulfur dioxide (SO_2) Emission Allowances. SO_2 emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.

a. No permit revision shall be required for 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.
b. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.
c. Allowances shall be accounted for under the Federal Acid Rain Program.

[Rule 62-213.440(1)(c)1., 2. & 3., F.A.C.]

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

Reporting Requirements

A.5. Demonstration of Compliance With the Phase II NO_X Averaging Plan. The Designated Representative shall provide a copy of the demonstration of compliance, prepared in accordance with 40 CFR 76.11(d), to the Department within 60 days after the end of the calendar year. [Rule 62-213.440, F.A.C.]

Acid Rain Part Application

For more information, see instructions and refer to 40 CFR 72.30, 72.31, and 74; and Chapter 62-214, F.A.C.

This submission is: ☐ New ☒ Revised ☐ Renewal

STEP 1

Identify the source by plant name, state, and ORIS or plant code.

Plant name	State	ORIS/Plant Code
LANSING SMITH ELECTRIC GENERATING PLANT	**FL**	**643**

STEP 2
Enter the unit ID# for every Acid Rain unit at the Acid Rain source in column "a."

If unit a SO_2 Opt-in unit, enter "yes" in column "b".

For new units or SO_2 Opt-in units, enter the requested information in columns "d" and "e."

a	b	c	d	e
Unit ID#	SO_2 Opt-in Unit? (Yes or No)	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	New or SO_2 Opt-in Units Commence Operation Date	New or SO_2 Opt-in Units Monitor Certification Deadline
001		Yes		
002		Yes		
004		Yes		
005		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		

DEP Form No. 62-210.900(1)(a) – Form
Effective: 3/16/08

1

LANSING SMITH ELECTRIC GENERATING PLANT
Plant Name (from STEP 1)

STEP 3

Read the standard requirements.

Acid Rain Part Requirements.

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

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.
(4) For applications including a SO_2 Opt-in unit, a monitoring plan for each SO_2 Opt-in unit must be submitted with this application pursuant to 40 CFR 74.14(a). For renewal applications for SO_2 Opt-in units include an updated monitoring plan if applicable under 40 CFR 75.53(b).

Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)), or in the compliance subaccount of another Acid Rain unit at the same source to the extent provided in 40 CFR 73.35(b)(3), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000, or the deadline for monitor certification under 40 CFR Part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain Part application, the Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the EPA or the DEP:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR Part 75, provided that to the extent that 40 CFR Part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

LANSING SMITH ELECTRIC GENERATING PLANT
Plant Name (from STEP 1)

STEP 3, Continued.

Recordkeeping and Reporting Requirements (cont)

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

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

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_x averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR Part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities.

No provision of the Acid Rain Program, an Acid Rain Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any state law regulating electric utility rates and charges, affecting any state law regarding such state regulation, or limiting such state regulation, including any prudence review requirements under such state law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a state in which such program is established.

STEP 4
For SO_2 Opt-in units only.

In column "f" enter the unit ID# for every SO_2 Opt-in unit identified in column "a" of STEP 2.

For column "g" describe the combustion unit and attach information and diagrams on the combustion unit's configuration.

In column "h" enter the hours.

f	g	h (not required for renewal application)
Unit ID#	Description of the combustion unit	Number of hours unit operated in the six months preceding initial application

DEP Form No. 62-210.900(1)(a) – Form
Effective: 3/16/08

3

LANSING SMITH ELECTRIC GENERATING PLANT
Plant Name (from STEP 1)

STEP 5

For SO_2 Opt-in units only.
(Not required for SO_2 Opt-in renewal applications.)

In column "i" enter the unit ID# for every SO_2 Opt-in unit identified in column "a" (and in column "f").

For columns "j" through "n," enter the information required under 40 CFR 74.20-74.25 and attach all supporting documentation required by 40 CFR 74.20-74.25.

i	J	k	l	m	n
Unit ID#	Baseline or Alternative Baseline under 40 CFR 74.20 (mmBtu)	Actual SO_2 Emissions Rate under 40 CFR 74.22 (lbs/mmBtu)	Allowable 1985 SO_2 Emissions Rate under 40 CFR 74.23 (lbs/mmBtu)	Current Allowable SO_2 Emissions Rate under 40 CFR 74.24 (lbs/mmBtu)	Current Promulgated SO_2 Emissions Rate under 40 CFR 74.25 (lbs/mmBtu)

STEP 6

For SO_2 Opt-in units only.

Attach additional requirements, certify and sign.

A. If the combustion source seeks to qualify for a transfer of allowances from the replacement of thermal energy, a thermal energy plan as provided in 40 CFR 74.47 for combustion sources must be attached.
B. A statement whether the combustion unit was previously an affected unit under 40 CFR 74.
C. A statement that the combustion unit is not an affected unit under 40 CFR 72.6 and does not have an exemption under 40 CFR 72.7, 72.8, or 72.14.
D. Attach a complete compliance plan for SO_2 under 40 CFR 72.40.
E. The designated representative of the combustion unit shall submit a monitoring plan in accordance with 40 CFR 74.61. For renewal application, submit an updated monitoring plan if applicable under 40 CFR 75.53(b).
F. The following statement must be signed by the designated representative or alternate designated representative of the combustion source: "I certify that the data submitted under 40 CFR Part 74, Subpart C, reflects actual operations of the combustion source and has not been adjusted in any way."

Signature	Date

STEP 7

Read the certification statement; provide name, title, owner company name, phone, and e-mail address; sign, and date.

Certification (for designated representative or alternate designated representative only)

I am authorized to make this submission on behalf of the owners and operators of the Acid Rain source or Acid Rain units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name **JAMES O. VICK**	Title **Director, Environmental Affairs**
Owner Company Name **Gulf Power Company**	
Phone **(850) 444- 6311**	E-mail address **jovick@southernco.com**
Signature James O Vick	Date 10/1/12

DEP Form No. 62-210.900(1)(a) – Form
Effective: 3/16/08

4

Page 1

Florida Department of Environmental Protection

Phase II NO_X Compliance Plan

For more information, see instructions and refer to 40 CFR 76.9

This submission is: ☐ New ☒ Revised

Page _1_ of _2_

STEP 1 Indicate plant name, state, and ORIS code from NADB, if applicable.	Plant Name: Lansing Smith Electric Generating Plant	State: FL	ORIS Code: 643
STEP 2	Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and"WB" for wet bottom. Indicate the compliance option selected for each unit.		

	ID# 001 Type T	ID# 002 Type T	ID# Type	ID# Type	ID# Type	ID# Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	☐	☐	☐	☐	☐	☐
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(c) EPA-approved early election plan under 40 CFR 76.8 through 12/31/07 (also indicate above emission limit specified in plan)	☐	☐	☐	☐	☐	☐
(d) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)	☐	☐	☐	☐	☐	☐
(e) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(f) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)	☐	☐	☐	☐	☐	☐
(g) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)	☐	☐	☐	☐	☐	☐
(h) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)	☐	☐	☐	☐	☐	☐
(i) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)	☐	☐	☐	☐	☐	☐
(j) NO_x Averaging Plan (include NO_x Averaging form)	☒	☒	☒	☒	☐	☐
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)	☐	☐	☐	☐	☐	☐

DEP Form No. 62-210.900(1)(a)4. - Form
Effective: 1/6/98

Page 2

LANSING SMITH ELECTRIC GENERATING PLANT Plant Name (from Step 1)

Page _2_ of _2_

STEP 2, cont'd.

	ID# 001	ID# 002	ID#	ID#	ID#	ID#
	Type T	Type T	Type	Type	Type	Type
(l) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_x Averaging (check the NO_x Averaging Plan box and include NO_x Averaging Form)	☒	☒	☐	☐	☐	☐
(m) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17 (a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)	☐	☐	☐	☐	☐	☐
(n) AEL (include Phase II AEL Demonstration Period, Final AEL Petition, or AEL Renewal form as appropriate)	☐	☐	☐	☐	☐	☐
(o) Petition for AEL demonstration period or final AEL under review by U.S. EPA or demonstration period ongoing	☐	☐	☐	☐	☐	☐
(p) Repowering extension plan approved or under review	☐	☐	☐	☐	☐	☐

STEP 3
Read the standard requirements and certification, enter the name of the designated representative, sign and date.

Standard Requirements
General. This source is subject to the standard requirements in 40 CFR 72.9 (consistent with 40 CFR 76.8(e)(1)(i)). These requirements are listed in this source's Acid Rain Part of its Title V permit.

Special Provisions for Early Election Units

Nitrogen Oxides. A unit that is governed by an approved early election plan shall be subject to an emissions limitation for NO_x as provided under 40 CFR 76.8(a)(2) except as provided under 40 CFR 76.8(e)(3)(iii).

Liability. The owners and operators of a unit governed by an approved early election plan shall be liable for any violation of the plan or 40 CFR 76.8 at that unit. The owners and operators shall be liable, beginning January 1, 2000, for fulfilling the obligations specified in 40 CFR Part 77.

Termination. An approved early election plan shall be in effect only until the earlier of January 1, 2008 or January 1 of the calendar year for which a termination of the plan takes effect. If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under 40 CFR 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year after the year for which there is a failure to demonstrate compliance, and the designated representative may not submit a new early election plan. The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated representative must submit a notice under 40 CFR 72.40(d) by January 1 of the year for which the termination is to take effect. If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7. If an early election plan is terminated on or after 2000, the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7.

DEP Form No. 62-210.900(1)(a)4. - Form
Effective: 1/6/98

Page 3

STEP 3, cont'd.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name **James O. Vick**	
Signature James O Vick	Date 5/5/09

DEP Form No. 62-210.900(1)(a)4. - Form
Effective: 1/6/98

Florida Department of Environmental Protection

Phase II NO_x Averaging Plan

For more information, refer to 40 CFR 76.11

This submission is: [ ] New [X] Revised

STEP 1

Identify the units participating in this averaging plan by plant name, state, and boiler ID# from NADB. In column (a), fill in each unit's applicable emission limitation from 40 CFR 76.5, 76.6, or 76.7. In column (b), assign an alternative contemporaneous annual emissions limitation in lb/mmBtu to each unit. In column (c), assign an annual heat input limitation in mmBtu to each unit. Continue to page 3 if necessary.

Plant Name	State	ID#	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
See Page 3.					

STEP 2

Use the formula to enter the Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan and the Btu-weighted annual average emission rate for the same units if they are operated in compliance with 40 CFR 76.5, 76.6, or 76.7. The former must be less than or equal to the latter.

Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan		Btu-weighted annual average emission rate for same units operated in compliance with 40 CFR 76.5, 76.6 or 76.7
0.46	≤	0.46

$$\frac{\sum_{i=1}^{n} (R_{Li} \, x \, HI_i)}{\sum_{i=1}^{n} HI_i} \leq \frac{\sum_{i=1}^{n} [R_{li} \, x \, HI_i]}{\sum_{i=1}^{n} HI_i}$$

Where,

R_{Li} = Alternative contemporaneous annual emissions limitation for unit i, in 16/mmBtu, as specified in column (b) of Step 1;

R_{li} = Applicable emission limitation for unit i, in lb/mmBtu, as specified in column (a) of Step 1;

HI_i = Annual heat input for unit i, in mmBtu, as specified in column (c) of Step 1;

n = Number of units in the averaging plan

DEP Form No. 62-210.900(1)(a)1.
Effective: 3/16/08

1

Participating Plants
Plant Name (from Step 1)

STEP 3

Mark one of the two options and enter dates.

☐ This plan is effective for calendar year _____ through calendar year _____ unless notification to terminate the plan is given.

[X] Treat this plan as [5] identical plans, each effective for one calendar year for the following calendar years: 2013, 2014, 2015, 2016, and 2017 unless notification to terminate one or more of these plans is given.

STEP 4

Read the special provisions and certification, enter the name of the designated representative, and sign and date.

Special Provisions

Emission Limitations

Each affected unit in an approved averaging plan is in compliance with the Acid Rain emission limitation for NO_x under the plan only if the following requirements are met:

(i) For each unit, the unit's actual annual average emission rate for the calendar year, in lb/mmBtu, is less than or equal to its alternative contemporaneous annual emission limitation in the averaging plan, and
(a) For each unit with an alternative contemporaneous emission limitation less stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year does not exceed the annual heat input limit in the averaging plan,
(b) For each unit with an alternative contemporaneous emission limitation more stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year is not less than the annual heat input limit in the averaging plan, or
(ii) If one or more of the units does not meet the requirements of (i), the designated representative shall demonstrate, in accordance with 40 CFR 76.11(d)(1)(ii)(A) and (B), that the actual Btu-weighted annual average emission rate for the units in the plan is less than or equal to the Btu-weighted annual average rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations in 40 CFR 76.5, 76.6, or 76.7.
(iii) If there is a successful group showing of compliance under 40 CFR 76.11(d)(1)(ii)(A) and (B) for a calendar year, then all units in the averaging plan shall be deemed to be in compliance for that year with their alternative contemporaneous emission limitations and annual heat input limits under (i).

Liability

The owners and operators of a unit governed by an approved averaging plan shall be liable for any violation of the plan or this section at that unit or any other unit in the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and sections 113 and 411 of the Act.

Termination

The designated representative may submit a notification to terminate an approved averaging plan, in accordance with 40 CFR 72.40(d), no later than October 1 of the calendar year for which the plan is to be terminated.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Chris M. Hobson	
Signature CMHob	Date 9/24/12

DEP Form No. 62-210.900(1)(a)1.
Effective: 3/16/08

2

Southern Company Averaging Plan
Participating Plants

Plant Name (from Step 1)

STEP 1

Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID#	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
Barry	AL	1	0.40	0.57	9,573,262
Barry	AL	2	0.40	0.57	8,444,579
Barry	AL	3	0.40	0.57	14,942,231
Barry	AL	4	0.40	0.45	25,805,532
Barry	AL	5	0.40	0.45	40,593,564
Bowen	GA	1	0.45	0.42	45,172,982
Bowen	GA	2	0.45	0.43	53,594,364
Bowen	GA	3	0.45	0.43	62,569,415
Bowen	GA	4	0.45	0.43	62,052,526
Branch	GA	1	0.68	0.99	15,439,840
Branch	GA	2	0.50	0.72	20,343,750
Branch	GA	3	0.68	0.84	33,478,822
Branch	GA	4	0.68	0.84	29,022,426
Crist	FL	4	0.45	0.52	5,152,003
Crist	FL	5	0.45	0.60	5,166,828
Crist	FL	6	0.50	0.45	22,730,882
Crist	FL	7	0.50	0.45	37,802,017
Daniel	MS	1	0.45	0.33	42,016,226
Daniel	MS	2	0.45	0.33	35,236,767
Gadsden	AL	1	0.45	0.75	2,493,711
Gadsden	AL	2	0.45	0.75	2,994,848
Gaston	AL	1	0.50	0.52	15,024,772
Gaston	AL	2	0.50	0.52	12,841,184
Gaston	AL	3	0.50	0.52	16,760,315
Gaston	AL	4	0.50	0.52	16,256,383
Gaston	AL	5	0.45	0.48	54,734,917
Gorgas	AL	6	0.46	0.55	5,532,199
Gorgas	AL	7	0.46	0.55	5,961,385
Gorgas	AL	8	0.40	0.52	12,802,318
Gorgas	AL	9	0.40	0.52	14,142,803
Gorgas	AL	10	0.40	0.52	53,551,197

DEP Form No. 62-210.900(1)(a)1.
Effective: 3/16/08

3

Southern Company Averaging Plan
Participating Plants

Plant Name (from Step 1)

STEP 1

Continue the identification of units from Step 1, page 1, here.

Plant Name	State	ID#	(a) Emission Limitation	(b) Alt. Contemp. Emission Limitation	(c) Annual Heat Input Limit
Greene Co	AL	1	0.68	0.60	17,188,813
Greene Co	AL	2	0.46	0.60	19,335,661
Hammond	GA	1	0.50	0.83	6,507,399
Hammond	GA	2	0.50	0.83	7,473,271
Hammond	GA	3	0.50	0.83	6,418,029
Hammond	GA	4	0.50	0.45	29,877,962
Kraft	GA	1	0.45	0.58	3,102,564
Kraft	GA	2	0.45	0.58	2,903,977
Kraft	GA	3	0.45	0.58	5,763,920
L. Smith	FL	1	0.40	0.62	13,246,415
L. Smith	FL	2	0.40	0.44	14,354,271
McIntosh	GA	1	0.50	0.86	8,947,363
Miller	AL	1	0.46	0.37	55,901,155
Miller	AL	2	0.46	0.37	54,571,268
Miller	AL	3	0.46	0.28	59,761,399
Miller	AL	4	0.46	0.28	58,617,301
Mitchell	GA	3	0.45	0.62	5,826,708
Scherer	GA	1	0.40	0.50	73,945,647
Scherer	GA	2	0.40	0.50	73,618,266
Scherer	GA	3	0.45	0.29	54,991,840
Scherer	GA	4	0.40	0.30	54,991,840
Scholz	FL	1	0.50	0.68	2,022,943
Scholz	FL	2	0.50	0.77	2,056,474
Wansley	GA	1	0.45	0.41	65,813,417
Wansley	GA	2	0.45	0.42	58,305,654
Watson	MS	4	0.50	0.50	13,070,990
Watson	MS	5	0.50	0.65	34,351,664
Yates	GA	1	0.45	0.48	5,317,858
Yates	GA	2	0.45	0.48	4,737,232
Yates	GA	3	0.45	0.48	4,689,751
Yates	GA	4	0.45	0.40	8,272,959
Yates	GA	5	0.45	0.40	7,457,836
Yates	GA	6	0.45	0.33	22,590,915
Yates	GA	7	0.45	0.30	20,429,275

DEP Form No. 62-210.900(1)(a)1.
Effective: 3/16/08

4

Clean Air Interstate Rule (CAIR).

Operated by: Gulf Power Company
Plant: Lansing Smith Electric Generating Plant
ORIS Code: 0643

The emissions units below are regulated under the Clean Air Interstate Rule.

EU No.	EPA Unit ID#	Brief Description
001	1	Boiler Number 1 - 1,944.8 million British thermal units (MMBtu)/hour
002	2	Boiler Number 2 - 2,246.2 MMBtu/hour
004	4	Combined Cycle Combustion Turbine Generator *Unit No. 1 (CC-1)*
005	5	Combined Cycle Combustion Turbine Generator *Unit No. 2 (CC-2)*
003	AA	Combustion Turbine A
003	AB	Combustion Turbine B

Notes: ID# AA & AB are associated with FDEP ID # Unit 3 Oil fired Combustion Turbine.

Clean Air Interstate Rule Application. The Clean Air Interstate Rule Part Form submitted for this facility is a part of this permit. The owners and operators of these CAIR units as identified in this form must comply with the standard requirements and special provisions set forth in the CAIR Part Form (DEP Form No. 62-210.900(1)(b)) dated May 5, 2009, which is attached at the end of this section. [Chapter 62-213, F.A.C. and Rule 62-210.200, F.A.C.]

Clean Air Interstate Rule (CAIR) Part

For more information, see instructions and refer to 40 CFR 96.121, 96.122, 96.221, 96.222, 96.321 and 96.322; and Rule 62-296.470, F.A.C.

This submission is: ☐ New ☐ Revised ☒ Renewal

STEP 1

Identify the source by plant name and ORIS or EIA plant code

Plant Name:	State:	ORIS or EIA Plant Code:
Lansing Smith Electric Generating Plant	Florida	643

STEP 2

In column "a" enter the unit ID# for every CAIR unit at the CAIR source.

In columns "b," "c," and "d," indicate to which CAIR program(s) each unit is subject by placing an "X" in the column(s).

For new units, enter the requested information in columns "e" and "f.

a	b	c	d	e	f
Unit ID#	Unit will hold nitrogen oxides (NO_X) allowances in accordance with 40 CFR 96.106(c)(1)	Unit will hold sulfur dioxide (SO_2) allowances in accordance with 40 CFR 96.206(c)(1)	Unit will hold NO_X Ozone Season allowances in accordance with 40 CFR 96.306(c)(1)	New Units Expected Commence Commercial Operation Date	New Units Expected Monitor Certification Deadline
001	X	X	X		
002	X	X	X		
004	X	X	X		
005	X	X	X		
AA	X	X	X		
AB	X	X	X		
Note:	ID #AA & AB are	associated with	FDEP ID #Unit 3	Oil fired CT.	

DEP Form No. 62-210.900(1)(b) – Form
Effective: 3/16/08

1

Plant Name (from STEP 1)	Lansing Smith Electric Generating Plant

STEP 3

Read the standard requirements.

CAIR NO_X ANNUAL TRADING PROGRAM

CAIR Part Requirements.

(1) The CAIR designated representative of each CAIR NO_X source and each CAIR NO_X unit at the source shall:
(i) Submit to the DEP a complete and certified CAIR Part form under 40 CFR 96.122 and Rule 62-296.470, F.A.C., in accordance with the deadlines specified in Rule 62-213.420, F.A.C.; and
(ii) [Reserved];
(2) The owners and operators of each CAIR NO_X source and each CAIR NO_X unit at the source shall have a CAIR Part included in the Title V operating permit issued by the DEP under 40 CFR Part 96, Subpart CC, and operate the source and the unit in compliance with such CAIR Part.

Monitoring, Reporting, and Recordkeeping Requirements.

(1) The owners and operators, and the CAIR designated representative, of each CAIR NO_X source and each CAIR NO_X unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR Part 96, Subpart HH, and Rule 62-296.470, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR Part 96, Subpart HH, shall be used to determine compliance by each CAIR NO_X source with the following CAIR NO_X Emissions Requirements.

NO_X Emission Requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X source and each CAIR NO_X unit at the source shall hold, in the source's compliance account, CAIR NO_X allowances available for compliance deductions for the control period under 40 CFR 96.154(a) in an amount not less than the tons of total NO_X emissions for the control period from all CAIR NO_X units at the source, as determined in accordance with 40 CFR Part 96, Subpart HH.
(2) A CAIR NO_X unit shall be subject to the requirements under paragraph (1) of the NO_X Requirements starting on the later of January 1, 2009, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 96.170(b)(1) or (2) and for each control period thereafter.
(3) A CAIR NO_X allowance shall not be deducted, for compliance with the requirements under paragraph (1) of the NO_X Requirements, for a control period in a calendar year before the year for which the CAIR NO_X allowance was allocated.
(4) CAIR NO_X allowances shall be held in, deducted from, or transferred into or among CAIR NO_X Allowance Tracking System accounts in accordance with 40 CFR Part 96, Subparts FF and GG.
(5) A CAIR NO_X allowance is a limited authorization to emit one ton of NO_X in accordance with the CAIR NO_X Annual Trading Program. No provision of the CAIR NO_X Annual Trading Program, the CAIR Part, or an exemption under 40 CFR 96.105 and no provision of law shall be construed to limit the authority of the state or the United States to terminate or limit such authorization.
(6) A CAIR NO_X allowance does not constitute a property right.
(7) Upon recordation by the Administrator under 40 CFR Part 96, Subpart EE, FF, or GG, every allocation, transfer, or deduction of a CAIR NO_X allowance to or from a CAIR NO_X unit's compliance account is incorporated automatically in any CAIR Part of the source that includes the CAIR NO_X unit.

Excess Emissions Requirements.

If a CAIR NO_X source emits NO_X during any control period in excess of the CAIR NO_X emissions limitation, then:
(1) The owners and operators of the source and each CAIR NO_X unit at the source shall surrender the CAIR NO_X allowances required for deduction under 40 CFR 96.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable state law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 96, Subpart AA, the Clean Air Act, and applicable state law.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the CAIR NO_X source and each CAIR NO_X unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the DEP or the Administrator.
(i) The certificate of representation under 40 CFR 96.113 for the CAIR designated representative for the source and each CAIR NO_X unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under 40 CFR 96.113 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with 40 CFR Part 96, Subpart HH, of this part, provided that to the extent that 40 CFR Part 96, Subpart HH, provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_X Annual Trading Program.
(iv) Copies of all documents used to complete a CAIR Part form and any other submission under the CAIR NO_X Annual Trading Program or to demonstrate compliance with the requirements of the CAIR NO_X Annual Trading Program.
(2) The CAIR designated representative of a CAIR NO_X source and each CAIR NO_X unit at the source shall submit the reports required under the CAIR NO_X Annual Trading Program, including those under 40 CFR Part 96, Subpart HH.

Plant Name (from STEP 1)	Lansing Smith Electric Generating Plant

STEP 3, Continued

Liability.

(1) Each CAIR NO_X source and each CAIR NO_X unit shall meet the requirements of the CAIR NO_X Annual Trading Program.
(2) Any provision of the CAIR NO_X Annual Trading Program that applies to a CAIR NO_X source or the CAIR designated representative of a CAIR NO_X source shall also apply to the owners and operators of such source and of the CAIR NO_X units at the source.
(3) Any provision of the CAIR NO_X Annual Trading Program that applies to a CAIR NO_X unit or the CAIR designated representative of a CAIR NO_X unit shall also apply to the owners and operators of such unit.

Effect on Other Authorities.

No provision of the CAIR NO_X Annual Trading Program, a CAIR Part, or an exemption under 40 CFR 96.105 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X source or CAIR NO_X unit from compliance with any other provision of the applicable, approved State Implementation Plan, a federally enforceable permit, or the Clean Air Act.

CAIR SO_2 TRADING PROGRAM

CAIR Part Requirements.

(1) The CAIR designated representative of each CAIR SO_2 source and each CAIR SO_2 unit at the source shall:
(i) Submit to the DEP a complete and certified CAIR Part form under 40 CFR 96.222 and Rule 62-296.470, F.A.C., in accordance with the deadlines specified in Rule 62-213.420, F.A.C.; and
(ii) [Reserved];
(2) The owners and operators of each CAIR SO_2 source and each CAIR SO_2 unit at the source shall have a CAIR Part included in the Title V operating permit issued by the DEP under 40 CFR Part 96, Subpart CCC, for the source and operate the source and each CAIR unit in compliance with such CAIR Part.

Monitoring, Reporting, and Recordkeeping Requirements.

(1) The owners and operators, and the CAIR designated representative, of each CAIR SO_2 source and each SO_2 CAIR unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR Part 96 ,Subpart HHH, and Rule 62-296.470, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR Part 96, Subpart HHH, shall be used to determine compliance by each CAIR SO_2 source with the following CAIR SO_2 Emission Requirements.

SO_2 Emission Requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO_2 source and each CAIR SO_2 unit at the source shall hold, in the source's compliance account, a tonnage equivalent in CAIR SO_2 allowances available for compliance deductions for the control period, as determined in accordance with 40 CFR 96.254(a) and (b), not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO_2 units at the source, as determined in accordance with 40 CFR Part 96, Subpart HHH.
(2) A CAIR SO_2 unit shall be subject to the requirements under paragraph (1) of the Sulfur Dioxide Emission Requirements starting on the later of January 1, 2010 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 96.270(b)(1) or (2) and for each control period thereafter.
(3) A CAIR SO_2 allowance shall not be deducted, for compliance with the requirements under paragraph (1) of the SO_2 Emission Requirements, for a control period in a calendar year before the year for which the CAIR SO_2 allowance was allocated.
(4) CAIR SO_2 allowances shall be held in, deducted from, or transferred into or among CAIR SO_2 Allowance Tracking System accounts in accordance with 40 CFR Part 96, Subparts FFF and GGG.
(5) A CAIR SO_2 allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO_2 Trading Program. No provision of the CAIR SO_2 Trading Program, the CAIR Part, or an exemption under 40 CFR 96.205 and no provision of law shall be construed to limit the authority of the state or the United States to terminate or limit such authorization.
(6) A CAIR SO_2 allowance does not constitute a property right.
(7) Upon recordation by the Administrator under 40 CFR Part 96, Subpart FFF or GGG, every allocation, transfer, or deduction of a CAIR SO_2 allowance to or from a CAIR SO_2 unit's compliance account is incorporated automatically in any CAIR Part of the source that includes the CAIR SO_2 unit.

Excess Emissions Requirements.

If a CAIR SO_2 source emits SO_2 during any control period in excess of the CAIR SO_2 emissions limitation, then:
(1) The owners and operators of the source and each CAIR SO_2 unit at the source shall surrender the CAIR SO_2 allowances required for deduction under 40 CFR 96.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable state law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 96, Subpart AAA, the Clean Air Act, and applicable state law.

Plant Name (from STEP 1)	Lansing Smith Electric Generating Plant

STEP 3, Continued

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Department or the Administrator.

(i) The certificate of representation under 40 CFR 96.213 for the CAIR designated representative for the source and each CAIR SO_2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under 40 CFR 96.213 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with 40 CFR Part 96, Subpart HHH, of this part, provided that to the extent that 40 CFR Part 96, Subpart HHH, provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR SO_2 Trading Program.

(iv) Copies of all documents used to complete a CAIR Part form and any other submission under the CAIR SO_2 Trading Program or to demonstrate compliance with the requirements of the CAIR SO_2 Trading Program.

(2) The CAIR designated representative of a CAIR SO_2 source and each CAIR SO_2 unit at the source shall submit the reports required under the CAIR SO_2 Trading Program, including those under 40 CFR Part 96, Subpart HHH.

Liability.

(1) Each CAIR SO_2 source and each CAIR SO_2 unit shall meet the requirements of the CAIR SO_2 Trading Program.

(2) Any provision of the CAIR SO_2 Trading Program that applies to a CAIR SO_2 source or the CAIR designated representative of a CAIR SO_2 source shall also apply to the owners and operators of such source and of the CAIR SO_2 units at the source.

(3) Any provision of the CAIR SO_2 Trading Program that applies to a CAIR SO_2 unit or the CAIR designated representative of a CAIR SO_2 unit shall also apply to the owners and operators of such unit.

Effect on Other Authorities.

No provision of the CAIR SO_2 Trading Program, a CAIR Part, or an exemption under 40 CFR 96.205 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR SO_2 source or CAIR SO_2 unit from compliance with any other provision of the applicable, approved State Implementation Plan, a federally enforceable permit, or the Clean Air Act.

CAIR NO_x OZONE SEASON TRADING PROGRAM

CAIR Part Requirements.

(1) The CAIR designated representative of each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall:

(i) Submit to the DEP a complete and certified CAIR Part form under 40 CFR 96.322 and Rule 62-296.470, F.A.C., in accordance with the deadlines specified in Rule 62-213.420, F.A.C.; and

(ii) [Reserved];

(2) The owners and operators of each CAIR NO_X Ozone Season source required to have a Title V operating permit or air construction permit, and each CAIR NO_X Ozone Season unit required to have a Title V operating permit or air construction permit at the source shall have a CAIR Part included in the Title V operating permit or air construction permit issued by the DEP under 40 CFR Part 96, Subpart CCCC, for the source and operate the source and the unit in compliance with such CAIR Part.

Monitoring, Reporting, and Recordkeeping Requirements.

(1) The owners and operators, and the CAIR designated representative, of each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR Part 96, Subpart HHHH, and Rule 62-296.470, F.A.C.

(2) The emissions measurements recorded and reported in accordance with 40 CFR Part 96, Subpart HHHH, shall be used to determine compliance by each CAIR NO_X Ozone Season source with the following CAIR NO_X Ozone Season Emissions Requirements.

NO_X Ozone Season Emission Requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, CAIR NO_X Ozone Season allowances available for compliance deductions for the control period under 40 CFR 96.354(a) in an amount not less than the tons of total NO_X emissions for the control period from all CAIR NO_X Ozone Season units at the source, as determined in accordance with 40 CFR Part 96, Subpart HHHH.

(2) A CAIR NO_X Ozone Season unit shall be subject to the requirements under paragraph (1) of the NO, Ozone Season Emission Requirements starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 96.370(b)(1),(2), or (3) and for each control period thereafter.

(3) A CAIR NO_X Ozone Season allowance shall not be deducted, for compliance with the requirements under paragraph (1) of the NO_X Ozone Season Emission Requirements, for a control period in a calendar year before the year for which the CAIR NO_X Ozone Season allowance was allocated.

(4) CAIR NO_X Ozone Season allowances shall be held in, deducted from, or transferred into or among CAIR NO_X Ozone Season Allowance Tracking System accounts in accordance with 40 CFR Part 96, Subparts FFFF and GGGG.

(5) A CAIR NO_X Ozone Season allowance is a limited authorization to emit one ton of NO_X in accordance with the CAIR NO_X Ozone Season Trading Program. No provision of the CAIR NO_X Ozone Season Trading Program, the CAIR Part, or an exemption under 40 CFR 96.305 and no provision of law shall be construed to limit the authority of the state or the United States to terminate or limit such authorization.

(6) A CAIR NO_X Ozone Season allowance does not constitute a property right.

(7) Upon recordation by the Administrator under 40 CFR Part 96, Subpart EEEE, FFFF or GGGG, every allocation, transfer, or deduction of a CAIR NO_X Ozone Season allowance to or from a CAIR NO_X Ozone Season unit's compliance account is incorporated automatically in any CAIR Part of the source that includes the CAIR NO_X Ozone Season unit.

Plant Name (from STEP 1)	Lansing Smith Electric Generating Plant

STEP 3, Continued

Excess Emissions Requirements.

If a CAIR NO_X Ozone Season source emits NO_X during any control period in excess of the CAIR NO_X Ozone Season emissions limitation, then:
(1) The owners and operators of the source and each CAIR NO_X Ozone Season unit at the source shall surrender the CAIR NO_X Ozone Season allowances required for deduction under 40 CFR 96.354(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable state law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 96, Subpart AAAA, the Clean Air Act, and applicable state law.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the DEP or the Administrator.
(i) The certificate of representation under 40 CFR 96.313 for the CAIR designated representative for the source and each CAIR NO_X Ozone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under 40 CFR 96.113 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with 40 CFR Part 96, Subpart HHHH, of this part, provided that to the extent that 40 CFR Part 96, Subpart HHHH, provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_X Ozone Season Trading Program.
(iv) Copies of all documents used to complete a CAIR Part form and any other submission under the CAIR NO_X Ozone Season Trading Program or to demonstrate compliance with the requirements of the CAIR NO_X Ozone Season Trading Program.
(2) The CAIR designated representative of a CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall submit the reports required under the CAIR NO_X Ozone Season Trading Program, including those under 40 CFR Part 96, Subpart HHHH.

Liability.

(1) Each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit shall meet the requirements of the CAIR NO_X Ozone Season Trading Program.
(2) Any provision of the CAIR NO_X Ozone Season Trading Program that applies to a CAIR NO_X Ozone Season source or the CAIR designated representative of a CAIR NO_X Ozone Season source shall also apply to the owners and operators of such source and of the CAIR NO_X Ozone Season units at the source.
(3) Any provision of the CAIR NO_X Ozone Season Trading Program that applies to a CAIR NO_X Ozone Season unit or the CAIR designated representative of a CAIR NO_X Ozone Season unit shall also apply to the owners and operators of such unit.

Effect on Other Authorities.

No provision of the CAIR NO_X Ozone Season Trading Program, a CAIR Part, or an exemption under 40 CFR 96.305 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X Ozone Season source or CAIR NO_X Ozone Season unit from compliance with any other provision of the applicable, approved State Implementation Plan, a federally enforceable permit, or the Clean Air Act.

STEP 4

Read the certification statement; provide name, title, owner company name, phone, and e-mail address; sign, and date.

Certification (for designated representative or alternate designated representative only)

I am authorized to make this submission on behalf of the owners and operators of the CAIR source or CAIR units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name	James O. Vick	Title	Director, Environmental Affairs
Company Owner Name	Gulf Power Company		
Phone	(850) 444-6311	E-mail Address	jovick@southernco.com
Signature	James O Vick	Date	5/5/09

DEP Form No. 62-210.900(1)(b) – Form
Effective: 3/16/08

5

SECTION VI. APPENDICES.

The Following Appendices Are Enforceable Part of This Permit:

Appendix A, Glossary.
Appendix CAM, Compliance Assurance Monitoring Plan.
Appendix I, List of Insignificant Emissions Units and/or Activities.
Appendix ICE, Requirements For Internal Combustion Engines.
Appendix 40 CFR 63, Subpart A, Standardized General Provisions.
Appendix NESHAP Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.
Appendix NSPS, Subpart A - General Provisions.
Appendix NSPS, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units.
Appendix NSPS, Subpart GG - Standards of Performance for Stationary Gas Turbines.
Appendix NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
Appendix PA-1, Patrol Area.
Appendix RR, Facility-wide Reporting Requirements.
Appendix SO-1, Secretarial Order(s).
Appendix TR, Facility-wide Testing Requirements.
Appendix TV, Title V General Conditions.
Appendix U, List of Unregulated Emissions Units and/or Activities.