TV RENEWAL/REVISION AIR PERMIT APPLICATION

Duke Energy Florida
Suwannee River Power Plant

REPORT

Submitted To: Florida Department of Environmental Protection
Division of Air Resource Management
Office of Permitting and Compliance
2600 Blair Stone Rd., MS No. 5505
Tallahassee, FL 32399-2400

Submitted By: Golder Associates Inc.
5100 W. Lemon Street, Suite 208
Tampa, FL 33609 USA

Distribution: Florida Department of Environmental Protection
Duke Energy Florida
Golder Associates Inc.

May 2014 **Project No. 1402802**

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PART I—FDEP APPLICATION REPORT

Attachments

1.0 APPLICATION BACKGROUND

Duke Energy Florida (DEF) operates the Suwannee River Power Plant. This existing facility consists of three fossil fuel fired steam generators, designated as Unit Nos. 1, 2 and 3, as well as three combustion turbine peaking units (CTP), designated as CTP Unit Nos. 1, 2 and 3. There are no pollution control devices associated with the boilers. These boilers now fire natural gas exclusively (Duke is requesting that this revised TV permit eliminate any reference to oil firing capability), as well as the potential use of propane as an igniter fuel. Also located at this site, and included in this permit, are miscellaneous insignificant emissions units and activities.

Operation of the Suwannee River Plant is currently authorized by Title V Operation Permit 1210003-007-AV. This permit was issued with an effective date of January 1, 2010 and an expiration date of December 31, 2014. In accordance with Rule 62-213.420(1)(a)2., F.A.C., an application for a Title V permit renewal must be submitted at least 225 days prior to permit expiration for permits that expire on or after June 1, 2009. For the Suwannee River Plant, this regulatory deadline requires the submittal of a Title V Permit renewal application no later than May 20, 2014. This application and supporting documents constitutes Duke's request for renewal of Suwannee River Plant Title V Operation Permit Number 1210003-007-AV.

The facility is a major source of air pollution under the Title V program [Chapter 62-213, Florida Administrative Code (F.A.C.)] and the Prevention of Significant Deterioration (Rule 62-212.400, F.A.C.) program and is subject to the Acid Rain Program, as well as the Clean Air Interstate Rule (CAIR) set forth in Rule 62-296.470, F.A.C.

This Title V air operation permit revision and renewal application incorporates the change of Suwannee's existing Units 001, 002, and 003 from use of heavy fuel oil and natural gas to exclusive use of natural gas. When exclusively firing natural gas in Units 1, 2 and 3, this facility is no longer considered to be a major source of hazardous air pollutants (HAP). Attachment B to this Application Report provides the HAP emissions summary for the site. The change in operation to the exclusive firing of natural gas only, also results in an associated request for removal of the COMs from these three units. The requested revisions for the removal of COMS and with respect to the major source HAP status will require concurrent processing of revisions to the underlying air construction permit conditions.

This air permit application consists of the appropriate application form required by the Florida Department of Environmental Protection (FDEP) Form 62-210.900(1), effective 3/11/2010 (see Part II of this application package), as well as required supporting documentation and attachments.

2.0 REQUESTED TV REVISIONS

The application serves to request the renewal of the current TV operating permit, as well as several requested revisions. The items addressed include the following:

- Revision to the permit language to clarify that the 1,500 operating hour limit for Combustion Turbine Peaking (CTP) Unit Nos. 1, 2 and 3 (EU004, EU005 and EU006) applies to EACH CT engine in the twin-pacs;
- The removal of all references to oil-firing capability for Units 1, 2 and 3 (EU001, EU002 and EU003);
- The removal of the requirement to operate Continuous Opacity Monitoring Systems (COMS) from the Title V operating and air construction (AC) permits from Units 1, 2 and 3, as these units are now defined as "gas-fired" units; and
- Title III applicability: upon the commitment to exclusive use of natural gas, this facility will no longer be a major source of HAPs.

Of the requested revisions above, two of these (the removal of COMS and the major source HAP status) will require concurrent processing of revisions to the underlying air construction permit conditions.

2.1 Clarification of Combustion Turbine Operation

DEF is requesting revised permit language with respect to the description of the Combustion Turbine Peaking (CTP) Units at the Suwannee facility. These units are currently designated as EU Nos. 004, 005 and 006 in Subsection B of the current TV permit. Each of these EUs is referred to as a "Combustion Turbine Peaking (CTP) Unit", which is comprised of two identical simple cycle aeroderivative combustion turbine engines (PA and PB) and one common electrical generator. The CTP Unit is a Turbo Power & Marine FT4C-3LF TwinPac.

The current permit language is not clear with respect to conditions that apply to the EU (i.e., the CTP Unit) versus the individual CT engines that comprise the EU. Specifically, the heat input rating and the MW output rating are representative of each CTP Unit. Similarly, the mass emission rates (lb/hr and ton/yr) are representative of the CTP Unit. In addition, the permit indicates that operation is restricted to 1,500 hr/yr/CT. DEF wants it to be clear that this limitation applies to EACH of the CT engines that comprise the CTP unit. Therefore, DEF requests that these designations (i.e., "the CTP Unit" and the "CT engines") be used where appropriate to avoid confusion.

2.2 Major Source HAP Status

Upon DEF's commitment to the exclusive use of natural gas, this facility is no longer considered to be a major source of HAPs. Calculations were conducted to confirm the current area source status and are included in Attachment B to this application.

2.3 Requirement for COMS

The requirement for COMS on Units 1, 2 and 3 at the site were initially driven by the Acid Rain Program requirement for “oil-fired” units. Based on a discussion with Louis Nichols (Nichols.louis@epa.gov) of the Clean Air Market Division (CAMD), the site should be able to remove the COMS, provided that the definition of “gas-fired unit” under 40 CFR Part 72.2 is met.

Gas-fired means:

(ii) For a unit for which a monitoring plan has already been submitted under § 75.62, that has not qualified as gas-fired under paragraph (3)(i) of this definition, and whose fuel usage changes, the designated representative submits either:

> *(A) Three calendar years of data following the change in the unit’s fuel usage, showing that no less than 90.0 percent of the unit’s average annual heat input during the previous three calendar years, and no less than 85.0 percent of the unit’s annual heat input during any one of the previous three calendar years, is from the combustion of gaseous fuels and the remaining heat input is from the combustion of fuel oil; or*
>
> *(B) A minimum of 720 hours of unit operating data following the change in the unit’s fuel usage, showing that no less than 90.0 percent of the unit’s heat input is from the combustion of gaseous fuels and the remaining heat input is from the combustion of fuel oil, and a statement that this changed pattern of fuel usage is considered permanent and is projected to continue for the foreseeable future.*

The Suwannee River Power Plant meets the requirements of Paragraph (ii)(B) above. DEF has committed to the exclusive use of natural gas and has operated the units as follows:

- Unit 1 – Operating hours since last operated on oil – > 8,700 hours
- Unit 2 – Operating hours since last operated on oil – > 12,000 hours
- Unit 3 – Operating hours since last operated on oil – > 15,000 hours

This permit application requests that any reference to the authorization to fire fuel oil be deleted from the permit. It is on this basis that DEF requests the removal of the use of COMS from the revised/renewed TV permit.

ATTACHMENT A

APPLICATION FOR AIR PERMIT - LONG FORM

DEP Form No. 62-210.900(1)

Department of
Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit:

- For any required purpose at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air operation permit;
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment new source review, or maximum achievable control technology (MACT);
- To assume a restriction on the potential emissions of one or more pollutants to escape a requirement such as PSD review, nonattainment new source review, MACT, or Title V; or
- To establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

- An initial federally enforceable state air operation permit (FESOP); or
- An initial, revised, or renewal Title V air operation permit.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Duke Energy Florida, Inc.**	
2. Site Name: **Suwannee River Plant**	
3. Facility Identification Number: **1210003**	
4. Facility Location... Street Address or Other Locator: **4037 River Road** City: **Live Oak** County: **Suwannee** Zip Code: **32060-8746**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Chris Bradley, Senior Environmental Specialist**
2. Application Contact Mailing Address... Organization/Firm: **Duke Energy Florida, Inc.** Street Address: **299 First Avenue North, FL-903** City: **St. Petersburg** State: **Florida** Zip Code: **33701-3308**
3. Application Contact Telephone Numbers... Telephone: **(727) 820 - 5962** ext. Fax: **(727) 820 - 5292**
4. Application Contact E-mail Address: **Chris.Bradley@duke-energy.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	3. PSD Number (if applicable):
2. Project Number(s):	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

This application for air permit is being submitted to obtain: (Check one)

Air Construction Permit

- [ ] Air construction permit.
- [ ] Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).
- [ ] Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

- [ ] Initial Title V air operation permit.
- [ ] Title V air operation permit revision.
- [ ] Title V air operation permit renewal.
- [ ] Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.
- [ ] Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

- [X] Air construction permit and Title V permit revision, incorporating the proposed project.
- [X] Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

- [X] I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Operation of the Duke Energy Florida, Inc. (Duke) Suwannee River Plant is currently authorized by Title V Operation Permit 1210003-007-AV. This permit was issued with an effective date of January 1, 2010 and an expiration date of December 31, 2014. In accordance with Rule 62-213.420(1)(a)2., F.A.C., an application for a Title V permit renewal must be submitted at least 225 days prior to permit expiration for permits that expire on or after June 1, 2009. For the Suwannee River Plant, this regulatory deadline requires the submittal of a Title V Permit renewal application no later than May 20, 2014. This application and supporting documents constitutes Duke's request for renewal of Suwannee River Plant Title V Operation Permit Number 1210003-007-AV.

This Title V air operation permit revision and renewal application incorporates the change of Suwannee's existing Units 001, 002, and 003 from use of heavy fuel oil and natural gas to exclusive use of natural gas. This operational change is also associated with the request for removal of the COMS and the revision to minor source HAP status. The requested revisions are summarized in the Application Report.

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
001	Fossil Fuel Fired Steam Generator No. 1	NA	NA
002	Fossil Fuel Fired Steam Generator No. 2	NA	NA
003	Fossil Fuel Fired Steam Generator No. 3	NA	NA
004	Combustion Turbine Peaking Unit No. 1 (P-1)	NA	NA
005	Combustion Turbine Peaking Unit No. 1 (P-2)	NA	NA
006	Combustion Turbine Peaking Unit No. 2 (P-3)	NA	NA

Application Processing Fee

Check one: ☐ Attached - Amount: $________________ ☐ Not Applicable

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. Owner/Authorized Representative Name :	
2. Owner/Authorized Representative Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:	
3. Owner/Authorized Representative Telephone Numbers... Telephone: Fax:	
4. Owner/Authorized Representative E-mail Address:	
5. Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.* _______________________________ ____________________ Signature Date	

Application Responsible Official Certification

Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name: **Brian V. Powers, Plant Manager**

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):

[X] For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.

[ ] For a partnership or sole proprietorship, a general partner or the proprietor, respectively.

[ ] For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.

[ ] The designated representative at an Acid Rain source or CAIR source.

3. Application Responsible Official Mailing Address...
Organization/Firm: **Duke Energy Florida, Inc.**
Street Address: **4037 River Road**
City: **Live Oak** State: **Florida** Zip Code: **32060-8746**

4. Application Responsible Official Telephone Numbers...
Telephone: **(386) 330-5402** ext. Fax: **(386) 330-5407**

5. Application Responsible Official E-mail Address: **Brian.Powers@duke-energy.com**

6. Application Responsible Official Certification:

I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

Signature

05/16/2014
Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **Scott Osbourn**
   Registration Number: **57557**
2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates, Inc.**
   Street Address: **5100 Lemon Street, Suite 208**
   City: **Tampa** State: **FL** Zip Code: **33609**
3. Professional Engineer Telephone Numbers...
   Telephone: **(813) 287 - 1717** ext. **53304** Fax: **(813) 287 – 1716**
4. Professional Engineer E-mail Address: **sosbourn@golder.com**
5. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here [ ], if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here [ ], if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here [X], if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here , if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Signature

(seal)

5/9/14
Date

SCOTT H. OSBOURN
LICENSE
No. 57557
STATE OF
FLORIDA
PROFESSIONAL ENGINEER

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **290.5** North (km) **3,362.5**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **30°22'36"** Longitude (DD/MM/SS) **-83°10'50"**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Brian V. Powers**
2. Facility Contact Mailing Address... Organization/Firm: **Duke Energy Florida, Inc.** Street Address: **4037 River Road** City: **Live Oak** State: **Florida** Zip Code: **32060-8746**
3. Facility Contact Telephone Numbers: Telephone: **(386) 330-5402** ext. Fax: **(386) 330-5407**
4. Facility Contact E-mail Address: **Brian.Powers@duke-energy.com**

Facility Primary Responsible Official – N/A

Complete if an "application responsible official" is identified in Section I that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official E-mail Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6.* ☐ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	

12. Facility Regulatory Classifications Comment:

Combustion Turbine Peaking (CTP) Units P-1, P-2, and P-3 (EU IDs. 004, 005, and 006) are subject to New Source Performance Standard Subpart GG, Standards of Performance for Stationary Gas Turbines.

*** Note: Currently the facility is categorized as a major with respect to HAPs. However, as part of the plan to comply with the Mercury & Air Toxics Standards (MATS) rule (40 CFR Part 63, Subpart UUUUU), Duke is requesting the removal of authorization to combust Nos. 2 and 6 fuel oil in Steam Units 1, 2 and 3 during this TV Operating Permit Renewal application. This approach to MATS compliance will result in the reduction of potential HAP (total and individual) emissions below the regulatory threshold for a major HAP facility.**

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
CO	**A**	**N**
NO_X	**A**	**N**
PM	**A**	**N**
PM_{10}	**A**	**N**
SO_2	**A**	**N**
VOC	**A**	**N**
HAPs (Total)	**A**	**N**

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility-Wide Cap [Y or N]? (all units)	3. Emissions Unit ID's Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [X] Attached, Document ID: **SRP-FI-C1** [ ] Previously Submitted, Date:
2.	Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [X] Attached, Document ID: **SRP-FI-C2** [ ] Previously Submitted, Date:
3.	Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [X] Attached, Document ID: **SRP-FI-C3** [ ] Previously Submitted, Date:

Additional Requirements for Air Construction Permit Applications – N/A

1.	Area Map Showing Facility Location: [ ] Attached, Document ID:__________ [ ] Not Applicable (existing permitted facility)
2.	Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): [ ] Attached, Document ID:
3.	Rule Applicability Analysis: [ ] Attached, Document ID:
4.	List of Exempt Emissions Units: [ ] Attached, Document ID:__________ [ ] Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification: [ ] Attached, Document ID:__________ [ ] Not Applicable
6.	Air Quality Analysis (Rule 62-212.400(7), F.A.C.): [ ] Attached, Document ID:__________ [ ] Not Applicable
7.	Source Impact Analysis (Rule 62-212.400(5), F.A.C.): [ ] Attached, Document ID:__________ [ ] Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): [ ] Attached, Document ID:__________ [ ] Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): [ ] Attached, Document ID:__________ [ ] Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): [ ] Attached, Document ID:__________ [ ] Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications – N/A

1.	List of Exempt Emissions Units: ☐ Attached, Document ID:__________ ☒ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications

1.	List of Insignificant Activities: (Required for initial/renewal applications only) ☒ Attached, Document ID: **SRP-FI-CV1** ☐ Not Applicable (revision application)
2.	Identification of Applicable Requirements: (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought) ☒ Attached, Document ID: **SRP-FI-CV2** ☐ Not Applicable (revision application with no change in applicable requirements)
3.	Compliance Report and Plan: (Required for all initial/revision/renewal applications) ☐ Attached, Document ID: **N/A** Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4.	List of Equipment/Activities Regulated under Title VI: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☐ Equipment/Activities Onsite but Not Required to be Individually Listed ☒ Not Applicable
5.	Verification of Risk Management Plan Submission to EPA: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☒ Not Applicable
6.	Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID: **N/A** ☒ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Facilities Subject to Acid Rain, CAIR, or Hg Budget Program

1. Acid Rain Program Forms:

   Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)):
   [X] Attached, Document ID: **SRP-FI-CA1** [ ] Previously Submitted, Date:___________
   [ ] Not Applicable (not an Acid Rain source)

   Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.):
   [ ] Attached, Document ID:___________ [ ] Previously Submitted, Date:___________
   [X] Not Applicable

   New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.):
   [ ] Attached, Document ID:___________ [ ] Previously Submitted, Date:___________
   [X] Not Applicable

2. CAIR Part (DEP Form No. 62-210.900(1)(b)):
   [X] Attached, Document ID: **SRPFI-CA2** [ ] Previously Submitted, Date:___________
   [ ] Not Applicable (not a CAIR source)

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   [X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   [ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   [X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   [ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   [ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
Fossil Fuel Fired Steam Generator No. 1

3. Emissions Unit Identification Number: **001**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**11/1/53**	**49**

8. Federal Program Applicability: (Check all that apply)

   [X] Acid Rain Unit

   [X] CAIR Unit

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: **35.0 MW (nominal)**

11. Emissions Unit Comment:

Emissions Unit Control Equipment/Method: **– N/A**

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

B. EMISSIONS UNIT CAPACITY INFORMATION
(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: **460** million Btu/hr		
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	hours/day weeks/year	days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Unit 1 in not restricted in hours of operation and may operate 8,760 hours/year [Permit No. 1210003-007-AV; Rule 62-210.200 (Definition Potential to Emit), F.A.C.]**		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **SRP-1**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: **V**	6. Stack Height: **110** feet	7. Exit Diameter: **7.0** feet
8. Exit Temperature: **320** °F	9. Actual Volumetric Flow Rate: **143,700** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **290.49** North (km): **3,362.50**		14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **1**

1. Segment Description (Process/Fuel Type): **External Combustion Boilers, Electric Generation, Natural Gas, Tangentially Fired Units**		
2. Source Classification Code (SCC): **1-01-006-04**	3. SCC Units: **Million cubic feet burned**	
4. Maximum Hourly Rate: **0.45**	5. Maximum Annual Rate: **3,951**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,020**
10. Segment Comment: **Maximum hourly and annual rates are based on 460 MMBtu/hr, natural gas heat content of 1,020 Btu/ft^3 (HHV) and 8,760 hours per year.**		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
SO_2			**NS**
NOx			**NS**
CO			**NS**
PM			**EL**
PM_{10}			**NS**
VOC			**NS**
HAPs (total)			**NS**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **27.0** lb/hour **118.3** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **60 lb/10^6 scf** Reference: **Table 1.4-2, AP-42 (Assumes 20 gr/100 scf)**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly Emissions:

SO2 = (60 lb/10^6 scf) x (0.45 x 10^6 scf/hr) = 27.0 lb/hr

Annual Emissions:

SO2 = (60 lb/10^6 scf) x (0.45 x 10^6 scf/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 118.3 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions_ of _**- N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **76.5** lb/hour **335** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **170 lb/10 ^{6} scf** Reference: **Table 1.4-1, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly Emissions:

NOx = (170 lb/10 ^{6} scf) x (0.45 x 10^6 scf/hr) = 76.5 lb/hr

Annual Emissions:

NOx = (170 lb/10 ^{6} scf) x (0.45 x 10^6 scf/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) =335 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions_ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **10.8** lb/hour **47.3** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **24 lb/10^6 scf** Reference: **Table 1.4-1, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly Emissions:

CO = (24 lb/10^6 scf) x (0.45 x 10^6 scf/hr) = 10.8 lb/hr

Annual Emissions:

CO = (24 lb/10^6 scf) x (0.45 x 10^6 scf/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 47.3 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __- **N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **138** lb/hour **252** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.1 lb/MMBtu; 0.3 lb/MMBtu** Reference: **Condition A.7 & A.8, Permit No. 1210003-007-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly Emissions:

PM = (0.3 lb/MMBtu) x (460 MMBtu/hr) = 138 lb/hr

Annual Emissions:

PM = [(0.1 lb/MMBtu) x (460 MMBtu/hr) x (8,760hr/yr) x (21hr/24hr)] + [(0.3 lb/MMBtu) x (460 MMBtu/hr) x (8,760 hr/yr) x (3hr/24 hr)] x (1 ton/2,000 lb) = 252 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:
PM emissions shall not exceed 0.1 lb/MMBtu during normal operation [Rule 62.296.405(1)(b), F.A.C.]

PM emissions shall not exceed 0.3 lb/MMBtu during the 3 hours in any 24-hour period of excess emissions allowed for soot blowing and load change. [Rule 62-210.700(3), F.A.C.)

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.1 lb/MMBtu**	4. Equivalent Allowable Emissions: **46** lb/hour **N/A** tons/year
5. Method of Compliance: **EPA Reference Methods 5, 5B, 5F, or 17**	
6. Allowable Emissions Comment (Description of Operating Method): **Applicable during normal operations [Rule 62.296.405(1)(b), F.A.C.]**	

Allowable Emissions Allowable Emissions **2** of **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.3 lb/MMBtu**	4. Equivalent Allowable Emissions: **138** lb/hour **N/A** tons/year
5. Method of Compliance: **EPA Reference Methods 5, 5B, 5F, or 17**	
6. Allowable Emissions Comment (Description of Operating Method): **Applicable during the 3 hours in any 24-hour period of excess emissions allowed for soot blowing and load change. [Rule 62-210.700(3), F.A.C.)**	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3.4** lb/hour **15** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **7.6 lb/10^6 scf** Reference: **Table 1.4-2, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly Emissions:

PM_{10} = (7.6 lb/10^6 scf) x (0.45 x 10^6 scf/hr) = 3.4 lb/hr

Annual Emissions:

PM_{10} = (7.6 lb/10^6 scf) x (0.45 x 10^6 scf/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 15.0 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.5** lb/hour **11** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **5.5 lb/10^6 scf** Reference: **Table 1.4-2, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly Emissions:

VOC = (5.5 lb/10^6 scf) x (0.45 x 10^6 scf/hr) = 2.5 lb/hr

Annual Emissions:

VOC = (5.5 lb/10^6 scf) x (0.45 x 10^6 scf/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 11 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __of___- **N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **HAPS (total)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **Various** Reference: **AP-42 Tables 1.4-3-1.4-4 and AB 2588**	7. Emissions Method Code: **3 and 5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Attachment B of the Report.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of ___**- N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation **1** of **2**

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **20 %** Exceptional Conditions: **40** % Maximum Period of Excess Opacity Allowed: **2** min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Applicable during normal operations [Rule 62-296.405(1)(A), F.A.C]**	

Visible Emissions Limitation: Visible Emissions Limitation **2** of **2**

1. Visible Emissions Subtype: **VE60**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **60**% Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Applicable during the 3 hours in any 24-hour period of excess emissions allowed for soot blowing and load change. [Rule 62-210.700(3), F.A.C.)**	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **1** of **3**

1. Parameter Code: **EM**	2. Pollutant(s): **NOx**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **42**	Serial Number: **42D-49861-284**
5. Installation Date: **01/01/1995**	6. Performance Specification Test Date: **07/23/2013**
7. Continuous Monitor Comment: **Required by 40 CFR Part 75 (Acid Rain Program).**	

Continuous Monitoring System: Continuous Monitor **2** of **3**

1. Parameter Code: **CO2**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **41H**	Serial Number: **41H-50088-284**
5. Installation Date: **01/01/1995**	6. Performance Specification Test Date: **07/23/2013**
7. Continuous Monitor Comment: **Required by 40 CFR Part 75 (Acid Rain Program).**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor **3** of **3**

1. Parameter Code: **VE**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information... Manufacturer: **DURAG** Model Number: **CEMOP-281**	Serial Number: **30634**
5. Installation Date: **01/01/1995**	6. Performance Specification Test Date: **01/01/1995**
7. Continuous Monitor Comment: **This application is requesting authorization for removal of the COMS. (Previously required by 40 CFR Part 75 [Acid Rain Program]).**	

Continuous Monitoring System: Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [ ] Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: SRP-FI-C2 [ ] Previously Submitted, Date

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: SRP-EU1-I2 [ ] Previously Submitted, Date

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [ ] Attached, Document ID: N/A [ ] Previously Submitted, Date ______________

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: SRP-EU1-I4 [ ] Previously Submitted, Date
   [ ] Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [ ] Attached, Document ID: __________ [ ] Previously Submitted, Date ___________
   [X] Not Applicable

6. Compliance Demonstration Reports/Records:
   [X] Attached, Document ID: SRP-EU1-I6
   Test Date(s)/Pollutant(s) Tested: ____
   ____
   [ ] Previously Submitted, Date: _______
   Test Date(s)/Pollutant(s) Tested: ____
   ____
   [ ] To be Submitted, Date (if known):___________
   Test Date(s)/Pollutant(s) Tested: ____
   ____
   [ ] Not Applicable
   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
   [ ] Attached, Document ID: __________ [X] Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications -- N/A

1.	Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☐ Attached, Document ID:__________ ☐ Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID:__________ ☐ Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: __________ ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1.	Identification of Applicable Requirements: ☒ Attached, Document ID: **SRP-FI-CV2**
2.	Compliance Assurance Monitoring: ☐ Attached, Document ID: __________ ☒ Not Applicable
3.	Alternative Methods of Operation: ☐ Attached, Document ID: __________ ☒ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: __________ ☒ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   [X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   [ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   [X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   [ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   [ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
Fossil Fuel Fired Steam Generator No. 2

3. Emissions Unit Identification Number: **002**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**11/1/54**	**49**

8. Federal Program Applicability: (Check all that apply)

   [X] Acid Rain Unit

   [X] CAIR Unit

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: **34.0 MW (nominal)**

11. Emissions Unit Comment:

<u>Emissions Unit Control Equipment/Method:</u> **– N/A**

1. Control Equipment/Method Description:
2. Control Device or Method Code:

<u>Emissions Unit Control Equipment/Method:</u> Control ___ of ___

1. Control Equipment/Method Description:
2. Control Device or Method Code:

<u>Emissions Unit Control Equipment/Method:</u> Control ___ of ___

1. Control Equipment/Method Description:
2. Control Device or Method Code:

<u>Emissions Unit Control Equipment/Method:</u> Control ___ of ___

1. Control Equipment/Method Description:
2. Control Device or Method Code:

B. EMISSIONS UNIT CAPACITY INFORMATION
(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: **450** million Btu/hr		
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	hours/day weeks/year	days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Unit 1 in not restricted in hours of operation and may operate 8,760 hours/year [Permit No. 1210003-007-AV; Rule 62-210.200 (Definition Potential to Emit), F.A.C.]**		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **SRP-2**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: **V**	6. Stack Height: **110** feet	7. Exit Diameter: **7.0** feet
8. Exit Temperature: **340** °F	9. Actual Volumetric Flow Rate: **197,000** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **290.46** North (km): **3,362.50**		14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **1**

1. Segment Description (Process/Fuel Type): **External Combustion Boilers, Electric Generation, Natural Gas, Tangentially Fired Units**		
2. Source Classification Code (SCC): **1-01-006-04**	3. SCC Units: **Million cubic feet burned**	
4. Maximum Hourly Rate: **0.44**	5. Maximum Annual Rate: **3,865**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,020**
10. Segment Comment: **Maximum hourly and annual rates are based on 450 MMBtu/hr, natural gas heat content of 1,020 Btu/ft^3 (HHV) and 8,760 hours per year.**		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
SO_2			**NS**
NOx			**NS**
CO			**NS**
PM			**EL**
PM_{10}			**NS**
VOC			**NS**
HAPs (total)			**NS**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **26.4** lb/hour **115.6** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **60 lb/10^6 scf** Reference: **Table 1.4-2, AP-42 (Assumes 20 gr/100 scf)**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly Emissions:

SO2 = (60 lb/10^6 scf) x (0.44 x 10^6 scf/hr) = 27.0 lb/hr

Annual Emissions:

SO2 = (60 lb/10^6 scf) x (0.44 x 10^6 scf/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 115.6 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions_ of _- **N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **74.8** lb/hour **328** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **170 lb/10 ^{6} scf** Reference: **Table 1.4-1, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly Emissions:

NOx = (170 lb/10 ^{6} scf) x (0.44 x 10^6 scf/hr) = 74.8 lb/hr

Annual Emissions:

NOx = (170 lb/10 ^{6} scf) x (0.44 x 10^6 scf/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) =328 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions_ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **10.6** lb/hour **46.3** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **24 lb/10^6 scf** Reference: **Table 1.4-1, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly Emissions:

CO = (24 lb/10^6 scf) x (0.44 x 10^6 scf/hr) = 10.6 lb/hr

Annual Emissions:

CO = (24 lb/10^6 scf) x (0.44 x 10^6 scf/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 46.3 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __- **N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **135** lb/hour **246** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.1 lb/MMBtu; 0.3 lb/MMBtu** Reference: **Condition A.7 & A.8, Permit No. 1210003-007-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly Emissions:

PM = (0.3 lb/MMBtu) x (450 MMBtu/hr) = 135 lb/hr

Annual Emissions:

PM = [(0.1 lb/MMBtu) x (450 MMBtu/hr) x (8,760hr/yr) x (21hr/24hr)] + [(0.3 lb/MMBtu) x (450 MMBtu/hr) x (8,760 hr/yr) x (3hr/24 hr)] x (1 ton/2,000 lb) = 246 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

PM emissions shall not exceed 0.1 lb/MMBtu during normal operation [Rule 62.296.405(1)(b), F.A.C.]

PM emissions shall not exceed 0.3 lb/MMBtu during the 3 hours in any 24-hour period of excess emissions allowed for soot blowing and load change. [Rule 62-210.700(3), F.A.C.)

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.1 lb/MMBtu**	4. Equivalent Allowable Emissions: **45** lb/hour **N/A** tons/year
5. Method of Compliance: **EPA Reference Methods 5, 5B, 5F, or 17**	
6. Allowable Emissions Comment (Description of Operating Method): **Applicable during normal operations [Rule 62.296.405(1)(b), F.A.C.]**	

Allowable Emissions Allowable Emissions **2** of **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.3 lb/MMBtu**	4. Equivalent Allowable Emissions: **135** lb/hour **N/A** tons/year
5. Method of Compliance: **EPA Reference Methods 5, 5B, 5F, or 17**	
6. Allowable Emissions Comment (Description of Operating Method): **Applicable during the 3 hours in any 24-hour period of excess emissions allowed for soot blowing and load change. [Rule 62-210.700(3), F.A.C.)**	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3.4** lb/hour **15** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **7.6 lb/10^6 scf** Reference: **Table 1.4-2, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly Emissions:

PM_{10} = (7.6 lb/10^6 scf) x (0.44 x 10^6 scf/hr) = 3.3 lb/hr

Annual Emissions:

PM_{10} = (7.6 lb/10^6 scf) x (0.44 x 10^6 scf/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 14.6 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.4** lb/hour **10.6** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **5.5 lb/10^6 scf** Reference: **Table 1.4-2, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly Emissions:

VOC = (5.5 lb/10^6 scf) x (0.44 x 10^6 scf/hr) = 2.4 lb/hr

Annual Emissions:

VOC = (5.5 lb/10^6 scf) x (0.44 x 10^6 scf/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 10.6 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __of___- **N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **HAPS (total)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **Various** Reference: **AP-42 Tables 1.4-3-1.4-4 and AB 2588**	7. Emissions Method Code: **3 and 5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Attachment B of the Report.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of ___ **- N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **20 %** Exceptional Conditions: **40** % Maximum Period of Excess Opacity Allowed: **2** min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Applicable during normal operations [Rule 62-296.405(1)(A), F.A.C]**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE60**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **60**% Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Applicable during the 3 hours in any 24-hour period of excess emissions allowed for soot blowing and load change. [Rule 62-210.700(3), F.A.C.)**	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **1** of **3**

1. Parameter Code: **EM**	2. Pollutant(s): **NOx**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **42**	Serial Number: **42D-49860-284**
5. Installation Date: **01/01/1995**	6. Performance Specification Test Date: **07/24/2013**
7. Continuous Monitor Comment: **Required by 40 CFR Part 75 (Acid Rain Program).**	

Continuous Monitoring System: Continuous Monitor **2** of **3**

1. Parameter Code: **CO2**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **41H**	Serial Number: **41H-50090-284**
5. Installation Date: **01/01/1995**	6. Performance Specification Test Date: **07/24/2013**
7. Continuous Monitor Comment: **Required by 40 CFR Part 75 (Acid Rain Program).**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor **3** of **3**

1. Parameter Code: **VE**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information... Manufacturer: **DURAG** Model Number: **CEMOP-281**	Serial Number: **30444**
5. Installation Date: **01/01/1995**	6. Performance Specification Test Date: **01/01/1995**
7. Continuous Monitor Comment: **This application is requesting authorization for removal of the COMS. (Previously required by 40 CFR Part 75 [Acid Rain Program]).**	

Continuous Monitoring System: Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [ ] Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: SRP-FI-C2 [ ] Previously Submitted, Date

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: SRP-EU1-I2 [ ] Previously Submitted, Date

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [ ] Attached, Document ID: N/A [ ] Previously Submitted, Date ______________

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: SRP-EU1-I4 [ ] Previously Submitted, Date
   [ ] Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [ ] Attached, Document ID: __________ [ ] Previously Submitted, Date ___________
   [X] Not Applicable

6. Compliance Demonstration Reports/Records:
   [X] Attached, Document ID: SRP-EU1-I6
   Test Date(s)/Pollutant(s) Tested: ____

   [ ] Previously Submitted, Date: _______
   Test Date(s)/Pollutant(s) Tested: ____

   [ ] To be Submitted, Date (if known):___________
   Test Date(s)/Pollutant(s) Tested: ____

   [ ] Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
   [ ] Attached, Document ID: __________ [X] Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications -- N/A

1.	Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☐ Attached, Document ID:__________ ☐ Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID:__________ ☐ Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: __________ ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1.	Identification of Applicable Requirements: ☒ Attached, Document ID: SRP-FI-CV2
2.	Compliance Assurance Monitoring: ☐ Attached, Document ID: __________ ☒ Not Applicable
3.	Alternative Methods of Operation: ☐ Attached, Document ID: __________ ☒ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: __________ ☒ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   [X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   [ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   [X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   [ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   [ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
Fossil Fuel Fired Steam Generator No. 3

3. Emissions Unit Identification Number: **003**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**10/1/56**	**49**

8. Federal Program Applicability: (Check all that apply)

   [X] Acid Rain Unit

   [X] CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: **84.0 MW (nominal)**

11. Emissions Unit Comment:

Emissions Unit Control Equipment/Method: – N/A

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

B. EMISSIONS UNIT CAPACITY INFORMATION
(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: **880** million Btu/hr		
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	hours/day weeks/year	days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Unit 1 in not restricted in hours of operation and may operate 8,760 hours/year [Permit No. 1210003-007-AV; Rule 62-210.200 (Definition Potential to Emit), F.A.C.]**		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **SRP-3**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: **V**	6. Stack Height: **135** feet	7. Exit Diameter: **7.7** feet
8. Exit Temperature: **300** °F	9. Actual Volumetric Flow Rate: **305,100** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: **17** East (km): **290.43** North (km): **3,362.48**	14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

<u>Segment Description and Rate:</u> Segment **1** of **1**

1. Segment Description (Process/Fuel Type): **External Combustion Boilers, Electric Generation, Natural Gas, Tangentially Fired Units**		
2. Source Classification Code (SCC): **1-01-006-04**	3. SCC Units: **Million cubic feet burned**	
4. Maximum Hourly Rate: **0.86**	5. Maximum Annual Rate: **7,558**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,020**
10. Segment Comment: **Maximum hourly and annual rates are based on 880 MMBtu/hr, natural gas heat content of 1,020 Btu/ft^3 (HHV) and 8,760 hours per year.**		

<u>Segment Description and Rate:</u> Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
SO_2			**NS**
NOx			**NS**
CO			**NS**
PM			**EL**
PM_{10}			**NS**
VOC			**NS**
HAPs (total)			**NS**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **51.6** lb/hour **226.0** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **60 lb/10^6 scf** Reference: **Table 1.4-2, AP-42 (Assumes 20 gr/100 scf)**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly Emissions:

SO2 = (60 lb/10^6 scf) x (0.86x 10^6 scf/hr) = 51.6 lb/hr

Annual Emissions:

SO2 = (60 lb/10^6 scf) x (0.86 x 10^6 scf/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 226.0 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions_ of _- **N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **146.2** lb/hour **640** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **170 lb/10 ^{6} scf** Reference: **Table 1.4-1, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly Emissions:

NOx = (170 lb/10 ^{6} scf) x (0.86 x 10^{6} scf/hr) = 146.2 lb/hr

Annual Emissions:

NOx = (170 lb/10 ^{6} scf) x (0.86 x 10^{6} scf/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 640 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions_ of _

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **20.6** lb/hour **90.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **24 lb/10^6 scf** Reference: **Table 1.4-1, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly Emissions:

CO = (24 lb/10^6 scf) x (0.86 x 10^6 scf/hr) = 20.6 lb/hr

Annual Emissions:

CO = (24 lb/10^6 scf) x (0.86 x 10^6 scf/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 90.4 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __- **N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **264** lb/hour **482** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.1 lb/MMBtu; 0.3 lb/MMBtu** Reference: **Condition A.7 & A.8, Permit No. 1210003-007-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly Emissions:

PM = (0.3 lb/MMBtu) x (881 MMBtu/hr) = 264 lb/hr

Annual Emissions:

PM = [(0.1 lb/MMBtu) x (881 MMBtu/hr) x (8,760hr/yr) x (21hr/24hr)] + [(0.3 lb/MMBtu) x (881 MMBtu/hr) x (8,760 hr/yr) x (3hr/24 hr)] x (1 ton/2,000 lb) = 482 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

PM emissions shall not exceed 0.1 lb/MMBtu during normal operation [Rule 62.296.405(1)(b), F.A.C.]

PM emissions shall not exceed 0.3 lb/MMBtu during the 3 hours in any 24-hour period of excess emissions allowed for soot blowing and load change. [Rule 62-210.700(3), F.A.C.)

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.1 lb/MMBtu**	4. Equivalent Allowable Emissions: **88** lb/hour **N/A** tons/year
5. Method of Compliance: **EPA Reference Methods 5, 5B, 5F, or 17**	
6. Allowable Emissions Comment (Description of Operating Method): **Applicable during normal operations** **[Rule 62.296.405(1)(b), F.A.C.]**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.3 lb/MMBtu**	4. Equivalent Allowable Emissions: **264** lb/hour **N/A** tons/year
5. Method of Compliance: **EPA Reference Methods 5, 5B, 5F, or 17**	
6. Allowable Emissions Comment (Description of Operating Method): **Applicable during the 3 hours in any 24-hour period of excess emissions allowed for soot blowing and load change. [Rule 62-210.700(3), F.A.C.)**	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **6.5** lb/hour **28.6** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **7.6 lb/10^6 scf** Reference: **Table 1.4-2, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly Emissions:

PM_{10} = (7.6 lb/10^6 scf) x (0.86 x 10^6 scf/hr) = 6.5 lb/hr

Annual Emissions:

PM_{10} = (7.6 lb/10^6 scf) x (0.86 x 10^6 scf/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 28.6 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **4.7** lb/hour **20.8** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **5.5 lb/10^6 scf** Reference: **Table 1.4-2, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly Emissions:

VOC = (5.5 lb/10^6 scf) x (0.86 x 10^6 scf/hr) = 4.7 lb/hr

Annual Emissions:

VOC = (5.5 lb/10^6 scf) x (0.86 x 10^6 scf/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 20.8 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __of___- **N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **HAPS (total)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **Various** Reference: **AP-42 Tables 1.4-3-1.4-4 and AB 2588**	7. Emissions Method Code: **3 and 5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Attachment B of the Report.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of ___**- N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **20 %** Exceptional Conditions: **40** % Maximum Period of Excess Opacity Allowed: **2** min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Applicable during normal operations [Rule 62-296.405(1)(A), F.A.C]**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE60**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **60**% Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Applicable during the 3 hours in any 24-hour period of excess emissions allowed for soot blowing and load change. [Rule 62-210.700(3), F.A.C.)**	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **1** of **3**

1. Parameter Code: **EM**	2. Pollutant(s): **NOx**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **42i**	Serial Number: **0808828666**
5. Installation Date: **05/01/2008**	6. Performance Specification Test Date: **07/25/2013**
7. Continuous Monitor Comment: **Required by 40 CFR Part 75 (Acid Rain Program).**	

Continuous Monitoring System: Continuous Monitor **2** of **3**

1. Parameter Code: **CO2**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **410i**	Serial Number: **0808828667**
5. Installation Date: **05/01/2008**	6. Performance Specification Test Date: **07/25/2013**
7. Continuous Monitor Comment: **Required by 40 CFR Part 75 (Acid Rain Program).**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor **3** of **3**

1. Parameter Code: **VE**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information... Manufacturer: **DURAG** Model Number: **CEMOP-281**	Serial Number: **30443**
5. Installation Date: **01/01/1995**	6. Performance Specification Test Date: **01/01/1995**
7. Continuous Monitor Comment: **This application is requesting authorization for removal of the COMS. (Previously required by 40 CFR Part 75 [Acid Rain Program]).**	

Continuous Monitoring System: Continuous Monitor _ of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [ ] Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: SRP-FI-C2 [ ] Previously Submitted, Date

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: SRP-EU1-I2 [ ] Previously Submitted, Date

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [ ] Attached, Document ID: N/A [ ] Previously Submitted, Date ______________

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: SRP-EU1-I4 [ ] Previously Submitted, Date
   [ ] Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [ ] Attached, Document ID: __________ [ ] Previously Submitted, Date ___________
   [X] Not Applicable

6. Compliance Demonstration Reports/Records:
   [X] Attached, Document ID: SRP-EU1-I6
   Test Date(s)/Pollutant(s) Tested: ____
   ____
   [ ] Previously Submitted, Date: _______
   Test Date(s)/Pollutant(s) Tested: ____
   ____
   [ ] To be Submitted, Date (if known):___________
   Test Date(s)/Pollutant(s) Tested: ____
   ____
   [ ] Not Applicable
   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
   [ ] Attached, Document ID: __________ [X] Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications -- N/A

1.	Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☐ Attached, Document ID:__________ ☐ Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID:__________ ☐ Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: __________ ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1.	Identification of Applicable Requirements: ☒ Attached, Document ID: SRP-FI-CV2
2.	Compliance Assurance Monitoring: ☐ Attached, Document ID: __________ ☒ Not Applicable
3.	Alternative Methods of Operation: ☐ Attached, Document ID: __________ ☒ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: __________ ☒ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   [X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   [ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   [X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   [ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   [ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
Two aeroderivative simple cycle combustion turbine engines (CTs) associated with a Turbo Power & Marine FT4C-3LF TwinPac Combustion Turbine Peaking (CTP) Unit.

3. Emissions Unit Identification Number: **004 (Unit P-1; P1A and P1B)**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**10/29/80**	**49**

8. Federal Program Applicability: (Check all that apply)

   [ ] Acid Rain Unit

   [X] CAIR Unit

9. Package Unit:
Manufacturer: **Turbo Power & Marine Systems** Model Number: **FT4C-3LF**

10. Generator Nameplate Rating: **63 MW (nominal)**

11. Emissions Unit Comment:

Combustion Turbine Peaking (CTP) Unit P-1 is comprised of two identical simple cycle aeroderivative combustion turbine engines (P1A and P1B) and one common electrical generator.

Emissions Unit Control Equipment/Method: Control **1** of **1**

1. Control Equipment/Method Description: **Water Injection – NO_x Pollution Control**	
2. Control Device or Method Code: **028**	

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:	
2. Control Device or Method Code:	

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:	
2. Control Device or Method Code:	

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:	
2. Control Device or Method Code:	

B. EMISSIONS UNIT CAPACITY INFORMATION
(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: **739** million Btu/hr **(HHV, Per CTP Unit*)**		
4. Maximum Incineration Rate: pounds/hr tons/day		
5. Requested Maximum Operating Schedule:	hours/day weeks/year	days/week **1,500** hours/year
6. Operating Capacity/Schedule Comment: ***Each Combustion Turbine Peaking (CTP) Unit is comprised of two CT engines.** **Maximum heat input rate is for natural gas or No. 2 fuel oil at 100% load and 59°F ambient temperature per CTP Unit. Heat input will vary with CTP Unit load, fuel type, and ambient conditions.**		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **P1A and P1B**		2. Emission Point Type Code: **3**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **P1A & P1B**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **22** feet	7. Exit Diameter: **11.3** feet
8. Exit Temperature: **830** °F	9. Actual Volumetric Flow Rate: **1,255,500** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: Feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **324.43** North (km): **3,188.93**		14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack and exhaust flow characteristics are for each of the CT engines in each CTP Unit. The flow rate will vary with CT load, fuel type, and ambient conditions.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **2**

1. Segment Description (Process/Fuel Type): **Internal Combustion - Electrical Generation - Natural Gas: Turbine**			
2. Source Classification Code (SCC): **2-01-002-01**		3. SCC Units: **Million cubic feet burned**	
4. Maximum Hourly Rate: **0.72**	5. Maximum Annual Rate: **1,087**		6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:		9. Million Btu per SCC Unit: **1,020**
10. Segment Comment: **Maximum hourly and annual rates are for each CTP Unit (comprised of two CT engines) and are based on 739 MMBtu/hr (HHV), natural gas heat content of 1,020 Btu/ft^3, and 1,500 hours per year.**			

Segment Description and Rate: Segment **2** of **2**

1. Segment Description (Process/Fuel Type): **Internal Combustion - Electrical Generation – No. 2 Fuel Oil: Turbine**			
2. Source Classification Code (SCC): **2-01-002-01**		3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **5.36**	5. Maximum Annual Rate: **8,033**		6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.5**	8. Maximum % Ash: **0.1**		9. Million Btu per SCC Unit: **138 (HHV)**
10. Segment Comment: **Maximum hourly and annual rates are for each CTP Unit (comprised of two CT engines) and are based on 739 MMBtu/hr (HHV), No. 2 fuel oil heat content of 138 MMBtu/1000 gal, and 1,500 hours per year.**			

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
SO_2			EL
NO_x	028		EL
CO			NS
PM			NS
PM_{10}			NS
VOC			NS
HAPs (total)			NS

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **(Per CTP Unit)** **379** lb/hour **284** tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **379 lbs/hr** Reference: **BACT Limit, PSD-FL-014**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years

10. Calculation of Emissions:

Hourly Emissions:

SO2 = 379 lbs/hr [BACT Limit, PSD-FL-014]

Annual Emissions:

SO2 = 379 lbs/hr x (1,500 hr/yr) x (1 ton/2,000 lb) = 284 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:
Potential Emissions are per CTP Unit.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **379 lb/hr**	4. Equivalent Allowable Emissions: **379** lb/hour **284** tons/year
5. Method of Compliance: **Fuel sampling and analysis per applicable ASTM method.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions are per CTP Unit. Condition B.7, Permit No. 1210003-007-AV**	

Allowable Emissions Allowable Emissions **2** of **2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.5% S by weight**	4. Equivalent Allowable Emissions: **379** lb/hour **284** tons/year
5. Method of Compliance: **Fuel sampling and analysis per applicable ASTM method.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions are per CTP Unit. Condition B.8, Permit No. 1210003-007-AV**	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control: **60**
3. Potential Emissions: **(Per CTP Unit)** **177.4** lb/hour **133.0** tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.24 lb/MMBtu (75 ppmvd)** Reference: **BACT Limit, PSD-FL-014**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years

10. Calculation of Emissions:

Hourly Emissions: (No. 2 Fuel Oil)

NOx = (0.24 lb/MMBtu) x (739 MMBtu/hr) = 177.4 lb/hr

Annual Emissions: (No. 2 Fuel Oil)

NOx = (0.24 lb/MMBtu) x (739 MMBtu/hr) x (1,500 hr/yr) x (1 ton/2,000 lb) = 133.0 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential Emissions are per CTP Unit.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **75 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **177.4** lb/hour **133.0** tons/year
5. Method of Compliance: **CAM Plan (Water-to-fuel ratio, per NSPS Subpart GG); EPA Method 7**	
6. Allowable Emissions Comment (Description of Operating Method): **While burning No. 2 Fuel Oil. Condition B.5, Permit No. 1210003-007-AV [40 CFR 60.332(a); PSD-FL-014; and BACT Determination dated 8/18/78] Allowable emissions are per CTP Unit.**	

Allowable Emissions Allowable Emissions **2** of **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **68 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **96.1** lb/hour **72.1** tons/year
5. Method of Compliance: **CAM Plan (Water-to-fuel ratio, per NSPS Subpart GG); EPA Method 7**	
6. Allowable Emissions Comment (Description of Operating Method): **While burning Natural Gas. Condition B.6, Permit No. 1210003-007-AV [PSD-FL-014] Allowable emissions are per CTP Unit.**	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS
(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **(Per CTP Unit)** **56.2** lb/hour **42.1** tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.076 lb/MMBtu** Reference: **Table 3.1-1, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years

10. Calculation of Emissions:

Hourly Emissions: (No. 2 Fuel Oil)

CO = (0.076 lb/MMBtu) x (739 MMBtu/hr) = 56.2 lb/hr

Annual Emissions: (No. 2 Fuel Oil)

CO = (0.076 lb/MMBtu) x (739 MMBtu/hr) x (1,500 hr/yr) x (1 ton/2,000 lb) = 42.1 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential Emissions are per CTP Unit.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of ___- **N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **PM/PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **(Per CTP Unit)** **8.9** lb/hour **6.7** tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.012 lb/MMBtu** Reference: **Table 3.1-2a, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years

10. Calculation of Emissions:

Hourly Emissions: (No. 2 Fuel Oil)

PM_{10} = (0.012 lb/MMBtu) x (739 MMBtu/hr) = 8.9 lb/hr

Annual Emissions: (No. 2 Fuel Oil)

PM_{10} = (0.012 lb/MMBtu) x (739 MMBtu/hr) x (1,500 hr/yr) x (1 ton/2,000 lb) = 6.7 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential Emissions are per CTP Unit.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __- **N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **(Per CTP Unit)** **1.6** lb/hour **1.2** tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0021 lb/MMBtu (Natural Gas)** Reference: **Table 3.1-2a, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years

10. Calculation of Emissions:

Hourly Emissions: (Natural Gas)

VOC = (0.0021 lb/MMBtu) x (739 MMBtu/hr) = 1.6 lb/hr

Annual Emissions: (Natural Gas)

VOC = (0.0021 lb/MMBtu) x (739 MMBtu/hr) x (1,500 hr/yr) x (1 ton/2,000 lb) = 1.2 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential Emissions are per CTP Unit.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of__ **- N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **HAPs (total)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **(Per CTP Unit)** lb/hour tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **Various** Reference: **AP-42 Tables 1.4-3-1.4-4 and AB 2588**	7. Emissions Method Code: **3 and 5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years
10. Calculation of Emissions: **See Attachment B of the Report.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Potential Emissions are per CTP Unit.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of ___**- N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation **1** of **1**

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **20 %** Exceptional Conditions: **N/A** % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Condition B.9, Permit No. 1210003-007-AV** **Per Condition B.23, Permit No. 1210003-007-AV, VE testing not required while burning: a.) only gaseous fuel(s) or b.) gaseous fuels in combination with any amount of liquid fuels for less than 400 hr/yr.** **Per Condition B.24, Permit No. 1210003-007-AV, VE testing required while firing fuel oil upon exceeding 400 hr/yr operation in any fiscal year**	

Visible Emissions Limitation: Visible Emissions Limitation _ of _

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **1** of **1**

1. Parameter Code: **WTF**	2. Pollutant(s): **N/A**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... **N/A** Manufacturer: Model Number:	Serial Number:
5. Installation Date: **1980**	6. Performance Specification Test Date: **1980**
7. Continuous Monitor Comment: **Required by NSPS Subpart GG.**	

Continuous Monitoring System: Continuous Monitor _of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: SRP-FI-C2 [ ] Previously Submitted, Date ______________

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: SRP-EU4-I2 [ ] Previously Submitted, Date ___________

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [ ] Attached, Document ID: N/A [ ] Previously Submitted, Date ___________

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: SRP-EU1-I4 [ ] Previously Submitted, Date ___________
   [ ] Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [ ] Attached, Document ID: __________ [ ] Previously Submitted, Date ___________
   [X] Not Applicable

6. Compliance Demonstration Reports/Records:
   [X] Attached, Document ID: SRP-EU4-I6
   Test Date(s)/Pollutant(s) Tested: 08/24/2013-08/26/2013: SO2, NOx, Visible Emissions
   [ ] Previously Submitted, Date: _______
   Test Date(s)/Pollutant(s) Tested: ____
   ____
   [ ] To be Submitted, Date (if known):___________
   Test Date(s)/Pollutant(s) Tested: ____
   ____
   [ ] Not Applicable
   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
   [ ] Attached, Document ID: __________ [X] Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications – N/A

1.	Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☐ Attached, Document ID:___________ ☐ Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID: ___________ ☐ Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ___________ ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1.	Identification of Applicable Requirements: ☒ Attached, Document ID: **SRP-FI-CV2**
2.	Compliance Assurance Monitoring: ☒ Attached, Document ID: **SRP-EU4-IV2** ☐ Not Applicable
3.	Alternative Methods of Operation: ☐ Attached, Document ID: __________ ☒ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: __________ ☒ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   [X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   [ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   [X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   [ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   [ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
Two aeroderiviative simple cycle combustion turbine engines (CTs) associated with a Turbo Power & Marine FT4C-3LF TwinPac Combustion Turbine Peaking (CTP) Unit.

3. Emissions Unit Identification Number: **005 (Unit P-2; P2A and P2B)**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**10/29/80**	**49**

8. Federal Program Applicability: (Check all that apply)

   [ ] Acid Rain Unit

   [X] CAIR Unit

9. Package Unit:
Manufacturer: **Turbo Power & Marine Systems** Model Number: **FT4C-3LF**

10. Generator Nameplate Rating: **63 MW (nominal)**

11. Emissions Unit Comment:
Combustion Turbine Peaking (CTP) Unit P-2 is comprised of two identical simple cycle aeroderivative combustion turbine engines (P2A and P2B) and one common electrical generator.

Emissions Unit Control Equipment/Method: Control **1** of **1**

1. Control Equipment/Method Description: **Water Injection – NO_x Pollution Control**
2. Control Device or Method Code: **028**

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:
2. Control Device or Method Code:

B. EMISSIONS UNIT CAPACITY INFORMATION
(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: **739** million Btu/hr **(HHV, Per CTP Unit*)**		
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	hours/day weeks/year	days/week **1,500** hours/year
6. Operating Capacity/Schedule Comment: ***Each Combustion Turbine Peaking (CTP) Unit is comprised of two CT engines.** **Maximum heat input rate is for natural gas or No. 2 fuel oil at 100% load and 59°F ambient temperature per CTP Unit. Heat input will vary with CTP Unit load, fuel type, and ambient conditions.**		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **P2A and P2B**	2. Emission Point Type Code: **3**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **P2A & P2B**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **22** feet	7. Exit Diameter: **11.3** feet
8. Exit Temperature: **830** °F	9. Actual Volumetric Flow Rate: **1,255,500** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: Dscfm	12. Nonstack Emission Point Height: Feet	
13. Emission Point UTM Coordinates... Zone: **17** East (km): **324.43** North (km): **3,188.93**	14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Stack and exhaust flow characteristics are for each of the CT engines in each CTP Unit. The flow rate will vary with CT load, fuel type, and ambient conditions.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **2**

1. Segment Description (Process/Fuel Type): **Internal Combustion - Electrical Generation - Natural Gas: Turbine**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million cubic feet burned**	
4. Maximum Hourly Rate: **0.72**	5. Maximum Annual Rate: **1,087**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,020**
10. Segment Comment: **Maximum hourly and annual rates are for each CTP Unit (comprised of two CT engines) and are based on 739 MMBtu/hr (HHV), natural gas heat content of 1,020 Btu/ft^3, and 1,500 hours per year.**		

Segment Description and Rate: Segment **2** of **2**

1. Segment Description (Process/Fuel Type): **Internal Combustion - Electrical Generation – No. 2 Fuel Oil: Turbine**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **5.36**	5. Maximum Annual Rate: **8,033**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.5**	8. Maximum % Ash: **0.1**	9. Million Btu per SCC Unit: **138 (HHV)**
10. Segment Comment: **Maximum hourly and annual rates are for each CTP Unit (comprised of two CT engines) and are based on 739 MMBtu/hr (HHV), No. 2 fuel oil heat content of 138 MMBtu/1000 gal, and 1,500 hours per year.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
SO2			**EL**
NOx	**028**		**EL**
CO			**NS**
PM			**NS**
PM10			**NS**
VOC			**NS**
HAPs (total)			**NS**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **(Per CTP Unit)** **379** lb/hour **284** tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **379 lbs/hr** Reference: **BACT Limit, PSD-FL-014**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years

10. Calculation of Emissions:

Hourly Emissions:

SO2 = 379 lbs/hr [BACT Limit, PSD-FL-014]

Annual Emissions:

SO2 = 379 lbs/hr x (1,500 hr/yr) x (1 ton/2,000 lb) = 3,614 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:
Potential Emissions are per CTP Unit.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **379 lb/hr**	4. Equivalent Allowable Emissions: **379** lb/hour **284** tons/year
5. Method of Compliance: **Fuel sampling and analysis per applicable ASTM method.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions are per CTP Unit. Condition B.7, Permit No. 1210003-007-AV**	

Allowable Emissions Allowable Emissions **2** of **2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.5% S by weight**	4. Equivalent Allowable Emissions: **379** lb/hour **284** tons/year
5. Method of Compliance: **Fuel sampling and analysis per applicable ASTM method.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions are per CTP Unit. Condition B.8, Permit No. 1210003-007-AV**	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control: **60**
3. Potential Emissions: **(Per CTP Unit)** **177.4** lb/hour **133.0** tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.24 lb/MMBtu (75 ppm)** Reference: **BACT Limit, PSD-FL-014**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years

10. Calculation of Emissions:

Hourly Emissions: (No. 2 Fuel Oil)

NOx = (0.24 lb/MMBtu) x (739 MMBtu/hr) = 177.4 lb/hr

Annual Emissions: (No. 2 Fuel Oil)

NOx = (0.24 lb/MMBtu) x (739 MMBtu/hr) x (1,500 hr/yr) x (1 ton/2,000 lb) = 133.0 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential Emissions are per CTP Unit.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **75 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **177.4** lb/hour **133.0** tons/year
5. Method of Compliance: **CAM Plan (Water-to-fuel ratio, per NSPS Subpart GG); EPA Method 7**	
6. Allowable Emissions Comment (Description of Operating Method): **While burning No. 2 Fuel Oil. Condition B.5, Permit No. 1210003-007-AV [40 CFR 60.332(a); PSD-FL-014; and BACT Determination dated 8/18/78] Allowable emissions are per CTP Unit.**	

Allowable Emissions Allowable Emissions **2** of **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **68 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **96.1** lb/hour **72.1** tons/year
5. Method of Compliance: **CAM Plan (Water-to-fuel ratio, per NSPS Subpart GG); EPA Method 7**	
6. Allowable Emissions Comment (Description of Operating Method): **While burning Natural Gas. Condition B.6, Permit No. 1210003-007-AV [PSD-FL-014] Allowable emissions are per CTP Unit.**	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **(Per CTP Unit)** **56.2** lb/hour **42.1** tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.076 lb/MMBtu** Reference: **Table 3.1-1, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years

10. Calculation of Emissions:

Hourly Emissions: (No. 2 Fuel Oil)

CO = (0.076 lb/MMBtu) x (739 MMBtu/hr) = 56.2 lb/hr

Annual Emissions: (No. 2 Fuel Oil)

CO = (0.076 lb/MMBtu) x (739 MMBtu/hr) x (1,500 hr/yr) x (1 ton/2,000 lb) = 42.1 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential Emissions are per CTP Unit.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of ___- **N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM/PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **(Per CTP Unit)** **8.9** lb/hour **6.7** tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.012 lb/MMBtu** Reference: **Table 3.1-2a, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years

10. Calculation of Emissions:

Hourly Emissions: (No. 2 Fuel Oil)

PM_{10} = (0.012 lb/MMBtu) x (739 MMBtu/hr) = 8.9 lb/hr

Annual Emissions: (No. 2 Fuel Oil)

PM_{10} = (0.012 lb/MMBtu) x (739 MMBtu/hr) x (1,500 hr/yr) x (1 ton/2,000 lb) = 6.7 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential Emissions are per CTP Unit.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of __- N/A

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **(Per CTP Unit)** **1.6** lb/hour **1.2** tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0021 lb/MMBtu (Natural Gas)** Reference: **Table 3.1-2a**, **AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years

10. Calculation of Emissions:

Hourly Emissions: (Natural Gas)

VOC = (0.0021 lb/MMBtu) x (739 MMBtu/hr) = 1.6 lb/hr

Annual Emissions: (Natural Gas)

VOC = (0.0021 lb/MMBtu) x (739 MMBtu/hr) x (1,500 hr/yr) x (1 ton/2,000 lb) = 1.2 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential Emissions are per CTP Unit.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of__ **- N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **HAPs (total)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **(Per CTP Unit)** lb/hour tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **Various** Reference: **AP-42 Tables 1.4-3-1.4-4 and AB 2588**	7. Emissions Method Code: **3 and 5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years
10. Calculation of Emissions: **See Attachment B of the Report.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Potential Emissions are per CTP Unit.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions __ of ___**- N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation **1** of **1**

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **20 %** Exceptional Conditions: **N/A** % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Condition B.9, Permit No. 1210003-007-AV** **Per Condition B.23, Permit No. 1210003-007-AV, VE testing not required while burning: a.) only gaseous fuel(s) or b.) gaseous fuels in combination with any amount of liquid fuels for less than 400 hr/yr.** **Per Condition B.24, Permit No. 1210003-007-AV, VE testing required while firing fuel oil upon exceeding 400 hr/yr operation in any fiscal year**	

Visible Emissions Limitation: Visible Emissions Limitation _ of _

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **1** of **1**

1. Parameter Code: **WTF**	2. Pollutant(s): **N/A**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information... **N/A** Manufacturer: Model Number:	Serial Number:
5. Installation Date: **1980**	6. Performance Specification Test Date: **1980**
7. Continuous Monitor Comment: **Required by NSPS Subpart GG.**	

Continuous Monitoring System: Continuous Monitor _of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [ ] Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [X] Attached, Document ID: **SRP-FI-C2** [ ] Previously Submitted, Date ______________
2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [X] Attached, Document ID: **SRP-EU4-I2** [ ] Previously Submitted, Date ___________
3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [ ] Attached, Document ID: **N/A** [ ] Previously Submitted, Date ___________
4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [X] Attached, Document ID: **SRP-EU1-I4** [ ] Previously Submitted, Date ___________ [ ] Not Applicable (construction application)
5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) [ ] Attached, Document ID: __________ [ ] Previously Submitted, Date ___________ [X] Not Applicable
6. Compliance Demonstration Reports/Records: [X] Attached, Document ID: **SRP-EU4-I6** Test Date(s)/Pollutant(s) Tested: **08/24/2013-08/26/2013: SO2, NOx, Visible Emissions** [ ] Previously Submitted, Date: _______ Test Date(s)/Pollutant(s) Tested: ______________________________ [ ] To be Submitted, Date (if known):___________ Test Date(s)/Pollutant(s) Tested: ______________________________ [ ] Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute: [ ] Attached, Document ID: __________ [X] Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications – N/A

1.	Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☐ Attached, Document ID:___________ ☐ Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID: ___________ ☐ Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ___________ ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1.	Identification of Applicable Requirements: ☒ Attached, Document ID: **SRP-FI-CV2**
2.	Compliance Assurance Monitoring: ☒ Attached, Document ID: **SRP-EU4-IV2** ☐ Not Applicable
3.	Alternative Methods of Operation: ☐ Attached, Document ID: __________ ☒ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: __________ ☒ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for an initial, revised or renewal Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for an air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised or renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes, and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit addressed in this application that is subject to air construction permitting and for each such emissions unit that is a regulated or unregulated unit for purposes of Title V permitting. (An emissions unit may be exempt from air construction permitting but still be classified as an unregulated unit for Title V purposes.) Emissions units classified as insignificant for Title V purposes are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

[X] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
Two aeroderivative simple cycle combustion turbine engines (CTs) associated with a Turbo Power & Marine FT4C-3LF TwinPac Combustion Turbine Peaking (CTP) Unit.

3. Emissions Unit Identification Number: **006 (Unit P-3; P3A and P3B)**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**10/29/80**	**49**

8. Federal Program Applicability: (Check all that apply)

[ ] Acid Rain Unit

[X] CAIR Unit

9. Package Unit:
Manufacturer: **Turbo Power & Marine Systems** Model Number: **FT4C-3LF**

10. Generator Nameplate Rating: **63 MW (nominal)**

11. Emissions Unit Comment:
CTP Unit P-3 is comprised of two identical simple cycle aeroderivative combustion turbine engines (P3A and P3B) and one common electrical generator.

<u>Emissions Unit Control Equipment/Method:</u> Control **1** of **1**

1.	Control Equipment/Method Description: **Water Injection – NO_x Pollution Control**
2.	Control Device or Method Code: **028**

<u>Emissions Unit Control Equipment/Method:</u> Control ___ of ___

1.	Control Equipment/Method Description:
2.	Control Device or Method Code:

<u>Emissions Unit Control Equipment/Method:</u> Control ___ of ___

1.	Control Equipment/Method Description:
2.	Control Device or Method Code:

<u>Emissions Unit Control Equipment/Method:</u> Control ___ of ___

1.	Control Equipment/Method Description:
2.	Control Device or Method Code:

B. EMISSIONS UNIT CAPACITY INFORMATION
(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: **739** million Btu/hr **(HHV, Per CTP Unit*)**		
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	hours/day weeks/year	days/week **1,500** hours/year
6. Operating Capacity/Schedule Comment: ***Each Combustion Turbine Peaking (CTP) Unit is comprised of two CT engines.** **Maximum heat input rate is for natural gas or No. 2 fuel oil at 100% load and 59°F ambient temperature per CTP Unit. Heat input will vary with CTP Unit load, fuel type, and ambient conditions.**		

C. EMISSION POINT (STACK/VENT) INFORMATION

(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **P1A and P1B**	2. Emission Point Type Code: **3**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **P1A & P1B**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **22** feet	7. Exit Diameter: **11.3** feet
8. Exit Temperature: **830** °F	9. Actual Volumetric Flow Rate: **1,255,500** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: Dscfm	12. Nonstack Emission Point Height: Feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **324.43** North (km): **3,188.93**	14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack and exhaust flow characteristics are for each of the CT engines in each CTP Unit. The flow rate will vary with CT load, fuel type, and ambient conditions.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **2**

1. Segment Description (Process/Fuel Type): **Internal Combustion - Electrical Generation - Natural Gas: Turbine**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million cubic feet burned**	
4. Maximum Hourly Rate: **0.72**	5. Maximum Annual Rate: **1,087**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,020**
10. Segment Comment: **Maximum hourly and annual rates are for each CTP Unit (comprised of two CT engines) and are based on 739 MMBtu/hr (HHV), natural gas heat content of 1,020 Btu/ft^3, and 1,500 hours per year.**		

Segment Description and Rate: Segment **2** of **2**

1. Segment Description (Process/Fuel Type): **Internal Combustion - Electrical Generation – No. 2 Fuel Oil: Turbine**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **5.36**	5. Maximum Annual Rate: **8,033**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.5**	8. Maximum % Ash: **0.1**	9. Million Btu per SCC Unit: **138 (HHV)**
10. Segment Comment: **Maximum hourly and annual rates are for each CTP Unit (comprised of two CT engines) and are based on 739 MMBtu/hr (HHV), No. 2 fuel oil heat content of 138 MMBtu/1000 gal, and 1,500 hours per year.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
SO2			**EL**
NOx	**028**		**EL**
CO			**NS**
PM			**NS**
PM10			**NS**
VOC			**NS**
HAPs (total)			**NS**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **(Per CTP Unit)** **379** lb/hour **284** tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **379 lbs/hr** Reference: **BACT Limit, PSD-FL-014**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years

10. Calculation of Emissions:

Hourly Emissions:

SO2 = 379 lbs/hr [BACT Limit, PSD-FL-014]

Annual Emissions:

SO2 = 379 lbs/hr x (1,500 hr/yr) x (1 ton/2,000 lb) = 284 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:
Potential Emissions are per CTP Unit.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

- **Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **379 lb/hr**	4. Equivalent Allowable Emissions: **379** lb/hour **284** tons/year
5. Method of Compliance: **Fuel sampling and analysis per applicable ASTM method.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions are per SCCT. Condition B.7, Permit No. 1210003-007-AV**	

Allowable Emissions Allowable Emissions **2** of **2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.5% S by weight**	4. Equivalent Allowable Emissions: **379** lb/hour **284** tons/year
5. Method of Compliance: **Fuel sampling and analysis per applicable ASTM method.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions are per CTP Unit. Condition B.8, Permit No. 1210003-007-AV**	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control: **60**
3. Potential Emissions: **(Per CTP Unit)** **177.4** lb/hour **133.0** tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.24 lb/MMBtu (75 ppmvd)** Reference: **BACT Limit**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years

10. Calculation of Emissions:

Hourly Emissions: (No. 2 Fuel Oil)

NOx = (0.24 lb/MMBtu) x (739 MMBtu/hr) = 177.4 lb/hr

Annual Emissions: (No. 2 Fuel Oil)

NOx = (0.24 lb/MMBtu) x (739 MMBtu/hr) x (1,500 hr/yr) x (1 ton/2,000 lb) = 133.0 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential Emissions are per CTP Unit.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

- **Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

Allowable Emissions Allowable Emissions **1** of **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **75 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **177.4** lb/hour **133.0** tons/year
5. Method of Compliance: **CAM Plan (Water-to-fuel ratio, per NSPS Subpart GG); EPA Method 7**	
6. Allowable Emissions Comment (Description of Operating Method): **While burning No. 2 Fuel Oil. Condition B.5, Permit No. 1210003-007-AV [40 CFR 60.332(a); PSD-FL-014; and BACT Determination dated 8/18/78] Allowable emissions are per CTP Unit.**	

Allowable Emissions Allowable Emissions **2** of **2**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **68 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **96.1** lb/hour **72.1** tons/year
5. Method of Compliance: **CAM Plan (Water-to-fuel ratio, per NSPS Subpart GG); EPA Method 7**	
6. Allowable Emissions Comment (Description of Operating Method): **While burning Natural Gas. Condition B.6, Permit No. 1210003-007-AV [PSD-FL-014] Allowable emissions are per CTP Unit.**	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **(Per CTP Unit)** **56.2** lb/hour **42.1** tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.076 lb/MMBtu** Reference: **Table 3.1-1, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years

10. Calculation of Emissions:

Hourly Emissions: (No. 2 Fuel Oil)

CO = (0.076 lb/MMBtu) x (739 MMBtu/hr) = 56.2 lb/hr

Annual Emissions: (No. 2 Fuel Oil)

CO = (0.076 lb/MMBtu) x (739 MMBtu/hr) x (1,500 hr/yr) x (1 ton/2,000 lb) = 42.1 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential Emissions are per CTP Unit.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

- **Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

Allowable Emissions Allowable Emissions __ of ___- **N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM/PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **(Per CTP Unit)** **8.9** lb/hour **6.7** tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.012 lb/MMBtu** Reference: **Table 3.1-2a, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years

10. Calculation of Emissions:

Hourly Emissions: (No. 2 Fuel Oil)

PM_{10} = (0.012 lb/MMBtu) x (739 MMBtu/hr) = 8.9 lb/hr

Annual Emissions: (No. 2 Fuel Oil)

PM_{10} = (0.012 lb/MMBtu) x (739 MMBtu/hr) x (1,500 hr/yr) x (1 ton/2,000 lb) = 6.7 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential Emissions are per CTP Unit.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

- **Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

Allowable Emissions Allowable Emissions __ of __- **N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **(Per CTP Unit)** **1.6** lb/hour **1.2** tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0021 lb/MMBtu (Natural Gas)** Reference: **Table 3.1-2a**, **AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years

10. Calculation of Emissions:

Hourly Emissions: (Natural Gas)

VOC = (0.0021 lb/MMBtu) x (739 MMBtu/hr) = 1.6 lb/hr

Annual Emissions: (Natural Gas)

VOC = (0.0021 lb/MMBtu) x (739 MMBtu/hr) x (1,500 hr/yr) x (1 ton/2,000 lb) = 1.2 ton/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential Emissions are per CTP Unit.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

- **Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

Allowable Emissions Allowable Emissions __ of__- **N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **HAPs (total)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **(Per CTP Unit)** lb/hour tons/year	4. Synthetically Limited? [X] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **Various** Reference: **AP-42 Tables 1.4-3-1.4-4 and AB 2588**	7. Emissions Method Code: **3 and 5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: [ ] 5 years [ ] 10 years
10. Calculation of Emissions: **See Attachment B of the Report.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Potential Emissions are per CTP Unit.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

- **Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

Allowable Emissions Allowable Emissions __ of ___**- N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation **1** of **1**

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **20 %** Exceptional Conditions: **N/A** % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Condition B.9, Permit No. 1210003-007-AV** **Per Condition B.23, Permit No. 1210003-007-AV, VE testing not required while burning: a.) only gaseous fuel(s) or b.) gaseous fuels in combination with any amount of liquid fuels for less than 400 hr/yr.** **Per Condition B.24, Permit No. 1210003-007-AV, VE testing required while firing fuel oil upon exceeding 400 hr/yr operation in any fiscal year**	

Visible Emissions Limitation: Visible Emissions Limitation _ of _

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor **1** of **1**

1. Parameter Code: **WTF**	2. Pollutant(s): **N/A**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information... **N/A** Manufacturer: Model Number:	Serial Number:
5. Installation Date: **1980**	6. Performance Specification Test Date: **1980**
7. Continuous Monitor Comment: **Required by NSPS Subpart GG.**	

Continuous Monitoring System: Continuous Monitor _of _

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [ ] Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: SRP-FI-C2 [ ] Previously Submitted, Date ______________

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: SRP-EU4-I2 [ ] Previously Submitted, Date ___________

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [ ] Attached, Document ID: N/A [ ] Previously Submitted, Date ___________

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [X] Attached, Document ID: SRP-EU1-I4 [ ] Previously Submitted, Date ___________
   [ ] Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   [ ] Attached, Document ID: __________ [ ] Previously Submitted, Date ___________
   [X] Not Applicable

6. Compliance Demonstration Reports/Records:
   [X] Attached, Document ID: SRP-EU4-I6
   Test Date(s)/Pollutant(s) Tested: 08/24/2013-08/26/2013: SO2, NOx, Visible Emissions

   [ ] Previously Submitted, Date: _______
   Test Date(s)/Pollutant(s) Tested: ____

   [ ] To be Submitted, Date (if known):___________
   Test Date(s)/Pollutant(s) Tested: ____

   [ ] Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
   [ ] Attached, Document ID: __________ [X] Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications – N/A

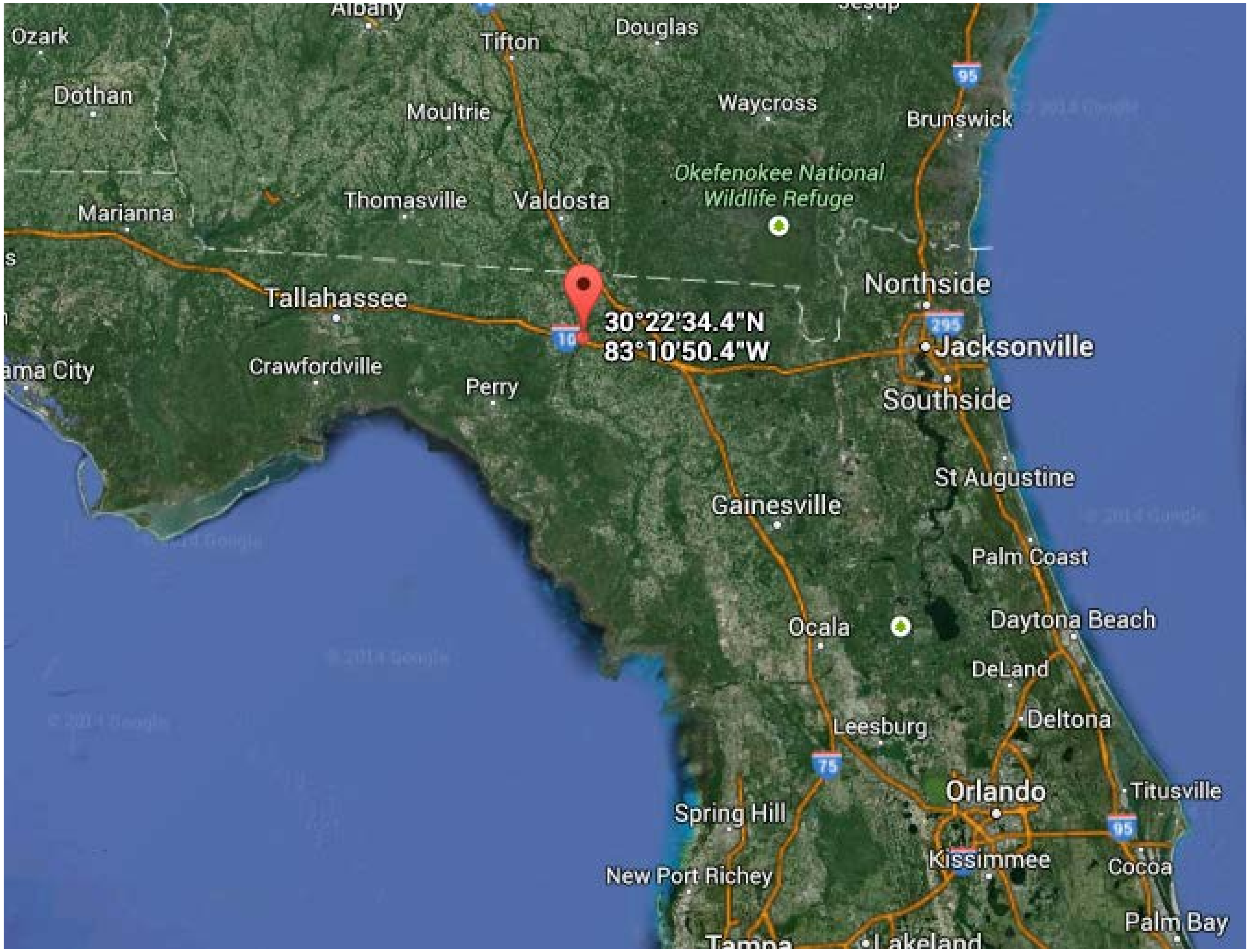
1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☐ Attached, Document ID:___________ ☐ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID: ___________ ☐ Not Applicable
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ___________ ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements: ☒ Attached, Document ID: **SRP-FI-CV2**
2. Compliance Assurance Monitoring: ☒ Attached, Document ID: **SRP-EU4-IV2** ☐ Not Applicable
3. Alternative Methods of Operation: ☐ Attached, Document ID: __________ ☒ Not Applicable
4. Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: __________ ☒ Not Applicable

Additional Requirements Comment

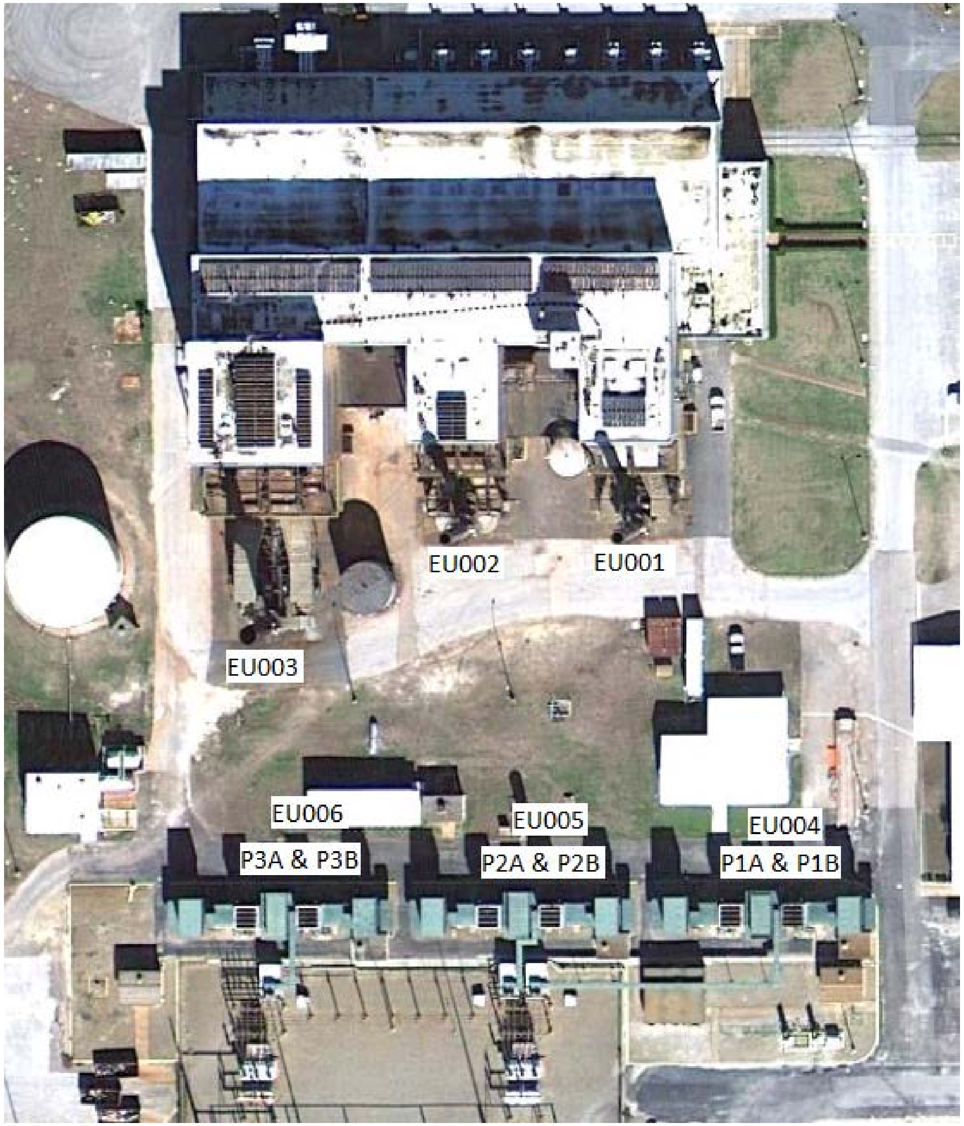
ATTACHMENT
SRP-FI-C1
FACILITY PLOT PLAN



SOURCE: 2014 Google Maps

CLIENT/PROJECT	TAMPA, FLORIDA	TITLE:
Duke Energy Florida, Inc.	Golder Associates	**Figure 1 Site Location** DRAFT

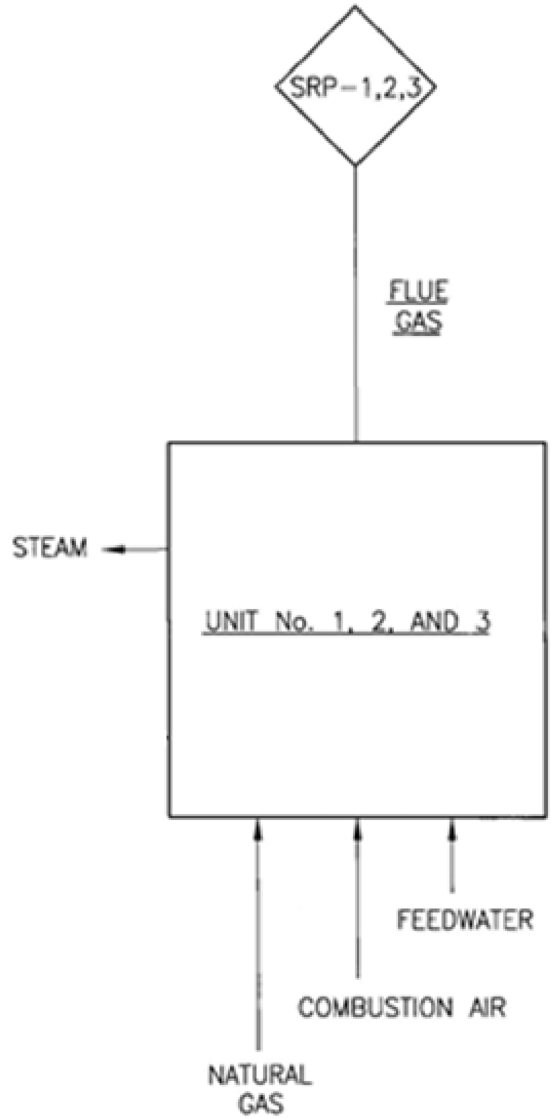
	DRAWN BY: JS	REVIEWED BY:	DATE: May 2014	NOT TO SCALE	FILE NO.:	JOB NO.: 1402802	Suwannee River Plant



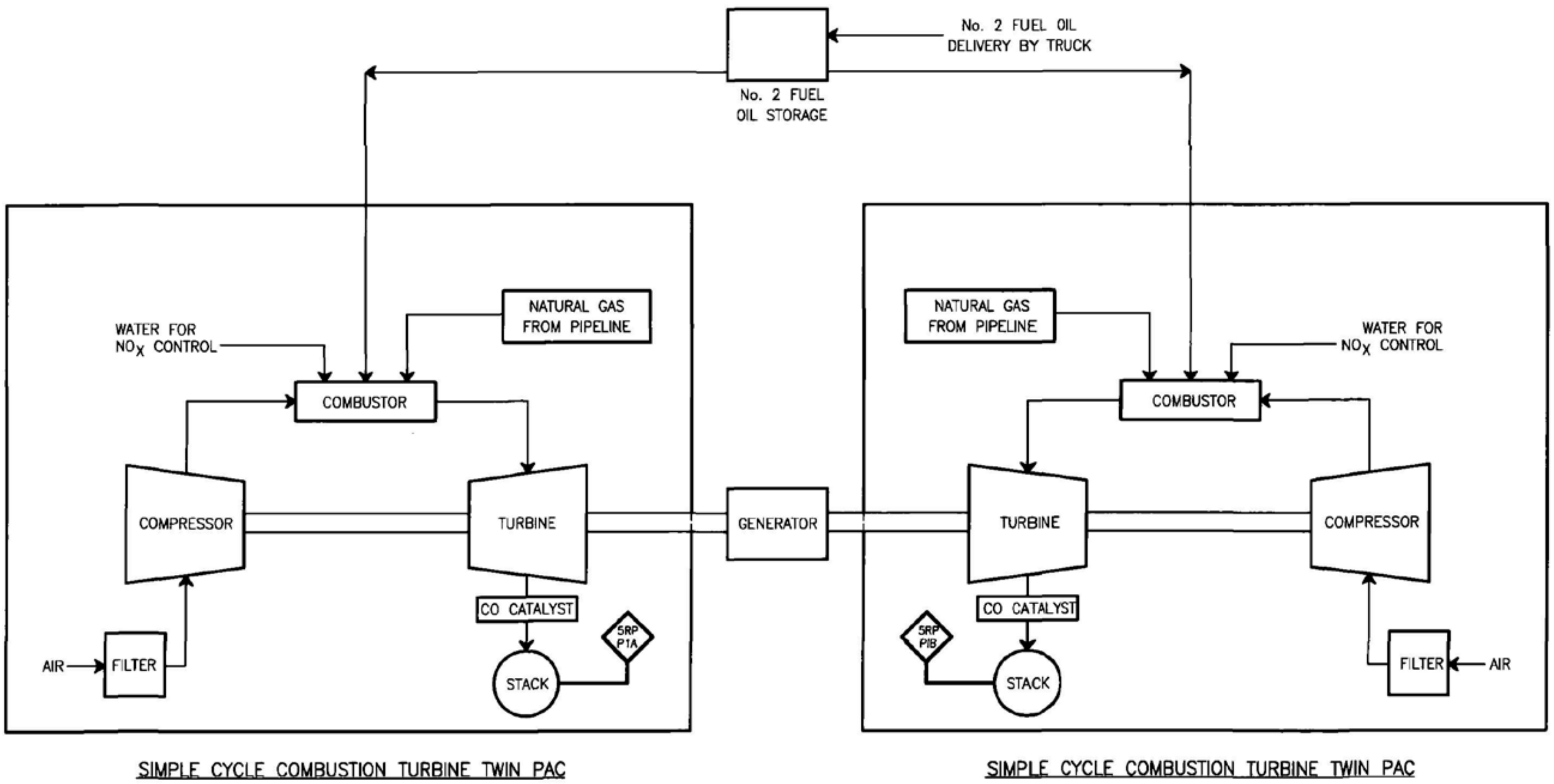
SOURCE: 2014 Google Earth Aerial

CLIENT/PROJECT **Duke Energy Florida, Inc.**			Golder Associates TAMPA, FLORIDA			TITLE: **Figure 2** **Facility Plot Plan** DRAFT
	DRAWN BY: JS	REVIEWED BY:	DATE: May 2014	NOT TO SCALE	FILE NO.:	JOB NO.: 1402802	Suwannee River Plant

ATTACHMENT
SRP-FI-C2
PROCESS FLOW DIAGRAM



CLIENT/PROJECT				TAMPA, FLORIDA			TITLE:
Duke Energy Florida, Inc.				Golder Associates			**Figure 3** **Process Flow Diagram** **EU001, EU002, EU003**
	DRAWN BY: JS	REVIEWED BY:	DATE: May 2014	NOT TO SCALE	FILE NO.:	JOB NO.: 1402802	Suwannee River Plant



CLIENT/PROJECT

Duke Energy Florida, Inc.

Golder Associates

TAMPA, FLORIDA

TITLE:

Figure 3
Process Flow Diagram
EU004, EU005, EU006

DRAFT

	DRAWN BY: JS	REVIEWED BY:	DATE: May 2014	NOT TO SCALE	FILE NO.:	JOB NO.: 1402802	Suwannee River Plant

ATTACHMENT
SRP-FI-C3
PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Precautions to Prevent Emissions of Unconfined Particulate Matter

Unconfined particulate matter (PM) emissions that may result from operations at the Suwannee River Plant include:

1. Vehicular traffic on paved and unpaved roads.
2. Wind-blown dust from material storage and yard areas.
3. Periodic abrasive blasting.

The following techniques may be used to control unconfined PM emissions on an as-needed basis:

1. Paving and maintenance of roads, parking areas, and yards.
2. Chemical (dust suppressants) or water application to:
   - Unpaved roads.
   - Unpaved yard areas.
   - Open stock piles.
3. Removal of PM from roads and other paved area to prevent reentrainment.
4. Removal of PM from buildings or work areas to prevent airborne particulate.
5. Landscaping or planting of vegetation.
6. Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent PM.
7. Confining abrasive blasting where possible.
8. Enclosure or covering of conveyor systems.
9. Other techniques, as necessary.

ATTACHMENT
SRP-FI-CV1
LIST OF INSIGNIFICANT ACTIVITIES

List of Insignificant Emissions Units and/or Activities.

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

1. Internal combustion engines – mobile sources.
2. Vacuum pumps in laboratory operations.
3. Equipment used for steam cleaning.
4. Equipment used exclusively for space heating, other than boilers.
5. Laboratory Equipment used exclusively for chemical or physical analysis.
6. Brazing, soldering, or welding equipment.
7. Fire protection and safety equipment.
8. Petroleum lubrication systems.
9. Application of fungicide, herbicide, or pesticide.
10. Vehicle refueling operations and associated fuel storage.
11. Degreasing Units using heavier-than air vapors exclusively that do not use any substance containing a hazardous air pollutant.
12. Non-halogenated solvent storage and cleaning operations that do not use any substance containing a hazardous air pollutant.
13. Boiler steam turbine lube oil vents
14. Gas turbine lube oil vents
15. Gas turbine dump tank vents
16. Used oil storage tanks.
17. Lube oil storage tanks
18. Diesel fuel oil tanks.
19. No. 2 diesel fuel oil tanks.
20. Storage tanks less than 550 gallons.
21. Architectural (equipment) maintenance painting.
22. Diesel fuel oil and No. 2 fuel oil truck unloading
23. The following engines are subject to regulation under 40 CFR 63, Subpart ZZZZ, however, since the engines meet the definition of “existing units”, there are no unit specific applicable requirements that must be met pursuant to the rule at this time:
    a. Diesel Emergency Generator;
    b. Diesel Fire Pump;
    c. Gasoline Welder.

ATTACHMENT
SRP-FI-CV2
IDENTIFICATION OF APPLICABLE REQUIREMENTS

Memorandum

Florida Department of Environmental Protection

TO: Joseph Kahn, Division of Air Resource Management

THROUGH: Trina L. Vielhauer, Chief, Bureau of Air Regulation TV
Jon Holtom, P.E., Title V Section JH

FROM: Scott M. Sheplak, P.E., Title V Section sms

DATE: December 3, 2009

SUBJECT: Final Permit No. 1210003-007-AV

Progress Energy Florida, Inc. (PEF), Suwannee River Power Plant
Title V Air Operation Permit Renewal

Permitting Clock: ARMS Day 30 was November 30, 2009

The final permit for this project is attached for your approval and signature. The permit renewal is for the operation of the Suwannee River Power Plant.

The attached final determination identifies issuance of the combined draft/proposed permit, summarizes the publication process, and provides the Department's response(s) to comment(s) (if any) on the draft permit. There are no pending petitions for administrative hearings or extensions of time to file a petition for an administrative hearing.

I recommend your approval of the attached final permit for this project.

TLV/jkh/sms

Attachments

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Florida Power Corporation dba Progress Energy Florida, Inc. (PEF)
4037 River Road
Live Oak, Florida 32060

Responsible Official:
Mr. Cary W. Hamilton, Plant Manager

Final Permit No. 1210003-007-AV
Suwannee River Power Plant

Title V Air Operation Permit Renewal
Suwannee County

Enclosed is the final permit package to renew the Title V air operation permit for the Suwannee River Power Plant. This existing facility is located South of Route 90 - Northwest of Live Oak in Suwannee County, Florida. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit) has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30-days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Trina L. Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

TLV/jkh/sms

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final Determination, the Statement of Basis and the Final Permit), or a link to these documents available electronically on a publicly accessible server, was sent by electronic mail with received receipt requested to the persons listed below:

Mr. Cary W. Hamilton, Plant Manager, PEF: cary.hamilton@pgnmail.com
Ms. Brenda E. Brickhouse, Director-EH&S, PEF: brenda.brickhouse@pgnmail.com
Ms. Patricia Q. West, Manager-Environmental Services, PEF: patricia.west@pgnmail.com
Mr. Chris Bradley, PEF: chris.bradley@pgnmail.com
Mr. Thomas W. Davis, P.E., ECT: tdavis@ectinc.com
Mr. Chris Kirts, P.E., DEP NED: christopher.kirts@dep.state.fl.us
Ms. Katy R. Forney, U.S. EPA Region 4: forney.kathleen@epa.epa.gov
Ms. Ana Oquendo-Vazquez, U.S. EPA Region 4: oquendo.ana@epa.gov
Ms. Barbara Friday, DEP BAR: barbara.friday@dep.state.fl.us (for posting with U.S. EPA, Region 4)
Ms. Victoria Gibson, DEP BAR: victoria.gibson@dep.state.fl.us (for reading file)

Clerk Stamp

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

Barbara J. Friday 12/18/09

(Clerk) (Date)

PERMITTEE

Florida Power Corporation dba Progress Energy Florida, Inc. (PEF)
Suwannee River Power Plant
4037 River Road
Live Oak, Florida 32060

PERMITTING AUTHORITY

Florida Department of Environmental Protection (Department)
Division of Air Resource Management
Bureau of Air Regulation, Title V Section
2600 Blair Stone Road, MS #5505
Tallahassee, Florida 32399-2400

PROJECT

Final Permit No. 1210003-007-AV
Suwannee River Power Plant

The purpose of this project is to renew the Title V air operation permit for the Suwannee River Power Plant.

This permit was processed using a parallel review.

PUBLIC NOTICE

A Written Notice of Intent to Issue a Draft/Proposed Title V Air Operation Permit to Progress Energy Florida, Inc. for the Suwannee River Power Plant, located in Suwannee County South of Route 90 - Northwest of Live Oak, Florida, was clerked on October 23, 2009. The Public Notice of Intent to Issue a Title V Air Operation Permit was published in the Suwannee Democrat on October 30, 2009. The draft/proposed Title V air operation permit was available for public inspection at the permitting authority's office in Tallahassee. Proof of publication of the Public Notice of Intent to Issue a Title V Air Operation Permit was received on November 3, 2009.

COMMENTS

On October 23, 2009, the Department informed US EPA Region 4 that this permit was being processed using a parallel review. US EPA Region 4 was notified of the publication date of the Public Notice on November 3, 2009. No comments on the draft/proposed permit were received from the US EPA Region 4 Office.

No comments were received from the public during the 30 day public comment period; however, comments were received from the Applicant. The comments were not considered significant enough to reissue the draft/proposed Title V air operation permit and require another Public Notice, therefore, the draft/proposed Title V air operation permit was changed. The comments are addressed below. Additions to the permit are indicated below by double underline. Deletions from the permit are indicated below by ~~strike through~~.

Letter from PEF dated and received via e-mail on November 24, 2009

Applicant Comments

1. Section I. Subsection A. Facility Description and Section III. Subsection A. Emissions Unit Descriptions for Fossil Fuel Fired Steam Generator Units. The requested change is to include in the descriptions the use of propane/liquefied propane (LP) gas as an igniter fuel. The facility has used propane/LP gas as an igniter fuel since its initial operation.

Response: The current Title V air operation permit, Permit No. 1210003-005-AV, mentions igniter fuels in the descriptions. The Department agrees with the requested change to better reflect actual operations since the initial operations of the boilers. The descriptions are updated to read as follows:

Section I. Subsection A. Facility Description. and **Statement of Basis**

This existing facility is a nominal 345 megawatt (MW) electrical generation facility comprised of three fossil fuel fired steam generators, Boiler Nos. 1, 2 and 3, and three combustion turbine peaking (CTP) units, CTP Unit Nos. 1, 2 and 3. There are no air pollution control devices associated with the boilers. Boilers Nos. 1, 2 and 3 fire natural gas, No. 2 fuel oil, No. 6 fuel oil, and/or on-specification used oil. In addition, propane/liquefied propane (LP) gas is sometimes used as an igniter fuel. …

Section III. Subsection A. Emissions Unit Descriptions for Fossil Fuel Fired Steam Generator Units.

Fossil fuel fired steam generator Unit No. 1 is a nominal 35.0 megawatt (MW) (electric) steam generator designated as Boiler No. 1. This emissions unit is allowed to fire No. 2 fuel oil, No. 6 fuel oil, "on specification" used oil, natural gas, and a blend of fuel oil and natural gas. The "on-specification" used oil is generally fired as a blended fuel oil with either the No. 2 fuel oil or the No. 6 fuel oil. In addition, propane/liquefied propane (LP) gas is sometimes used as an igniter fuel. …

Fossil fuel fired steam generator Unit No. 2 is a nominal 34.0 MW (electric) steam generator designated as Boiler No. 2. This emissions unit is allowed to fire No. 2 fuel oil, No. 6 fuel oil, "on specification" used oil, natural gas, and a blend of fuel oil and natural gas. The "on-specification" used oil is generally fired as a blended fuel oil with either the No. 2 fuel oil or the No. 6 fuel oil. In addition, propane/liquefied propane (LP) gas is sometimes used as an igniter fuel. …

Fossil fuel fired steam generator Unit No. 3 is a nominal 84.0 MW (electric) steam generator designated as Boiler No. 3. This emissions unit is allowed to fire No. 2 fuel oil, No. 6 fuel oil, "on specification" used oil, natural gas, and a blend of fuel oil and natural gas. The "on-specification" used oil is generally fired as a blended fuel oil with either the No. 2 fuel oil or the No. 6 fuel oil. In addition, propane/liquefied propane (LP) gas is sometimes used as an igniter fuel. …

2. Section III. Subsection A., Specific Condition A.17. and Section III. Subsection B., Specific Condition B.16. The requested changes are to clarify that there are other methods of determining sulfur dioxide emissions other than those identified in the tables.

Response: This table within the permit specific conditions is part of the new Title V air operation permitting formats. Note that "Table 2, Summary of Compliance Requirements" summarizes key compliance information for each air pollutant like the methods of compliance and test frequencies, and contains cross references to the corresponding permit specific conditions. To clarify the test methods cited in these new tables, the tables are changed to read as follows:

A.17. Test Methods. Required tests shall be performed in accordance with the following reference method(s):

Method(s)	Description of Method(s) and Comment(s)
…	
EPA Methods 6, 6A, 6B or 6C (Also see Specific Conditions **A.15.**, **A.24.** and **A.25.**)	Methods for Determining Sulfur Dioxide Emissions
Appendix D, 40 CFR 75 (Also see Specific	Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units

Conditions **A.15.**, **A.24.** and **A.25.**)	

...

B.16. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
...	
EPA Methods 6, 6A, 6B or 6C (Also see Specific Conditions **B.8.** and **B.21.**)	Methods for Determining SO_2 Emissions
Appendix D, 40 CFR 75 (Also see Specific Conditions **B.8.** and **B.21.**)	Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units

...

3. Section III. Subsection A., Specific Condition A.30. Records. The requested change is for other alternatives to determine sulfur content for liquid fuels.

***Response*:** The requested change is already contained in Specific Condition A.25. This language had been included as a result of the request in the Title V air operation permit renewal application. No change is necessary.

DEPARTMENT INITIATED CHANGES

Changes initiated by the Department were made in this final permit.

Statewide Format Changes

1. Section II. of the Permit, Facility-wide Condition FW4. Based on a recent comment from U.S. EPA Region 4, the regulatory citation for facility-wide condition FW4 is updated. This specific condition is changed to read as follows:

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.]

CONCLUSION

The draft/proposed Title V air operation permit was changed. The final action of the Department is to issue the final permit with the changes noted above.

Florida Power Corporation dba Progress Energy Florida, Inc. (PEF)
Suwannee River Power Plant
Title V Operation Permit Renewal

APPLICANT

The applicant for this project is Florida Power Corporation dba Progress Energy Florida, Inc. The applicant's responsible official and mailing address are: Mr. Cary W. Hamilton, Plant Manager, Suwannee River Power Plant, Florida Power Corporation dba Progress Energy Florida, Inc. (PEF), 4037 River Road, Live Oak, Florida 32060.

FACILITY DESCRIPTION

The applicant operates the existing Suwannee River Power Plant, which is located South of Route 90 - Northwest of Live Oak in Suwannee County, Florida.

This existing facility is a nominal 345 megawatt (MW) electrical generation facility comprised of three fossil fuel fired steam generators, Boiler Nos. 1, 2 and 3, and three combustion turbine peaking (CTP) units, CTP Unit Nos. 1, 2 and 3. There are no air pollution control devices associated with the boilers. Boilers Nos. 1, 2 and 3 fire natural gas, No. 2 fuel oil, No. 6 fuel oil, and/or on-specification used oil. In addition, propane/liquefied propane (LP) gas is sometimes used as an igniter fuel. CTP Unit Nos. 1, 2 and 3 fire natural gas or No. 2 fuel oil. Nitrogen oxide emissions from each CTP unit are controlled by using water injection for both fuel oil and natural gas firing. Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

PROJECT DESCRIPTION

The purpose of this permitting project is to renew the existing Title V air operation permit for the above referenced facility.

PROCESSING SCHEDULE AND RELATED DOCUMENTS

Application for a Title V Air Operation Permit Renewal received on May 19, 2009.
Request for Additional Information dated and sent via e-mail on June 25, 2009.
Additional Information Response received via e-mail on August 25, 2009.
Request for Additional Information dated and sent via e-mail on October 9, 2009.
Additional Information Response received via e-mail on October 16, 2009.

Draft/Proposed Permit posted onto web site on October 23, 2009.
Public Notice published on October 30, 2009.
Notification to U.S. EPA Region 4 of Publication of Public Notice on November 3, 2009.

PRIMARY REGULATORY REQUIREMENTS

Title III: This facility is a major source of hazardous air pollutants (HAP), based on the Title V air operation permit renewal application received on May 19, 2009.

NESHAP: This facility operates units subject to the National Emissions Standards for Hazardous Air Pollutants (NESHAP) of 40 Code of Federal Regulations (CFR) 63.

Title IV: This facility operates units subject to the acid rain provisions of the Clean Air Act.

Title V: This facility is a Title V major source of air pollution in accordance with Chapter 62-213, Florida Administrative Code (F.A.C.).

PSD: This facility is a Prevention of Significant Deterioration (PSD)-major source of air pollution in accordance with Rule 62-212.400, F.A.C.

NSPS: This facility operates units subject to the New Source Performance Standards (NSPS) of 40 Code of Federal Regulations (CFR) 60.

This facility has engines which were potentially subject to the recently promulgated NSPS 40 CFR 60 Subpart IIII also known as (a.k.a.) NSPS "4-I's" or "CI-ICE" and 40 CFR 60 Subpart JJJJ a.k.a. NSPS "4-J's" or "SI-ICE." These federal regulations do not apply since these engines are 'existing' units under these subparts.

CAIR: This facility operates units subject to the Clean Air Interstate Rule (CAIR) set forth in Rule 62-296.470, F.A.C.

Siting: This facility does not operate units subject to the power plant siting provisions of Chapter 62-17, F.A.C.

CAM: This facility operates units subject to Compliance Assurance Monitoring (CAM).

PROJECT REVIEW

Changes were made in the format of this renewed Title V air operation permit.

Permit

- Conditions were removed from the previous permit and new conditions were added into this permit. For these reasons, the conditions in this new permit were renumbered.
- Removed all references to state air operation (AO) permits within the regulatory citations of permit specific conditions.
- The permitting note on heat input was kept for the fossil fuel fired steam generators, Boiler Nos. 1, 2 and 3 (Emission Unit ID Nos. -001, -002 and -003) since these emissions units have not been issued either an air construction (AC) permit or a prevention of significant deterioration (PSD) permit.
- At the applicant's request, included in this permit is Appendix D 40 CFR 75 which may be used to demonstrate compliance with the liquid fuel sulfur limits for the fossil fuel fired steam generators, Boiler Nos. 1, 2 and 3 (Emission Unit ID Nos. -001, -002 and -003).
- The previously included requirements from NSPS 40 CFR 60 Subpart A within the emissions unit section of the permit for the combustion turbine peaking units (Emission Unit ID Nos. -004, -005 and -006), were removed and are now specifically attached to the permit as Appendix 40 CFR 60 Subpart A.
- The previously included requirements from NSPS 40 CFR 60 Subpart GG within the emissions unit section of the permit for the combustion turbine peaking units (Emission Unit ID Nos. -004, -005 and -006), were removed and are now specifically attached to the permit as Appendix 40 CFR 60 Subpart GG.
- At the applicant's request, included in this permit is Appendix D 40 CFR 75 which may be used to demonstrate compliance with the fuel oil and natural gas fuel sulfur limits for the combustion turbine peaking units (Emission Unit ID Nos. -004, -005 and -006).
- Reclassified the emissions units and/or activities listed in Appendix U to the Appendix I, List of Insignificant Emissions Units and/or Activities.

CONCLUSION

This project renews Title V air operation permit No. 1210003-005-AV, which was effective January 1, 2005.

Florida Power Corporation
dba Progress Energy Florida, Inc. (PEF)
Suwannee River Power Plant
Facility ID No. 1210003
Suwannee County

Title V Air Operation Permit Renewal

Final Permit No. 1210003-007-AV
(2nd Renewal, Renewal of Title V Air Operation Permit No. 1210003-005-AV)

<u>**Permitting Authority**</u>
State of Florida
Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Title V Section

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

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

<u>**Compliance Authority**</u>
State of Florida
Department of Environmental Protection
Northeast District Office

7825 Baymeadows Way, Suite 200B
Jacksonville, Florida 32256-7590

Telephone: 904/807-3300
Fax: 904/448-4363

Title V Air Operation Permit Renewal
Final Permit No. 1210003-007-AV

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Section **Page Number**

Florida Department of
Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

PERMITTEE:
Florida Power Corporation
dba Progress Energy Florida, Inc.
Suwannee River Power Plant

Final Permit No. 1210003-007-AV
Facility ID No. 1210003
SIC No. 4911
Project: Title V Air Operation Permit Renewal

The purpose of this permit is to renew the Title V air operation permit for the Suwannee River Power Plant. This existing facility is located South of Route 90 - Northwest of Live Oak, Suwannee County; UTM Coordinates: Zone 17, 290.5 km East and 3362.2 km North; Latitude: 30° 22' 35" North and Longitude: 83° 10' 50" West.

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

Effective Date: January 1, 2010
Renewal Application Due Date: May 20, 2014
Expiration Date: December 31, 2014

Joseph Kahn, Director
Division of Air Resource Management

JK/tlv/jkh/sms

Subsection A. Facility Description.

This existing facility is a nominal 345 megawatt (MW) electrical generation facility comprised of three fossil fuel fired steam generators, Boiler Nos. 1, 2 and 3, and three combustion turbine peaking (CTP) units, CTP Unit Nos. 1, 2 and 3. There are no air pollution control devices associated with the boilers. Boilers Nos. 1, 2 and 3 fire natural gas, No. 2 fuel oil, No. 6 fuel oil, and/or on-specification used oil. In addition, propane/liquefied propane (LP) gas is sometimes used as an igniter fuel. CTP Unit Nos. 1, 2 and 3 fire natural gas or No. 2 fuel oil. Nitrogen oxide emissions from each CTP are controlled by using water injection for both fuel oil and natural gas firing. Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Subsection B. Summary of Emissions Units.

E.U. ID No.	Brief Description
Regulated Emissions Units	
	Fossil Fuel Fired Steam Generator Units
-001	Fossil Fuel Fired Steam Generator Unit No. 1
-002	Fossil Fuel Fired Steam Generator Unit No. 2
-003	Fossil Fuel Fired Steam Generator Unit No. 3
	Combustion Turbine Peaking Units (Simple Cycle units)
-004	Combustion Turbine Peaking (CTP) Unit No. 1 (P-1)
-005	Combustion Turbine Peaking (CTP) Unit No. 2 (P-2)
-006	Combustion Turbine Peaking (CTP) Unit No. 3 (P-3)

Subsection C. Applicable Requirements.

Based on the Title V air operation permit renewal application received on May 19, 2009, this facility is a major source of hazardous air pollutants (HAP). Because this facility operates stationary reciprocating internal combustion engines, it is subject to regulation under 40 CFR 63, Subpart ZZZZ - National Emissions Standards For Hazardous Air Pollutants For Stationary Reciprocating Internal Combustion Engines. However, since the engines being operated meet the Subpart ZZZZ definition of "existing units," there are no unit specific applicable requirements that must be met pursuant to this rule at this time. This facility is classified as a Prevention of Significant Deterioration (PSD) major facility. A summary of important applicable requirements is shown in the following table.

Applicable Requirement	E.U. ID No(s).
Rule 62-296.405(1), F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input	-001, -002 & -003
Acid Rain, Phase II SO_2	-001, -002 & -003
Rule 62-296.470, F.A.C., Clean Air Interstate Rule	-001, -002, -003, -004, -005 & -006
40 CFR 60, Subpart A, New Stationary Source Performance Standards (NSPS) General Provisions	-004, -005 & -006
NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines	-004, -005 & -006
Compliance Assurance Monitoring (CAM)	-004, -005 & -006

Applicable Requirement	E.U. ID No(s).
Rule 62-212.400, F.A.C., Prevention of Significant Deterioration	-004, -005 & -006

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 was 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), 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: paving and maintenance of roads, parking areas and yards; chemical (dust suppressants) or water application to unpaved roads, unpaved yard areas and open stock piles; removal of particulate matter (PM) from roads and other unpaved areas to prevent reentrainment and from buildings or work areas to prevent airborne PM; landscaping or planting of vegetation; use of hoods, fans, filters and similar equipment to contain, capture and/or vent PM; confining abrasive blasting where possible; and, enclosure or covering of conveyor systems. [Rule 62-296.320(4)(c), F.A.C.; proposed by applicant in Title V air operation permit renewal application received on May 20, 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 air operation 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]

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

E.U. ID No.	Brief Description
	Fossil Fuel Fired Steam Generator Units
-001	Fossil Fuel Fired Steam Generator Unit No. 1
-002	Fossil Fuel Fired Steam Generator Unit No. 2
-003	Fossil Fuel Fired Steam Generator Unit No. 3

Fossil fuel fired steam generator Unit No. 1 is a nominal 35.0 megawatt (MW) (electric) steam generator designated as Boiler No. 1. This emissions unit is allowed to fire No. 2 fuel oil, No. 6 fuel oil, "on specification" used oil, natural gas, and a blend of fuel oil and natural gas. The "on-specification" used oil is generally fired as a blended fuel oil with either the No. 2 fuel oil or the No. 6 fuel oil. In addition, propane/liquefied propane (LP) gas is sometimes used as an igniter fuel. The stack parameters are: height, 110 feet; diameter, 7.0 feet; exit temperature, 320 degrees F; and, actual stack gas flow rate, 143,700 acfm. Fossil fuel fired steam generator No. 1 began commercial operation in 1953.

Fossil fuel fired steam generator Unit No. 2 is a nominal 34.0 MW (electric) steam generator designated as Boiler No. 2. This emissions unit is allowed to fire No. 2 fuel oil, No. 6 fuel oil, "on specification" used oil, natural gas, and a blend of fuel oil and natural gas. The "on-specification" used oil is generally fired as a blended fuel oil with either the No. 2 fuel oil or the No. 6 fuel oil. In addition, propane/liquefied propane (LP) gas is sometimes used as an igniter fuel. The stack parameters are: height, 110 feet; diameter, 7.0 feet; exit temperature, 340 degrees F; and, actual stack gas flow rate, 197,000 acfm. Fossil fuel fired steam generator No. 2 began commercial operation in 1954.

Fossil fuel fired steam generator Unit No. 3 is a nominal 84.0 MW (electric) steam generator designated as Boiler No. 3. This emissions unit is allowed to fire No. 2 fuel oil, No. 6 fuel oil, "on specification" used oil, natural gas, and a blend of fuel oil and natural gas. The "on-specification" used oil is generally fired as a blended fuel oil with either the No. 2 fuel oil or the No. 6 fuel oil. In addition, propane/liquefied propane (LP) gas is sometimes used as an igniter fuel. The stack parameters are: height, 135 feet; diameter, 7.7 feet; exit temperature, 300 degrees F; and, actual stack gas flow rate, 305,100 acfm. Fossil fuel fired steam generator No. 3 began commercial operation in 1956.

These emissions units may burn on-specification used oil generated on or off-site. Each boiler/steam generator drives a turbine generator and vents to its own stack. Air pollutant emissions from each boiler are uncontrolled.

{Permitting note(s): These emissions units are regulated under Acid Rain, Phase II; Rule 62-296.405(1), F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input; and, Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR).}

Essential Potential to Emit (PTE) Parameters

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

Unit No.	MMBtu/hr Heat Input	Fuel Type
1	460	Natural Gas
	450	Fuel Oil[2]
	450 - 460[1]	Fuel Oil[2] and Natural Gas
	450	On-specification used oil[6]
2	450	Natural Gas
	444	Fuel Oil[2]
	444 - 450[1]	Fuel Oil[2] and Natural Gas
	444	On-specification used oil[6]

3	880	Natural Gas
	881	Fuel Oil[3]
	880 - 881[1]	Natural Gas and Fuel Oil[3]
	388[4]	Natural Gas
	493[5]	Fuel Oil[2]
	388 - 493[1]	Natural Gas and Fuel Oil[2]
	493 - 881	On-specification used oil[6]

Notes:
[1] When a blend of fuel oil and natural gas is fired, the heat input is prorated based on the percent heat input of each fuel.
[2] Fuel oil sulfur content maximum of 2.5%, by weight.
[3] Fuel oil sulfur content maximum of 1.0%, by weight.
[4] Basis: 44% of 881 MMBtu/hr heat input.
[5] Basis: 56% of 881 MMBtu/hr heat input.
[6] Maximum sulfur content, percent by weight, shall be the same as that allowed for the fuel oil for each boiler. The on-specification used oil burned at this facility may be generated on or off-site.
[Rules 62-4.160(2), 62-210.200 (Definitions - Potential to Emit (PTE)) and 62-296.405(1), F.A.C.; and, Applicant Request.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

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 - Fuels.
a. Startup and Normal. The only fuels allowed to be burned are No. 2 fuel oil, No. 6 fuel oil, "on-specification" used oil, natural gas, and a blend of fuel oil and natural gas.
b. On-specification used oil. The maximum amount of on-specification used oil, whether generated on or off-site, that can be burned facility-wide shall not exceed 10% of the heat input (monthly) or 11,267,000 gallons per year cumulatively. On-specification used oil with a polychlorinated biphenyls (PCB) concentration of 2 to less than 50 parts per million (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.
[Rules 62-4.160(2), 62-210.200, 62-213.410, 62-213.440(1) and 62-4.070(1)&(3), F.A.C.; and, 40 CFR 271.20(e)(3).]

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

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Conditions **A.5. - A.9.** are based on the specified averaging time of the applicable test method.

A.5. Visible Emissions (VE). Visible emissions shall not exceed 20 percent opacity, except for one two-minute period per hour during which opacity shall not exceed 40 percent. Emissions units governed by this visible emissions limit shall compliance test for particulate matter emissions annually and as otherwise required by Chapter 62-297, F.A.C. [Rule 62-296.405(1)(a), F.A.C.]

A.6. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. Visible emissions above 60 percent opacity shall be allowed for not more than four, 6-minute periods, during the 3-hour period of excess emissions allowed by Rule 62-210.700(3), F.A.C., for boiler cleaning and load changes, at emissions units which have installed and are operating, or have committed to install and operate, continuous opacity monitors. 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. [Rule 62-210.700(3), F.A.C.]

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

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

A.9. Sulfur Dioxide (SO_2) Emissions. When burning liquid fuel, sulfur dioxide emissions shall not exceed 2.75 pounds per million Btu heat input, as measured by applicable compliance methods. Any calculations or methods used to demonstrate compliance shall be based on the total heat input from all fossil fuels, including natural gas, and the sulfur from all fuels fired. [Rules 62-213.440(1) and 62-296.405(1)(c)1.j., F.A.C.]

A.10. Sulfur Dioxide - Sulfur Content.

a. Boiler Nos. 1 and 2. The sulfur content of the as fired fuel oil shall not exceed 2.5%, by weight.

b. Boiler No. 3.

(1) When firing only fuel oil, the sulfur content of the as fired fuel oil shall not exceed 1.0%, by weight. However, this fuel oil can be fired in combination with natural gas; or,

(2) When firing fuel oil having a maximum sulfur content of 2.5%, by weight, then only 493 MMBtu/hr heat input (56% of the permitted capacity) can be provided by the fuel oil and 388 MMBtu/hr heat input can be provided by natural gas (44% of the permitted capacity). However, if less heat input is provided by the fuel oil, then the difference in heat input from the permitted capacity can be provided by natural gas.

[Rules 62-213.440(1) and 62-296.405(1)(e)3., F.A.C.; and, Applicant Request.]

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

A.12. Excess Emissions Allowed - Startup And 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.13. Best Operational Practices to Minimize Excess Emissions. The permittee shall follow the best operational practices to minimize excess emissions during startup and shutdown as described in **Appendix**

BOP, Best Operational Practices for Start up and Shutdown. [Rules 62-210.700(2) and 62-213.440(1) (Operational Requirements that Assure Compliance), F.A.C.; and, Proposed by the Applicant in the Renewal Application.]

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. Sulfur Dioxide. The permittee elected to demonstrate compliance by accepting a liquid fuel sulfur limit that will be verified with a by fuel analysis provided by the vendor. This protocol is allowed because the emissions units do not have an operating flue gas desulfurization device. [Rule 62-296.405(1)(f)1.b., F.A.C.; Appendix D of 40 CFR 75; and, Applicant Request.]

Continuous Monitoring Requirements

{Permitting Note: In accordance with the Acid Rain Phase II requirements, the following continuous monitors are installed on these units: opacity, NOx and CO_2.}

A.16. COMS for Periodic Monitoring. The owner or operator is required to install, calibrate, operate and maintain continuous opacity monitoring systems (COMS) pursuant to 40 CFR Part 75. The owner or operator shall maintain and operate the COMS and shall make and maintain records of opacity measured by the COMS, for purposes of periodic monitoring. [Rule 62-213.440(1)(b)1.b. (Periodic Monitoring), F.A.C.; and, Applicant Request.]

Test Methods and Procedures

A.17. Test Methods. Required tests shall be performed in accordance with the following reference method(s):

Method(s)	Description of Method(s) and Comment(s)
EPA Methods 1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
EPA Methods 5, 5B, 5F or 17	Methods for Determining Particulate Matter Emissions
EPA Methods 6, 6A, 6B or 6C (Also see Specific Conditions **A.15.**, **A.24.** and **A.25.**)	Methods for Determining Sulfur Dioxide Emissions
Appendix D, 40 CFR 75 (Also see Specific Conditions **A.15.**, **A.24.** and **A.25.**)	Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units
DEP Method 9	Visual Determination of the Opacity of Emissions

The above methods are described in Chapter 62-297, F.A.C. and/or 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. [Chapter 62-297, F.A.C.]

A.18. Annual Compliance Test. Except as specified in Specific Conditions **A.26.** and **A.27.**, during each federal fiscal year (October 1st to September 30th), Emissions Unit ID Nos. -001, -002 and -003 shall be tested to demonstrate compliance with the emission limitations and standards for VE, VE-SB (VE while soot blowing), PM and particulate matter while soot blowing (PM-SB). [Rule 62-297.310(7), F.A.C.]

A.19. Compliance Test Prior To Renewal. Prior to permit renewal, Emissions Unit ID Nos. -001, -002 and -003 shall be tested to demonstrate compliance with the emission limitations and standards for VE, VE-SB (VE while soot blowing), PM and PM-SB. [Rule 62-297.310(7)(a)3., F.A.C.]

A.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.]

A.21. 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. [Rule 62-296.405(1)(e)1., F.A.C.]

A.22. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

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

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

A.23. Particulate Matter. The test methods for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17. [Rules 62-296.405(1)(e)2. and 62-297.401, F.A.C.]

A.24. 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. **The permittee may use the EPA test methods, referenced above, to demonstrate compliance;**

however, as an alternate sampling procedure authorized by permit, the permittee elected to demonstrate compliance by accepting a liquid fuel sulfur limit that will be verified with a fuel analysis provided by the vendor or the permittee upon each fuel delivery. ***Data substitution techniques shall not be used to determine compliance with the fuel oil sulfur limits.*** [Rules 62-213.440, 62-296.405(1)(e)3. and 62-297.401, F.A.C.]

A.25. Fuel Sampling and Analysis - Sulfur Dioxide/Sulfur Content. For each emissions unit, the following fuel sampling and analysis protocol shall be used as an alternate sampling procedure authorized by permit to demonstrate compliance and for periodic monitoring with the sulfur dioxide standard:

a. Determine and record the as-fired fuel sulfur content, percent by weight, for liquid fuels using either ASTM D 2622-92, ASTM D 4294-90, both ASTM D 4057-88 and ASTM D 129-91, ASTM D 1552-95, or later editions, to analyze a representative sample of the blended fuel following any fuel delivery that exceeds the fuel sulfur content limits, percent by weight; and, no as-fired sampling of the fuel oil is required for sulfur content, percent by weight, if any delivery of fuel oil is equal to or less than the compliant fuel oil sulfur content limits, percent by weight and pursuant to the vendor's bill of lading.

b. The analyses of any fuel oil, as received from the vendor or as-fired, shall include the following:
   (1) Density (ASTM D 1298-80 or later editions).
   (2) Calorific heat value in Btu per pound (ASTM D 240-76 or later editions).

Alternatively, fuel oil sulfur content may be evaluated using the methods specified in Section 2.2.5 of Appendix D to 40 CFR 75, "Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units," as amended. In addition, any ASTM method (or later editions) referenced in Rule 62-297.440(1) F.A.C. is acceptable.

[Rules 62-213.440(1), 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440(1), F.A.C.; and, Applicant Request.]

A.26. PM Testing Not Required. Annual and permit renewal compliance testing for particulate matter emissions is not required for this emissions unit while burning:

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

See Specific Condition **TR7.** [Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

A.27. VE Testing Not Required. By this permit, annual emissions compliance testing for visible emissions is not required for this emissions unit while burning:

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

See Specific Condition **TR7.** [Rule 62-297.310(7)(a)4., F.A.C.]

Recordkeeping and Reporting Requirements

A.28. Reporting Schedule. The following report shall be submitted to the Compliance Authority:

Report	Reporting Deadline(s)	Related Condition(s)
Quarterly Excess Emissions {Rule 62-296.405(1)(g), F.A.C.}	Every 3 months (quarterly)	**A.29.**

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

A.29. Quarterly Excess Emissions Report. Submit to the Department's District Office 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.30. Records. The owner or operator shall maintain records of the fuel oil heating value, density or specific gravity, and the percent sulfur content. Fuel sulfur content, percent by weight, for liquid fuels shall be determined by either ASTM D2622-94, ASTM D4294-90 (95), ASTM D1552-95, ASTM D1266-91, or both ASTM D4057-88, and ASTM D129-95 (or later editions) to analyze a representative sample of the fuel oil. [Rules 62-213.440(1), 62-296.405(1)(e)3, 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.; and, Applicant Request.]

A.31. Records. Create and maintain for each emissions unit hourly records of the amount of each fuel fired, and the ratio of fuel oil to natural gas if co-fired. [Rules 62-213.440(1), 62-296.405(1)(e)3, 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.; and, Applicant Request.]

A.32. Other Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements. [Rule 62-213.440, F.A.C.]

Other Requirements

A.33. On-Specification Used Oil. Burning of on-specification used oil is allowed in these emissions units in accordance with all other conditions of this permit and the following conditions:

a. *On-Specification Used Oil Emissions Limitations.* These emissions units are permitted to burn on-specification used oil, which contains a Polychlorinated Biphenyl (PCB) concentration of less than 50 parts per million (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.* By this permit, these emissions units are permitted to burn on-specification used oil that is generated on or off-site, not to exceed 10 percent of the heat input (monthly) or 11,267,000 gallons per year (268,262 barrels) during any calendar year.

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:

(1) 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)]

(2) 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.
   (a) 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.
   (b) 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.
   (c) 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).

f. *Recordkeeping 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.
   (2) Results of the analyses of each deposit of used oil, as required by the above conditions.
   (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.
   (4) The source and quantity of each batch of used oil received each month, including the name, address and EPA identification number (if applicable) of all marketers that delivered used oil to the facility, and the quantity delivered.
   (5) Records of the operating rate of each emissions unit while burning used oil and the dates and time periods each emissions unit burns used oil.
   [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 (AOR) 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. The quantity of used oil burned by each emissions unit shall be individually reported and shall not be combined with other fuels.
   [Rules 62-4.070(1)&(3) and 62-213.440(1), F.A.C., 40 CFR 279 and 40 CFR 761, unless otherwise noted.]

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

E.U. ID No.	Brief Description
	Combustion Turbine Peaking Units (Simple Cycle units)
-004	Combustion Turbine Peaking (CTP) Unit No. 1 (P-1)
-005	Combustion Turbine Peaking (CTP) Unit No. 2 (P-2)
-006	Combustion Turbine Peaking (CTP) Unit No. 3 (P-3)

All three combustion turbines (CT) are identical in configuration. The three combustion turbines are Turbo Power and Marine Systems, Model FT4C-3 LF water injected TwinPac units. Nitrogen oxide emissions are controlled by using water injection for both fuel oil and natural gas firing. Natural gas and new No. 2 distillate fuel oil are allowed to be fired in these emissions units; however, P-2 does not fire natural gas because it has not yet been connected to do so; and, the maximum allowable fuel oil sulfur content is 0.5%, by weight. Each emissions unit has a maximum generating output of 63,000 kW (63 megawatt (MW)). The stack parameters are identical for all three units: height, 22 feet; diameter, 11.3 feet; exit temperature, 830 degrees F; and, actual stack gas flow rate, 1,255,500 acfm. Temperature and exhaust flow rate will vary with CT load, fuel type and ambient conditions. Unit Nos. 1 and 2 (P-1 and P-2) commenced commercial operation in October, 1980. Unit No. 3 (P-3) commenced commercial operation in November, 1980.

{Permitting note(s): These emissions units are regulated under NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800(8)(b), F.A.C.; Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) [PSD-FL-014, as amended]; Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination dated August 16, 1978; 40 CFR 64, Compliance Assurance Monitoring (CAM); and, Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR).}

Essential Potential to Emit (PTE) Parameters

B.1. Hours of Operation. These emissions units may operate 1500 hours/year/CT. [Rule 62-210.200 (Definitions - Potential to Emit (PTE), F.A.C.; and, AC61-11862, -11863 & -11864; and, PSD-FL-014, Condition 6.]

B.2. Permitted Capacity. The maximum heat input to each Combustion Turbine (CT) shall not exceed 739 MMBtu/hr at the lower heating value (LHV) at 59 degrees F while firing new No. 2 distillate fuel oil or natural gas. Manufacturer's curves approved by the Department for the heat input correction to other temperatures may be utilized to establish heat input rates over a range of temperatures for compliance determination. [Rules 62-4.160(2), 62-210.200 (Definitions - PTE); 40 CFR 60.332(b); and, PSD-FL-014.]

B.3. Methods of Operation - Fuels.
a. Only natural gas or new No. 2 distillate fuel oil shall be fired in the CTs. The burning of other fuels requires review, public notice, and approval through the preconstruction process (Chapters 62-4, 62-210 and 62-212, F.A.C.). Initial compliance has not yet been demonstrated for firing natural gas in CTP Unit No. 2 (P-2); as such the permittee must comply with the attached compliance plan in **Appendix CP-1, Compliance Plan**.
b. The maximum new No. 2 distillate fuel oil that can be fired is 37,910 lbs/hr (127 barrels at 59 degrees F). [Rules 62-4.160(2), 62-210.200 (Definitions - PTE), 62-213.410, 62-213.440(1) & 213.440(2), F.A.C.; AC61-11862, -11863 & -11864; BACT Determination dated August 16, 1978; and, PSD-FL-014.]

Air Pollution Control Technologies and Measures

B.4. Water Injection - Nitrogen Oxides Control. Nitrogen oxides from the CTs shall be controlled by water injection for both fuel oil and natural gas firing. [Rules 62-4.070(1) & (3), and 62-210.650, F.A.C.; PSD-FL-014; and, BACT Determination dated August 16, 1978.]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Conditions **B.5.** - **B.7.** and **B.9.** are based on the specified averaging time of the applicable test method.

B.5. Nitrogen Oxides (NOx) - While burning new No. 2 Distillate Fuel Oil. Nitrogen oxides emissions, expressed as NOx, shall not exceed 75 ppm by volume at 15 percent oxygen and on a dry basis, adjusted per 40 CFR 60.332(a), while burning new No. 2 distillate fuel oil. [40 CFR 60.332(a); PSD-FL-014; and, BACT Determination dated August 16, 1978.]

B.6. Nitrogen Oxides - While burning Natural Gas. Nitrogen oxides emissions, expressed as NOx, shall not exceed 68 ppm by volume at 15 percent oxygen and on a dry basis, while burning natural gas. [PSD-FL-014.]

B.7. Sulfur Dioxide (SO_2). The owner or operator shall not cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.0095 percent by volume at 15 percent oxygen on a dry basis. {The equivalent maximum allowed sulfur dioxide emission rate shall not exceed 379 lbs/hr/CT.} [PSD-FL-014.]

B.8. Sulfur Dioxide - Sulfur Content. The sulfur content of any fuel fired in any stationary gas turbine shall not exceed 0.5 percent, by weight, and may be used to determine compliance with the SO_2 limit. [PSD-FL-014.]

B.9. Visible Emissions (VE). Visible emissions shall be less than 20 percent opacity. [PSD-FL-014; BACT Determination dated August 16, 1978; and, AC61-11862, -11863 & -11864.]

Excess Emissions

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

B.10. Excess Emissions Allowed - Startup, Shutdown or Malfunction. Excess emissions resulting from startup, shutdown or malfunction shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

B.11. Best Operational Practices to Minimize Excess Emissions. The permittee shall follow the best operational practices to minimize excess emissions during startup and shutdown as described in **Appendix BOP, Best Operational Practices for Start up and Shutdown**. [Rules 62-210.700(2) and 62-213.440(1) (Operational Requirements that Assure Compliance), F.A.C.; and, Proposed by the Applicant in the Renewal Application.]

B.12. 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.13. Monitoring of Fuel being Fired. The owner or operator of any stationary gas turbine subject to the provisions of 40 CFR 60, Subpart GG, shall monitor and record on a weekly basis the sulfur content, nitrogen content, and lower heating value of the fuel being fired in the turbine. [40 CFR 60.334(b); and, PSD-FL-014(A).]

B.14. Monitoring of Fuel being Fired. The permittee shall monitor sulfur content and nitrogen content of the new No. 2 distillate fuel oil and sulfur content of natural gas. These values may be provided by the vendor and the frequency of determinations of these values shall be as follows:

a. New No. 2 Distillate Fuel Oil. The values, sulfur and nitrogen content, shall be determined on each occasion that fuel is transferred to the storage tanks from any other source. Records of these values shall be kept by the facility for a five year period for regulatory agency inspection purposes.
b. Natural Gas. Pursuant to 40 CFR 60.334(b)(2), a custom fuel monitoring schedule for the determination of these values shall be followed for the natural gas fired at this facility and shall be as follows:

Custom Fuel Monitoring Schedule for Natural Gas (NG)

1. Monitoring of fuel nitrogen content shall not be required if NG is the only fuel being fired in the gas turbines.
2. Sulfur Monitoring:
(a). Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternative method. The reference methods are ASTM D1072-80, ASTM D3031-81, ASTM D3246-81, and ASTM D4084-82, or later editions, as referenced in 40 CFR 60.335(b)(2). In addition, any ASTM method (or later editions) referenced in Rule 62-297.440(1) F.A.C. is acceptable.
(b). This custom fuel monitoring schedule shall become effective on the date this permit becomes valid. Effective the date of this custom schedule, sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333 and the conditions of this permit, then sulfur monitoring shall be conducted once per quarter for six quarters. If monitoring data is provided by the applicant which demonstrates consistent compliance with the requirements herein the applicant may begin monitoring as per the requirements of 2(c).
(c). If after the monitoring required in item 2(b) above, or herein, the sulfur content of the fuel shows little variability and, calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333 and the conditions of this permit, sample analysis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.
(d). Should any sulfur analysis as required in items 2(b) or 2(c) above indicate non-compliance with 40 CFR 60.333 and the conditions of this permit, the owner or operator shall notify the Department of such excess emissions and the custom schedule shall be re-examined by the Environmental Protection Agency. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.
3. If there is a change in fuel supply, the owner or operator must notify the Department of such change for re-examination of this custom schedule. A substantial change in fuel quality shall be considered as a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.
4. Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of five years, and be available for inspection by personnel of federal, state, and local air pollution control agencies.
[40 CFR 60.334(b); Custom Fuel Monitoring Schedule clerked on 03/22/1999; and, Rules 62-213.440 and 62-297.440, F.A.C.]

Monitoring Requirements

B.15. CAM Plan. These emissions units are subject to the Compliance Assurance Monitoring (CAM) requirements contained in the attached Appendix CAM for the controlled emissions of NOx. 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.]

Test Methods and Procedures

B.16. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
EPA Methods 1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
EPA Methods 6, 6A, 6B or 6C (Also see Specific Conditions **B.8.** and **B.21.**)	Methods for Determining SO_2 Emissions
Appendix D, 40 CFR 75 (Also see Specific Conditions **B.8.** and **B.21.**)	Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units
EPA Method 7, 7A, 7C, 7D or 7E	Determination of NOx Emissions
EPA Method 9	Visual Determination of the Opacity of Emissions (VE)
EPA Method 20	Determination of NOx, SO_2 and Diluent Emissions from Stationary Gas Turbines

The above methods are described in Chapter 62-297, F.A.C. and/or 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. [Chapter 62-297, F.A.C.]

B.17. Annual Compliance Test. Except as specified in Specific Conditions **B.23.** and **B.24.**, during each federal fiscal year (October 1st to September 30th), Emissions Unit ID Nos. -004, -005 and -006 shall be tested to demonstrate compliance with the emission limitations and standards for VE and NOx. [Rule 62-297.310(7), F.A.C.]

B.18. Compliance Test Prior To Renewal. Prior to permit renewal, Emissions Unit ID Nos. -004, -005 and -006 shall be tested to demonstrate compliance with the emission limitations and standards for VE and NOx. [Rule 62-297.310(7)(a)3., F.A.C.]

B.19. 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.20. Testing. The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with the permitted NOx standard at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer. Testing at the four load points and correction to ISO is an initial compliance test requirement only and not an annual compliance test requirement; however, when testing shows that NOx emissions exceed the standard when operating at capacity, the permittee shall recalibrate the NOx emission control system using the emission testing at four loads as required in 40 CFR 60.335(b)(2). [40 CFR 60.335(b)(2); and, Applicant Request (originally requested in a letter received on 11/12/1997).]

B.21. Sulfur Dioxide - Sulfur Content. The owner or operator shall determine compliance with the sulfur content standard of 0.5 percent, by weight, as follows: ASTM D 2880-96, or later editions, shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-90(94)E-1, ASTM D 3031-81(86), ASTM D 4084-94, ASTM D 3246-92, ASTM D 1552-95, or later editions, shall be used for the sulfur content of gaseous fuels (incorporated by reference-see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator. Alternatively, fuel oil sulfur content may be evaluated using the methods specified in Section 2.2.5 (for fuel oil) and in Section 2.3.3.1.2 (for natural gas) of Appendix D to 40 CFR 75, as amended. In addition, any ASTM method (or later editions) referenced in Rule 62-297.440(1) F.A.C. is acceptable. Sulfur content monitoring is not required for gaseous fuels that meet the 40 CFR 60.331(u) definition of "natural gas" in accordance with the procedures specified in 40 CFR 60.334(h)(3). [40 CFR 60.335(d); Rules 62-213.440 and 62-297.440, F.A.C.; and, Applicant Request.]

B.22. Operating Rate During Testing. Testing of emissions shall be conducted with each emissions unit operation at capacity. Capacity is defined as 95 to 100 percent of the manufacturer's rated heat input achievable for the average ambient (or conditioned) air temperature during the test. If it is impracticable to test at capacity, then an emissions unit may be tested at less than capacity. In such cases, the entire heat input vs. inlet temperature curve will be adjusted by the increment equal to the difference between the design heat input value and 105 percent of the value reached during the test. Data, curves, and calculations necessary to demonstrate the heat input rate correction at both design and test conditions shall be submitted to the Department with the compliance test report. [Rule 62-297.310(2), F.A.C.; and, Applicant Request (originally requested in a letter received on 11/12/1997).]

B.23. VE Testing Not Required. By this permit, annual emissions compliance testing for visible emissions is not required for this emissions unit while burning:

a. only gaseous fuel(s); or

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

See Specific Condition **TR7.** [Rule 62-297.310(7)(a)4., F.A.C.]

B.24. VE Testing. The owner shall conduct VE compliance tests while firing fuel oil for each combustion turbine upon that combustion turbine exceeding 400 hours of operation on fuel oil in any given federal fiscal year (October 1 through September 30). Regardless of the number of hours of operation on fuel oil, at least one VE compliance test shall be conducted on all three combustion turbines every five (5) years, coinciding with the term of the operation permit for these combustion turbines. [Rule 62-297.310(7)(a)4., F.A.C.]

Recordkeeping and Reporting Requirements

B.25. Reporting Schedule. The following report shall be submitted to the Compliance Authority:

Report	Reporting Deadline(s)	Related Condition(s)
NSPS Excess Emissions and Monitoring System Performance	Every 6 months (semi-annual), except when more frequent reporting is specifically required	**B.28.**

[40 CFR 60, Subpart A.]

B.26. Plant Log. A log shall be kept at the plant, showing the hours of operation and the amount of fuel used. The log shall be made available for inspection at the plant at any time. [PSD-FL-014, Condition 6.]

B.27. Other Reporting Requirements. See Appendix RR, Facility-Wide Reporting Requirements, for additional reporting requirements. [Rule 62-213.440, F.A.C.]

NSPS 40 CFR 60 Requirements

B.28. NSPS Requirements - Subpart A. This emissions unit shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions, including:

40 CFR 60.7, Notification and Recordkeeping
40 CFR 60.8, Performance Tests
40 CFR 60.11, Compliance with Standards and Maintenance Requirements
40 CFR 60.12, Circumvention
40 CFR 60.13, Monitoring Requirements
40 CFR 60.19, General Notification and Reporting Requirements,

which have been adopted by reference in Rule 62-204.800(8)(d), F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 60.4, 40 CFR 60.8(b)(2) and (3), 40 CFR 60.11(e)(7) and (8), 40 CFR 60.13(g), (i) and (j)(2), and 40 CFR 60.16. This emissions unit shall comply with **Appendix 40 CFR 60 Subpart A** included with this permit. [Rule 62-204.800(8)(d), F.A.C.]

B.29. NSPS Requirements - Subpart GG. Except as otherwise provided in this permit, the combustion turbine shall comply with all applicable provisions of 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(8)(b), F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 60.334(b)(2) and 40 CFR 60.335(f)(1). The Subpart GG requirement to correct test data to ISO conditions applies, but such correction is not required to demonstrate compliance with the non-NSPS permit standard(s). This emissions unit shall comply with **Appendix 40 CFR 60 Subpart GG** attached to this permit. [Rule 62-204.800(8)(b)39., F.A.C.]

Federal Acid Rain Provisions

Operated by: Florida Power Corporation dba Progress Energy Florida, Inc. (PEF)
ORIS Code: 0638

Subsection A. This Subsection addresses Acid Rain, Phase II SO_2.

The emissions units listed below are regulated under Phase II SO_2 of the federal Acid Rain Program.

E.U. ID No.	EPA Unit ID#	Brief Description
-001	1	Fossil Fuel Fired Steam Generator Unit No. 1
-002	2	Fossil Fuel Fired Steam Generator Unit No. 2
-003	3	Fossil Fuel Fired Steam Generator Unit No. 3

A.1. The Phase II SO_2 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(s) listed below:

a. DEP Form No. 62-210.900(1)(a) - Form, Effective: 3/16/08, received on August 25, 2009, and signed by the Designated Representative on August 21, 2009, which is included at the end of this subsection.

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

A.2. 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.3. Comments, notes, and justifications: None.

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
Suwannee River Plant	FL	638

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
1		Yes		
2		Yes		
3		Yes		

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

Suwannee River 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,

Suwannee River 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

Suswannee River 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 Brenda E. Brickhouse	Title Director, Environmental, Health & Safety Section, Progress Energy, Inc.
Owner Company Name Florida Power Corporation dba Progress Energy Florida, Inc.	
Phone (727) 820-5153	E-mail address Brenda.Brickhouse@pgnmail.com
Signature [signature]	Date 8/21/09

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

4

Clean Air Interstate Rule (CAIR).

Operated by: Florida Power Corporation dba Progress Energy Florida, Inc. (PEF)
ORIS Code: 0638

<u>Subsection A. This Subsection addresses CAIR.</u>

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

E.U. ID No.	EPA Unit ID#	Brief Description
-001	1	Fossil Fuel Fired Steam Generator Unit No. 1
-002	2	Fossil Fuel Fired Steam Generator Unit No. 2
-003	3	Fossil Fuel Fired Steam Generator Unit No. 3
-004	1A & 1B	Combustion Turbine Peaking Unit No. 1
-005	2A & 2B	Combustion Turbine Peaking Unit No. 2
-006	3A & 3B	Combustion Turbine Peaking Unit No. 3

1. 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) - Form, Effective: 3/16/08), which is attached at the end of this subsection. [Chapter 62-213, F.A.C. and Rule 62-210.200, F.A.C.]

2. Comments, notes, and justifications: None.

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: SUWANNEE RIVER PLANT	State: Florida	ORIS or EIA Plant Code: 638

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
1	X	X	X		
2	X	X	X		
3	X	X	X		
1A	X	X	X		
1B	X	X	X		
2A	X	X	X		
2B	X	X	X		
3A	X	X	X		
3B	X	X	X		

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

1

SUWANNEE RIVER PLANT
Plant Name (from STEP 1)

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.

SUWANNEE RIVER PLANT
Plant Name (from STEP 1)

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.

SUWANNEE RIVER PLANT
Plant Name (from STEP 1)

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_x 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.

SUWANNEE RIVER PLANT
Plant Name (from STEP 1)

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: Patricia Q. West	Title: Manager, Environmental Services, Energy Supply Florida
Company Owner Name FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC.	
Phone: 727.820.5739	E-mail Address: Patricia.West@pgnmail.com
Signature Patricia Q. West	Date 5/1/09

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

SECTION VI. APPENDICES.

The Following Appendices Are Enforceable Parts of This Permit:

Appendix A, Glossary.
Appendix ASP, ASP Number 97-B-01 (With Scrivener's Order Dated July 2, 1997).
Appendix BOP, Best Operational Practices for Start up and Shutdown.
Appendix CAM, Compliance Assurance Monitoring Plan.
Appendix CP-1, Compliance Plan.
Appendix 40 CFR 60, Subpart A, General Provisions.
Appendix 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines.
Appendix I, List of Insignificant Emissions Units and/or Activities.
Appendix RR, Facility-wide Reporting Requirements.
Appendix TR, Facility-wide Testing Requirements.
Appendix TV, Title V General Conditions.

APPENDIX A

ABBREVIATIONS, ACRONYMS, CITATIONS AND IDENTIFICATION NUMBERS

Abbreviations and Acronyms:

° F: degrees Fahrenheit

acfm: actual cubic feet per minute

AOR: Annual Operating Report

ARMS: Air Resource Management System (Department's database)

BACT: best available control technology

Btu: British thermal units

CAM: compliance assurance monitoring

CEMS: continuous emissions monitoring system

cfm: cubic feet per minute

CFR: Code of Federal Regulations

CO: carbon monoxide

COMS: continuous opacity monitoring system

DARM: Division of Air Resources Management

DCA: Department of Community Affairs

DEP: Department of Environmental Protection

Department: Department of Environmental Protection

dscfm: dry standard cubic feet per minute

EPA: Environmental Protection Agency

ESP: electrostatic precipitator (control system for reducing particulate matter)

EU: emissions unit

F.A.C.: Florida Administrative Code

F.D.: forced draft

F.S.: Florida Statutes

FGR: flue gas recirculation

Fl: fluoride

ft²: square feet

ft³: cubic feet

gpm: gallons per minute

gr: grains

HAP: hazardous air pollutant

Hg: mercury

I.D.: induced draft

ID: identification

ISO: International Standards Organization (refers to those conditions at 288 Kelvin, 60% relative humidity and 101.3 kilopascals pressure.)

kPa: kilopascals

LAT: Latitude

lb: pound

lbs/hr: pounds per hour

LONG: Longitude

MACT: maximum achievable technology

mm: millimeter

MMBtu: million British thermal units

MSDS: material safety data sheets

MW: megawatt

NESHAP: National Emissions Standards for Hazardous Air Pollutants

NO_X: nitrogen oxides

NSPS: New Source Performance Standards

O&M: operation and maintenance

O_2: oxygen

ORIS: Office of Regulatory Information Systems

OS: Organic Solvent

Pb: lead

PM: particulate matter

PM_{10}: particulate matter with a mean aerodynamic diameter of 10 microns or less

PSD: prevention of significant deterioration

psi: pounds per square inch

PTE: potential to emit

RACT: reasonably available control technology

RATA: relative accuracy test audit

RMP: Risk Management Plan

RO: Responsible Official

SAM: sulfuric acid mist

scf: standard cubic feet

scfm: standard cubic feet per minute

SIC: standard industrial classification code

SNCR: selective non-catalytic reduction (control system used for reducing emissions of nitrogen oxides)

SOA: Specific Operating Agreement

SO_2: sulfur dioxide

TPH: tons per hour

TPY: tons per year

UTM: Universal Transverse Mercator coordinate system

VE: visible emissions

VOC: volatile organic compounds

x: By or times

Citations:

The following examples illustrate the methods used in this permit to abbreviate and cite the references of rules, regulations, guidance memorandums, permit numbers and ID numbers.

Code of Federal Regulations:

Example: **[40 CFR 60.334]**

Where:			
	40	refers to	Title 40
	CFR	refers to	Code of Federal Regulations
	60	refers to	Part 60
	60.334	refers to	Regulation 60.334

Florida Administrative Code (F.A.C.) Rules:

Example: **[Rule 62-213.205, F.A.C.]**

Where:			
	62	refers to	Title 62
	62-213	refers to	Chapter 62-213
	62-213.205	refers to	Rule 62-213.205, F.A.C.

Identification Numbers:

Facility Identification (ID) Number:

Example: Facility ID No.: 1050221

Where:

105 = 3-digit number code identifying the facility is located in Polk County
0221 = 4-digit number assigned by state database.

Permit Numbers:

Example: 1050221-002-AV, or
1050221-001-AC

Where:

AC =	Air Construction Permit
AV =	Air Operation Permit (Title V Source)
105 =	3-digit number code identifying the facility is located in Polk County
0221=	4-digit number assigned by permit tracking database
001 or 002=	3-digit sequential project number assigned by permit tracking database

Example: PSD-FL-185
PA95-01
AC53-208321

Where:

PSD =	Prevention of Significant Deterioration Permit
PA =	Power Plant Siting Act Permit
AC53 =	old Air Construction Permit numbering identifying the facility is located in Polk County

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

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

ORDER ON REQUEST
FOR
ALTERNATE PROCEDURES AND REQUIREMENTS

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

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

FINDINGS OF FACT

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

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

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

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

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

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

6. Rule 297.310(7)(a)3., F.A.C., states, "The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision.

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

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

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

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

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

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

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

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

CONCLUSIONS OF LAW

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

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

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

ORDER

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

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

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

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

4. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of particulate matter emission compliance test results for any fossil fuel steam generator emissions unit that burned liquid and/or solid fuel for a total of no more than 400 hours during the year prior to renewal.

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

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

PETITION FOR ADMINISTRATIVE REVIEW

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

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

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the Florida Statutes, or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-5.207 of the Florida Administrative Code.

A petition must contain the following information:

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

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

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

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

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

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

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

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

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

A request for mediation must contain the following information:

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

(b) A statement of the preliminary agency action;

(c) A statement of the relief sought; and

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

The agreement to mediate must include the following:

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

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

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

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

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

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

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

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

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

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

The petition must specify the following information:

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

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

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

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

(e) The type of action requested;

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

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

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

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

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

RIGHT TO APPEAL

Any party to this Order has the right to seek judicial review of the Order pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000; and, by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date the Notice of Agency Action is filed with the Clerk of the Department.

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

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Howard L Rhodes

HOWARD L. RHODES, Director
Division of Air Resources Management
Twin Towers Office Building
2600 Blair Stone Road
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(904) 488-0114

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CERTIFICATE OF SERVICE

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

Clerk Stamp

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

Martha Wise 3-18-97
Clerk Date

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

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

ORDER CORRECTING SCRIVENER'S ERROR

The Order which authorizes owners of natural gas fired fossil fuel steam generators to forgo particulate matter compliance testing on an annual basis and prior to renewal of an operation permit entered on the 17th day of March, 1997, is hereby corrected on page 4, paragraph number 4, by deleting the words "pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C.":

4. In renewing an air operation permit ~~pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C.,~~ the Department shall not require submission of particulate matter emission compliance test results for any fossil fuel steam generator emissions unit that burned liquid and/or solid fuel for a total of no more than 400 hours during the year prior to renewal.

DONE AND ORDERED this 2 day of July, 1997 in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Howard L. Rhodes

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

ASP NUMBER 97-B-01

The above two documents comprise Appendix ASP, ASP Number 97-B-01 (With Scrivener's Order Dated July 2, 1997).

SUWANNEE RIVER PLANT
PROCEDURES FOR STARTUP AND SHUTDOWN

A. Boilers Nos. 1 - 3

Boiler startup is accomplished by starting an air flow purge and establishing a No. 2 fuel oil fire. After a 300°F temperature is attained, a No. 6 fuel oil fire is established. When the normal throttle pressure set point is reached, the turbine is pre-warmed and then put into service. If high opacity is encountered, the air flow is lowered and fuel oil guns inspected. During the boiler ramp-up, No. 6 fuel oil or natural gas may be used depending on Energy Controls needs.

When shutting down, fuel flow is decreased as the load is lowered. The turbine eventually trips which opens the generator breakers. When the turbine coasts to zero revolutions per minute (rpm), it is put on turning gear.

B. Peaking Combustion Turbine Units P1 – P3

Peaker startup is accomplished by spark lighting of either natural gas or No. 2 distillate fuel oil. NO_x emissions are controlled in the auto or manual mode by injecting demineralized water into the fuel. If the CT control system shows no injection water flow for 30 minutes, the peaker will shut itself down in either mode.

Shutdown is accomplished by lowering the CT load to 0 MW and opening the generators on reverse power

CAM REQUIREMENTS

(version dated 06/09/2005)

Pursuant to Rule 62-213.440(1)(b)1.a., F.A.C., the CAM plans that are included in this appendix contain the monitoring requirements necessary to satisfy 40 CFR 64. Conditions 1. - 17. are generic conditions applicable to all emissions units that are subject to the CAM requirements. Specific requirements related to each emissions unit are contained in the attached tables, as submitted by the applicant and approved by the Department.

40 CFR 64.6 Approval of Monitoring.

1. The attached CAM plan(s), as submitted by the applicant, is/are approved for the purposes of satisfying the requirements of 40 CFR 64.3. [40 CFR 64.6(a)]

2. The attached CAM plan(s) include the following information:
   a. The indicator(s) to be monitored (such as temperature, pressure drop, emissions, or similar parameter);
   b. The means or device to be used to measure the indicator(s) (such as temperature measurement device, visual observation, or CEMS); and
   c. The performance requirements established to satisfy 40 CFR 64.3(b) or (d), as applicable.
   [40 CFR 64.6(c)(1)]

3. The attached CAM plan(s) describe the means by which the owner or operator will define an exceedance of the permitted limits or an excursion from the stated indicator ranges and averaging periods for purposes of responding to (see **CAM Conditions 5. - 14.)** and reporting exceedances or excursions (see **CAM Conditions 15. - 16.**). [40 CFR 64.6(c)(2)]

4. The permittee is required to conduct the monitoring specified in the attached CAM plan(s) and shall fulfill the obligations specified in the conditions below (see **CAM Conditions 5. - 16.**). [40 CFR 64.6(c)(3)]

40 CFR 64.7 Operation of Approved Monitoring.

5. Commencement of Operation. The owner or operator shall conduct the monitoring required under this appendix upon the effective date of this Title V permit. [40 CFR 64.7(a)]

6. Proper Maintenance. At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment. [40 CFR 64.7(b)]

7. Continued Operation. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. [40 CFR 64.7(c)]

8. Response to Excursions or Exceedances.
   a. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions, if allowed by this permit). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

b. Determination of whether the owner or operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

[40 CFR 64.7(d)(1) & (2)]

9. Documentation of Need For Improved Monitoring. If the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the permitting authority and, if necessary, submit a proposed modification to the Title V permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. [40 CFR 64.7(e)]

40 CFR 64.8 Quality Improvement Plan (QIP) Requirements.

10. Based on the results of a determination made under **CAM Condition 8.b.**, above, the permitting authority may require the owner or operator to develop and implement a QIP. Consistent with **CAM Condition 4.**, an accumulation of exceedances or excursions exceeding 5 percent duration of a pollutant-specific emissions unit's operating time for a reporting period, may require the implementation of a QIP. The threshold may be set at a higher or lower percent or may rely on other criteria for purposes of indicating whether a pollutant-specific emissions unit is being maintained and operated in a manner consistent with good air pollution control practices. [40 CFR 64.8(a)]

11. Elements of a QIP.

a. The owner or operator shall maintain a written QIP, if required, and have it available for inspection.
b. The plan initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:
   (1) Improved preventive maintenance practices.
   (2) Process operation changes.
   (3) Appropriate improvements to control methods.
   (4) Other steps appropriate to correct control performance.
   (5) More frequent or improved monitoring (only in conjunction with one or more steps under **CAM Condition 11.b(i)** through **(iv)**, above).

[40 CFR 64.8(b)]

12. If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the permitting authority if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined. [40 CFR 64.8(c)]

13. Following implementation of a QIP, upon any subsequent determination pursuant to **CAM Condition 8.b.**, the permitting authority may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

a. Failed to address the cause of the control device performance problems; or
b. Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

[40 CFR 64.8(d)]

14. Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act. [40 CFR 64.8(e)]

40 CFR 64.9 Reporting And Recordkeeping Requirements.

15. General Reporting Requirements.
   a. Commencing from the effective date of this permit, the owner or operator shall submit monitoring reports semi-annually to the permitting authority in accordance with Rule 62-213.440(1)(b)3.a., F.A.C.
   b. A report for monitoring under this part shall include, at a minimum, the information required under Rule 62-213.440(1)(b)3.a., F.A.C., and the following information, as applicable:
      (1) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;
      (2) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and
      (3) A description of the actions taken to implement a QIP during the reporting period as specified in **CAM Conditions 10.** through **14.** Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

   [40 CFR 64.9(a)]

16. General Recordkeeping Requirements.
   a. The owner or operator shall comply with the recordkeeping requirements specified in Rule 62-213.440(1)(b)2., F.A.C. The owner or operator shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to **CAM Conditions 10.** through **14.** and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this part (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).
   b. Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements.

   [40 CFR 64.9(b)]

40 CFR 64.10 Savings Provisions.

17. It should be noted that nothing in this appendix shall:
   a. Excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act. The requirements of this appendix shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purpose of determining the monitoring to be imposed under separate authority under the Act, including monitoring in permits issued pursuant to Title I of the Act. The purpose of this part is to require, as part of the issuance of a permit under Title V of the Act, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of this part.
   b. Restrict or abrogate the authority of the Administrator or the permitting authority to impose additional or more stringent monitoring, recordkeeping, testing, or reporting requirements on any owner or operator of a source under any provision of the Act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable.
   c. Restrict or abrogate the authority of the Administrator or permitting authority to take any enforcement action under the Act for any violation of an applicable requirement or of any person to take action under section 304 of the Act.

   [40 CFR 64.10]

CAM PLAN

(version dated 10/19/2009)

The following emissions units are subject to the CAM provisions only for the pollutant(s) indicated:

E.U. ID No.	**Brief Description**	Pollutant(s) subject to CAM
	Combustion Turbine Peaking Units (Simple Cycle units)	
-004	Combustion Turbine Peaking (CTP) Unit No. 1 (P-1)	NOx
-005	Combustion Turbine Peaking (CTP) Unit No. 2 (P-2)	NOx
-006	Combustion Turbine Peaking (CTP) Unit No. 3 (P-3)	NOx

For ease of reference the following definitions are cited from 40 CFR 64.1 Definitions (10/03/1997):

> Exceedance *shall mean a condition that is detected by monitoring that provides data in terms of an emission limitation or standard and that indicates that emissions (or opacity) are greater than the applicable emission limitation or standard (or less than the applicable standard in the case of a percent reduction requirement) consistent with any averaging period specified for averaging the results of the monitoring.*
>
> Excursion *shall mean a departure from an indicator range established for monitoring under this part, consistent with any averaging period specified for averaging the results of the monitoring.*

CAM PLAN

(version dated 10/19/2009)

E.U. ID No.	Brief Description
	Combustion Turbine Peaking Units (Simple Cycle units)
-004	Combustion Turbine Peaking (CTP) Unit No. 1 (P-1)
-005	Combustion Turbine Peaking (CTP) Unit No. 2 (P-2)
-006	Combustion Turbine Peaking (CTP) Unit No. 3 (P-3)

No. 2 fuel oil and natural gas fired combustion turbines
NOx emissions from each combustion turbine are controlled individually by water injection

Table 1. Monitoring Approach

		Indicator
I.	Indicator	Water-to-fuel ratio
	Measurement Approach	Continuous monitoring system measuring water injection rate, fuel consumption, and water-to-fuel ratio.
II.	Indicator Range	(see below)
III.	Performance Criteria	
	A. Data Representativeness	The system meets the specifications of 40 CFR 60, Subpart GG.
	B. Verification of Operational Status	Not applicable, the use of existing monitoring equipment is proposed.

II. Indicator Range:

Fuel	target ratio values* (minimum water-to-fuel ratio)
Fuel Oil	0.570
Natural Gas	0.370

An excursion is defined as any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the target ratio values (excluding startup, shutdown and malfunction) for each of the CTs. Note, CT2A and CT2B do not currently fire natural gas.

These water-to-fuel ratios have been determined to provide reasonable assurance of compliance with the limits contained in NSPS, 40 CFR 60, Subpart GG, and the Title V air operation permit.

In addition, if water flow to any unit is unavailable for more than 90 minutes, the affected CT will automatically shut down.

An excursion will trigger an evaluation of the operation of the affected CT and the water injection system. Corrective action shall be taken as necessary. Any excursion shall trigger recordkeeping and reporting requirements.

CAM PLAN
(version dated 10/19/2009)

C. QA/QC Practices and Criteria	All data QA/QC is in accordance with the requirements of 40 CFR 60.
D. Monitoring Frequency	Continuous.
E. Data Collection Procedures	Automated data acquisition handling system (DAHS).
F. Averaging Period	1 hour average (data collection frequency is continuous).

* The excursion level (target ratio value) specified in this CAM Plan was established based upon data established at the plant. The excursion level shall be re-evaluated at the time of renewal of Permit No. 1210003-007-AV based upon plant data.

COMBUSTION TURBINE PEAKING UNIT NO. 2 (P-2) FIRING NATURAL GAS

Suwannee River Power Plant's Combustion Turbine Peaking Unit No. 2 (P-2) is allowed to fire both natural gas and distillate fuel oil. Initial compliance has been demonstrated for fuel oil firing, but not on natural gas firing. Water injection is used to control NOx (nitrogen oxides). The amount of water is automatically regulated by the manufacturer's control system. The following Compliance Plan, for initial compliance while firing natural gas, follows the requirements of air construction permit, AC61-11863/PSD-FL-014:

1. The Department's Northeast District Office, Air Section, will be notified of the actual date of initial operation firing natural gas within 15 days of such date.
2. The emission limiting standards for NOx and visible emissions, when firing natural gas, are identified in the permit, respectively, and compliance shall be demonstrated on the emissions unit within 60 days of achieving maximum production rate, but no later than 180 days of initial operation on natural gas.
3. Initial performance tests for NOx and visible emissions shall be conducted using the test methods identified in the permit, respectively.
4. The Department's Northeast District Office, Air Section, shall be notified in writing at least 30 days prior to the initial performance tests.
5. Performance test results shall be submitted to the Department's Northeast District Office, Air Section, no later than 45 days after the last test run.

[Rule 62-213.440(2), F.A.C.; and, AC61-11863/PSD-FL-014.]

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(version dated 10/9/2008)

E.U. ID No.	Brief Description
-004	Combustion Turbine Peaking (CTP) Unit No. 1
-005	Combustion Turbine Peaking (CTP) Unit No. 2
-006	Combustion Turbine Peaking (CTP) Unit No. 3

Federal Regulations Adopted by Reference

In accordance with Rule 62-204.800, F.A.C., the following federal regulation in Title 40 of the Code of Federal Regulations (CFR) was adopted by reference. The original federal rule numbering has been retained.

Federal Revision Date: June 13, 2007

Rule Effective Date: October 1, 2007

Standardized Conditions Revision Date: October 9, 2008

40 CFR Part 60, Subpart A - General Provisions

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End of Index

§ 60.1 Applicability.

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

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

(c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution control agency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (Act) as amended November 15, 1990 (42 U.S.C. 7661). For more information about obtaining an operating permit see part 70 of this chapter.

(d) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* *{Not Applicable}*

§ 60.2 Definitions.

The terms used in this part are defined in the Act or in this section as follows:

Act means the Clean Air Act (42 U.S.C. 7401 *et seq.*)

Administrator means the Administrator of the Environmental Protection Agency or his authorized representative.

Affected facility means, with reference to a stationary source, any apparatus to which a standard is applicable.

Alternative method means any method of sampling and analyzing for an air pollutant which is not a reference or equivalent method but which has been demonstrated to the Administrator's satisfaction to, in specific cases, produce results adequate for his determination of compliance.

Approved permit program means a State permit program approved by the Administrator as meeting the requirements of part 70 of this chapter or a Federal permit program established in this chapter pursuant to Title V of the Act (42 U.S.C. 7661).

Capital expenditure means an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable "annual asset guideline repair allowance percentage" specified in the latest edition of Internal Revenue Service (IRS) Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code. However, the total expenditure for a physical or operational change to an existing facility must not be reduced by any "excluded additions" as defined in IRS Publication 534, as would be done for tax purposes.

Clean coal technology demonstration project means a project using funds appropriated under the heading 'Department of Energy-Clean Coal Technology', up to a total amount of $2,500,000,000 for commercial demonstrations of clean coal technology, or similar projects funded through appropriations for the Environmental Protection Agency.

Commenced means, with respect to the definition of *new source* in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

Construction means fabrication, erection, or installation of an affected facility.

Continuous monitoring system means the total equipment, required under the emission monitoring sections in applicable subparts, used to sample and condition (if applicable), to analyze, and to provide a permanent record of emissions or process parameters.

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

Equivalent method means any method of sampling and analyzing for an air pollutant which has been demonstrated to the Administrator's satisfaction to have a consistent and quantitatively known relationship to the reference method, under specified conditions.

Excess Emissions and Monitoring Systems Performance Report is a report that must be submitted periodically by a source in order to provide data on its compliance with stated emission limits and operating parameters, and on the performance of its monitoring systems.

Existing facility means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type.

Force majeure means, for purposes of §60.8, an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents the owner or operator from complying with the regulatory requirement to conduct performance tests within the specified timeframe despite the affected facility's best efforts to fulfill the obligation. Examples of such events are acts of nature, acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility.

Isokinetic sampling means sampling in which the linear velocity of the gas entering the sampling nozzle is equal to that of the undisturbed gas stream at the sample point.

Issuance of a part 70 permit will occur, if the State is the permitting authority, in accordance with the requirements of part 70 of this chapter and the applicable, approved State permit program. When the EPA is the permitting authority, issuance of a Title V permit occurs immediately after the EPA takes final action on the final permit.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Modification means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

Monitoring device means the total equipment, required under the monitoring of operations sections in applicable subparts, used to measure and record (if applicable) process parameters.

Nitrogen oxides means all oxides of nitrogen except nitrous oxide, as measured by test methods set forth in this part.

One-hour period means any 60-minute period commencing on the hour.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Owner or operator means any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part.

Part 70 permit means any permit issued, renewed, or revised pursuant to part 70 of this chapter.

Particulate matter means any finely divided solid or liquid material, other than uncombined water, as measured by the reference methods specified under each applicable subpart, or an equivalent or alternative method.

Permit program means a comprehensive State operating permit system established pursuant to title V of the Act (42 U.S.C. 7661) and regulations codified in part 70 of this chapter and applicable State regulations, or a comprehensive Federal operating permit system established pursuant to title V of the Act and regulations codified in this chapter.

Permitting authority means:

(1) The State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to carry out a permit program under part 70 of this chapter; or

(2) The Administrator, in the case of EPA-implemented permit programs under title V of the Act (42 U.S.C. 7661).

Proportional sampling means sampling at a rate that produces a constant ratio of sampling rate to stack gas flow rate.

Reactivation of a very clean coal-fired electric utility steam generating unit means any physical change or change in the method of operation associated with the commencement of commercial operations by a coal-fired utility unit after a period of discontinued operation where the unit:

(1) Has not been in operation for the two-year period prior to the enactment of the Clean Air Act Amendments of 1990, and the emissions from such unit continue to be carried in the permitting authority's emissions inventory at the time of enactment;

(2) Was equipped prior to shut-down with a continuous system of emissions control that achieves a removal efficiency for sulfur dioxide of no less than 85 percent and a removal efficiency for particulates of no less than 98 percent;

(3) Is equipped with low-NO_X burners prior to the time of commencement of operations following reactivation; and

(4) Is otherwise in compliance with the requirements of the Clean Air Act.

Reference method means any method of sampling and analyzing for an air pollutant as specified in the applicable subpart.

Repowering means replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of November 15, 1990. Repowering shall also include any oil and/or gas-fired unit which has been awarded clean coal technology demonstration funding as of January 1, 1991, by the Department of Energy.

Run means the net period of time during which an emission sample is collected. Unless otherwise specified, a run may be either intermittent or continuous within the limits of good engineering practice.

Shutdown means the cessation of operation of an affected facility for any purpose.

Six-minute period means any one of the 10 equal parts of a one-hour period.

Standard means a standard of performance proposed or promulgated under this part.

Standard conditions means a temperature of 293 K (68F) and a pressure of 101.3 kilopascals (29.92 in Hg).

Startup means the setting in operation of an affected facility for any purpose.

State means all non-Federal authorities, including local agencies, interstate associations, and State-wide programs, that have delegated authority to implement: (1) The provisions of this part; and/or (2) the permit program established under part 70 of this chapter. The term State shall have its conventional meaning where clear from the context.

Stationary source means any building, structure, facility, or installation which emits or may emit any air pollutant.

Title V permit means any permit issued, renewed, or revised pursuant to Federal or State regulations established to implement title V of the Act (42 U.S.C. 7661). A title V permit issued by a State permitting authority is called a part 70 permit in this part.

Volatile Organic Compound means any organic compound which participates in atmospheric photochemical reactions; or which is measured by a reference method, an equivalent method, an alternative method, or which is determined by procedures specified under any subpart.

[44 FR 55173, Sept. 25, 1979, as amended at 45 FR 5617, Jan. 23, 1980; 45 FR 85415, Dec. 24, 1980; 54 FR 6662, Feb. 14, 1989; 55 FR 51382, Dec. 13, 1990; 57 FR 32338, July 21, 1992; 59 FR 12427, Mar. 16, 1994; 72 FR 27442, May 16, 2007]

§ 60.3 Units and abbreviations.

Used in this part are abbreviations and symbols of units of measure. These are defined as follows:

(a) System International (SI) units of measure:

A—ampere

g—gram

Hz—hertz

J—joule

K—degree Kelvin

kg—kilogram

m—meter

m^3 —cubic meter

mg—milligram—10^{-3}gram

mm—millimeter—10^{-3}meter

Mg—megagram—10^6 gram

mol—mole

N—newton

ng—nanogram—10^{-9}gram

nm—nanometer—10^{-9}meter

Pa—pascal

s—second

V—volt

W—watt

Ω—ohm

µg—microgram—10^{-6}gram

(b) Other units of measure:

Btu—British thermal unit

°C—degree Celsius (centigrade)

cal—calorie

cfm—cubic feet per minute

cu ft—cubic feet

dcf—dry cubic feet

dcm—dry cubic meter

dscf—dry cubic feet at standard conditions

dscm—dry cubic meter at standard conditions

eq—equivalent

°F—degree Fahrenheit

ft—feet

gal—gallon

gr—grain

g-eq—gram equivalent

hr—hour

in—inch

k—1,000

l—liter

lpm—liter per minute

lb—pound

meq—milliequivalent

min—minute

ml—milliliter

mol. wt.—molecular weight

ppb—parts per billion

ppm—parts per million

psia—pounds per square inch absolute

psig—pounds per square inch gage

°R—degree Rankine

scf—cubic feet at standard conditions

scfh—cubic feet per hour at standard conditions

scm—cubic meter at standard conditions

sec—second

sq ft—square feet

std—at standard conditions

(c) Chemical nomenclature:

CdS—cadmium sulfide

CO—carbon monoxide

CO_2—carbon dioxide

HCl—hydrochloric acid

Hg—mercury

H_2O—water

H_2S—hydrogen sulfide

H_2SO_4—sulfuric acid

N_2—nitrogen

NO—nitric oxide

NO_2—nitrogen dioxide

NO_X—nitrogen oxides

O_2—oxygen

SO_2—sulfur dioxide

SO_3—sulfur trioxide

SO_X—sulfur oxides

(d) Miscellaneous:

A.S.T.M.—American Society for Testing and Materials

[42 FR 37000, July 19, 1977; 42 FR 38178, July 27, 1977]

§ 60.4 Address.

All addresses that pertain to Florida have been incorporated. To see the complete list of addresses please go to http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&rgn=div6&view=text&node=40:6.0.1.1.1.1&idno=40.

GENERAL PROVISIONS
(version dated 10/9/2008)

Link to an amendment published at 73 FR 18164, Apr. 3, 2008.

(a) All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted in duplicate to the appropriate Regional Office of the U.S. Environmental Protection Agency to the attention of the Director of the Division indicated in the following list of EPA Regional Offices.

Region IV (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, 345 Courtland Street, NE., Atlanta, GA 30365.

(b) Section 111(c) directs the Administrator to delegate to each State, when appropriate, the authority to implement and enforce standards of performance for new stationary sources located in such State. All information required to be submitted to EPA under paragraph (a) of this section, must also be submitted to the appropriate State Agency of any State to which this authority has been delegated (provided, that each specific delegation may except sources from a certain Federal or State reporting requirement). The appropriate mailing address for those States whose delegation request has been approved is as follows:

(K) Bureau of Air Quality Management, Department of Environmental Regulation, Twin Towers Office Building, 2600 Blair Stone Road, Tallahassee, FL 32301.

[40 FR 18169, Apr. 25, 1975]

Editorial Note: For Federal Register citations affecting §60.4 see the List of CFR Sections Affected which appears in the Finding Aids section of the printed volume and on GPO Access.

§ 60.5 Determination of construction or modification.

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

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

[40 FR 58418, Dec. 16, 1975]

§ 60.6 Review of plans.

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

(b)

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

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

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

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 9314, Mar. 8, 1974]

§ 60.7 Notification and record keeping.

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

(1) A notification of the date construction (or reconstruction as defined under §60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

(2) [Reserved]

(3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.

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

(5) A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with §60.13(c). Notification shall be postmarked not less than 30 days prior to such date.

(6) A notification of the anticipated date for conducting the opacity observations required by §60.11(e)(1) of this part. The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

(7) A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by §60.8 in lieu of Method 9 observation data as allowed by §60.11(e)(5) of this part. This notification shall be postmarked not less than 30 days prior to the date of the performance test.

(b) Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(c) Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

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

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

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

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

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

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

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

Figure 1—Summary Report—Gaseous and Opacity Excess Emission and Monitoring System Performance

Pollutant (Circle One—SO_2/NO_X/TRS/H_2S/CO/Opacity)

Reporting period dates: From _____ to _____

Company:

Emission Limitation_____________________

Address:

Monitor Manufacturer and Model No.____________________
Date of Latest CMS Certification or Audit____________________

Process Unit(s) Description:

Total source operating time in reporting period[1] ____________________

Emission data summary[1]		**CMS performance summary**[1]	
1. Duration of excess emissions in reporting period due to:		1. CMS downtime in reporting period due to:	
a. Startup/shutdown		a. Monitor equipment malfunctions	
b. Control equipment problems		b. Non-Monitor equipment malfunctions	
c. Process problems		c. Quality assurance calibration	
d. Other known causes		d. Other known causes	
e. Unknown causes		e. Unknown causes	
2. Total duration of excess emission		2. Total CMS Downtime	
3. Total duration of excess emissions × (100) [Total source operating time]	%[2]	3. [Total CMS Downtime] × (100) [Total source operating time]	%[2]

[1]For opacity, record all times in minutes. For gases, record all times in hours.

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

On a separate page, describe any changes since last quarter in CMS, process or controls. I certify that the information contained in this report is true, accurate, and complete.

____
Name

____
Signature

____
Title

____
Date

(e)

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

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

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in this subpart and the applicable standard; and

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

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

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

(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows:

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

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

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

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

(g) If notification substantially similar to that in paragraph (a) of this section is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of paragraph (a) of this section.

(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.

[36 FR 24877, Dec. 28, 1971, as amended at 40 FR 46254, Oct. 6, 1975; 40 FR 58418, Dec. 16, 1975; 45 FR 5617, Jan. 23, 1980; 48 FR 48335, Oct. 18, 1983; 50 FR 53113, Dec. 27, 1985; 52 FR 9781, Mar. 26, 1987; 55 FR 51382, Dec. 13, 1990; 59 FR 12428, Mar. 16, 1994; 59 FR 47265, Sep. 15, 1994; 64 FR 7463, Feb. 12, 1999]

§ 60.8 Performance tests.

(a) Except as specified in paragraphs (a)(1),(a)(2), (a)(3), and (a)(4) of this section, within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, or at such other times specified by this part, and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(1) If a force majeure is about to occur, occurs, or has occurred for which the affected owner or operator intends to assert a claim of force majeure, the owner or operator shall notify the Administrator, in writing as soon as practicable following the date the owner or operator first knew, or through due diligence should have known that the event may cause or caused a delay in testing beyond the regulatory deadline, but the notification must occur before the performance test deadline unless the initial force majeure or a subsequent force majeure event delays the notice, and in such cases, the notification shall occur as soon as practicable.

(2) The owner or operator shall provide to the Administrator a written description of the force majeure event and a rationale for attributing the delay in testing beyond the regulatory deadline to the force majeure; describe the measures taken or to be taken to minimize the delay; and identify a date by which the owner or operator proposes to conduct the performance test. The performance test shall be conducted as soon as practicable after the force majeure occurs.

(3) The decision as to whether or not to grant an extension to the performance test deadline is solely within the discretion of the Administrator. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an extension as soon as practicable.

(4) Until an extension of the performance test deadline has been approved by the Administrator under paragraphs (a)(1), (2), and (3) of this section, the owner or operator of the affected facility remains strictly subject to the requirements of this part.

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

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

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

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

(1) Sampling ports adequate for test methods applicable to such facility. This includes (i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and (ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

(2) Safe sampling platform(s).

(3) Safe access to sampling platform(s).

(4) Utilities for sampling and testing equipment.

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

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 9314, Mar. 8, 1974; 42 FR 57126, Nov. 1, 1977; 44 FR 33612, June 11, 1979; 54 FR 6662, Feb. 14, 1989; 54 FR 21344, May 17, 1989; 64 FR 7463, Feb. 12, 1999; 72 FR 27442, May 16, 2007]

§ 60.9 Availability of information.

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

§ 60.10 State authority.

The provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from:

(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.

(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

§ 60.11 Compliance with standards and maintenance requirements.

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

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

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

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

(e)

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

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

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

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

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

(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by §60.8, the opacity observation results and observer certification required by §60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by §60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with §60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, he shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

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

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

(f) Special provisions set forth under an applicable subpart shall supersede any conflicting provisions in paragraphs (a) through (e) of this section.

(g) For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[38 FR 28565, Oct. 15, 1973, as amended at 39 FR 39873, Nov. 12, 1974; 43 FR 8800, Mar. 3, 1978; 45 FR 23379, Apr. 4, 1980; 48 FR 48335, Oct. 18, 1983; 50 FR 53113, Dec. 27, 1985; 51 FR 1790, Jan. 15, 1986; 52 FR 9781, Mar. 26, 1987; 62 FR 8328, Feb. 24, 1997; 65 FR 61749, Oct. 17, 2000]

§ 60.12 Circumvention.

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

[39 FR 9314, Mar. 8, 1974]

§ 60.13 Monitoring requirements.

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

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

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

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

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

(d)

  (1) Owners and operators of a CEMS installed in accordance with the provisions of this part, must check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span must, as a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit of the applicable performance specification in appendix B of this part. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified. Owners and operators of a COMS installed in accordance with the provisions of this part, must automatically, intrinsic to the opacity monitor, check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is as defined in the applicable version of PS–1 in appendix B of this part. For a COMS, the optical surfaces, exposed to the effluent gases, must be cleaned before performing the zero and upscale drift adjustments, except for systems using automatic zero adjustments. The optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

  (2) Unless otherwise approved by the Administrator, the following procedures must be followed for a COMS. Minimum procedures must include an automated method for producing a simulated zero opacity condition and an upscale opacity condition using a certified neutral density filter or other related technique to produce a known obstruction of the light beam. Such procedures must provide a system check of all active analyzer internal optics with power or curvature, all active electronic circuitry including the light source and photodetector assembly, and electronic or electro-mechanical systems and hardware and or software used during normal measurement operation.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under paragraph (d) of this section, all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

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

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

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of this part shall be used.

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

(h)

(1) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in §60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period.

(2) For continuous monitoring systems other than opacity, 1-hour averages shall be computed as follows, except that the provisions pertaining to the validation of partial operating hours are only applicable for affected facilities that are required by the applicable subpart to include partial hours in the emission calculations:

(i) Except as provided under paragraph (h)(2)(iii) of this section, for a full operating hour (any clock hour with 60 minutes of unit operation), at least four valid data points are required to calculate the hourly average, *i.e.* , one data point in each of the 15-minute quadrants of the hour.

(ii) Except as provided under paragraph (h)(2)(iii) of this section, for a partial operating hour (any clock hour with less than 60 minutes of unit operation), at least one valid data point in each 15-minute quadrant of the hour in which the unit operates is required to calculate the hourly average.

(iii) For any operating hour in which required maintenance or quality-assurance activities are performed:

(A) If the unit operates in two or more quadrants of the hour, a minimum of two valid data points, separated by at least 15 minutes, is required to calculate the hourly average; or

(B) If the unit operates in only one quadrant of the hour, at least one valid data point is required to calculate the hourly average.

(iv) If a daily calibration error check is failed during any operating hour, all data for that hour shall be invalidated, unless a subsequent calibration error test is passed in the same hour and the requirements of paragraph (h)(2)(iii) of this section are met, based solely on valid data recorded after the successful calibration.

(v) For each full or partial operating hour, all valid data points shall be used to calculate the hourly average.

(vi) Except as provided under paragraph (h)(2)(vii) of this section, data recorded during periods of continuous monitoring system breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph.

(vii) Owners and operators complying with the requirements of §60.7(f)(1) or (2) must include any data recorded during periods of monitor breakdown or malfunction in the data averages.

(viii) When specified in an applicable subpart, hourly averages for certain partial operating hours shall not be computed or included in the emission averages (*e.g.* hours with < 30 minutes of unit operation under §60.47b(d)).

(ix) Either arithmetic or integrated averaging of all data may be used to calculate the hourly averages. The data may be recorded in reduced or nonreduced form (*e.g.* , ppm pollutant and percent O_2or ng/J of pollutant).

(3) All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in the applicable subpart. After conversion into units of the standard, the data may be rounded to the same number of significant digits used in the applicable subpart to specify the emission limit.

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

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

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

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

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

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

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

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

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

(9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities is released to the atmosphere through more than one point.

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

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

other than NSPS) and may require specifications more stringent than in Performance Specification 2 (e.g., the applicable emission limit is more stringent than NSPS).

(2) The waiver of a CEMS RA test will be reviewed and may be rescinded at such time, following successful completion of the alternative RA procedure, that the CEMS data indicate that the source emissions are approaching the level. The criterion for reviewing the waiver is the collection of CEMS data showing that emissions have exceeded 70 percent of the applicable standard for seven, consecutive, averaging periods as specified by the applicable regulation(s). For sources subject to standards expressed as control efficiency levels, the criterion for reviewing the waiver is the collection of CEMS data showing that exhaust emissions have exceeded 70 percent of the level needed to meet the control efficiency requirement for seven, consecutive, averaging periods as specified by the applicable regulation(s) [e.g., §60.45(g) (2) and (3), §60.73(e), and §60.84(e)]. It is the responsibility of the source operator to maintain records and determine the level of emissions relative to the criterion on the waiver of RA testing. If this criterion is exceeded, the owner or operator must notify the Administrator within 10 days of such occurrence and include a description of the nature and cause of the increasing emissions. The Administrator will review the notification and may rescind the waiver and require the owner or operator to conduct a RA test of the CEMS as specified in Section 8.4 of Performance Specification 2.

[40 FR 46255, Oct. 6, 1975; 40 FR 59205, Dec. 22, 1975, as amended at 41 FR 35185, Aug. 20, 1976; 48 FR 13326, Mar. 30, 1983; 48 FR 23610, May 25, 1983; 48 FR 32986, July 20, 1983; 52 FR 9782, Mar. 26, 1987; 52 FR 17555, May 11, 1987; 52 FR 21007, June 4, 1987; 64 FR 7463, Feb. 12, 1999; 65 FR 48920, Aug. 10, 2000; 65 FR 61749, Oct. 17, 2000; 66 FR 44980, Aug. 27, 2001; 71 FR 31102, June 1, 2006; 72 FR 32714, June 13, 2007]

Editorial Note: At 65 FR 61749, Oct. 17, 2000, §60.13 was amended by revising the words "ng/J of pollutant" to read "ng of pollutant per J of heat input" in the sixth sentence of paragraph (h). However, the amendment could not be incorporated because the words "ng/J of pollutant" do not exist in the sixth sentence of paragraph (h).

§ 60.14 Modification.

(a) Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

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

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

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

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.

(d) [Reserved]

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

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of paragraph (c) of this section and §60.15.

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

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by §60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

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

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in paragraph (a) of this section, compliance with all applicable standards must be achieved.

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

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

(j)

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

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

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

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

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

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

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

[40 FR 58419, Dec. 16, 1975, as amended at 43 FR 34347, Aug. 3, 1978; 45 FR 5617, Jan. 23, 1980; 57 FR 32339, July 21, 1992; 65 FR 61750, Oct. 17, 2000]

§ 60.15 Reconstruction.

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

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

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

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

(c) "Fixed capital cost" means the capital needed to provide all the depreciable components.

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

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

(3) A brief description of the existing facility and the components which are to be replaced.

(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.

(6) The estimated life of the existing facility after the replacements.

(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

(e) The Administrator will determine, within 30 days of the receipt of the notice required by paragraph (d) of this section and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under paragraph (e) shall be based on:

(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;

(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;

(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and

(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

[40 FR 58420, Dec. 16, 1975]

§ 60.16 Priority list.

A list of prioritized major source categories may be found at the following EPA web site:
http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&rgn=div6&view=text&node=40:6.0.1.1.1.1&idno=40

§ 60.17 Incorporations by reference.

GENERAL PROVISIONS

(version dated 10/9/2008)

The materials listed below are incorporated by reference in the corresponding sections noted. These incorporations by reference were approved by the Director of the Federal Register on the date listed. These materials are incorporated as they exist on the date of the approval, and a notice of any change in these materials will be published in the Federal Register. The materials are available for purchase at the corresponding address noted below, and all are available for inspection at the Library (C267–01), U.S. EPA, Research Triangle Park, NC or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

(a) The following materials are available for purchase from at least one of the following addresses: American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959; or ProQuest, 300 North Zeeb Road, Ann Arbor, MI 48106.

(1) ASTM A99–76, 82 (Reapproved 1987), Standard Specification for Ferromanganese, incorporation by reference (IBR) approved for §60.261.

(2) ASTM A100–69, 74, 93, Standard Specification for Ferrosilicon, IBR approved for §60.261.

(3) ASTM A101–73, 93, Standard Specification for Ferrochromium, IBR approved for §60.261.

(4) ASTM A482–76, 93, Standard Specification for Ferrochromesilicon, IBR approved for §60.261.

(5) ASTM A483–64, 74 (Reapproved 1988), Standard Specification for Silicomanganese, IBR approved for §60.261.

(6) ASTM A495–76, 94, Standard Specification for Calcium-Silicon and Calcium Manganese-Silicon, IBR approved for §60.261.

(7) ASTM D86–78, 82, 90, 93, 95, 96, Distillation of Petroleum Products, IBR approved for §§60.562–2(d), 60.593(d), 60.593a(d), and 60.633(h).

(8) ASTM D129–64, 78, 95, 00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§60.106(j)(2), 60.335(b)(10)(i), and Appendix A: Method 19, 12.5.2.2.3.

(9) ASTM D129–00 (Reapproved 2005), Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §60.4415(a)(1)(i).

(10) ASTM D240–76, 92, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for §§60.46(c), 60.296(b), and Appendix A: Method 19, Section 12.5.2.2.3.

(11) ASTM D270–65, 75, Standard Method of Sampling Petroleum and Petroleum Products, IBR approved for Appendix A: Method 19, Section 12.5.2.2.1.

(12) ASTM D323–82, 94, Test Method for Vapor Pressure of Petroleum Products (Reid Method), IBR approved for §§60.111(l), 60.111a(g), 60.111b(g), and 60.116b(f)(2)(ii).

(13) ASTM D388–77, 90, 91, 95, 98a, 99 (Reapproved 2004)ε^1, Standard Specification for Classification of Coals by Rank, IBR approved for §§60.24(h)(8), 60.41 of subpart D of this part, 60.45(f)(4)(i), 60.45(f)(4)(ii), 60.45(f)(4)(vi), 60.41Da of subpart Da of this part, 60.41b of subpart Db of this part, 60.41c of subpart Dc of this part, and 60.4102.

(14) ASTM D388–77, 90, 91, 95, 98a, Standard Specification for Classification of Coals by Rank, IBR approved for §§60.251(b) and (c) of subpart Y of this part.

(15) ASTM D396–78, 89, 90, 92, 96, 98, Standard Specification for Fuel Oils, IBR approved for §§60.41b of subpart Db of this part, 60.41c of subpart Dc of this part, 60.111(b) of subpart K of this part, and 60.111a(b) of subpart Ka of this part.

(16) ASTM D975–78, 96, 98a, Standard Specification for Diesel Fuel Oils, IBR approved for §§60.111(b) of subpart K of this part and 60.111a(b) of subpart Ka of this part.

(17) ASTM D1072–80, 90 (Reapproved 1994), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for §60.335(b)(10)(ii).

(18) ASTM D1072–90 (Reapproved 1999), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for §60.4415(a)(1)(ii).

(19) ASTM D1137–53, 75, Standard Method for Analysis of Natural Gases and Related Types of Gaseous Mixtures by the Mass Spectrometer, IBR approved for §60.45(f)(5)(i).

(20) ASTM D1193–77, 91, Standard Specification for Reagent Water, IBR approved for Appendix A: Method 5, Section 7.1.3; Method 5E, Section 7.2.1; Method 5F, Section 7.2.1; Method 6, Section 7.1.1; Method 7, Section 7.1.1; Method 7C, Section 7.1.1; Method 7D, Section 7.1.1; Method 10A, Section 7.1.1; Method 11, Section 7.1.3; Method 12, Section 7.1.3; Method 13A, Section 7.1.2; Method 26, Section 7.1.2; Method 26A, Section 7.1.2; and Method 29, Section 7.2.2.

(21) ASTM D1266–87, 91, 98, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§60.106(j)(2) and 60.335(b)(10)(i).

(22) ASTM D1266–98 (Reapproved 2003)e1, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §60.4415(a)(1)(i).

(23) ASTM D1475–60 (Reapproved 1980), 90, Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for §60.435(d)(1), Appendix A: Method 24, Section 6.1; and Method 24A, Sections 6.5 and 7.1.

(24) ASTM D1552–83, 95, 01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§60.106(j)(2), 60.335(b)(10)(i), and Appendix A: Method 19, Section 12.5.2.2.3.

(25) ASTM D1552–03, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §60.4415(a)(1)(i).

(26) ASTM D1826–77, 94, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for §§60.45(f)(5)(ii), 60.46(c)(2), 60.296(b)(3), and Appendix A: Method 19, Section 12.3.2.4.

(27) ASTM D1835–87, 91, 97, 03a, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§60.41Da of subpart Da of this part, 60.41b of subpart Db of this part, and 60.41c of subpart Dc of this part.

(28) ASTM D1945–64, 76, 91, 96, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for §60.45(f)(5)(i).

(29) ASTM D1946–77, 90 (Reapproved 1994), Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §§60.18(f)(3), 60.45(f)(5)(i), 60.564(f)(1), 60.614(e)(2)(ii), 60.614(e)(4), 60.664(e)(2)(ii), 60.664(e)(4), 60.704(d)(2)(ii), and 60.704(d)(4).

(30) ASTM D2013–72, 86, Standard Method of Preparing Coal Samples for Analysis, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(31) ASTM D2015–77 (Reapproved 1978), 96, Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved for §60.45(f)(5)(ii), 60.46(c)(2), and Appendix A: Method 19, Section 12.5.2.1.3.

(32) ASTM D2016–74, 83, Standard Test Methods for Moisture Content of Wood, IBR approved for Appendix A: Method 28, Section 16.1.1.

(33) ASTM D2234–76, 96, 97b, 98, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for Appendix A: Method 19, Section 12.5.2.1.1.

(34) ASTM D2369–81, 87, 90, 92, 93, 95, Standard Test Method for Volatile Content of Coatings, IBR approved for Appendix A: Method 24, Section 6.2.

(35) ASTM D2382–76, 88, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for §§60.18(f)(3), 60.485(g)(6), 60.485a(g)(6), 60.564(f)(3), 60.614(e)(4), 60.664(e)(4), and 60.704(d)(4).

(36) ASTM D2504–67, 77, 88 (Reapproved 1993), Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§60.485(g)(5) and 60.485a(g)(5).

(37) ASTM D2584–68 (Reapproved 1985), 94, Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved for §60.685(c)(3)(i).

(38) ASTM D2597–94 (Reapproved 1999), Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography, IBR approved for §60.335(b)(9)(i).

(39) ASTM D2622–87, 94, 98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§60.106(j)(2) and 60.335(b)(10)(i).

(40) ASTM D2622–05, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §60.4415(a)(1)(i).

(41) ASTM D2879–83, 96, 97, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for §§60.111b(f)(3), 60.116b(e)(3)(ii), 60.116b(f)(2)(i), 60.485(e)(1), and 60.485a(e)(1).

(42) ASTM D2880–78, 96, Standard Specification for Gas Turbine Fuel Oils, IBR approved for §§60.111(b), 60.111a(b), and 60.335(d).

(43) ASTM D2908–74, 91, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, IBR approved for §60.564(j).

(44) ASTM D2986–71, 78, 95a, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test, IBR approved for Appendix A: Method 5, Section 7.1.1; Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(45) ASTM D3173–73, 87, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(46) ASTM D3176–74, 89, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved for §60.45(f)(5)(i) and Appendix A: Method 19, Section 12.3.2.3.

(47) ASTM D3177–75, 89, Standard Test Method for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(48) ASTM D3178–73 (Reapproved 1979), 89, Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved for §60.45(f)(5)(i).

(49) ASTM D3246–81, 92, 96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for §60.335(b)(10)(ii).

(50) ASTM D3246–05, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for §60.4415(a)(1)(ii).

(51) ASTM D3270–73T, 80, 91, 95, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for Appendix A: Method 13A, Section 16.1.

(52) ASTM D3286–85, 96, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(53) ASTM D3370–76, 95a, Standard Practices for Sampling Water, IBR approved for §60.564(j).

(54) ASTM D3792–79, 91, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, IBR approved for Appendix A: Method 24, Section 6.3.

(55) ASTM D4017–81, 90, 96a, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for Appendix A: Method 24, Section 6.4.

(56) ASTM D4057–81, 95, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for Appendix A: Method 19, Section 12.5.2.2.3.

(57) ASTM D4057–95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for §60.4415(a)(1).

(58) ASTM D4084–82, 94, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for §60.334(h)(1).

(59) ASTM D4084–05, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for §§60.4360 and 60.4415(a)(1)(ii).

(60) ASTM D4177–95, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for Appendix A: Method 19, Section 12.5.2.2.1.

(61) ASTM D4177–95 (Reapproved 2000), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for §60.4415(a)(1).

(62) ASTM D4239–85, 94, 97, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(63) ASTM D4294–02, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §60.335(b)(10)(i).

(64) ASTM D4294–03, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §60.4415(a)(1)(i).

(65) ASTM D4442–84, 92, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials, IBR approved for Appendix A: Method 28, Section 16.1.1.

(66) ASTM D4444–92, Standard Test Methods for Use and Calibration of Hand-Held Moisture Meters, IBR approved for Appendix A: Method 28, Section 16.1.1.

(67) ASTM D4457–85 (Reapproved 1991), Test Method for Determination of Dichloromethane and 1, 1, 1-Trichloroethane in Paints and Coatings by Direct Injection into a Gas Chromatograph, IBR approved for Appendix A: Method 24, Section 6.5.

(68) ASTM D4468–85 (Reapproved 2000), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, IBR approved for §§60.335(b)(10)(ii) and 60.4415(a)(1)(ii).

(69) ASTM D4629–02, Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection, IBR approved for §§60.49b(e) and 60.335(b)(9)(i).

(70) ASTM D4809–95, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for §§60.18(f)(3), 60.485(g)(6), 60.485a(g)(6), 60.564(f)(3), 60.614(d)(4), 60.664(e)(4), and 60.704(d)(4).

(71) ASTM D4810–88 (Reapproved 1999), Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length of Stain Detector Tubes, IBR approved for §§60.4360 and 60.4415(a)(1)(ii).

(72) ASTM D5287–97 (Reapproved 2002), Standard Practice for Automatic Sampling of Gaseous Fuels, IBR approved for §60.4415(a)(1).

(73) ASTM D5403–93, Standard Test Methods for Volatile Content of Radiation Curable Materials, IBR approved for Appendix A: Method 24, Section 6.6.

(74) ASTM D5453–00, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for §60.335(b)(10)(i).

(75) ASTM D5453–05, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for §60.4415(a)(1)(i).

(76) ASTM D5504–01, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, IBR approved for §§60.334(h)(1) and 60.4360.

(77) ASTM D5762–02, Standard Test Method for Nitrogen in Petroleum and Petroleum Products by Boat-Inlet Chemiluminescence, IBR approved for §60.335(b)(9)(i).

(78) ASTM D5865–98, Standard Test Method for Gross Calorific Value of Coal and Coke, IBR approved for §60.45(f)(5)(ii), 60.46(c)(2), and Appendix A: Method 19, Section 12.5.2.1.3.

(79) ASTM D6216–98, Standard Practice for Opacity Monitor Manufacturers to Certify Conformance with Design and Performance Specifications, IBR approved for Appendix B, Performance Specification 1.

(80) ASTM D6228–98, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for §60.334(h)(1).

(81) ASTM D6228–98 (Reapproved 2003), Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for §§60.4360 and 60.4415.

(82) ASTM D6348–03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, IBR approved for table 7 of Subpart IIII of this part and table 2 of subpart JJJJ of this part.

(83) ASTM D6366–99, Standard Test Method for Total Trace Nitrogen and Its Derivatives in Liquid Aromatic Hydrocarbons by Oxidative Combustion and Electrochemical Detection, IBR approved for §60.335(b)(9)(i).

(84) ASTM D6420–99 (Reapproved 2004) Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, IBR approved for table 2 of subpart JJJJ of this part.

(85) ASTM D6522–00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for §60.335(a).

(86) ASTM D6522–00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for table 2 of subpart JJJJ of this part.

(87) ASTM D6667–01, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for §60.335(b)(10)(ii).

(88) ASTM D6667–04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for §60.4415(a)(1)(ii).

(89) ASTM D6784–02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), IBR approved for Appendix B to part 60, Performance Specification 12A, Section 8.6.2.

(90) ASTM E168–67, 77, 92, General Techniques of Infrared Quantitative Analysis, IBR approved for §§60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), and 60.632(f).

(91) ASTM E169–63, 77, 93, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), and 60.632(f).

(92) ASTM E260–73, 91, 96, General Gas Chromatography Procedures, IBR approved for §§60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), and 60.632(f).

(b) The following material is available for purchase from the Association of Official Analytical Chemists, 1111 North 19th Street, Suite 210, Arlington, VA 22209.

(1) AOAC Method 9, Official Methods of Analysis of the Association of Official Analytical Chemists, 11th edition, 1970, pp. 11–12, IBR approved January 27, 1983 for §§60.204(b)(3), 60.214(b)(3), 60.224(b)(3), 60.234(b)(3).

(c) The following material is available for purchase from the American Petroleum Institute, 1220 L Street NW., Washington, DC 20005.

(1) API Publication 2517, Evaporation Loss from External Floating Roof Tanks, Second Edition, February 1980, IBR approved January 27, 1983, for §§60.111(i), 60.111a(f), 60.111a(f)(1) and 60.116b(e)(2)(i).

(d) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), Dunwoody Park, Atlanta, GA 30341.

(1) TAPPI Method T624 os–68, IBR approved January 27, 1983 for §60.285(d)(3).

(e) The following material is available for purchase from the Water Pollution Control Federation (WPCF), 2626 Pennsylvania Avenue NW., Washington, DC 20037.

(1) Method 209A, Total Residue Dried at 103–105 °C, in Standard Methods for the Examination of Water and Wastewater, 15th Edition, 1980, IBR approved February 25, 1985 for §60.683(b).

(f) The following material is available for purchase from the following address: Underwriter's Laboratories, Inc. (UL), 333 Pfingsten Road, Northbrook, IL 60062.

(1) UL 103, Sixth Edition revised as of September 3, 1986, Standard for Chimneys, Factory-built, Residential Type and Building Heating Appliance.

(g) The following material is available for purchase from the following address: West Coast Lumber Inspection Bureau, 6980 SW. Barnes Road, Portland, OR 97223.

(1) West Coast Lumber Standard Grading Rules No. 16, pages 5–21 and 90 and 91, September 3, 1970, revised 1984.

(h) The following material is available for purchase from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990.

(1) ASME QRO–1–1994, Standard for the Qualification and Certification of Resource Recovery Facility Operators, IBR approved for §§60.56a, 60.54b(a), 60.54b(b), 60.1185(a), 60.1185(c)(2), 60.1675(a), and 60.1675(c)(2).

(2) ASME PTC 4.1–1964 (Reaffirmed 1991), Power Test Codes: Test Code for Steam Generating Units (with 1968 and 1969 Addenda), IBR approved for §§60.46b of subpart Db of this part, 60.58a(h)(6)(ii), 60.58b(i)(6)(ii), 60.1320(a)(3) and 60.1810(a)(3).

(3) ASME Interim Supplement 19.5 on Instruments and Apparatus: Application, Part II of Fluid Meters, 6th Edition (1971), IBR approved for §§60.58a(h)(6)(ii), 60.58b(i)(6)(ii), 60.1320(a)4), and 60.1810(a)(4).

(4) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], IBR approved for Tables 1 and 3 of subpart EEEE, Tables 2 and 4 of subpart FFFF, Table 2 of subpart JJJJ, and §§60.4415(a)(2) and 60.4415(a)(3) of subpart KKKK of this part.

(i) Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication SW–846 Third Edition (November 1986), as amended by Updates I (July 1992), II (September 1994), IIA (August, 1993), IIB (January 1995), and III (December 1996). This document may be obtained from the U.S. EPA, Office of Solid Waste and Emergency Response, Waste Characterization Branch, Washington, DC 20460, and is incorporated by reference for appendix A to part 60, Method 29, Sections 7.5.34; 9.2.1; 9.2.3; 10.2; 10.3; 11.1.1; 11.1.3; 13.2.1; 13.2.2; 13.3.1; and Table 29–3.

(j) "Standard Methods for the Examination of Water and Wastewater," 16th edition, 1985. Method 303F: "Determination of Mercury by the Cold Vapor Technique." This document may be obtained from the American Public Health Association, 1015 18th Street, NW., Washington, DC 20036, and is incorporated by reference for appendix A to part 60, Method 29, Sections 9.2.3; 10.3; and 11.1.3.

(k) This material is available for purchase from the American Hospital Association (AHA) Service, Inc., Post Office Box 92683, Chicago, Illinois 60675–2683. You may inspect a copy at EPA's Air and Radiation Docket and Information Center (Docket A–91–61, Item IV–J–124), Room M–1500, 1200 Pennsylvania Ave., NW., Washington, DC.

(1) An Ounce of Prevention: Waste Reduction Strategies for Health Care Facilities. American Society for Health Care Environmental Services of the American Hospital Association. Chicago, Illinois. 1993. AHA Catalog No. 057007. ISBN 0–87258–673–5. IBR approved for §60.35e and §60.55c.

(l) This material is available for purchase from the National Technical Information Services, 5285 Port Royal Road, Springfield, Virginia 22161. You may inspect a copy at EPA's Air and Radiation Docket and Information Center (Docket A–91–61, Item IV–J–125), Room M–1500, 1200 Pennsylvania Ave., NW., Washington, DC.

(1) OMB Bulletin No. 93–17: Revised Statistical Definitions for Metropolitan Areas. Office of Management and Budget, June 30, 1993. NTIS No. PB 93–192–664. IBR approved for §60.31e.

(m) This material is available for purchase from at least one of the following addresses: The Gas Processors Association, 6526 East 60th Street, Tulsa, OK, 74145; or Information Handling Services, 15 Inverness Way East, PO Box 1154, Englewood, CO 80150–1154. You may inspect a copy at EPA's Air and Radiation Docket and Information Center, Room B108, 1301 Constitution Ave., NW., Washington, DC 20460.

(1) Gas Processors Association Method 2377–86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes, IBR approved for §§60.334(h)(1), 60.4360, and 60.4415(a)(1)(ii).

(2) [Reserved]

(n) This material is available for purchase from IHS Inc., 15 Inverness Way East, Englewood, CO 80112.

(1) International Organization for Standards 8178–4: 1996(E), Reciprocating Internal Combustion Engines—Exhaust Emission Measurement—Part 4: Test Cycles for Different Engine Applications, IBR approved for §60.4241(b).

(2) [Reserved]

[48 FR 3735, Jan. 27, 1983]

Editorial Note: For Federal Register citations affecting §60.17, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and on GPO Access.

§ 60.18 General control device requirements.

(a) *Introduction.* This section contains requirements for control devices used to comply with applicable subparts of parts 60 and 61. The requirements are placed here for administrative convenience and only apply to facilities covered by subparts referring to this section.

(b) *Flares.* Paragraphs (c) through (f) apply to flares.

(c)

(1) Flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

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

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

(i)

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

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

Where:

V_{max} = Maximum permitted velocity, m/sec.

K_1 = Constant, 6.0 volume-percent hydrogen.

K_2 = Constant, 3.9(m/sec)/volume-percent hydrogen.

X_{H2} = The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946–77. (Incorporated by reference as specified in §60.17).

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

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

(4)

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

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

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

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

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

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

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

(f)

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

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

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

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

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where:

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

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

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

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

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

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

(5) The maximum permitted velocity, V_{max}, for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation.

$$Log_{10}(V_{max})=(H_T+28.8)/31.7$$

V_{max} = Maximum permitted velocity, M/sec

28.8 = Constant

31.7 = Constant

H_T = The net heating value as determined in paragraph (f)(3).

(6) The maximum permitted velocity, V_{max}, for air-assisted flares shall be determined by the following equation.

$$V_{max} = 8.706+0.7084\ (H_T)$$

V_{max} = Maximum permitted velocity, m/sec

8.706 = Constant

0.7084 = Constant

H_T = The net heating value as determined in paragraph (f)(3).

[51 FR 2701, Jan. 21, 1986, as amended at 63 FR 24444, May 4, 1998; 65 FR 61752, Oct. 17, 2000]

§ 60.19 General notification and reporting requirements.

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

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

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

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

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

(f)

(1)

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

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

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

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

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

[59 FR 12428, Mar. 16, 1994, as amended at 64 FR 7463, Feb. 12, 1998]

STANDARDS OF PERFORMANCE FOR STATIONARY GAS TURBINES

(version dated 7/8/2004)

E.U. ID No.	Brief Description
-004	Combustion Turbine Peaking (CTP) Unit No. 1
-005	Combustion Turbine Peaking (CTP) Unit No. 2
-006	Combustion Turbine Peaking (CTP) Unit No. 3

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

In accordance with Rule 62-204.800(8), F.A.C., the following emissions units are subject to the applicable requirements of 40 CFR 60 Subpart GG. For these requirements, the original rule numbering has been retained.

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End of Index

§ 60.330 Applicability and designation of affected facility.

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

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

§ 60.331 Definitions.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(o) *Garrison facility* means any permanent military installation.

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

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

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

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

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

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

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

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

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

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

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

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

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

§ 60.332 Standard for nitrogen oxides.

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

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

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

where:

STD = allowable ISO corrected (if required as given in Sec. 60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

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

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

where:

STD = allowable ISO corrected (if required as given in Sec. 60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NOX emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

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

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

Fuel-bound nitrogen (% by weight)   F (NOx% by volume)

N≤0.015..................................	0
0.015<N≤0.1...........................	0.04(N)
0.1<N≤0.25.............................	0.004+0.0067(N-0.1)
N>0.25....................................	0.005

Where:

N = the nitrogen content of the fuel (percent by weight).

or:

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

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

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

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

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

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

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

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

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

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

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

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

§ 60.333 Standard for sulfur dioxide.

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

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

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

§ 60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control

NO_X emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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(1) Nitrogen oxides.

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

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

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

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

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

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

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

(iii) For turbines using NO_X and diluent CEMS:

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

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

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

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

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

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

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

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

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

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

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

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

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

Sec. 60.335 Test methods and procedures.

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

(1) EPA Method 20,

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

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

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

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

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

(A) [Reserved]

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

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

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

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

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

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

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

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

Where:

NO_X = emission concentration of NO_X at 15 percent O2 and ISO standard ambient conditions, ppm by volume, dry basis,

NO_{Xo} = mean observed NO_X concentration, ppm by volume, dry basis, at 15 percent O2,

P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,

P_o = observed combustor inlet absolute pressure at test, mm Hg,

H_o = observed humidity of ambient air, g H2O/g air,

e = transcendental constant, 2.718, and

T_a = ambient temperature, [deg]K.

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

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NO_X emissions after the duct burner rather than directly after the turbine. If the owner or operator

elects to use this alternative sampling location, the applicable NO_X emission limit in Sec. 60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with Sec. 60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522-00 (incorporated by reference, see Sec. 60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable Sec. 60.332 NO_X emission limit.

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

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

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

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

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

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

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

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

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

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

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

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

(ii) For gaseous fuels, ASTM D1072-80, 90 (Reapproved 1994); D3246-81, 92, 96; D4468-85 (Reapproved 2000); or D6667-01 (all of which are incorporated by reference, see Sec. 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

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

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

LIST OF INSIGNIFICANT EMISSIONS UNITS AND/OR ACTIVITIES

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

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

Brief Description of Emissions Units and/or Activities

1. Internal combustion engines - mobile sources.
2. Vacuum pumps in laboratory operations.
3. Equipment used for steam cleaning.
4. Equipment used exclusively for space heating, other than boilers.
5. Laboratory equipment used exclusively for chemical or physical analyses.
6. Brazing, soldering or welding equipment.
7. Fire protection and safety equipment.
8. Petroleum lubrication systems.
9. Application of fungicide, herbicide, or pesticide.
10. Vehicle refueling operations and associated fuel storage.
11. Degreasing units using heavier-than air vapors exclusively that do not use any substance containing a hazardous air pollutant.
12. Non-halogenated solvent storage and cleaning operations that do not use any substance containing a hazardous air pollutant.
13. Boiler steam turbine lube oil vents.
14. Gas turbine lube oil vents.
15. Gas turbine dump tank vents.
16. Used oil storage tanks.
17. Lube oil storage tanks.
18. Diesel fuel oil storage tanks.
19. No. 2 fuel oil storage tanks.
20. No. 6 fuel oil storage tanks.
21. Storage tanks less than 550 gallons.
22. Architectural (equipment) maintenance painting.
23. Diesel fuel oil, No. 2 fuel oil, No. 6 fuel oil, and used oil truck unloading.
24. The following engines are subject to regulation under 40 CFR 63, Subpart ZZZZ also known as (a.k.a.) MACT "4-Z's" or "RICE MACT," however, since the engines meet the Subpart ZZZZ definition of "existing units," there are no unit specific applicable requirements that must be met pursuant to this rule at this time. The following engines are considered to be 'existing' units for purposes of 40 CFR 60 Subpart IIII also known as (a.k.a.) NSPS "4-I's" or "CI-ICE" and 40 CFR 60 Subpart JJJJ a.k.a. NSPS "4-J's" or "SI-ICE" {CI engines pre-May 2006 and SI engines pre-7/2/2007 are exempt from the NSPS}:

Identification	Model	Type	Horsepower (HP)

	year/construction (manufacturer) date		
Diesel Emergency Generator	1967	Compression Ignition (CI)	190
Diesel Fire Pump	1971	Compression Ignition (CI)	210
Gasoline Welder	2004	Spark Ignition (SI)	20

There is no air pollution control equipment associated with this/ese unit(s).

FACILITY-WIDE REPORTING REQUIREMENTS

(version dated 09/17/2009)

RR1. Reporting Schedule. This table summarizes information for convenience purposes only. It does not supersede any of the terms or conditions of this permit.

Report	Reporting Deadline(s)	Related Condition(s)
Plant Problems/Permit Deviations	Immediately upon occurrence (See RR2.d.)	RR2., RR3.
Malfunction Excess Emissions Report	Every 3 months (quarterly), if requested	RR3.
Semi-Annual Monitoring Report	Every 6 months	RR4.
Annual Operating Report	April 1st of each year	RR5.
Annual Emissions Fee Form and Fee	March 1st of each year	RR6.
Annual Statement of Compliance	Within 60 days after the end of each calendar year (or more frequently if specified by Rule 62-213.440(2), F.A.C., or by any other applicable requirement); and Within 60 days after submittal of a written agreement for transfer of responsibility, or Within 60 days after permanent shutdown.	RR7.
Notification of Administrative Permit Corrections	As needed	RR8.
Notification of Startup after Shutdown for More than One Year	Minimum of 60 days prior to the intended startup date or, if emergency startup, as soon as possible after the startup date is ascertained	RR9.
Permit Renewal Application	225 days prior to the expiration date of permit	TV17.

{Permitting Note: See permit Section III. Emissions Units and Specific Conditions, for any additional Emission Unit-specific reporting requirements.}

RR2. Reports of Problems.

a. Plant Operation-Problems. If the permittee is temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately notify the Department. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules.

b. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

(1) A description of and cause of noncompliance; and

(2) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the noncompliance. The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

c. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware the relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

d. "Immediately" shall mean the same day, if during a workday (i.e., 8:00 a.m. - 5:00 p.m.), or the first business day after the incident, excluding weekends and holidays; and, for purposes of Rule 62-4.160(15) and 40 CFR 70.6(a)(3)(iii)(B), "promptly" or "prompt" shall have the same meaning as "immediately".

[Rule 62-4.130, Rule 62-4.160(8), Rule 62-4.160(15), and Rule 62-213.440(1)(b), F.A.C.; 40 CFR 70.6(a)(3)(iii)(B)]

RR3. Reports of Deviations from Permit Requirements. The permittee shall report in accordance with the requirements of Rule 62-210.700(6), F.A.C. (below), and Rule 62-4.130, F.A.C. (condition RR2.), deviations from permit requirements, including those attributable to upset conditions as defined in the permit. Reports shall include the probable cause of such deviations, and any corrective actions or preventive measures taken.

Rule 62-210.700(6): In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. (See condition RR2.). A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.

[Rules 62-213.440(1)(b)3.b., and 62-210.700(6), F.A.C.]

RR4. Semi-Annual Monitoring Reports. The permittee shall submit reports of any required monitoring at least every six (6) months. All instances of deviations from permit requirements must be clearly identified in such reports. [Rule 62-213.440(1)(b)3.a., F.A.C.]

RR5. Annual Operating Report.

a. The permittee shall submit to the Compliance Authority, each calendar year, on or before April 1, a completed DEP Form No. 62-210.900(5), "Annual Operating Report for Air Pollutant Emitting Facility", for the preceding calendar year.

b. Emissions shall be computed in accordance with the provisions of Rule 62-210.370(2), F.A.C.

[Rules 62-210.370(2) & (3), and 62-213.440(3)(a)2., F.A.C.]

RR6. Annual Emissions Fee Form and Fee. Each Title V source permitted to operate in Florida must pay between January 15 and March 1 of each year, an annual emissions fee in an amount determined as set forth in Rule 62-213.205(1), F.A.C.

a. If the Department has not received the fee by February 15 of the year following the calendar year for which the fee is calculated, the Department will send the primary responsible official of the Title V source a written warning of the consequences for failing to pay the fee by March 1. If the fee is not postmarked by March 1 of the year due, the Department shall impose, in addition to the fee, a penalty of 50 percent of the amount of the fee unpaid plus interest on such amount computed in accordance with Section 220.807, F.S. If the Department determines that a submitted fee was inaccurately calculated, the Department shall either refund to the permittee any amount overpaid or notify the permittee of any amount underpaid. The Department shall not impose a penalty or interest on any amount underpaid, provided that the permittee has timely remitted payment of at least 90 percent of the amount determined to be due and remits full payment within 60 days after receipt of notice of the amount underpaid. The Department shall waive the collection of underpayment and shall not refund overpayment of the fee, if the amount is less than 1 percent of the fee due, up to $50.00. The Department shall make every effort to provide a timely assessment of the adequacy of the submitted fee. Failure to pay timely any required annual emissions fee, penalty, or interest constitutes grounds for permit revocation pursuant to Rule 62-4.100, F.A.C.

b. Any documentation of actual hours of operation, actual material or heat input, actual production amount, or actual emissions used to calculate the annual emissions fee shall be retained by the owner for a minimum of five (5) years and shall be made available to the Department upon request.

c. A completed DEP Form 62-213.900(1), "Major Air Pollution Source Annual Emissions Fee Form", must be submitted by a responsible official with the annual emissions fee.

[Rules 62-213.205(1), (1)(g), (1)(i) & (1)(j), F.A.C.]

RR7. Annual Statement of Compliance.

a. The permittee shall submit a Statement of Compliance with all terms and conditions of the permit that includes all the provisions of 40 CFR 70.6(c)(5)(iii), incorporated by reference at Rule 62-204.800, F.A.C., using DEP Form No. 62-213.900(7). Such statement shall be accompanied by a certification in accordance with Rule 62-213.420(4), F.A.C., for Title V requirements and with Rule 62-214.350, F.A.C., for Acid Rain requirements. Such statements shall be submitted (postmarked) to the Department and EPA:

(1) Annually, within 60 days after the end of each calendar year during which the Title V permit was effective, or more frequently if specified by Rule 62-213.440(2), F.A.C., or by any other applicable requirement; and
(2) Within 60 days after submittal of a written agreement for transfer of responsibility as required pursuant to 40 CFR 70.7(d)(1)(iv), adopted and incorporated by reference at Rule 62-204.800, F.A.C., or within 60 days after permanent shutdown of a facility permitted under Chapter 62-213, F.A.C.; provided that, in either such case, the reporting period shall be the portion of the calendar year the permit was effective up to the date of transfer of responsibility or permanent facility shutdown, as applicable.

b. In lieu of individually identifying all applicable requirements and specifying times of compliance with, non-compliance with, and deviation from each, the responsible official may use DEP Form No. 62-213.900(7) as such statement of compliance so long as the responsible official identifies all reportable deviations from and all instances of non-compliance with any applicable requirements and includes all information required by the federal regulation relating to each reportable deviation and instance of non-compliance.
c. The responsible official may treat compliance with all other applicable requirements as a surrogate for compliance with Rule 62-296.320(2), Objectionable Odor Prohibited.

[Rules 62-213.440(3)(a)2. & 3. and (b), F.A.C.]

RR8. Notification of Administrative Permit Corrections.

a. A facility owner shall notify the Department by letter of minor corrections to information contained in a permit. Such notifications shall include:
   (1) Typographical errors noted in the permit;
   (2) Name, address or phone number change from that in the permit;
   (3) A change requiring more frequent monitoring or reporting by the permittee;
   (4) A change in ownership or operational control of a facility, subject to the following provisions:
      (a) The Department determines that no other change in the permit is necessary;
      (b) The permittee and proposed new permittee have submitted an Application for Transfer of Air Permit, and the Department has approved the transfer pursuant to Rule 62-210.300(7), F.A.C.; and
      (c) The new permittee has notified the Department of the effective date of sale or legal transfer.
   (5) Changes listed at 40 CFR 72.83(a)(1), (2), (6), (9) and (10), adopted and incorporated by reference at Rule 62-204.800, F.A.C., and changes made pursuant to Rules 62-214.340(1) and (2), F.A.C., to Title V sources subject to emissions limitations or reductions pursuant to 42 USC ss. 7651-7651o;
   (6) Changes listed at 40 CFR 72.83(a)(11) and (12), adopted and incorporated by reference at Rule 62-204.800, F.A.C., to Title V sources subject to emissions limitations or reductions pursuant to 42 USC ss. 7651-7651o, provided the notification is accompanied by a copy of any EPA determination concerning the similarity of the change to those listed at Rule 62-210.360(1)(e), F.A.C.; and
   (7) Any other similar minor administrative change at the source.
b. Upon receipt of any such notification, the Department shall within 60 days correct the permit and provide a corrected copy to the owner.
c. After first notifying the owner, the Department shall correct any permit in which it discovers errors of the types listed at Rules 62-210.360(1)(a) and (b), F.A.C., and provide a corrected copy to the owner.
d. For Title V source permits, other than general permits, a copy of the corrected permit shall be provided to EPA and any approved local air program in the county where the facility or any part of the facility is located.

[Rule 62-210.360, F.A.C.]

RR9. Notification of Startup. The owners or operator of any emissions unit or facility which has a valid air operation permit which has been shut down more than one year, shall notify the Department in writing of the intent to start up such emissions unit or facility, a minimum of 60 days prior to the intended startup date.

a. The notification shall include information as to the startup date, anticipated emission rates or pollutants released, changes to processes or control devices which will result in changes to emission rates, and any other conditions which may differ from the valid outstanding operation permit.
b. If, due to an emergency, a startup date is not known 60 days prior thereto, the owner shall notify the Department as soon as possible after the date of such startup is ascertained.

[Rule 62-210.300(5), F.A.C.]

RR10. Report Submission. The permittee shall submit all compliance related notifications and reports required of this permit to the Compliance Authority. {See front of permit for address and phone number.}

RR11. EPA Report Submission. Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to: Air, Pesticides & Toxics Management Division, United States Environmental Protection Agency, Region 4, Sam Nunn Atlanta Federal Center, 61 Forsyth Street SW, Atlanta, GA 30303-8960. Phone: 404/562-9077.

RR12. Acid Rain Report Submission. Acid Rain Program Information shall be submitted, as necessary, to: Department of Environmental Protection, 2600 Blair Stone Road, Mail Station #5510, Tallahassee, Florida 32399-2400. Phone: 850/488-6140. Fax: 850/922-6979.

RR13. Report Certification. All reports shall be accompanied by a certification by a responsible official, pursuant to Rule 62-213.420(4), F.A.C. [Rule 62-213.440(1)(b)3.c, F.A.C.]

RR14. Certification by Responsible Official (R.O.). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Any responsible official who fails to submit any required information or who has submitted incorrect information shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or correct information. [Rule 62-213.420(4), F.A.C.]

RR15. Confidential Information. Whenever an applicant submits information under a claim of confidentiality pursuant to Section 403.111, F.S., the applicant shall also submit a copy of all such information and claim directly to EPA. Any permittee may claim confidentiality of any data or other information by complying with this procedure. [Rules 62-213.420(2), and 62-213.440(1)(d)6., F.A.C.]

RR16. Forms and Instructions. The forms used by the Department in the Title V source operation program are adopted and incorporated by reference in Rule 62-213.900, F.A.C. The forms are listed by rule number, which is also the form number, and with the subject, title, and effective date. Copies of forms may be obtained by writing to the Department of Environmental Protection, Division of Air Resource Management, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, by contacting the appropriate permitting authority or by accessing the Department's web site at: http://www.dep.state.fl.us/air/rules/forms.htm.

a. Major Air Pollution Source Annual Emissions Fee Form (Effective 10/12/2008).
b. Statement of Compliance Form (Effective 06/02/2002).
c. Responsible Official Notification Form (Effective 06/02/2002).

[Rule 62-213.900, F.A.C.: Forms (1), (7) and (8)]

FACILITY-WIDE TESTING REQUIREMENTS

(version dated 9/12/2008)

Unless otherwise specified in the permit, the following testing requirements apply to each emissions unit for which testing is required. The terms "stack" and "duct" are used interchangeably in this appendix.

TR1. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

TR2. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. [Rule 62-297.310(2), F.A.C.]

TR3. Calculation of Emission Rate. For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

TR4. Applicable Test Procedures.

a. *Required Sampling Time.*

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

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

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

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

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

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

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

d. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

TABLE 297.310-1 CALIBRATION SCHEDULE			
ITEM	**MINIMUM CALIBRATION FREQUENCY**	**REFERENCE INSTRUMENT**	**TOLERANCE**
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass	5° F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5° F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/- 0.001" mean of at least three readings; Max. deviation between readings, 0.004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, when 5% change observed, annually	Spirometer or calibrated wet test or dry gas test meter	2%
	2. One Point: Semiannually		
	3. Check after each test series	Comparison check	5%

e. *Allowed Modification to EPA Method 5.* When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

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

TR5. Determination of Process Variables.

a. *Required Equipment*. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
b. *Accuracy of Equipment*. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

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

TR6. Sampling Facilities. Permittees that are required to sample mass emissions from point sources shall install stack sampling ports and provide sampling facilities that meet the requirements of this condition. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must also comply with all applicable Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

a. *Permanent Test Facilities*. The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.
b. *Temporary Test Facilities*. The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.
c. *Sampling Ports*.
   (1) All sampling ports shall have a minimum inside diameter of 3 inches.
   (2) The ports shall be capable of being sealed when not in use.
   (3) The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.
   (4) For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.
   (5) On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.
d. *Work Platforms*.
   (1) Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.
   (2) On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the

stack.

(3) On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

(4) All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toe board, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

e. *Access to Work Platform.*

(1) Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

(2) Walkways over free-fall areas shall be equipped with safety rails and toe boards.

f. *Electrical Power.*

(1) A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

(2) If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

g. *Sampling Equipment Support.*

(1) A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

(a) The bracket shall be a standard 3 inch × 3 inch × one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

(b) A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

(c) The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

(2) A complete monorail or dual rail arrangement may be substituted for the eyebolt and bracket.

(3) When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

[Rule 62-297.310(6), F.A.C.]

TR7. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

a. *General Compliance Testing.*

(1) The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

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

(3) The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to sub-subparagraph 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   (a) Did not operate; or
   (b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.
(4) During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
   (a) Visible emissions, if there is an applicable standard;
   (b) Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and
   (c) Each NESHAP pollutant, if there is an applicable emission standard.
(5) An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.
(6) For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.
(7) For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.
(8) Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.
(9) The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.
(10) An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.

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

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

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

TR8. Test Reports.

a. The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
b. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.
c. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information.
   (1) The type, location, and designation of the emissions unit tested.
   (2) The facility at which the emissions unit is located.
   (3) The owner or operator of the emissions unit.
   (4) The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
   (5) The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
   (6) The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
   (7) A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
   (8) The date, starting time and duration of each sampling run.
   (9) The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
   (10) The number of points sampled and configuration and location of the sampling plane.
   (11) For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
   (12) The type, manufacturer and configuration of the sampling equipment used.
   (13) Data related to the required calibration of the test equipment.
   (14) Data on the identification, processing and weights of all filters used.
   (15) Data on the types and amounts of any chemical solutions used.
   (16) Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
   (17) The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
   (18) All measured and calculated data required to be determined by each applicable test procedure for each run.
   (19) The detailed calculations for one run that relate the collected data to the calculated emission rate.
   (20) The applicable emission standard and the resulting maximum allowable emission rate for the

emissions unit plus the test result in the same form and unit of measure.

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

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

TITLE V GENERAL CONDITIONS
(version dated 09/17/2009)

Operation

TV1. General Prohibition. A permitted installation may only be operated, maintained, constructed, expanded or modified in a manner that is consistent with the terms of the permit.
[Rule 62-4.030, Florida Administrative Code (F.A.C.)]

TV2. Validity. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department. [Rule 62-4.160(2), F.A.C.]

TV3. Proper Operation and Maintenance. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed and used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules. [Rule 62-4.160(6), F.A.C.]

TV4. **Not federally enforceable.** Health, Safety and Welfare. To ensure protection of public health, safety, and welfare, any construction, modification, or operation of an installation which may be a source of pollution, shall be in accordance with sound professional engineering practices pursuant to Chapter 471, F.S. [Rule 62-4.050(3), F.A.C.]

TV5. Continued Operation. An applicant making timely and complete application for permit, or for permit renewal, shall continue to operate the source under the authority and provisions of any existing valid permit or Florida Electrical Power Plant Siting Certification, and in accordance with applicable requirements of the Acid Rain Program, applicable requirements of the CAIR Program, and applicable requirements of the Hg Budget Trading Program, until the conclusion of proceedings associated with its permit application or until the new permit becomes effective, whichever is later, provided the applicant complies with all the provisions of subparagraphs 62-213.420(1)(b)3., F.A.C. [Rule 62-213.420(1)(b)2., F.A.C.]

TV6. Changes Without Permit Revision. Title V sources having a valid permit issued pursuant to Chapter 62-213, F.A.C., may make the following changes without permit revision, provided that sources shall maintain source logs or records to verify periods of operation:

a. Permitted sources may change among those alternative methods of operation allowed by the source's permit as provided by the terms of the permit;
b. A permitted source may implement operating changes, as defined in Rule 62-210.200, F.A.C., after the source submits any forms required by any applicable requirement and provides the Department and EPA with at least 7 days written notice prior to implementation. The source and the Department shall attach each notice to the relevant permit;
   (1) The written notice shall include the date on which the change will occur, and a description of the change within the permitted source, the pollutants emitted and any change in emissions, and any term or condition becoming applicable or no longer applicable as a result of the change;
   (2) The permit shield described in Rule 62-213.460, F.A.C., shall not apply to such changes;
c. Permitted sources may implement changes involving modes of operation only in accordance with Rule 62-213.415, F.A.C.

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

TV7. Circumvention. 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. [Rule 62-210.650, F.A.C.]

Compliance

TV8. Compliance with Chapter 403, F.S., and Department Rules. Except as provided at Rule 62-213.460, Permit Shield, F.A.C., the issuance of a permit does not relieve any person from complying with the requirements of Chapter 403, F.S., or Department rules. [Rule 62-4.070(7), F.A.C.]

TV9. Compliance with Federal, State and Local Rules. Except as provided at Rule 62-213.460, F.A.C., issuance of a permit does not relieve the owner or operator of a facility or an emissions unit from complying with any applicable requirements, any emission limiting standards or other requirements of the air pollution rules of the Department or any other such requirements under federal, state, or local law. [Rule 62-210.300, F.A.C.]

TV10. Binding and enforceable. The terms, conditions, requirements, limitations and restrictions set forth in this permit, are "permit conditions" and are binding and enforceable pursuant to Sections 403.141, 403.727, or 403.859 through 403.861, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions. [Rule 62-4.160(1), F.A.C.]

TV11. Timely information. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware the relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly. [Rule 62-4.160(15), F.A.C.]

TV12. Halting or reduction of source activity. It shall not be a defense for a permittee in an enforcement action that maintaining compliance with any permit condition would necessitate halting of or reduction of the source activity. [Rule 62-213.440(1)(d)3., F.A.C.]

TV13. Final permit action. Any Title V source shall comply with all the terms and conditions of the existing permit until the Department has taken final action on any permit renewal or any requested permit revision, except as provided at Rule 62-213.412(2), F.A.C. [Rule 62-213.440(1)(d)4., F.A.C.]

TV14. Sudden and unforeseeable events beyond the control of the source. A situation arising from sudden and unforeseeable events beyond the control of the source which causes an exceedance of a technology-based emissions limitation because of unavoidable increases in emissions attributable to the situation and which requires immediate corrective action to restore normal operation, shall be an affirmative defense to an enforcement action in accordance with the provisions and requirements of 40 CFR 70.6(g)(2) and (3), hereby adopted and incorporated by reference. [Rule 62-213.440(1)(d)5., F.A.C.]

TV15. Permit Shield. Except as provided in Chapter 62-213, F.A.C., compliance with the terms and conditions of a permit issued pursuant to Chapter 62-213, F.A.C., shall, as of the effective date of the permit, be deemed compliance with any applicable requirements in effect, provided that the source included such applicable requirements in the permit application. Nothing in this condition or in any permit shall alter or affect the ability of EPA or the Department to deal with an emergency, the liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance, or the requirements of the Federal Acid Rain Program, the CAIR Program. [Rule 62-213.460, F.A.C.]

TV16. Compliance With Federal Rules. A facility or emissions unit subject to any standard or requirement of 40 CFR, Part 60, 61, 63 or 65, adopted and incorporated by reference at Rule 62-204.800, F.A.C., shall comply with such standard or requirement. Nothing in this chapter shall relieve a facility or emissions unit from complying with such standard or requirement, provided, however, that where a facility or emissions unit is subject to a standard established in Rule 62-296, F.A.C., such standard shall also apply. [Rule 62-296.100(3), F.A.C.]

Permit Procedures

TV17. Permit Revision Procedures. The permittee shall revise its permit as required by Rules 62-213.400, 62-213.412, 62-213.420, 62-213.430 & 62-4.080, F.A.C.; and, in addition, the Department shall revise permits as provided in Rule 62-4.080, F.A.C. & 40 CFR 70.7(f).

TV18. Permit Renewal. The permittee shall renew its permit as required by Rules 62-4.090, 62.213.420(1) and 62-213.430(3), F.A.C. Permits being renewed are subject to the same requirements that apply to permit issuance at the time of application for renewal. Permit renewal applications shall contain that information identified in Rules 62-210.900(1) [Application for Air Permit - Long Form], 62-213.420(3) [Required Information], 62-213.420(6) [CAIR Part Form], F.A.C. Unless a Title V source submits a timely and complete application for permit renewal in accordance with the requirements this rule, the existing permit shall expire and the source's right to operate shall terminate. For purposes of a permit renewal, a timely application is one that is submitted 225 days before the expiration of a permit that expires on or after June 1, 2009. No Title V permit will be issued for a new term except through the renewal process. [Rules 62-213.420 & 62-213.430, F.A.C.]

TV19. Insignificant Emissions Units or Pollutant-Emitting Activities. The permittee shall identify and evaluate insignificant emissions units and activities as set forth in Rule 62-213.430(6), F.A.C.

TV20. Savings Clause. If any portion of the final permit is invalidated, the remainder of the permit shall remain in effect. [Rule 62-213.440(1)(d)1., F.A.C.]

TV21. Suspension and Revocation.

a. Permits shall be effective until suspended, revoked, surrendered, or expired and shall be subject to the provisions of Chapter 403, F.S., and rules of the Department.
b. Failure to comply with pollution control laws and rules shall be grounds for suspension or revocation.
c. A permit issued pursuant to Chapter 62-4, F.A.C., shall not become a vested property right in the permittee. The Department may revoke any permit issued by it if it finds that the permit holder or his agent:
   (1) Submitted false or inaccurate information in his application or operational reports.
   (2) Has violated law, Department orders, rules or permit conditions.
   (3) Has failed to submit operational reports or other information required by Department rules.
   (4) Has refused lawful inspection under Section 403.091, F.S.
d. No revocation shall become effective except after notice is served by personal services, certified mail, or newspaper notice pursuant to Section 120.60(7), F.S., upon the person or persons named therein and a hearing held if requested within the time specified in the notice. The notice shall specify the provision of the law, or rule alleged to be violated, or the permit condition or Department order alleged to be violated, and the facts alleged to constitute a violation thereof.

[Rule 62-4.100, F.A.C.]

TV22. Not federally enforceable. Financial Responsibility. The Department may require an applicant to submit proof of financial responsibility and may require the applicant to post an appropriate bond to guarantee compliance with the law and Department rules. [Rule 62-4.110, F.A.C.]

TV23. Emissions Unit Reclassification.

a. Any emissions unit whose operation permit has been revoked as provided for in Chapter 62-4, F.A.C., shall be deemed permanently shut down for purposes of Rule 62-212.500, F.A.C. Any emissions unit whose permit to operate has expired without timely renewal or transfer may be deemed permanently shut down, provided, however, that no such emissions unit shall be deemed permanently shut down if, within 20 days after receipt of written notice from the Department, the emissions unit owner or operator demonstrates that the permit expiration resulted from inadvertent failure to comply with the requirements of Rule 62-4.090, F.A.C., and that the owner or operator intends to continue the emissions unit in operation, and either submits an application for an air operation permit or complies with permit transfer requirements, if applicable.
b. If the owner or operator of an emissions unit which is so permanently shut down, applies to the Department for a permit to reactivate or operate such emissions unit, the emissions unit will be reviewed and permitted as a new emissions unit.

[Rule 62-210.300(6), F.A.C.]

TV24. Transfer of Permits. Per Rule 62-4.160(11), F.A.C., this permit is transferable only upon Department approval in accordance with Rule 62-4.120, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department. The permittee transferring the permit shall remain liable for corrective actions that may be required as a result of any violations occurring prior to the sale or legal transfer of the facility. The permittee shall also comply with the requirements of Rule 62-210.300(7), F.A.C., and use DEP Form No. 62-210.900(7). [Rules 62-4.160(11), 62-4.120, and 62-210.300(7), F.A.C.]

Rights, Title, Liability, and Agreements

TV25. Rights. As provided in Subsections 403.987(6) and 403.722(5), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in this permit. [Rule 62-4.160(3), F.A.C.]

TV26. Title. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title. [Rule 62-4.160(4), (F.A.C.]

TV27. Liability. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of F.S. and Department rules, unless specifically authorized by an order from the Department. [Rule 62-4.160(5), F.A.C.]

TV28. Agreements.

a. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at reasonable times, access to the premises where the permitted activity is located or conducted to:

(1) Have access to and copy any records that must be kept under conditions of the permit;

(2) Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,

(3) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules. Reasonable time may depend on the nature of the concern being investigated.

b. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.111 and 403.73, F.S. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

c. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

[Rules 62-4.160(7), (9), and (10), F.A.C.]

Recordkeeping and Emissions Computation

TV29. Permit. The permittee shall keep this permit or a copy thereof at the work site of the permitted activity. [Rule 62-4.160(12), F.A.C.]

TV30. Recordkeeping.

a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least five (5) years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c. Records of monitoring information shall include:
   (1) The date, exact place, and time of sampling or measurements, and the operating conditions at the time of sampling or measurement;
   (2) The person responsible for performing the sampling or measurements;
   (3) The dates analyses were performed;
   (4) The person and company that performed the analyses;
   (5) The analytical techniques or methods used;
   (6) The results of such analyses.

[Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

TV31. Emissions Computation. Pursuant to Rule 62-210.370, F.A.C., the following required methodologies are to be used by the owner or operator of a facility for computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for computing emissions for purposes of the reporting requirements of subsection 62-210.370(3) and paragraph 62-212.300(1)(e), F.A.C., or of any permit condition that requires emissions be computed in accordance with Rule 62-210.370, F.A.C. Rule 62-210.370, F.A.C., is not intended to establish methodologies for determining compliance with the emission limitations of any air permit.

For any of the purposes specified above, the owner or operator of a facility shall compute emissions in accordance with the requirements set forth in this subsection.

a. Basic Approach. The owner or operator shall employ, on a pollutant-specific basis, the most accurate of the approaches set forth below to compute the emissions of a pollutant from an emissions unit; provided, however, that nothing in this rule shall be construed to require installation and operation of any continuous emissions monitoring system (CEMS), continuous parameter monitoring system (CPMS), or predictive emissions monitoring system (PEMS) not otherwise required by rule or permit, nor shall anything in this rule be construed to require performance of any stack testing not otherwise required by rule or permit.
   (1) If the emissions unit is equipped with a CEMS meeting the requirements of paragraph 62-210.370(2)(b), F.A.C., the owner or operator shall use such CEMS to compute the emissions of the pollutant, unless the owner or operator demonstrates to the department that an alternative approach is more accurate because the CEMS represents still-emerging technology.
   (2) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C, but emissions of the pollutant can be computed pursuant to the mass balance methodology of paragraph 62-210.370(2)(c), F.A.C., the owner or operator shall use such methodology, unless the owner or operator demonstrates to the department that an alternative approach is more accurate.
   (3) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C., and emissions cannot be computed pursuant to the mass balance methodology, the owner or operator shall use an emission factor meeting the requirements of paragraph 62-210.370(2)(d), F.A.C., unless the owner or operator demonstrates to the department that an alternative approach is more accurate.

b. Continuous Emissions Monitoring System (CEMS).
   (1) An owner or operator may use a CEMS to compute emissions of a pollutant for purposes of this rule provided:
      (a) The CEMS complies with the applicable certification and quality assurance requirements of 40 CFR Part 60, Appendices B and F, or, for an acid rain unit, the certification and quality assurance requirements of 40 CFR Part 75, all adopted by reference at Rule 62-204.800, F.A.C.; or,
      (b) The owner or operator demonstrates that the CEMS otherwise represents the most accurate means of computing emissions for purposes of this rule.
   (2) Stack gas volumetric flow rates used with the CEMS to compute emissions shall be obtained by the most accurate of the following methods as demonstrated by the owner or operator:

(a) A calibrated flowmeter that records data on a continuous basis, if available; or
(b) The average flow rate of all valid stack tests conducted during a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

(3) The owner or operator may use CEMS data in combination with an appropriate f-factor, heat input data, and any other necessary parameters to compute emissions if such method is demonstrated by the owner or operator to be more accurate than using a stack gas volumetric flow rate as set forth at subparagraph 62-210.370(2)(b)2., F.A.C., above.

c. Mass Balance Calculations.

(1) An owner or operator may use mass balance calculations to compute emissions of a pollutant for purposes of this rule provided the owner or operator:
(a) Demonstrates a means of validating the content of the pollutant that is contained in or created by all materials or fuels used in or at the emissions unit; and,
(b) Assumes that the emissions unit emits all of the pollutant that is contained in or created by any material or fuel used in or at the emissions unit if it cannot otherwise be accounted for in the process or in the capture and destruction of the pollutant by the unit's air pollution control equipment.

(2) Where the vendor of a raw material or fuel which is used in or at the emissions unit publishes a range of pollutant content from such material or fuel, the owner or operator shall use the highest value of the range to compute the emissions, unless the owner or operator demonstrates using site-specific data that another content within the range is more accurate.

(3) In the case of an emissions unit using coatings or solvents, the owner or operator shall document, through purchase receipts, records and sales receipts, the beginning and ending VOC inventories, the amount of VOC purchased during the computational period, and the amount of VOC disposed of in the liquid phase during such period.

d. Emission Factors.

(1) An owner or operator may use an emission factor to compute emissions of a pollutant for purposes of this rule provided the emission factor is based on site-specific data such as stack test data, where available, unless the owner or operator demonstrates to the department that an alternative emission factor is more accurate. An owner or operator using site-specific data to derive an emission factor, or set of factors, shall meet the following requirements.
(a) If stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid stack tests conducted during at least a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.
(b) Multiple emission factors shall be used as necessary to account for variations in emission rate associated with variations in the emissions unit's operating rate or operating conditions during the period over which emissions are computed.
(c) The owner or operator shall compute emissions by multiplying the appropriate emission factor by the appropriate input, output or gas volume value for the period over which the emissions are computed. The owner or operator shall not compute emissions by converting an emission factor to pounds per hour and then multiplying by hours of operation, unless the owner or operator demonstrates that such computation is the most accurate method available.

(2) If site-specific data are not available to derive an emission factor, the owner or operator may use a published emission factor directly applicable to the process for which emissions are computed. If no directly-applicable emission factor is available, the owner or operator may use a factor based on a similar, but different, process.

e. Accounting for Emissions During Periods of Missing Data from CEMS, PEMS, or CPMS. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of missing data from CEMS, PEMS, or CPMS using other site-specific data to generate a reasonable estimate of such emissions.
f. Accounting for Emissions During Periods of Startup and Shutdown. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit.
g. Fugitive Emissions. In computing the emissions of a pollutant from a facility or emissions unit, the owner or operator shall account for the fugitive emissions of the pollutant, to the extent quantifiable, associated with such facility or emissions unit.
h. Recordkeeping. The owner or operator shall retain a copy of all records used to compute emissions pursuant to this rule for a period of five years from the date on which such emissions information is submitted to the department for any regulatory purpose.

[Rule 62-210.370(1) & (2), F.A.C.]

Responsible Official

TV32. Designation and Update. The permittee shall designate and update a responsible official as required by Rule 62-213.202, F.A.C.

Prohibitions and Restrictions

TV33. Asbestos. This permit does not authorize any demolition or renovation of the facility or its parts or components which involves asbestos removal. This permit does not constitute a waiver of any of the requirements of Chapter 62-257, F.A.C., and 40 CFR 61, Subpart M, National Emission Standard for Asbestos, adopted and incorporated by reference in Rule 62-204.800, F.A.C. Compliance with Chapter 62-257, F.A.C., and 40 CFR 61, Subpart M, Section 61.145, is required for any asbestos demolition or renovation at the source. [40 CFR 61; Rule 62-204.800, F.A.C.; and, Chapter 62-257, F.A.C.]

TV34. Refrigerant Requirements. Any facility having refrigeration equipment, including air conditioning equipment, which uses a Class I or II substance (listed at 40 CFR 82, Subpart A, Appendices A and B), and any facility which maintains, services, or repairs motor vehicles using a Class I or Class II substance as refrigerant must comply with all requirements of 40 CFR 82, Subparts B and F, and with Chapter 62-281, F.A.C.

TV35. Open Burning Prohibited. Unless otherwise authorized by Rule 62-296.320(3) or Chapter 62-256, F.A.C., open burning is prohibited.

REFERENCED ATTACHMENTS.

The Following Attachments Are Included for Applicant Convenience:

Table 1, Summary of Air Pollutant Standards and Terms.
Table 2, Compliance Requirements.
Table H, Permit History.

Table 1, Summary of Air Pollutant Standards and Terms

Florida Power Corporation dba Progress Energy Florida, Inc. (PEF)
Suwannee River Power Plant

Final Permit No. 1210003-007-AV
Facility ID No. 1210003

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

E.U. ID No. | **Brief Description**
-001 & -002 & -003 | Fossil Fuel Fired Steam Generator Unit Nos. 1, 2 & 3

Unless otherwise indicated, the following apply to each individual emissions unit listed.

Pollutant Name or Parameter	Fuel(s)	Hours/Year	Allowable Emissions Standard(s)	lbs./hour	TPY	Equivalent Emissions* lbs./hour	TPY	Regulatory Citation(s)	See permit condition(s)
VE	Gas/Oil	8,760	20% w/ 40% for 2 min/hr					Rule 62-296.405(1)(a), F.A.C.	III.A.5.
VE-SB	Gas/Oil		60% 3 hrs/24 hrs					Rule 62-210.700(3), F.A.C.	III.A.6.
-001 PM	Gas/Oil	8,760	0.1 lb/MMBtu			45.0	246.4	Rule 62-296.405(1)(b), F.A.C.	III.A.7.
-001 PM-SB	Gas/Oil	1,095	0.3 lb/MMBtu			135.0		Rule 62-210.700(3), F.A.C.	III.A.8.
-002 PM	Gas/Oil	8,760	0.1 lb/MMBtu			44.4	243.1	Rule 62-296.405(1)(b), F.A.C.	III.A.7.
-002 PM-SB	Gas/Oil	1,095	0.3 lb/MMBtu			133.2		Rule 62-210.700(3), F.A.C.	III.A.8.
-003 PM	Gas/Oil	8,760	0.1 lb/MMBtu			88.1	482.3	Rule 62-296.405(1)(b), F.A.C.	III.A.7.
-003 PM-SB	Gas/Oil	1,095	0.3 lb/MMBtu			264.3		Rule 62-210.700(3), F.A.C.	III.A.8.
-001 SO_2	Oil	8,760	2.75 lb/MMBtu					Rule 62-296.405(1)(c)1.j., F.A.C	III.A.9.
-001 SO_2	Oil	8,760	max. 2.5% S by weight			1,237.5	5,420.3	Rule 62-296.405(1)(e)3., F.A.C.	III.A.10.
-002 SO_2	Oil	8,760	2.75 lb/MMBtu					Rule 62-296.405(1)(c)1.j., F.A.C	III.A.9.
-002 SO_2	Oil	8,760	max. 2.5% S by weight			1,221.0	5,348.0	Rule 62-296.405(1)(e)3., F.A.C.	III.A.10.
-003 SO_2	Oil	8,760	2.75 lb/MMBtu					Rule 62-296.405(1)(c)1.j., F.A.C	III.A.9.
-003 SO_2	Oil	8,760	max. 1.0% S by weight			922.1	4,038.9	Rule 62-296.405(1)(e)3., F.A.C.	III.A.10.
-003 SO_2	Oil	8,760	max. 2.5% S by weight			1,290.2	5,651.2	Rule 62-296.405(1)(e)3., F.A.C.	III.A.10.
Arsenic	Used Oil		5 ppm (11,267,000 gal/yr)			0.05	0.23	40 CFR 279	III.A.40.
Cadmium	Used Oil		2 ppm (11,267,000 gal/yr)			0.02	0.09	40 CFR 279	III.A.40.
Chromium	Used Oil		10 ppm (11,267,000 gal/yr)			0.11	0.47	40 CFR 279	III.A.40.
Lead	Used Oil		100 ppm (11,267,000 gal/yr)			1.07	4.69	40 CFR 279	III.A.40.
Total Halogens	Used Oil		1,000 ppm (11,267,000 gal/yr)			10.71	46.93	40 CFR 279	III.A.40.
PCBs	Used Oil		<50 ppm (11,267,000 gal/yr)			0.54	2.35	40 CFR 279	III.A.40.

Notes:
* The "Equivalent Emissions" listed are for informational purposes only.

Table 1, Summary of Air Pollutant Standards and Terms

Florida Power Corporation dba Progress Energy Florida, Inc. (PEF)
Suwannee River Power Plant

Final Permit No. 1210003-007-AV
Facility ID No. 1210003

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

E.U. ID No.	**Brief Description**
-004, -005 & -006	Combustion Turbine Peaking (CTP) Unit Nos. 1 (P-1), 2 (P-2) & 3 (P-3)

The following apply to each individual unit.

Pollutant Name or Parameter	Fuel(s)	Hours/Year	Allowable Emissions Standard(s)	Allowable Emissions lbs./hour	Allowable Emissions TPY	Equivalent Emissions* lbs./hour	Equivalent Emissions* TPY	Regulatory Citation(s)	See permit condition(s)
NO_X	No. 2 fuel oil	1500 hrs/yr/CT	75 ppmvd @ 15% O_2			177.4	133.0	PSD-FL-014	III.B.5.
NO_X	Natural Gas	1500 hrs/yr/CT	68 ppmvd @ 15% O_2			96.1	72.1	PSD-FL-014	III.B.6.
SO_2	All	1500 hrs/yr/CT	0.5% sulfur by weight			379.0	284.3	PSD-FL-014	III.B.8.
VE	All	1500 hrs/yr/CT	<20% opacity	NA	NA			PSD-FL-014	III.B.9.

Notes:
* The "Equivalent Emissions" listed are for informational purposes only.

Table 2, Summary of Compliance Requirements

Florida Power Corporation dba Progress Energy Florida, Inc. (PEF)
Final Permit No. 1210003-007-AV

Suwannee River Power Plant
Facility ID No. 1210003

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

E.U. ID No.	**Brief Description**
-001 & -002 & -003	Fossil Fuel Fired Steam Generator Unit Nos. 1, 2 & 3

Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS**	See permit condition(s)
VE	Gas/Oil	DEP Method 9	annual & renewal		60 minutes	Yes	III.A.17., 18, 19., 21. & 22.
VE-SB	Gas/Oil	DEP Method 9	annual & renewal		60 minutes	Yes	III.A.17., 18, 19., 21. & 22.
PM	Gas/Oil	EPA Method 17, 5, 5B,or 5F	annual & renewal		1 hour		III.A.17., 18, 19. & 23.
PM-SB	Gas/Oil	EPA Method 17, 5, 5B,or 5F	annual & renewal		1 hour		III.A.17., 18, 19. & 23.
SO2	Oil	EPA Method 6, 6A, 6B,or 6C			1 hour		III.A.17., 18, 19., 24. & 25.
SO2	Gas/Oil	Appendix D, 40 CFR 75					III.A.17., 18, 19., 24. & 25.
SO2	Oil	Fuel sampling & analysis for 1.8% S by weight	Each Delivery			Yes	III.A.17., 18, 19., 24. & 25.
SO2	Oil	Fuel sampling & analysis for 1.8% S by weight	Each Delivery			Yes	III.A.17., 18, 19., 24. & 25.
Arsenic	Used Oil	ASTM Standard D140-70	Each Delivery				III.A.32.
Cadmium	Used Oil	ASTM Standard D140-70	Each Delivery				III.A.32.
Chromium	Used Oil	ASTM Standard D140-70	Each Delivery				III.A.32.
Lead	Used Oil	ASTM Standard D140-70	Each Delivery				III.A.32.
Total Halogens	Used Oil	ASTM Standard D140-70	Each Delivery				III.A.32.
Flash Point	Used Oil	ASTM Standard D140-70	Each Delivery				III.A.32.
PCBs	Used Oil	ASTM Standard D140-70	Each Delivery				III.A.32.

Notes:
* The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
**CMS [=] continuous monitoring system

Table 2, Summary of Compliance Requirements

Florida Power Corporation dba Progress Energy Florida, Inc. (PEF) — Final Permit No. 1210003-007-AV

Suwannee River Power Plant — Facility ID No. 1210003

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

E.U. ID No.	Brief Description
-004, -005 & -006	Combustion Turbine Peaking (CTP) Unit Nos. 1 (P-1), 2 (P-2) & 3 (P-3)

Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS**	See permit condition(s)
NO_X	All	EPA Method 20	Annual		1-hour		III.B.16. - 19. & 20.
% Sulfur	All	Fuel Sampling & Analysis	Daily / Transfer				III.B.16. - 19. & 21.
SO_2	All	EPA Method 20			1-hour		III.B.16. - 19.
VE	All	EPA Method 9	Annual		30-minutes		III.B.16. - 19., 23. & 24.

Notes:

* The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.

**CMS [=] continuous monitoring system

TABLE H

PERMIT HISTORY/ID NUMBER CHANGES

This permit history summarizes primarily projects issued after project number -005-AV. For previously issued projects, also refer to the Appendix H-1's referenced in Permit Nos. 1210003-001-AV and 1210003-005-AV posted on the web site.

Relevant Permits Issued & Projects:

E.U. ID No.	Description	Permit No.	Effective Date	Expiration Date	Project Type
All	Facility	1210003-001-AV	01/01/2000	12/31/2004	Initial
All	Facility	1210003-005-AV[1]	01/01/2005	12/31/2009	Renewal (1st)
All	Facility	1210003-007-AV	01/01/2010	12/31/2014	Renewal (2nd)
-001 - -006	CAIR	1210003-006-AV	03/19/2009	NA	Revision (CAIR)
-004, -005 & -006	Combustion Turbine Peaking Unit Nos. 1, 2 & 3 (P-1, P-2 & P-3)	1210003-004-AC	10/29/2002	12/31/2004	Construction (mod.)
-004, -005 & -006	Custom Fuel Monitoring Schedule	NA	02/16/1998 & 03/02/1999	NA	Construction (mod.)
-004, -005 & -006	Combustion Turbine Peaking Unit Nos. 1, 2 & 3 (P-1, P-2 & P-3) - Addition of Natural Gas	PSD-FL-014A/ 1210003-002-AC	05/06/1997	NA	Construction (mod.)
-004, -005 & -006	Combustion Turbine Peaking Unit Nos. 1, 2 & 3 (P-1, P-2 & P-3)	PSD-FL-014 amendment	05/22/1980 (EPA issued)	NA	Construction (mod.)
-004, -005 & -006	Combustion Turbine Peaking Unit Nos. 1, 2 & 3 (P-1, P-2 & P-3)	PSD-FL-014	07/09/1979 (EPA issued)		Construction (new)
-004	Combustion Turbine Peaking Unit No. 1 (P-1)	AC61-11862	11/28/1978	05/01/1981	Construction (new)
-005	Combustion Turbine Peaking Unit No. 2 (P-2)	AC61-11863	11/28/1978	05/01/1981	Construction (new)
-006	Combustion Turbine Peaking Unit No. 3 (P-3)	AC61-11864	11/28/1978	05/01/1981	Construction (new)
-004, -005 & -006	Combustion Turbine Peaking Unit Nos. 1, 2 & 3 (P-1, P-2 & P-3)	NA	08/16/1978 (DER issued)	NA	BACT Determination

[1] the most recent Title V air operation permit posted on the web site.
"NA" represents not applicable.

Friday, Barbara

To:	cary.hamilton@pgnmail.com
Cc:	Brickhouse, Brenda; patricia.west@pgnmail.com; chris.bradley@pgnmail.com; 'Tom Davis'; Kirts, Christopher; 'Forney.Kathleen@epamail.epa.gov'; Oquendo.Ana@epamail.epa.gov; Gibson, Victoria; Sheplak, Scott; Holtom, Jonathan
Subject:	FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV
Attachments:	1210003-007-AVSignedNoticeofFinalPermit.pdf

Dear Sir/ Madam:

Attached is the official **Notice of Final Permit** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/1210003.007.AV.F_pdf.zip

Attention: Scott Sheplak

Owner/Company Name: FLORIDA POWER CORPDBAPROGRESS ENERGY FLA
Facility Name: SUWANNEE RIVER PLANT
Project Number: 1210003-007-AV
Permit Status: FINAL
Permit Activity: PERMIT RENEWAL
Facility County: SUWANNEE

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/emission/apds/default.asp . "

Permit project documents that are addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation.

Barbara Friday
Bureau of Air Regulation
Division of Air Resource Management (DARM)
(850)921-9524

Friday, Barbara

From: Exchange Administrator
Sent: Friday, December 18, 2009 9:56 AM
To: Friday, Barbara
Subject: Delivery Status Notification (Relay)
Attachments: ATT102627.txt; FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV

This is an automatically generated Delivery Status Notification.

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

cary.hamilton@pgnmail.com
Brenda.Brickhouse@pgnmail.com
patricia.west@pgnmail.com
chris.bradley@pgnmail.com

Friday, Barbara

From: Hamilton, Cary W [Cary.Hamilton@pgnmail.com]
To: Friday, Barbara
Sent: Sunday, December 20, 2009 10:00 AM
Subject: Read: FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV

Your message

To: Cary.Hamilton@pgnmail.com
Subject:

was read on 12/20/2009 10:00 AM.

Friday, Barbara

From: Brickhouse, Brenda [Brenda.Brickhouse@pgnmail.com]
To: Friday, Barbara
Sent: Monday, December 21, 2009 8:14 AM
Subject: Read: FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV

Your message

To: Brenda.Brickhouse@pgnmail.com
Subject:

was read on 12/21/2009 8:14 AM.

Friday, Barbara

From: West, Patricia Q. [Patricia.West@pgnmail.com]
To: Friday, Barbara
Sent: Friday, December 18, 2009 10:05 AM
Subject: Read: FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV

Your message

To: Patricia.West@pgnmail.com
Subject:

was read on 12/18/2009 10:05 AM.

Friday, Barbara

From: Exchange Administrator
Sent: Friday, December 18, 2009 9:56 AM
To: Friday, Barbara
Subject: Delivery Status Notification (Relay)
Attachments: ATT102626.txt; FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV

This is an automatically generated Delivery Status Notification.

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

tdavis@ectinc.com

Friday, Barbara

From: Tom Davis [tdavis@ectinc.com]
Sent: Friday, December 18, 2009 10:03 AM
To: Friday, Barbara
Subject: RE: FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV

Barbara,

I have received and can access the documents referenced in your email below.

Thanks.

From: Friday, Barbara [mailto:Barbara.Friday@dep.state.fl.us]
Sent: Friday, December 18, 2009 9:55 AM
To: cary.hamilton@pgnmail.com
Cc: Brickhouse, Brenda; patricia.west@pgnmail.com; chris.bradley@pgnmail.com; Tom Davis; Kirts, Christopher; Forney.Kathleen@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov; Gibson, Victoria; Sheplak, Scott; Holtom, Jonathan
Subject: FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV

Dear Sir/ Madam:

Attached is the official **Notice of Final Permit** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/1210003.007.AV.F_pdf.zip

Attention: Scott Sheplak

Owner/Company Name: FLORIDA POWER CORPDBAPROGRESS ENERGY FLA
Facility Name: SUWANNEE RIVER PLANT
Project Number: 1210003-007-AV
Permit Status: FINAL
Permit Activity: PERMIT RENEWAL
Facility County: SUWANNEE

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/emission/apds/default.asp . "

Permit project documents that are addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation.

Barbara Friday
Bureau of Air Regulation
Division of Air Resource Management (DARM)
(850)921-9524

The Department of Environmental Protection values your feedback as a customer. DEP Secretary Michael W. Sole is committed to continuously assessing and improving the level and quality of services provided to you. Please take a few minutes to comment on the quality of service you received. Simply click on this link to the DEP Customer Survey. Thank you in advance for completing the survey.

Friday, Barbara

From: System Administrator
To: Kirts, Christopher; Gibson, Victoria
Sent: Friday, December 18, 2009 9:55 AM
Subject: Delivered:FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV

Your message

To: cary.hamilton@pgnmail.com
Cc: Brickhouse, Brenda; patricia.west@pgnmail.com; chris.bradley@pgnmail.com; Tom Davis; Kirts, Christopher; Forney.Kathleen@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov; Gibson, Victoria; Sheplak, Scott; Holtom, Jonathan
Subject: FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV
Sent: 12/18/2009 9:55 AM

was delivered to the following recipient(s):

Kirts, Christopher on 12/18/2009 9:55 AM
Gibson, Victoria on 12/18/2009 9:55 AM

Friday, Barbara

From: Kirts, Christopher
To: Friday, Barbara
Sent: Friday, December 18, 2009 1:26 PM
Subject: Read: FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV

Your message

To: cary.hamilton@pgnmail.com
Cc: Brickhouse, Brenda; patricia.west@pgnmail.com; chris.bradley@pgnmail.com; Tom Davis; Kirts, Christopher; Forney.Kathleen@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov; Gibson, Victoria; Sheplak, Scott; Holtom, Jonathan
Subject: FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV
Sent: 12/18/2009 9:55 AM

was read on 12/18/2009 1:26 PM.

Friday, Barbara

From: Gibson, Victoria
To: Friday, Barbara
Sent: Friday, December 18, 2009 9:58 AM
Subject: Read: FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV

Your message

To: cary.hamilton@pgnmail.com
Cc: Brickhouse, Brenda; patricia.west@pgnmail.com; chris.bradley@pgnmail.com; Tom Davis; Kirts, Christopher; Forney.Kathleen@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov; Gibson, Victoria; Sheplak, Scott; Holtom, Jonathan
Subject: FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV
Sent: 12/18/2009 9:55 AM

was read on 12/18/2009 9:58 AM.

Friday, Barbara

From: Mail Delivery System [MAILER-DAEMON@mseive02.rtp.epa.gov]
Sent: Friday, December 18, 2009 9:56 AM
To: Friday, Barbara
Subject: Successful Mail Delivery Report
Attachments: Delivery report; Message Headers

This is the mail system at host mseive02.rtp.epa.gov.

Your message was successfully delivered to the destination(s) listed below. If the message was delivered to mailbox you will receive no further notifications. Otherwise you may still receive notifications of mail delivery errors from other systems.

The mail system

<Forney.Kathleen@epamail.epa.gov>: delivery via 127.0.0.1[127.0.0.1]:10025: 250 OK, sent 4B2B97E9_15323_7560_3 A70B51DC004

<Oquendo.Ana@epamail.epa.gov>: delivery via 127.0.0.1[127.0.0.1]:10025: 250 OK, sent 4B2B97E9_15323_7560_3 A70B51DC004

Friday, Barbara

From: System Administrator
To: Sheplak, Scott
Sent: Friday, December 18, 2009 9:55 AM
Subject: Delivered:FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV

Your message

To: cary.hamilton@pgnmail.com
Cc: Brickhouse, Brenda; patricia.west@pgnmail.com; chris.bradley@pgnmail.com; Tom Davis; Kirts, Christopher; Forney.Kathleen@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov; Gibson, Victoria; Sheplak, Scott; Holtom, Jonathan
Subject: FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV
Sent: 12/18/2009 9:55 AM

was delivered to the following recipient(s):

Sheplak, Scott on 12/18/2009 9:55 AM

Friday, Barbara

From: Sheplak, Scott
To: Friday, Barbara
Sent: Tuesday, December 22, 2009 10:40 AM
Subject: Read: FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV

Your message

To: cary.hamilton@pgnmail.com
Cc: Brickhouse, Brenda; patricia.west@pgnmail.com; chris.bradley@pgnmail.com; Tom Davis; Kirts, Christopher; Forney.Kathleen@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov; Gibson, Victoria; Sheplak, Scott; Holtom, Jonathan
Subject: FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV
Sent: 12/18/2009 9:55 AM

was read on 12/22/2009 10:40 AM.

Friday, Barbara

From: System Administrator
To: Holtom, Jonathan
Sent: Friday, December 18, 2009 9:55 AM
Subject: Delivered:FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV

Your message

To: cary.hamilton@pgnmail.com
Cc: Brickhouse, Brenda; patricia.west@pgnmail.com; chris.bradley@pgnmail.com; Tom Davis; Kirts, Christopher; Forney.Kathleen@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov; Gibson, Victoria; Sheplak, Scott; Holtom, Jonathan
Subject: FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV
Sent: 12/18/2009 9:55 AM

was delivered to the following recipient(s):

Holtom, Jonathan on 12/18/2009 9:55 AM

Friday, Barbara

From: Holtom, Jonathan
To: Friday, Barbara
Sent: Friday, December 18, 2009 10:10 AM
Subject: Read: FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV

Your message

To: cary.hamilton@pgnmail.com
Cc: Brickhouse, Brenda; patricia.west@pgnmail.com; chris.bradley@pgnmail.com; Tom Davis; Kirts, Christopher; Forney.Kathleen@epamail.epa.gov; Oquendo.Ana@epamail.epa.gov; Gibson, Victoria; Sheplak, Scott; Holtom, Jonathan
Subject: FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC. - SUWANNEE RIVER PLANT; 1210003-007-AV
Sent: 12/18/2009 9:55 AM

was read on 12/18/2009 10:10 AM.

ATTACHMENT
SRP-FI-CA1
ACID RAIN PROGRAM FORMS

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
Suwannee River	**FL**	**638**

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
1		**Yes**		
2		**Yes**		
3		**Yes**		

Plant Name (from STEP 1) **Suwannee River**

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,

Plant Name (from STEP 1)	**Suwannee River**

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

Suwannee River
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 **Jeffrey R. Swartz**	Title **Vice President, Florida – Power Generation Operations**
Owner Company Name **Duke Energy Florida, Inc.**	
Phone **(727) 820-5188**	E-mail address **Jeffrey.Swartz@duke-energy.com**
Signature JR Swartz	Date 5/1/2014

ATTACHMENT
SRP-FI-CA2
CAIR PART

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:
Suwannee River	**Florida**	**638**

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
1	**X**	**X**	**X**		
2	**X**	**X**	**X**		
3	**X**	**X**	**X**		
1A	**X**	**X**	**X**		
1B	**X**	**X**	**X**		
2A	**X**	**X**	**X**		
2B	**X**	**X**	**X**		
3A	**X**	**X**	**X**		
3B	**X**	**X**	**X**		

Plant Name (from STEP 1) **Suwannee River**

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) **Suwannee River**

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) **Suwannee River**

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) **Suwannee River**

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 **Jeffrey R. Swartz**	Title **Vice President, Florida – Power Generation Operations**
Owner Company Name **Duke Energy Florida, Inc.**	
Phone **(727) 820-5188**	E-mail address **Jeffrey.Swartz@duke-energy.com**
Signature JR Swartz	Date 5/1/2014

ATTACHMENT
SRP-EU1-I2
FUEL ANALYSIS AND SPECIFICATION

SGS

DATE: 24-Jan-2014

SGS Oil, Gas and Chemicals
SGS Port Canaveral
8985 Columbia Road
Cape Canaveral, FL, 32920
U.S.A.
Tel: +1-(321)-784-1941
Fax: +1-(321)-784-1943

DUKE ENERGY
4037 RIVER ROAD
LIVE OAK
UNITED STATES
32060

Certificate of Analysis: PC14-00013.006

CLIENT ORDER NUMBER :	Job# 313620	SGS ORDER NO.:	--
CLIENT ID :	JANUARY 2014	PRODUCT DESCRIPTION :	Natural Gas
LOCATION :	Duke Energy - Suwanee		
SAMPLE SOURCE :	Natural Gas Line	SOURCE ID :	Pipeline
SAMPLE TYPE :	Submitted Sample	SAMPLED BY :	Duke Energy
SAMPLED :	20-Jan-2014	RECEIVED	21-Jan-2014
ANALYSED :	24-Jan-2014	COMPLETED :	24-Jan-2014

PROPERTY	METHOD	RESULT	UNITS	
Ideal Gross Heating Value	ASTM D3588	1050	Btu/ft³	
Ideal Net Heating Value	ASTM D3588	947	Btu/ft³	
Ideal Relative Density	ASTM D3588	0.5989	---	
Sulfur Compounds in Natural Gas and Gaseous Fuels by GC	ASTM D5504			
Hydrogen Sulfide		0.01020	ppm(mole)	#
Total Sulfur		0.01335	ppm	
Total Sulfur		0.00079	gr/100ft³	
Analysis of Natural Gas and Similar Gaseous mixtures by GC	GPA 2261			
Hexanes and Heavier		<0.010	% Mole	
Nitrogen		0.706	% Mole	
Methane		93.923	% Mole	
Carbon Dioxide		0.741	% Mole	
Ethane		3.108	% Mole	
Propane		0.671	% Mole	
Iso-Butane		0.235	% Mole	
n-Butane		0.440	% Mole	
Iso-Pentane		0.070	% Mole	
n-Pentane		0.101	% Mole	

**** End of Analytical Results ****

- Result is outside of test method limits and/or analytical range used in method precision study

AUTHORISED SIGNATORY

Jason Hobbs

Jason Hobbs
Laboratory Supervisor

SGS North America Inc | Oil, Gas & Chemicals Services 8985 Columbia Road, Cape Canaveral, FL, 32920, U.S.A. Tel: +1-(321)-784-1941 Fax: +1-(321)-784-1943

ATTACHMENT
SRP-EU1-I4
PROCEDURES FOR STARTUP AND SHUTDOWN

SUWANNEE RIVER PLANT
PROCEDURES FOR STARTUP AND SHUTDOWN

A. Fossil Fuel Fired Steam Generator Nos. 1-3

Boiler startup is accomplished by starting an air flow purge and establishing a natural gas fire. When the normal throttle pressure set point is reached, the turbine is pre-warmed and then put into service.

When shutting down, fuel flow is decreased as the load is lowered. The turbine eventually trips which opens the generator breakers. When the turbine coasts to zero revolutions per minute (rpm), it is put on turning gear.

B. Combustion Turbine Peaking Units Nos. Pl-P3

Peaker startup is accomplished by spark lighting of either natural gas or No. 2 distillate fuel oil. NO_x emissions are controlled in the auto or manual mode by injecting demineralized water into the fuel. If the CT control system shows no injection water flow for 30 minutes, the peaker will shut itself down in either mode.

Shutdown is accomplished by lowering the CT load to 0 MW and opening the generators on reverse power

ATTACHMENT
SRP-EU1-I6
COMPLIANCE DEMONSTRATION REPORTS

DUKE ENERGY.
FLORIDA

August 29, 2013

Mr. Raymond Barata
Environmental Manager
Air Compliance & Enforcement
Florida Dept. of Environmental Protection, Northeast District
7777 Baymeadows Way West, Suite 100, Jacksonville, FL 32256-7590

Re: **RATA Test Report Submittal**
Duke Energy Florida.
Suwannee River Power Plant
Title V Air Operating Permit 1210003-007-AV
EUs -001, -002, -003

Dear Mr. Barata,

Please find enclosed the RATA test report for the units referenced above. Per Condition A.26 and A.27 of the permit referenced above, Emission Units -001, -002, and -003 were not tested for Particulate Matter or Visible Emissions. As of August 28, 2013, hours burned on liquid fuel were 47 for Unit -001, 2 for Unit -002 and 0 for Unit -003.

The test results demonstrate compliance with applicable permit conditions. The report was prepared by CEM Solutions, Inc.

Please call Charles Dufeny at (727) 820-5854 if you have any questions or need additional information.

I hereby certify that to the best of my knowledge, all applicable field procedures and calculations comply with Florida Department of Environmental Protection requirements, and all test data and plant operating data are true and correct.

Sincerely,

Brian V. Powers, PE
Station Manager

Enclosures

Cc: Stuart Bartlett (Florida Dept. of Environmental Protection, Northeast District)

Bcc: Chris Harrell
Patty Nemec
Charles Dufeny
Chris Bradley

RATA Test Report

Completed for:

Duke Energy Florida
Suwannee River Facility
Unit 1 (EU-001), Unit 2 (EU-002) and Unit 3 (EU-003)

Test Report Number: 20-6396-010203

Test Completed: July 23 - 25, 2013

RATA Test Report

Duke Energy Florida
Suwannee River Facility
Unit 1 (EU-001), Unit 2 (EU-002) and Unit 3 (EU-003)

Live Oak, Florida

C.E.M. Solutions Project No. 6396

Testing Completed: July 23 through 25, 2013

C.E.M. Solutions, Inc Report Number: 20-6396-010203

C.E.M. Solutions, Inc.
1183 E. Overdrive Circle
Crystal River, Florida 34442
Phone: 352-489-4337

Declaration of Conformance to ASTM D 7036-04: Standard Practice for Competence of Air Emission Testing Bodies

C.E.M. Solutions operates in conformance with the requirements of ASTM D 7036-04: Standard Practice for Competence of Air Emission Testing Bodies through the use of a quality system which incorporates a quality manual, internal audit system, systematic training of personnel and rigorous review of test methods and operating procedures.

Joe Conti
Quality Assurance Manager,
C.E.M. Solutions, Inc.

Statement of Validity

I hereby certify the information and data provided in this emissions test report for tests performed at the Duke Energy Florida Inc. Suwannee River Facility conducted on July 23 through 25, 2013 are complete and accurate to the best of my knowledge.

Joe Conti
Quality Assurance Manager,
C.E.M. Solutions, Inc.

Project Background

Name of Source Owner:	Duke Energy Florida, Inc.
Address of Owner:	299 First Avenue North St. Petersburg, Florida 33701
Source Identification:	Oris Code: 638 Facility ID: 1210003 Emissions Unit: 1 (EU -001), 2 (EU -002), 3 (EU -003)
Location of Source:	Suwannee County, Florida
Type of Operation:	SIC Code: 49, 4911
Tests Performed:	Method 1 – Traverse Points Method 3A – Determination of Oxygen and Carbon Dioxide Method 7E – Determination of Nitrogen Oxides Method 19 – Determination of Nitrogen Oxide Emissions Rates
Test Supervisor (QSTI):	Mr. Matthew Savin
Test Technicians:	Mr. Derek Kopera
Date(s) Tests Conducted:	July 23, 2013: RATA on Unit 1 July 24, 2013: RATA on Unit 2 July 25, 2013: RATA on Unit 3
Site Test Coordinator:	Christopher Harrell
State Regulatory Observers:	No Observers Present

Table of Contents

List of Tables

Appendices

1.0 Introduction

Duke Energy Florida retained C.E.M. Solutions, Inc. to conduct relative accuracy tests on the Unit 1 (EU -001), Unit 2 (EU -002) and Unit 3 (EU -003) boiler exhaust located at its Suwannee River Facility in Live Oak, Florida.

A Relative Accuracy Test Audit (RATA) was conducted on Units 1, 2 and 3 in order to evaluate the accuracy of the NO_X-diluent CEMS in accordance with the United States Environmental Protection Agency (USEPA) requirements in the Code of Federal Regulations, Title 40, Part 75, Appendix B, and Section 2.3.1.

Christopher Harrell of the Duke Energy Florida, Inc. Suwannee River Facility coordinated plant operations throughout the test program. All testing was conducted in accordance with test methods promulgated by the USEPA. A summary of the test program results are located in Table 1.

Table 1: Summary of RATA Results
Suwannee River Facility
Units 1, 2 and 3

Unit	Emission	Result	Status
Unit 1	NO_X RATA	0.008 lb/mmbtu difference (BAF = 1.000)	PASS
Unit 2	NO_X RATA	4.60 % RA (BAF = 1.000)	PASS
Unit 3	NO_X RATA	4.49 % RA (BAF = 1.000)	PASS

2.0 Facility Description

The Suwannee facility consists of three fossil fuel fired steam generators. Units 1, 2 and 3 are allowed to fire No. 2 fuel oil, No. 6 fuel oil, “on specification” used oil, natural gas, and a blend of fuel oil and natural gas. Unit 1 is a nominal 35.0 megawatt (electric) steam generator. Unit 2 is a nominal 34.0 megawatt (electric) steam generator. Unit 3 is a nominal 84.0 megawatt (electric) steam generator.

2.1 Process Equipment

Emissions are uncontrolled on these units. Units 1 and 2 exhaust through separate 110 foot stacks. The Unit 3 combustion gases exhaust through a separate 135 foot stack.

2.2 Regulatory Requirements

A Part 75 NO_X RATA was conducted in order to validate emissions data collected by the CEMS for the Acid Rain Program.

Table 2 summarizes the applicable emissions and CEMS accuracy limits for Units 1, 2 and 3.

Table 2: Summary of CEMS Accuracy Limits
Suwannee River Facility
Units 1, 2 and 3

Pollutant	Emission Limit, Performance Specification	Permit Condition
NO_X	RA ≤ 7.5% of average RM value or $\pm$ 0.015 lb/mmBtu[a]	40CFR75

[a] 40CFR75 low emitter alternate specification

3.0 Test Program/Operating Conditions

The Relative Accuracy Test Audit was conducted to determine relative accuracy of the Units 1, 2 and 3 NO_X-diluent monitoring CEMS.

The Unit 1 NO_X RATA was conducted on July 23, 2013 while the unit was at mid load, operating at an average of 27 MW. The Unit 2 RATA was conducted on July 24, 2013, while the unit was at low load, operating at an average of 20 MW. The Unit 3 RATA was conducted on July 25, 2013, while the unit was at high load, operating at an average of 76 MW.

Plant operating data are located in Appendix A.

4.0 Test Methods

All testing was performed in accordance with methods approved by the USEPA and FDEP. The following discusses the methods, as well as quality assurance and sample handling procedures.

4.1 Sampling Location/Traverse Points/Test Run Duration

The Unit 1 and 2 exhaust stack inner diameter, at the sample location, is 7 feet (84 inches). The emissions sampling location on Unit 1 and 2 is 17 feet downstream from the nearest flow disturbance and 76 feet from the stack exhaust. The Unit 3 exhaust stack inner diameter, at the sample location, is 8.7 feet (104 inches). Unit 3 emissions sampling location is 42 feet downstream from the nearest flow disturbance, and 76 feet upstream from the stack exhaust. A diagram of the sample locations can be viewed in Appendix D.

A 3 point sample traverse was used to test Unit 1. Sample points were located at 16.7 % (14.0 inches), 50% (42.0 inches) and 83.3% (70.0 inches) of the diameter from the inner stack wall. A 12 point stratification test was conducted during Run 1 of the RATA test on Units 2 and 3. Each unit passed the single sample point stratification criteria. A single point was used for the remaining runs of the RATA.

Run 1 on Units 2 and 3 was 35 minutes in duration. Run durations for the remaining RATA runs were 21 minutes long.

4.2 NO_X Relative Accuracy Test Audit (RATA)

NO_X reference method (RM) data was determined using instrument analyzer procedures. In addition, diluent gas concentrations of oxygen (O_2) were also measured via instrumental methods. O_2 data was also used to calculate NO_X pollutant emissions in pounds per million Btu. Data collected by the reference method is compared to the CEMS data.

Mathematical equations used to determine calculated emissions standards and RATA accuracy are located in Appendix B. Table 3 summarizes the EPA methods and instrumentation:

Table 3: Summary of EPA Reference Methods and Instrumentation
Duke Energy
Suwannee River Facility
Units 1, 2 and 3

Pollutant	EPA Method	Instrument	Serial Number
NO_X, Unit 1	7E	TEI Model 42i	1007540756
O_2, Unit 1	3A	TEI Model 410i	1009241630
NO_X, Unit 2	7E	TEI Model 42i	1007540756
O_2, Unit 2	3A	TEI Model 410i	1009241630
NO_X, Unit 3	7E	TEI Model 42i	1007540756
O_2, Unit 3	3A	TEI Model 410i	1009241630

All reference method analyzers used meet or exceed applicable performance specifications detailed in the appropriate method.

Gas samples were continuously extracted from the stack by a gas sample probe. Samples were then transported to a gas sample conditioner via a heated Teflon sample line. The gas sample conditioner lowers the dew point of the sample gas to approximately 5ºC through minimum interference heat exchangers. The dry, cool sample is then sent to the gas analyzers, located in the environmentally controlled test trailer for analysis by the reference method analyzers.

Instrument outputs were recorded continuously with a Windows compatible personal computer, compiled into 15 second averages, and stored in a database for future reference.

Instrument ranges and calibration gases were chosen in accordance with each pollutant's applicable EPA method. Instrument ranges and calibration gases used are shown in Table 4:

Table 4: Reference Method Calibration Spans and Calibration Gases
Duke Energy
Suwannee River Facility
Units 1, 2 and 3

Pollutant	Test Location	Calibration Span	Calibration Gases[a]
NO_X	Unit 1	95.36 ppm	0.0 ppm NO 46.22 ppm NO 95.36 ppm NO
NO_X	Units 2 and 3	210.4 ppm	0.0 ppm NO 95.36 ppm NO 210.4 ppm NO
O_2	Units 1 - 3	20.37 %	0.0 % O_2 10.03 % O_2 20.37 % O_2

[a] Concentrations of NO, and O_2, are in a balance of purified nitrogen (N_2). All analyzers were zeroed with ultra high purity N_2. All calibration gases have been certified to NIST traceable standards.

Calibration gas Certificates of Analysis can be found in Appendix C.

4.2.1 Quality Assurance/Quality Control Procedures

All sampling, analytical, and Quality Assurance/Quality Control (QA/QC) procedures outlined in the EPA methods were followed. All test equipment was calibrated before or during use in the field. Interference checks, response time checks, and NO_2 to NO converter checks were performed on each instrumental analyzer, as applicable, before field use. In the field, each analyzer and the entire instrument measurement system was checked for system bias before and following each test run using the calibration gases listed in Table 4.

Appendix E contains the QA/QC checks.

5.0 Test Results

The following presents the results of the test program. Tables 5 through 7 summarize the NO_X Relative Accuracy Test Audit results. Supporting RM field data and calculated values are presented in Appendix F. CEMS support data are located in Appendix A.

5.1 Unit 1 NO_X RATA Results

5.1.1 NO_X RATA

The average absolute difference between the Unit 1 NO_x-diluent CEMS and the reference method, over the nine test runs was 0.008 lb/mmbtu, passing the alternate annual performance specification of $\pm$ 0.015 lb/mmbtu.

The Unit 1 NO_X-diluent CEMS passed the BAF test. A BAF of 1.000 has been assigned to the Unit 1 NO_X CEMS.

5.2 Unit 2 NO_X RATA Results

5.2.1 NO_X RATA

The relative accuracy of the Unit 2 NO_x-diluent CEMS over the nine test runs was 4.60 %, passing the annual performance specification of 7.5%.

The Unit 2 NO_X-diluent CEMS passed the BAF test. A BAF of 1.000 has been assigned to the Unit 2 NO_X CEMS.

5.3 Unit 3 NO_X RATA Results

5.3.1 NO_X RATA

The relative accuracy of the Unit 3 NO_x-diluent CEMS over the nine test runs was 4.49 %, passing the annual performance specification of 7.5%.

The Unit 3 NO_X-diluent CEMS also passed the BAF test. A BAF of 1.000 has been assigned to the Unit 3 NO_X CEMS.

Table 5: Unit 1 NO_x CEMS Relative Accuracy Test Audit Summary

Test Performed For:
Duke Energy Florida
Suwannee
Unit 1
RATA
Date:7/23/13

Test Performed By:
C.E.M. Solutions, Inc.
1183 East Overdrive Circle
Hernando, FL 34442
(352) 489-4337

Run Number	Date of Run	Start Time	Stop Time	Unit Load MW	NO_X RM lbs/mmBtu	CEM lbs/mmBtu	Difference Like lbs/mmBtu
Run 1	23-Jul	6:18:00	6:39:00	27	0.093	0.101	-0.008
Run 2	23-Jul	6:49:00	7:10:00	27	0.093	0.100	-0.007
Run 3	23-Jul	7:19:00	7:40:00	27	0.091	0.099	-0.008
Run 4	23-Jul	7:56:00	8:17:00	27	0.089	0.098	-0.009
Run 5	23-Jul	8:26:00	8:47:00	27	0.086	0.094	-0.008
Run 6	23-Jul	8:57:00	9:18:00	27	0.086	0.094	-0.008
Run 7	23-Jul	9:26:00	9:47:00	27	0.085	0.093	-0.008
Run 8	23-Jul	9:55:00	10:16:00	27	0.084	0.092	-0.008
Run 9	23-Jul	10:25:00	10:46:00	27	0.082	0.090	-0.008
		Average:		27	0.088	0.096	-0.008 lbs/mmBtu

Bias Test (pass/fail): Passed
Bias Adjustment Factor: 1.000
Method of RA Determination: Part 75, Low Emitter

Standard Deviation:	0.0005
Confidence Coefficient:	0.0004
T-Factor:	2.306
Number of runs Reported:	9
Relative Accuracy:	**0.008**
Maximum RA	0.020
RA Status	**Passed**

Note:
All ppm values are corrected to lbs/mmBtu NO_X
using RM O2 and CEM O2 as diluents

Table 6: Unit 2 NO_x CEMS Relative Accuracy Test Audit Summary

Test Performed For:	Test Performed By:
Duke Energy Florida	C.E.M. Solutions, Inc.
Suwannee	1183 East Overdrive Circle
Unit 2	Hernando, FL 34442
RATA	(352) 489-4337
Date:7/24/13	

Run Number	Date of Run	Start Time	Stop Time	Unit Load MW	NO_X RM lbs/mmBtu	CEM lbs/mmBtu	Difference Like lbs/mmBtu
Run 1	24-Jul	7:19:15	7:49:15	20	0.175	0.180	-0.005
Run 2	24-Jul	8:06:00	8:27:00	20	0.173	0.178	-0.005
Run 3	24-Jul	8:36:00	8:57:00	20	0.172	0.178	-0.006
Run 4	24-Jul	9:06:00	9:27:00	20	0.172	0.177	-0.005
Run 5	24-Jul	9:37:00	9:58:00	20	0.170	0.177	-0.007
Run 6	24-Jul	10:08:00	10:29:00	20	0.169	0.177	-0.008
Run 7	24-Jul	10:37:15	10:58:15	20	0.167	0.176	-0.009
Run 8	24-Jul	11:07:15	11:28:15	20	0.167	0.174	-0.007
Run 9	24-Jul	11:43:00	12:04:00	20	0.165	0.173	-0.008
		Average:		20	0.170	0.177	-0.007 lbs/mmBtu

Bias Test (pass/fail): Passed
Bias Adjustment Factor: 1.000
Method of RA Determination: Part 75, Standard Emitter

Standard Deviation:	0.0015
Confidence Coefficient:	0.0012
T-Factor:	2.306
Number of runs Reported:	9
Relative Accuracy:	**4.60**
Maximum RA	10.0
RA Status	**Passed**

Note:
All ppm values are corrected to lbs/mmBtu NO_X
using RM O2 and CEM O2 as diluents

Table 7: Unit 3 NO_x CEMS Relative Accuracy Test Audit Summary

Test Performed For:
Duke Energy Florida
Suwannee
Unit 3
RATA
Date:7/25/13

Test Performed By:
C.E.M. Solutions, Inc.
1183 East Overdrive Circle
Hernando, FL 34442
(352) 489-4337

Run Number	Date of Run	Start Time	Stop Time	Unit Load MW	NO_X RM lbs/mmBtu	CEM lbs/mmBtu	Difference Like lbs/mmBtu
Run 1	25-Jul	6:31:00	7:01:00	76	0.245	0.255	-0.010
Run 2	25-Jul	7:23:00	7:44:00	76	0.244	0.254	-0.010
Run 3	25-Jul	7:53:00	8:14:00	76	0.246	0.257	-0.011
Run 4	25-Jul	8:23:00	8:44:00	76	0.245	0.255	-0.010
Run 5	25-Jul	8:53:00	9:14:00	76	0.245	0.255	-0.010
Run 6	25-Jul	9:23:00	9:44:00	76	0.248	0.259	-0.011
Run 7	25-Jul	9:53:00	10:14:00	76	0.245	0.255	-0.010
Run 8	25-Jul	10:23:00	10:44:00	76	0.244	0.254	-0.010
Run 9	25-Jul	10:53:00	11:14:00	76	0.243	0.255	-0.012
		Average:		76	0.245	0.255	-0.010 lbs/mmBtu

Bias Test (pass/fail): Passed
Bias Adjustment Factor: 1.000
Method of RA Determination: Part 75, Standard Emitter

Standard Deviation:	0.0007
Confidence Coefficient:	0.0006
T-Factor:	2.306
Number of runs Reported:	9
Relative Accuracy:	**4.49**
Maximum RA	10.0
RA Status	**Passed**

Note:
All ppm values are corrected to lbs/mmBtu NO_X
using RM O2 and CEM O2 as diluents

ATTACHMENT
SRP-EU4-I2
FUEL ANALYSIS AND SPECIFICATION

Tampa Electric Laboratory Services

5012 Causeway Blvd Tampa Fl. 33619 * Ph (813)630-7490 * Fax (813)630-7360 * DOH #E54272

Duke Energy - Suwannee River
Bart Byrd
4037 River Road - MAC BT11
Live Oak, FL 32060
barton.byrd@pgnmail.com

Report Date: 04/28/14 13:18

Sample Information

Client:	Duke Energy - Suwannee River	Project:	Gas Turbines (#2 oil)
Lab Sample ID:	**L14D186-01**	Sampled By:	Phillip Watson
Sample Description:	1 - #2 oil from #10 Tank - Suwannee Gas Turbines	Date and Time Collected:	4/4/14 8:45
Sample Collection Method:	Grab	Date of Sample Receipt:	4/22/14 11:00

Laboratory Results

Parameter	Result	Units	PQL	Qualifier Code	Dil	Test Method	Analyst	Analysis Date & Time
Tampa Electric Company, Laboratory Services								
CHN in Oil								
Carbon	**85.5**	%	0.100		1	ASTM 5291	CAC	4/22/14 13:13
Hydrogen	**13.4**	%	0.100		1	ASTM 5291	CAC	4/22/14 13:13
Nitrogen	0.200	%	0.200	U	1	ASTM 5291	CAC	4/22/14 13:13
General Fuel Parameters								
API Gravity @ 60 Deg. F	**34.4**	Degrees API	0.01		1	ASTM D-5002	CAC	4/23/14 9:19
Gross Heat of Combustion in Oil (HHV)	**19472.72**	BTU/Lb	1		1	ASTM D-240	CAC	4/23/14 9:41
Gross Heat of Combustion in Oil (HHV)	**5808390**	BTU/Barrel	1		1	ASTM D-240	CAC	4/23/14 14:37
Gross Heat of Combustion in Oil (HHV)	**138295**	BTU/Gal	1		1	ASTM D-240	CAC	4/23/14 14:37
Density @15 C (59 F)	**0.8525**	kg/L	0.0001		1	ASTM Table 3	CAC	4/23/14 12:17
Pounds/Gallon @ 60 Deg. F	**7.102**	Lbs/gal	1.000		1	D1250-80 Tbl 8	CAC	4/23/14 14:37
Net Heat of Combustion (LHV)	**18250**	BTU/Lb	1		1	ASTM D-240	CAC	4/23/14 14:37
Net Heat of Combustion (LHV)	**5443746**	BTU/Barrel	1		1	ASTM D-240	CAC	4/23/14 14:37
Net Heat of Combustion (LHV)	**129613**	BTU/Gal	1		1	ASTM D-240	CAC	4/23/14 14:37
Relative Density 60/60 Deg F	**0.8528**	-	0.0001		1	ASTM D-1250	CAC	4/23/14 9:19
Sulfur, Low Level	**0.0551**	%	0.0001		1	ASTM D-5453	CAC	4/23/14 10:39

TECO TAMPA ELECTRIC

Tampa Electric Laboratory Services

5012 Causeway Blvd Tampa Fl. 33619 * Ph (813)630-7490 * Fax (813)630-7360 * DOH #E54272

Sample Information

Client:	Duke Energy - Suwannee River	Project:	Gas Turbines (#2 oil)
Lab Sample ID:	**L14D186-02**	Sampled By:	Phillip Watson
Sample Description:	2 - #2 oil from #10 Tank - Suwannee Gas Turbines	Date and Time Collected:	4/11/14 9:45
Sample Collection Method:	Grab	Date of Sample Receipt:	4/22/14 11:00

Laboratory Results

Tampa Electric Company, Laboratory Services

Parameter	Result	Units	PQL	Qualifier Code	Dil	Test Method	Analyst	Analysis Date & Time
CHN in Oil								
Carbon	**87.6**	%	0.100		1	ASTM 5291	CAC	4/22/14 13:18
Hydrogen	**13.6**	%	0.100		1	ASTM 5291	CAC	4/22/14 13:18
Nitrogen	0.200	%	0.200	U	1	ASTM 5291	CAC	4/22/14 13:18
General Fuel Parameters								
API Gravity @ 60 Deg. F	**34.4**	Degrees API	0.01		1	ASTM D-5002	CAC	4/23/14 9:19
Gross Heat of Combustion in Oil (HHV)	**19502.66**	BTU/Lb	1		1	ASTM D-240	CAC	4/23/14 9:41
Gross Heat of Combustion in Oil (HHV)	**5817336**	BTU/Barrel	1		1	ASTM D-240	CAC	4/23/14 14:37
Gross Heat of Combustion in Oil (HHV)	**138508**	BTU/Gal	1		1	ASTM D-240	CAC	4/23/14 14:37
Density @15 C (59 F)	**0.8525**	kg/L	0.0001		1	ASTM Table 3	CAC	4/23/14 12:17
Pounds/Gallon @ 60 Deg. F	**7.102**	Lbs/gal	1.000		1	D1250-80 Tbl 8	CAC	4/23/14 14:37
Net Heat of Combustion (LHV)	**18262**	BTU/Lb	1		1	ASTM D-240	CAC	4/23/14 14:37
Net Heat of Combustion (LHV)	**5447274**	BTU/Barrel	1		1	ASTM D-240	CAC	4/23/14 14:37
Net Heat of Combustion (LHV)	**129697**	BTU/Gal	1		1	ASTM D-240	CAC	4/23/14 14:37
Relative Density 60/60 Deg F	**0.8528**	-	0.0001		1	ASTM D-1250	CAC	4/23/14 9:19
Sulfur, Low Level	**0.0554**	%	0.0001		1	ASTM D-5453	CAC	4/23/14 10:49

Comments

U Indicates that the compound was analyzed for but not detected.

Subcontract Laboratories:

Tampa Electric Company, Laboratory Services

The results in this report apply to the samples analyzed in accordance with the chain of custody document. This analytical report must be reproduced in its entirety.

Cheryl L. Howard

Cheryl Howard, QA Coordinator

Laboratory Services certifies that the test result in this report meet all requirements of the NELAC standards, unless indicated otherwise in the body of the report. Unless otherwise noted, all methods followed are per the most current published version of 40 CFR Part 136, Table B. Results reported on this report pertain to the above referenced sample only.

TECO
TAMPA ELECTRIC

Analysis Request & Chain of Custody

Tampa Electric Laboratory Services

5012 Causeway Blvd., Tampa, FL 33619 Phone:(813)630-7490 Fax: (813)630-7360

Project Reference:	Subcontracted Laboratory (if applicable):
Sampler's Printed Name: Phillip Watson	Sampler's Signature: Phillip Watson
Sample Location: Suwannee Gas Turbines	Project Description:
Client Name: Duke Energy-	Client Phone: 386-330-5434 / Client Fax:
Client Email: phillip.watson at PGNmail.com	Client Address:

Required Analysis: HHV, LHV, Sulfur, Density, API, CHN, Ash in Oil, Water in

Preservative:

☐ Due Date:

☑ Standard 10 working day TAT

Number of coolers submitted per shipment:

Sample ID	Sample Description	Sampling Date	Sampling Time	* Matrix	HHV	LHV	Sulfur	Density	API	CHN	Ash in Oil	Water in			Remarks
1	#2 oil from #10 Tank	4/4/14	0845		1	"	"	"	"	"					L14D186-01A
2	#2 oil from #10 Tank	4/18/14	0945		1	"	"	"	"	"					L14D186-02A

* GW - GROUND WATER SW - SURFACE WATER DW - DRINKING WATER WW - WASTE WATER C - COAL O - OIL SO - SOLID/SOIL SL - SLUDGE W - WASTE SAMPLE A - AIR

On Ice? ☐ Yes ☒ No

Cooler Temperature (°C): N/A

Containers Intact? ☒ Yes ☐ No

Sampling Kit Transfers

Relinquished By:	Date	Time	Received By:	Date	Time
Person's Name: Facility Name:			Person's Name: Facility Name:		

Sample Transfers

Relinquished By:	Date	Time	Received By:	Date	Time
Person's Name: Phillip Watson Facility Name: Suwannee Gas Turbines			Person's Name: Clayton A. G[illegible] Facility Name: TECO - EHS Lab Services	04/22/14	1100
Person's Name: Facility Name:			Person's Name: Facility Name:		
Person's Name: Facility Name:			Person's Name: Facility Name:		
Shipping Vendor:	Bill of Lading Number:		Logged in by: Cac	04/22/14	1106

SGS

DATE: 24-Jan-2014

SGS Oil, Gas and Chemicals
SGS Port Canaveral
8985 Columbia Road
Cape Canaveral, FL, 32920
U.S.A.
Tel: +1-(321)-784-1941
Fax: +1-(321)-784-1943

DUKE ENERGY
4037 RIVER ROAD
LIVE OAK
UNITED STATES
32060

Certificate of Analysis: PC14-00013.006

CLIENT ORDER NUMBER :	Job# 313620	SGS ORDER NO.:	--
CLIENT ID :	JANUARY 2014	PRODUCT DESCRIPTION :	Natural Gas
LOCATION :	Duke Energy - Suwanee		
SAMPLE SOURCE :	Natural Gas Line	SOURCE ID :	Pipeline
SAMPLE TYPE :	Submitted Sample	SAMPLED BY :	Duke Energy
SAMPLED :	20-Jan-2014	RECEIVED	21-Jan-2014
ANALYSED :	24-Jan-2014	COMPLETED :	24-Jan-2014

PROPERTY	METHOD	RESULT	UNITS
Ideal Gross Heating Value	ASTM D3588	1050	Btu/ft³
Ideal Net Heating Value	ASTM D3588	947	Btu/ft³
Ideal Relative Density	ASTM D3588	0.5989	---
Sulfur Compounds in Natural Gas and Gaseous Fuels by GC	ASTM D5504		
Hydrogen Sulfide		0.01020	ppm(mole) #
Total Sulfur		0.01335	ppm
Total Sulfur		0.00079	gr/100ft³
Analysis of Natural Gas and Similar Gaseous mixtures by GC	GPA 2261		
Hexanes and Heavier		<0.010	% Mole
Nitrogen		0.706	% Mole
Methane		93.923	% Mole
Carbon Dioxide		0.741	% Mole
Ethane		3.108	% Mole
Propane		0.671	% Mole
Iso-Butane		0.235	% Mole
n-Butane		0.440	% Mole
Iso-Pentane		0.070	% Mole
n-Pentane		0.101	% Mole

**** End of Analytical Results ****

- Result is outside of test method limits and/or analytical range used in method precision study

AUTHORISED SIGNATORY

Jason Hobbs

Jason Hobbs
Laboratory Supervisor

SGS North America Inc | Oil, Gas & Chemicals Services 8985 Columbia Road, Cape Canaveral, FL, 32920, U.S.A. Tel: +1-(321) -784-1941 Fax: +1-(321)-784-1943

ATTACHMENT
SRP-EU4-I6
COMPLIANCE DEMONSTRATION REPORTS

DUKE ENERGY
FLORIDA

November 6, 2013

RAY BARATA, Environmental Specialist III
Air Program Compliance & Enforcement
Florida Department of Environmental Protection
NORTHEAST DISTRICT OFFICE
8800 Baymeadows Way West, Suite 100,
Jacksonville, FL 32256

Re: **Emissions Test Report Submittal**
Duke Energy Florida.
Suwannee River Power Plant
Title V Air Operating Permit 1210003-007-AV
EUs -004, -005, -006

Dear Mr. Barata,

Please find enclosed the compliance test report for the units referenced above. The test results demonstrate compliance with applicable permit conditions. The report was prepared by CEM Solutions, Inc.

Please call Charles Dufeny at (727) 820-5854 if you have any questions or need additional information.

I hereby certify that to the best of my knowledge, all applicable field procedures and calculations comply with Florida Department of Environmental Protection requirements, and all test data and plant operating data are true and correct.

Sincerely,

Brian V. Powers, PE
Station Manager

Enclosures

Cc: Stuart Bartlett (Florida Dept. of Environmental Protection, Northeast District)

Air Emissions Compliance Test Report

Completed for:

Duke Energy Florida, Inc.
Suwannee River Facility
Units P1 – P3 (EU 004 - 006)

Test Report Number: 20-6504-010203-001

Test Completed: September 24 - 26, 2013

1183 East Overdrive Circle • Hernando, FL 34442 • (352) 489-4337 • Fax: (352) 489-4801

Air Emissions Compliance Test Report

Duke Energy Florida, Inc.
Suwannee River Facility
Peaking Units 1 - 3
(EU-004, -005 and -006)
Live Oak, Florida

C.E.M. Solutions Project No. 6504

Testing Completed: September 24 – 26, 2013

C.E.M. Solutions, Inc Report Number: 20-6504-010203-001

C.E.M. Solutions, Inc.
1183 E. Overdrive Circle
Hernando, Florida 34442
Phone: 352-489-4337

Declaration of Conformance to ASTM D 7036-04: Standard Practice for Competence of Air Emission Testing Bodies

C.E.M. Solutions operates in conformance with the requirements of ASTM D 7036-04: Standard Practice for Competence of Air Emission Testing Bodies through the use of a quality system which incorporates a quality manual, internal audit system, systematic training of personnel and rigorous review of test methods and operating procedures.

Joe Conti
Quality Assurance Manager
C.E.M. Solutions

Statement of Validity

I hereby certify the information and data provided in this emissions test report for tests performed at the Duke Energy Florida, Suwannee River Facility, conducted on September 24, 2013 through September 26, 2013, are complete and accurate to the best of my knowledge.

Joe Conti
Quality Assurance Manager,
C.E.M. Solutions, Inc.

Project Background

Name of Source Owner:	Duke Energy Florida, Inc.
Address of Owner:	299 First Avenue North St. Petersburg, Florida 33701
Source Identification:	Oris Code: 638 Facility ID: 1210003 Emissions Unit: P1 (EU-004), P2 (EU-005) and P3 (EU-006)
Location of Source:	Suwannee County, Florida
Type of Operation:	SIC Code: 4911
Tests Performed:	Method 1 – Traverse Points Method 9 – Visual Determination of Opacity Method 20 – Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions From Stationary Gas Turbines ASTM D-240 – Fuel Analysis (by others) ASTM D-1552 – Sulfur in Petroleum Products (by others)
Test Supervisor (QSTI):	Mr. Matt Savin
Test Technicians:	Mr. Derek Kopera Mr. Josh Cooper
Date(s) Tests Conducted:	September 24, 2013: Unit 1A & B CT on gas and oil September 25, 2013: Unit 3A & B CT on gas and oil September 26, 2013: Unit 2A & B CT on oil
Site Test Coordinator:	Chuck Dufeny
State Regulatory Observers:	No Observers Present

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Appendices

1.0 Introduction

Duke Energy, Florida (DEF) retained C.E.M. Solutions, Inc. to perform source emissions testing on Combustion Turbine Peaking Units 1, 2 and 3 (emissions units -004, -005 and -006) located at its Suwannee River Facility in Live Oak, Florida.

The test program was conducted in order to evaluate the compliance status of the Unit 1 and 3 exhausts, while firing Pipeline Natural Gas (PNG) and Units 1, 2 and 3 while firing No. 2 distillate fuel oil, with respect to the United States Environmental Protection Agency (USEPA) Standards of Performance for Stationary Turbines (Title 40 of the Code of Federal Regulations, Part 60, Subpart GG) and the Florida Department of Environmental Protection's (FDEP's) permit number 1210003-007-AV. The test program and results are presented and discussed in this report.

Charles Dufeny of Duke Energy Florida coordinated plant operations throughout the test program. All testing was conducted in accordance with test methods promulgated by the USEPA.

Peaking Units 1 through 3 of the Suwannee Plant were found to be in compliance with permit number 1210003-007-AV, as summarized in Table 1.

1.1 Errors and Omissions

Peaking Unit 2 shut down during Run 1. The Unit was restarted and testing was resumed. Run 1 was not used. Runs 2 through 4 were used to show Unit 2 compliance.

Table 1: Summary of Compliance Test
Duke Energy Florida
Suwannee River Facility
Units 1 - 3

Pollutant	Unit	Fuel Type	Emission Limit	Measured Value	Pass/Fail
NO_X	1	PNG	68 ppmvd @15% O_2 dry basis for PNG	49.2 A 33.7 B	PASS
SO_2	1	PNG	0.5% S by weight for PNG	0.0002%	PASS
Visible Emission	1	PNG	20% for both fuels	0% A 0% B	PASS
NO_X	1	Oil	75 ppmvd @15% O_2 dry basis for No. 2 fuel oil	53.5 A 33.0 B	PASS
SO_2	1	Oil	0.5% S by weight for Oil	0.057%	PASS
Visible Emission	1	Oil	20% for both fuels	0% A 0% B	PASS
NO_X	2	Oil	75 ppmvd @15% O_2 dry basis for No. 2 fuel oil	61.3 A 48.8 B	PASS
SO_2	2	Oil	0.5% S by weight for Oil	0.057%	PASS
Visible Emission	2	Oil	20% for both fuels	0% A 0% B	PASS
NO_X	3	PNG	68 ppmvd @15% O_2 dry basis for PNG	48.8 A 47.1 B	PASS
SO_2	3	PNG	0.5% S by weight for PNG	0.0002%	PASS
Visible Emission	3	PNG	20% for both fuels	0% A 0% B	PASS
NO_X	3	Oil	75 ppmvd @15% O_2 dry basis for No. 2 fuel oil	55.4 A 48.3 B	PASS
SO_2	3	Oil	0.5% S by weight for Oil	0.057%	PASS
Visible Emission	3	Oil	20% for both fuels	0% A 0% B	PASS

2.0 Facility Description

Suwannee Plant's Peaking Units 1, 2 and 3 are identical in configuration. They are Combustion Turbines Model Turbo Power Systems FT4C-3 LF water injected TwinPacs. Each Turbine pack consists of two turbines and a single generator. Units 1 and 3 (EU -004 and -006) can be fired on PNG or No. 2 distillate fuel oil. Unit 2 (EU -005) can be fired on No. 2 distillate fuel oil only. Each emissions unit has a maximum generating output of 63,000 KW (63 MW).

2.1 Process Equipment

Peaking Units 1, 2 and 3 each have a maximum heat input rating at 59º Fahrenheit (F) of 739 MMBtu/hour, based upon the lower heating value (LHV) of each fuel. NO_X emissions are controlled by using water injection. Each turbine's emissions are exhausted through separate 121 inch deep by 121 inch wide square stacks.

2.2 Regulatory Requirements

DEF is required to conduct annual emissions tests for the following pollutants while operating at 95-100 percent of the unit operating range. Emission testing was conducted to determine the compliance status of the following pollutants:

- NO_X in parts per million corrected to 15% O_2
- SO_2 in % S by weight of fuel, and in pounds per hour
- Opacity in percent

Table 2 summarizes the applicable emissions limits for Units 1, 2 and 3.

Table 2: Summary of Emissions Limits
Duke Energy Florida
Suwannee River Facility
Units 1 - 3

Pollutant	Control Technology	Emission Limit	Permit Condition
NO_X	Water Injection	68 ppmvd @15% O_2-dry basis for PNG, and 75 ppmvd @15% O_2-dry basis for No. 2 fuel oil	B.5 and B.6
SO_2	Low Sulfur Fuel	≤0.5% S by weight, 0.0095% by volume @15% O_2-dry basis, and ≤379 lbs/hr/CT	B.7 and B.8
Visible Emission	Good Combustion	≤20% for Both Fuels	B.9

3.0 Test Program/Operating Conditions

Emissions tests were completed on Peaking Units 1, 2 and 3 at the Suwannee Plant to determine the compliance status of the PNG and No. 2 fuel oil fired turbines on September 24 through 26, 2013.

Compliance testing was performed on Peaking Units 1, 2 and 3 at base load while firing No. 2 distillate fuel oil; and on Units 1 and 3 at base load while firing PNG. SO_2 emissions were calculated from fuel analysis and fuel flow rates while the units were operating at base load.

Number 2 fuel oil analyses were performed by TECO Laboratory Services in accordance with 40CFR, Part 60, Appendix A-7, Method 19, Section 12.5.2.2. A fuel oil sample was taken September 24, 2013 while compliance testing was being conducted.

Turbine operating data was collected and provided by facility personnel during the entire test program. Data provided include, but was not limited to:

- Unit Generation (MW)
- Combustor inlet air temperature
- Fuel flow rate
- Water injection rate
- Water-to-fuel ratio

Table 3 presents the percentage of the maximum heat input, for each Unit, during each test. Operating data can be viewed in Appendix A.

Table 3: Heat Input During Test
Duke Energy Florida, Inc.
Suwannee River Facility
Units 1 - 3

Unit/Fuel	Calculated Heat Input mmBtu/hr	Permitted Heat Input at Inlet Temp. mmBtu/hr	Inlet Temp. ^oF	Percent Max H.I.
1, oil	714.7	727.5	83.2	98.2
1, gas	606.4	724.5	89.5	83.7
2, oil	641.2	727.8	82.5	88.1
3, oil	674.8	729.0	80.8	92.6
3, gas	583.6	724.6	90.1	80.5

4.0 Test Methods

All testing was performed in accordance with methods approved by the USEPA and FDEP. The following discusses the methods, as well as quality assurance and sample handling procedures.

4.1 Instrument Analyzer Procedures

NO_X and O_2 reference method (RM) data were determined using United States Environmental Protection Agency's (USEPA) test methods 7E and 3A. O_2 data was used to calculate NO_X pollutant emissions in parts per million corrected to 15% O_2.

Mathematical equations used to determine calculated emissions standards are located in Appendix B.

Table 4 summarizes the EPA methods and instrumentation:

Table 4: Summary of EPA Instrument Reference Methods
Duke Energy Florida
Suwannee River Facility
Units 1 - 3

Pollutant	Instrument	Serial Number
Unit 1A,NO_X	TEI Model 42i	1200951381
Unit 1A, O_2	Servomex 1440	1420D/3379
Unit 1B,NO_X	TEI Model 42i	1007540756
Unit 1B, O_2	TEI Model 410i	1016942785
Unit 2A,NO_X	TEI Model 42i	1200951381
Unit 2A, O_2	Servomex 1440	1420D/3379
Unit 2B,NO_X	TEI Model 42i	1007540756
Unit 2B, O_2	TEI Model 410i	1016942785
Unit 3A,NO_X	TEI Model 42i	1200951381
Unit 3A, O_2	Servomex 1440	1420D/3379
Unit 3B,NO_X	TEI Model 42i	1007540756
Unit 3B, O_2	TEI Model 410i	1016942785

All reference method analyzers used meet or exceed applicable performance specifications detailed in the appropriate method.

Gas samples were continuously extracted from the stack by a gas sample probe. Samples were then transported to a gas sample conditioner via a Teflon sample line. The gas sample conditioner lowers the dew point of the sample gas to approximately 5ºC through minimum interference heat exchangers. The dry, cool sample is then sent to the gas analyzers, located in the environmentally controlled test trailer for analysis by the reference method analyzers.

Instrument outputs were recorded continuously with a Windows compatible personal computer, compiled into 15 second averages, and stored in a database for future reference.

Instrument ranges and calibration gases were chosen in accordance with each pollutant's applicable EPA method. Instrument ranges and calibration gases used are shown in Table 5:

Table 5: Reference Method Calibration Span and Calibration Gases
Duke Energy Florida
Suwannee River Facility
Units 1 - 3

Pollutant	Test Location	Calibration Span	Calibration Gases[a]
NO_X	All Units	96.48 ppm	0.0 ppm NO 46.34 ppm NO 96.48 ppm NO
O_2	All Units	20.77 %	0.0 % O_2 9.92 % O_2 20.77 % O_2

[a] Concentrations of NO and O_2 are in a balance of purified nitrogen (N_2). All analyzers were zeroed with ultra high purity N_2. All calibration gases have been certified to NIST traceable standards.

Calibration gas Certificates of Analysis can be found in Appendix C.

4.1.1 Sampling Location/Traverse Points/Test Run Duration

Peaking Units 1 through 3 exhaust stack inner depths, at the sample location, are each 10 feet 1 inch (121”). Each stack has 7 test ports equally spaced across the side of each stack. A diagram of the sample location can be viewed in Appendix D.

4.1.1.1 Reference Measurement Point

Reference method measurements were taken at a total of 12 traverse points located at the center of each equal area sector. Each traverse point was sampled for a period of five (5) minutes, for a total run duration of 60 minutes.

4.1.2 Quality Assurance/Quality Control Procedures

All sampling, analytical, and Quality Assurance/Quality Control (QA/QC) procedures outlined in the EPA methods were followed. All test equipment was calibrated before or during use in the field. Interference checks, response time checks, and NO_2 to NO converter checks were performed on each instrumental analyzer, as applicable, before field use. In the field, each analyzer and the entire instrument measurement system was checked for system bias before and following each test run using the calibration gases listed in Table 5.
Appendix E contains the QA/QC checks.

4.2 Determination of Visible Emissions

USEPA Method 9 was utilized to determine visible emissions.

Visible emissions observations were performed by a FDEP certified Visible Emissions reader. Readings were taken at 15 second intervals and reduced into six minute averages as required by the applicable EPA standard. One, sixty (60) minute visible emissions run was performed, on each fuel, while the Units were operating at maximum capacity.

4.3 Fuel Analysis

Ongoing compliance with the fuel sulfur limit for natural gas is demonstrated by the fuel supplier’s analysis reports containing the sulfur content of the fuel being supplied. Methods for determining the sulfur content of natural gas are ASTM Methods D4084-82, D3246-81, or more recent versions.

5.0 Test Results

The test program results are summarized in Tables 6, 7 and 8 and are discussed below. Summaries of the compliance test results for NO_X and SO_2, supporting reference method (RM) field data, fuel analysis reports, and calculated values are presented in Appendix F through H.

5.1 Peaker 1 (EU-004)

5.1.1 Nitrogen Oxides (NO_X)

NO_X emissions for Unit 1A, over the three test runs, while firing No. 2 distillate fuel oil averaged 53.5 ppm corrected to 15% O_2, passing the emission limitations of 75 ppm @ 15% O_2.

NO_X emissions for Unit 1A, over the three test runs, while firing natural gas averaged 49.2 ppm corrected to 15% O_2, passing the emission limitations of 68 ppm @ 15% O_2.

NO_X emissions for Unit 1B, over the three test runs, while firing No. 2 distillate fuel oil averaged 33.0 ppm corrected to 15% O_2, passing the emission limitations of 75 ppm @ 15% O_2.

NO_X emissions for Unit 1B, over the three test runs, while firing natural gas averaged 33.7 ppm corrected to 15% O_2, passing the emission limitations of 68 ppm @ 15% O_2.

5.1.2 Sulfur Dioxide (SO_2)

The sulfur content of the natural gas burned during the compliance test was 0.0002% of the fuel by weight, below the 0.5% limitation. The sulfur content of the oil burned during the compliance test was 0.057%, also below the 0.5% limitation.

5.1.3 Visible Emissions

The highest six-minute average visible emissions during the one hour test run, while firing natural gas was 0% for Units 1A and 1B passing the 20% emission limitation.

The highest six-minute average visible emissions during the one hour test run, while firing No. 2 distillate fuel oil was 0% for both Units 1A and 1B. Both units passed the 20% emission limitation.

5.2 Peaker 2 (EU-005)

5.2.1 Nitrogen Oxides (NO_X)

NO_X emissions for Unit 2A, over the three test runs, while firing No. 2 distillate fuel oil averaged 61.3 ppm corrected to 15% O_2, passing the emission limitations of 75 ppm @ 15% O_2.

NO_X emissions for Unit 2B, over the three test runs, while firing No. 2 distillate fuel oil averaged 48.8 ppm corrected to 15% O_2, passing the emission limitations of 75 ppm @ 15% O_2.

5.2.2 Sulfur Dioxide (SO_2)

The sulfur content of the natural gas burned during the compliance test was 0.0002% of the fuel by weight, below the 0.5% limitation. The sulfur content of the oil burned during the compliance test was 0.057%, also below the 0.5% limitation.

5.2.3 Visible Emissions

The highest six-minute average visible emissions during the one hour test run, while firing No. 2 distillate fuel oil was 0% for both Units 2A and 2B. Both units passed the 20% emission limitation.

5.3 Peaker 3 (EU-006)

5.3.1 Nitrogen Oxides (NO_X)

NO_X emissions for Unit 3A, over the three test runs, while firing No. 2 distillate fuel oil averaged 55.4 ppm corrected to 15% O_2, passing the emission limitations of 75 ppm @ 15% O_2.

NO_X emissions for Unit 3A, over the three test runs, while firing natural gas averaged 48.8 ppm corrected to 15% O_2, passing the emission limitations of 68 ppm @ 15% O_2.

NO_X emissions for Unit 3B, over the three test runs, while firing No. 2 distillate fuel oil averaged 48.3 ppm corrected to 15% O_2, passing the emission limitations of 75 ppm @ 15% O_2.

NO_X emissions for Unit 3B, over the three test runs, while firing natural gas averaged 47.1 ppm corrected to 15% O_2, passing the emission limitations of 68 ppm @ 15% O_2.

5.3.2 Sulfur Dioxide (SO_2)

The sulfur content of the natural gas burned during the compliance test was 0.0002% of the fuel by weight, below the 0.5% limitation. The sulfur content of the oil burned during the compliance test was 0.057%, also below the 0.5% limitation.

5.3.3 Visible Emissions

The highest six-minute average visible emissions during the one hour test run, while firing natural gas was 0% for both Units 3A and 3B. Both units passed the 20% emission limitation.

The highest six-minute average visible emissions during the one hour test run, while firing No. 2 distillate fuel oil was 0% for both Units 3A and 3B. Both units passed the 20% emission limitation.

Table 6: Unit 1 (EU-004) NO_X Compliance Results
Duke Energy Florida
Suwannee River Facility
Units 1A and 1B on Oil and Gas

UNIT 1A on OIL

Run Number	Units	Run 1	Run 2	Run 3	Average	Standard
Date of Run	2013	24-Sep	24-Sep	24-Sep		
Start Time		7:15:30	8:52:00	10:05:00		
Stop Time		8:15:30	9:52:00	11:05:00		
O2	%	18.6	18.2	18.5	18.4	
NOX	ppm	23.6	22.5	20.7	22.3	
NOX / O2	ppm@15% O2	60.5	49.2	50.9	53.5	75

UNIT 1A on GAS

Run Number	Units	Run 1	Run 2	Run 3	Average	Standard
Date of Run	2013	24-Sep	24-Sep	24-Sep		
Start Time		12:27:00	14:06:00	15:19:00		
Stop Time		13:27:00	15:06:00	16:19:00		
O2	%	18.5	18.4	18.2	18.4	
NOX	ppm	20.8	20.0	22.6	21.1	
NOX / O2	ppm@15% O2	51.1	47.2	49.4	49.2	68

UNIT 1B on OIL

Run Number	Units	Run 1	Run 2	Run 3	Average	Standard
Date of Run	2013	24-Sep	24-Sep	24-Sep		
Start Time		7:15:30	8:52:00	10:05:00		
Stop Time		8:15:30	9:52:00	11:05:00		
O2	%	17.5	17.5	17.3	17.4	
NOX	ppm	19.2	18.9	20.1	19.4	
NOX / O2	ppm@15% O2	33.3	32.8	32.9	33.0	75

UNIT 1B on GAS

Run Number	Units	Run 1	Run 2	Run 3	Average	Standard
Date of Run	2013	24-Sep	24-Sep	24-Sep		
Start Time		12:27:00	14:06:00	15:19:00		
Stop Time		13:27:00	15:06:00	16:19:00		
O2	%	17.4	17.2	17.4	17.3	
NOX	ppm	19.4	20.9	20.8	20.4	
NOX / O2	ppm@15% O2	32.7	33.3	35.1	33.7	68

Table 7: Unit 2 (EU-005) NO_X Compliance Results
Duke Energy Florida
Suwannee River Facility
Units 2A and 2B on Oil

UNIT 2A on OIL

Run Number	Units	Run 2	Run 3	Run 4	Average	Standard
Date of Run	2013	26-Sep	26-Sep	26-Sep		
Start Time		10:08:15	11:21:00	12:46:00		
Stop Time		11:08:15	12:21:00	13:46:00		
O2	%	18.4	18.7	17.7	18.3	
NOX	ppm	25.1	23.7	33.1	27.3	
NOX / O2	ppm@15% O2	59.2	63.6	61.0	61.3	75

UNIT 2B on OIL

Run Number	Units	Run 2	Run 3	Run 4	Average	Standard
Date of Run	2013	26-Sep	26-Sep	26-Sep		
Start Time		10:08:15	11:21:00	12:46:00		
Stop Time		11:08:15	12:21:00	13:46:00		
O2	%	17.3	17.6	17.4	17.4	
NOX	ppm	29.7	27.1	29.1	28.6	
NOX / O2	ppm@15% O2	48.7	48.5	49.1	48.8	75

Table 8: Unit 3 (EU-006) NO_X Compliance Results
Duke Energy Florida
Suwannee River Facility
Unit 3A and 3B on Oil and Gas

UNIT 3A on OIL

Run Number	Units	Run 1	Run 2	Run 3	Average	Standard
Date of Run	2013	25-Sep	25-Sep	25-Sep		
Start Time		7:25:00	9:03:00	10:15:00		
Stop Time		8:25:00	10:03:00	11:15:00		
O2	%	18.1	18.2	18.1	18.1	
NOX	ppm	28.2	24.1	25.7	26.0	
NOX / O2	ppm@15% O2	59.4	52.7	54.2	55.4	75

UNIT 3A on GAS

Run Number	Units	Run 1	Run 2	Run 3	Average	Standard
Date of Run	2013	25-Sep	25-Sep	25-Sep		
Start Time		12:05:15	13:47:00	14:59:00		
Stop Time		13:05:15	14:47:00	15:59:00		
O2	%	18.0	18.0	18.0	18.0	
NOX	ppm	25.0	23.6	23.4	24.0	
NOX / O2	ppm@15% O2	50.9	48.0	47.6	48.8	68

UNIT 3B on OIL

Run Number	Units	Run 1	Run 2	Run 3	Average	Standard
Date of Run	2013	25-Sep	25-Sep	25-Sep		
Start Time		7:25:00	9:03:00	10:15:00		
Stop Time		8:25:00	10:03:00	11:15:00		
O2	%	17.4	17.2	17.5	17.4	
NOX	ppm	28.5	29.9	28.3	28.9	
NOX / O2	ppm@15% O2	48.0	47.7	49.1	48.3	75

UNIT 3B on GAS

Run Number	Units	Run 1	Run 2	Run 3	Average	Standard
Date of Run	2013	25-Sep	25-Sep	25-Sep		
Start Time		12:05:15	13:47:00	14:59:00		
Stop Time		13:05:15	14:47:00	15:59:00		
O2	%	17.8	17.3	17.7	17.6	
NOX	ppm	24.8	28.5	25.7	26.3	
NOX / O2	ppm@15% O2	47.2	46.7	47.4	47.1	68

ATTACHMENT
SRP-EU4-IV2
CAM PLAN

CAM REQUIREMENTS
(version dated 06/09/2005)

Pursuant to Rule 62-213.440(1)(b)1.a., F.A.C., the CAM plans that are included in this appendix contain the monitoring requirements necessary to satisfy 40 CFR 64. Conditions 1. - 17. are generic conditions applicable to all emissions units that are subject to the CAM requirements. Specific requirements related to each emissions unit are contained in the attached tables, as submitted by the applicant and approved by the Department.

<u>40 CFR 64.6 Approval of Monitoring</u>.

1. The attached CAM plan(s), as submitted by the applicant, is/are approved for the purposes of satisfying the requirements of 40 CFR 64.3. [40 CFR 64.6(a)]

2. The attached CAM plan(s) include the following information:
   a. The indicator(s) to be monitored (such as temperature, pressure drop, emissions, or similar parameter);
   b. The means or device to be used to measure the indicator(s) (such as temperature measurement device, visual observation, or CEMS); and
   c. The performance requirements established to satisfy 40 CFR 64.3(b) or (d), as applicable.

   [40 CFR 64.6(c)(1)]

3. The attached CAM plan(s) describe the means by which the owner or operator will define an exceedance of the permitted limits or an excursion from the stated indicator ranges and averaging periods for purposes of responding to (see **CAM Conditions 5. - 14.**) and reporting exceedances or excursions (see **CAM Conditions 15. - 16.**). [40 CFR 64.6(c)(2)]

4. The permittee is required to conduct the monitoring specified in the attached CAM plan(s) and shall fulfill the obligations specified in the conditions below (see **CAM Conditions 5. - 16.**). [40 CFR 64.6(c)(3)]

<u>40 CFR 64.7 Operation of Approved Monitoring</u>.

5. <u>Commencement of Operation</u>. The owner or operator shall conduct the monitoring required under this appendix upon the effective date of this Title V permit. [40 CFR 64.7(a)]

6. <u>Proper Maintenance</u>. At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment. [40 CFR 64.7(b)]

7. <u>Continued Operation</u>. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. [40 CFR 64.7(c)]

8. <u>Response to Excursions or Exceedances</u>.
   a. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions, if allowed by this permit). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

b. Determination of whether the owner or operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

[40 CFR 64.7(d)(1) & (2)]

9. Documentation of Need For Improved Monitoring. If the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the permitting authority and, if necessary, submit a proposed modification to the Title V permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. [40 CFR 64.7(e)]

40 CFR 64.8 Quality Improvement Plan (QIP) Requirements.

10. Based on the results of a determination made under **CAM Condition 8.b.,** above, the permitting authority may require the owner or operator to develop and implement a QIP. Consistent with **CAM Condition 4.**, an accumulation of exceedances or excursions exceeding 5 percent duration of a pollutant-specific emissions unit's operating time for a reporting period, may require the implementation of a QIP. The threshold may be set at a higher or lower percent or may rely on other criteria for purposes of indicating whether a pollutant-specific emissions unit is being maintained and operated in a manner consistent with good air pollution control practices. [40 CFR 64.8(a)]

11. Elements of a QIP.

a. The owner or operator shall maintain a written QIP, if required, and have it available for inspection.

b. The plan initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:

(1) Improved preventive maintenance practices.
(2) Process operation changes.
(3) Appropriate improvements to control methods.
(4) Other steps appropriate to correct control performance.
(5) More frequent or improved monitoring (only in conjunction with one or more steps under **CAM Condition 11.b(i)** through **(iv)**, above).

[40 CFR 64.8(b)]

12. If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the permitting authority if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined. [40 CFR 64.8(c)]

13. Following implementation of a QIP, upon any subsequent determination pursuant to **CAM Condition 8.b.,** the permitting authority may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

a. Failed to address the cause of the control device performance problems; or

b. Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

[40 CFR 64.8(d)]

14. Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act. [40 CFR 64.8(e)]

40 CFR 64.9 Reporting And Recordkeeping Requirements.

15. General Reporting Requirements.

a. Commencing from the effective date of this permit, the owner or operator shall submit monitoring reports semi-annually to the permitting authority in accordance with Rule 62-213.440(1)(b)3.a., F.A.C.

b. A report for monitoring under this part shall include, at a minimum, the information required under Rule 62-213.440(1)(b)3.a., F.A.C., and the following information, as applicable:

(1) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

(2) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

(3) A description of the actions taken to implement a QIP during the reporting period as specified in **CAM Conditions 10.** through **14.** Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

[40 CFR 64.9(a)]

16. General Recordkeeping Requirements.

a. The owner or operator shall comply with the recordkeeping requirements specified in Rule 62-213.440(1)(b)2., F.A.C. The owner or operator shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to **CAM Conditions 10.** through **14.** and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this part (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions).

b. Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements.

[40 CFR 64.9(b)]

40 CFR 64.10 Savings Provisions.

17. It should be noted that nothing in this appendix shall:

a. Excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act. The requirements of this appendix shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purpose of determining the monitoring to be imposed under separate authority under the Act, including monitoring in permits issued pursuant to Title I of the Act. The purpose of this part is to require, as part of the issuance of a permit under Title V of the Act, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of this part.

b. Restrict or abrogate the authority of the Administrator or the permitting authority to impose additional or more stringent monitoring, recordkeeping, testing, or reporting requirements on any owner or operator of a source under any provision of the Act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable.

c. Restrict or abrogate the authority of the Administrator or permitting authority to take any enforcement action under the Act for any violation of an applicable requirement or of any person to take action under section 304 of the Act.

[40 CFR 64.10]

CAM PLAN

(version dated 10/19/2009)

The following emissions units are subject to the CAM provisions only for the pollutant(s) indicated:

E.U. ID No.	Brief Description	Pollutant(s) subject to CAM
	Combustion Turbine Peaking Units (Simple Cycle units)	
-004	Combustion Turbine Peaking (CTP) Unit No. 1 (P-1)	NOx
-005	Combustion Turbine Peaking (CTP) Unit No. 2 (P-2)	NOx
-006	Combustion Turbine Peaking (CTP) Unit No. 3 (P-3)	NOx

For ease of reference the following definitions are cited from 40 CFR 64.1 Definitions (10/03/1997):

Exceedance shall mean a condition that is detected by monitoring that provides data in terms of an emission limitation or standard and that indicates that emissions (or opacity) are greater than the applicable emission limitation or standard (or less than the applicable standard in the case of a percent reduction requirement) consistent with any averaging period specified for averaging the results of the monitoring.

Excursion shall mean a departure from an indicator range established for monitoring under this part, consistent with any averaging period specified for averaging the results of the monitoring.

CAM PLAN
(version dated 10/19/2009)

E.U. ID No.	Brief Description
	Combustion Turbine Peaking Units (Simple Cycle units)
-004	Combustion Turbine Peaking (CTP) Unit No. 1 (P-1)
-005	Combustion Turbine Peaking (CTP) Unit No. 2 (P-2)
-006	Combustion Turbine Peaking (CTP) Unit No. 3 (P-3)

No. 2 fuel oil and natural gas fired combustion turbines
NOx emissions from each combustion turbine are controlled individually by water injection

Table 1. Monitoring Approach

	Indicator
I. Indicator	Water-to-fuel ratio
Measurement Approach	Continuous monitoring system measuring water injection rate, fuel consumption, and water-to-fuel ratio.
II. Indicator Range	<table><tr><td>Fuel</td><td>target ratio values* (minimum water-to-fuel ratio)</td></tr><tr><td>Fuel Oil</td><td>0.570</td></tr><tr><td>Natural Gas</td><td>0.370</td></tr></table> An excursion is defined as any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the target ratio values (excluding startup, shutdown and malfunction) for each of the CTs. Note, CT2A and CT2B do not currently fire natural gas. These water-to-fuel ratios have been determined to provide reasonable assurance of compliance with the limits contained in NSPS, 40 CFR 60, Subpart GG, and the Title V air operation permit. In addition, if water flow to any unit is unavailable for more than 90 minutes, the affected CT will automatically shut down. An excursion will trigger an evaluation of the operation of the affected CT and the water injection system. Corrective action shall be taken as necessary. Any excursion shall trigger recordkeeping and reporting requirements.
III. Performance Criteria	
A. Data Representativeness	The system meets the specifications of 40 CFR 60, Subpart GG.
B. Verification of Operational Status	Not applicable, the use of existing monitoring equipment is proposed.

C. QA/QC Practices and Criteria	All data QA/QC is in accordance with the requirements of 40 CFR 60.
D. Monitoring Frequency	Continuous.
E. Data Collection Procedures	Automated data acquisition handling system (DAHS).
F. Averaging Period	1 hour average (data collection frequency is continuous).

* The excursion level (target ratio value) specified in this CAM Plan was established based upon data established at the plant. The excursion level shall be re-evaluated at the time of renewal of Permit No. 1210003-007-AV based upon plant data.

ATTACHMENT B

FACILITY EMISSION CALCULATIONS

Emissions Summary

Units	Total HAPs (TPY)	
	Gas	No. 2 FO
Unit 1	0.68	NA
Unit 2	0.08	NA
Unit 3	0.15	NA
P1	0.57	0.69
P2	NA	0.69
P3	0.57	0.69
Total by Fuel	2.05	2.07
Facility Total	4.12	

EU001 Fossil Fuel-fired Steam Generator #1

Fuel Consumption and Fuel Characteristics		
Natural Gas	**Potential[1]**	
Fuel Heating Value	1,020	Btu/scf
Fuel Usage	4,029,600	MMBtu/yr
Fuel Usage	3,951	MMscf/yr
Sulfur Content		%

1. Potential fuel consumption and fuel characteristics based on permitted limits in Title V Permit No. 1210003-005-AV. Potential heating values based on standard fuel higher heating values listed in AP-42.

EU001 Emissions From Natural Gas

Pollutant	Reporting Threshold (tpy)	Natural Gas Emission Factor		Potential Emissions (tpy)	Above Reporting Threshold?
CPM	5	5.70	lb/MMscf	11.26	Yes
PM2.5	5	1.90	lb/MMscf	3.75	No
TBAC	5	-	-		-
NH3	5	3.20	lb/MMscf	6.32	Yes
1,1,1-Trichloroethane	0.5	-	-		-
2-Methylnaphthalene	0.5	2.40E-05	lb/MMscf	4.74E-05	No
3-Methylchloranthrene	0.5	1.80E-06	lb/MMscf	3.56E-06	No
7,12-Dimethylbenz(a)anthracene	0.5	1.60E-05	lb/MMscf	3.16E-05	No
Acetaldehyde	0.5	9.00E-04	lb/MMscf	1.78E-03	No
Acetophenone	0.5	-	-		-
Acrolein	0.5	8.00E-04	lb/MMscf	1.58E-03	No
Benzene	0.5	1.70E-03	lb/MMscf	3.36E-03	No
Benzyl Chloride	0.5	-	-		-
Biphenyl	0.5	-	-		-
Bis(2-ethylhexyl)phthalate (DEHP)	0.5	-	-		-
Bromoform	0.5	-	-		-
1,3-Butadiene	0.5	-	-		-
Carbon Disulfide	0.5	-	-		-
2-Chloroacetophenone	0.5	-	-		-
Chlorobenzene	0.5	-	-		-
Chloroform	0.5	-	-		-
Cumene	0.5	-	-		-
Cyanide	0.5	-	-		-
Dichlorobenzene	0.5	1.20E-03	lb/MMscf	2.37E-03	No
2,4-Dinitrotoluene	0.5	-	-		-
Dimethyl sulfate	0.5	-	-		-
Ethylbenzene	0.5	2.00E-03	lb/MMscf	3.95E-03	No
Ethyl chloride	0.5	-	-		-
Ethylene dibromide	0.5	-	-		-
Ethylene dichloride	0.5	-	-		-
Formaldehyde	0.5	3.60E-03	lb/MMscf	7.11E-03	No
Hexachlorobenzene	0.5	-	-		-
Hexane	0.5	1.30E-03	lb/MMscf	2.57E-03	No
HCl	0.5	1.24E-05	lb/MMBtu	2.50E-02	No
HF	0.5	-	-		-
Isophorone	0.5	-	-		-
Methyl bromide	0.5	-	-		-
Methyl chloride	0.5	-	-		-
Methyl hydrazine	0.5	-	-		-
Methyl methacrylate	0.5	-	-		-
Methyl tert butyl ether	0.5	-	-		-
Methylene chloride	0.5	-	-		-
Naphthalene	0.5	3.00E-04	lb/MMscf	6.04E-01	Yes
Phenol	0.5	-	-		-
Propionaldehyde	0.5	-	-		-
Poplylein Oxide	0.5	-	-		-
Styrene	0.5	-	-		-
Tetrachloroethylene	0.5	-	-		-
Toluene	0.5	10	lb/trillion Btu	2.01E-02	No
o-Xylene	0.5	-	-		-
Vinyl acetate	0.5	-	-		-

Metal HAP					
Antimony	0.5	-	-		
Arsenic	0.5	0.23	lb/trillion Btu	4.63E-04	No
Beryllium	0.5	0.01	lb/trillion Btu	2.01E-05	No
Cadmium	0.5	0.04	lb/trillion Btu	8.06E-05	No
Chromium	0.5	1.10	lb/trillion Btu	2.22E-03	No
Chromium VI	0.5	-	-		-
Cobalt	0.5	0.08	lb/trillion Btu	1.61E-04	No
Lead	0.25	0.40	lb/trillion Btu	8.06E-04	No
Manganese	0.5	0.40	lb/trillion Btu	8.06E-04	No
Mercury	0.5	8.00E-04	lb/trillion Btu	1.61E-06	No
Nickel	0.5	2.40	lb/trillion Btu	4.84E-03	No
Selenium	0.5	0.02	lb/trillion Btu	4.03E-05	No
POM					
					-
Acenaphthene	0.5	1.80E-06	lb/MMscf	3.56E-06	No
Acenaphthylene	0.5	1.80E-06	lb/MMscf	3.56E-06	No
Anthracene	0.5	2.40E-06	lb/MMscf	4.74E-06	No
Benz(a)anthracene	0.5	1.80E-06	lb/MMscf	3.56E-06	No
Benzo(b)fluoranthene	0.5	1.80E-06	lb/MMscf	3.56E-06	No
Benzo(k)fluoranthene	0.5	1.80E-06	lb/MMscf	3.56E-06	No
Benzo(g,h,i)perylene	0.5	1.20E-06	lb/MMscf	2.37E-06	No
Benzo(a)pyrene	0.5	1.20E-06	lb/MMscf	2.37E-06	No
Chrysene	0.5	1.80E-06	lb/MMscf	3.56E-06	No
Dibenzo(a,h)anthracene	0.5	1.20E-06	lb/MMscf	2.37E-06	No
Fluoranthene	0.5	3.00E-06	lb/MMscf	5.93E-06	No
Fluorene	0.5	2.80E-06	lb/MMscf	5.53E-06	No
Indo(1,2,3-cd)pyrene	0.5	1.80E-06	lb/MMscf	3.56E-06	No
Phenanthrene	0.5	1.70E-05	lb/MMscf	3.36E-05	No
Pyrene	0.5	5.00E-06	lb/MMscf	9.88E-06	No
Total POM	0.5	4.64E-05	lb/MMscf	9.17E-05	No
Dioxin / Furans					
Total Dioxins	0.5	-	-		-
1,2,3,4,6,7,8 - HpCDF	0.5	-	-		-
1,2,3,4,7,8,9 - HpCDF	0.5	-	-		-
1,2,3,4,7,8 - HxCDF	0.5	-	-		-
1,2,3,6,7,8 - HxCDF	0.5	-	-		-
1,2,3,7,8,9 - HxCDF	0.5	-	-		-
2,3,4,6,7,8 - HxCDF	0.5	-	-		-
1,2,3,4,7,8 - HxCDD	0.5	-	-		-
1,2,3,6,7,8 - HxCDD	0.5	-	-		-
1,2,3,7,8,9 - HxCDD	0.5	-	-		-
1,2,3,4,6,7,8 - HpCDD	0.5	-	-		-
1,2,3,4,6,7,8,9 - OCDF	0.5	-	-		-
1,2,3,4,6,7,8,9 - OCDD	0.5	-	-		-
1,2,3,7,8 - PeCDF	0.5	-	-		-
2,3,4,7,8 - PeCDF	0.5	-	-		-
1,2,3,7,8 - PeCDD	0.5	-	-		-
2,3,7,8 - TCDF	0.5	-	-		-
2,3,7,8 - TCDD	0.5	-	-		-

EU002 Fossil Fuel-fired Steam Generator #2

Fuel Consumption and Fuel Characteristics		
Natural Gas	**Potential[1]**	
Fuel Heating Value	1,020	Btu/scf
Fuel Usage	3,942,000	MMBtu/yr
Fuel Usage	3,865	MMscf/yr
Sulfur Content		%

1. Potential fuel consumption and fuel characteristics based on permitted limits in Title V Permit No. 1210003-005-AV.
Potential heating values based on standard fuel higher heating values listed in AP-42.

EU002 Emissions From Natural Gas

Pollutant	Reporting Threshold (tpy)	Natural Gas Emission Factor		Potential Emissions (tpy)	Above Reporting Threshold?
CPM	5	5.70	lb/MMscf	11.01	Yes
PM2.5	5	1.90	lb/MMscf	3.67	No
TBAC	5	-	-		-
NH3	5	3.20	lb/MMscf	6.18	Yes
1,1,1-Trichloroethane	0.5	-	-		-
2-Methylnaphthalene	0.5	2.40E-05	lb/MMscf	4.64E-05	No
3-Methylchloranthrene	0.5	1.80E-06	lb/MMscf	3.48E-06	No
7,12-Dimethylbenz(a)anthracene	0.5	1.60E-05	lb/MMscf	3.09E-05	No
Acetaldehyde	0.5	9.00E-04	lb/MMscf	1.74E-03	No
Acetophenone	0.5	-	-		-
Acrolein	0.5	8.00E-04	lb/MMscf	1.55E-03	No
Benzene	0.5	1.70E-03	lb/MMscf	3.29E-03	No
Benzyl Chloride	0.5	-	-		-
Biphenyl	0.5	-	-		-
Bis(2-ethylhexyl)phthalate (DEHP)	0.5	-	-		-
Bromoform	0.5	-	-		-
1,3-Butadiene	0.5	-	-		-
Carbon Disulfide	0.5	-	-		-
2-Chloroacetophenone	0.5	-	-		-
Chlorobenzene	0.5	-	-		-
Chloroform	0.5	-	-		-
Cumene	0.5	-	-		-
Cyanide	0.5	-	-		-
Dichlorobenzene	0.5	1.20E-03	lb/MMscf	2.32E-03	No
2,4-Dinitrotoluene	0.5	-	-		-
Dimethyl sulfate	0.5	-	-		-
Ethylbenzene	0.5	0.00	lb/MMscf	3.86E-03	No
Ethyl chloride	0.5	-	-		-
Ethylene dibromide	0.5	-	-		-
Ethylene dichloride	0.5	-	-		-
Formaldehyde	0.5	3.60E-03	lb/MMscf	6.96E-03	No
Hexachlorobenzene	0.5	-	-		-
Hexane	0.5	1.30E-03	lb/MMscf	2.51E-03	No
HCl	0.5	1.24E-05	lb/MMBtu	2.44E-02	No
HF	0.5	-	-		-
Isophorone	0.5	-	-		-
Methyl bromide	0.5	-	-		-
Methyl chloride	0.5	-	-		-
Methyl hydrazine	0.5	-	-		-
Methyl methacrylate	0.5	-	-		-
Methyl tert butyl ether	0.5	-	-		-
Methylene chloride	0.5	-	-		-
Naphthalene	0.5	3.00E-04	lb/MMscf	5.80E-04	No
Phenol	0.5	-	-		-
Propionaldehyde	0.5	-	-		-
Poplylein Oxide	0.5	-	-		-
Styrene	0.5	-	-		-
Tetrachloroethylene	0.5	-	-		-
Toluene	0.5	10	lb/trillion Btu	1.97E-02	No
o-Xylene	0.5	-	-		-
Vinyl acetate	0.5	-	-		-

Metal HAP					
Antimony	0.5	-	-		
Arsenic	0.5	0.23	lb/trillion Btu	4.53E-04	No
Beryllium	0.5	0.01	lb/trillion Btu	1.97E-05	No
Cadmium	0.5	0.04	lb/trillion Btu	7.88E-05	No
Chromium	0.5	1.10	lb/trillion Btu	2.17E-03	No
Chromium VI	0.5	-	-		-
Cobalt	0.5	0.08	lb/trillion Btu	1.58E-04	No
Lead	0.25	0.40	lb/trillion Btu	7.88E-04	No
Manganese	0.5	0.40	lb/trillion Btu	7.88E-04	No
Mercury	0.5	8.00E-04	lb/trillion Btu	1.58E-06	No
Nickel	0.5	2.40	lb/trillion Btu	4.73E-03	No
Selenium	0.5	0.02	lb/trillion Btu	3.94E-05	No
POM					
					-
Acenaphthene	0.5	1.80E-06	lb/MMscf	3.48E-06	No
Acenaphthylene	0.5	1.80E-06	lb/MMscf	3.48E-06	No
Anthracene	0.5	2.40E-06	lb/MMscf	4.64E-06	No
Benz(a)anthracene	0.5	1.80E-06	lb/MMscf	3.48E-06	No
Benzo(b)fluoranthene	0.5	1.80E-06	lb/MMscf	3.48E-06	No
Benzo(k)fluoranthene	0.5	1.80E-06	lb/MMscf	3.48E-06	No
Benzo(g,h,i)perylene	0.5	1.20E-06	lb/MMscf	2.32E-06	No
Benzo(a)pyrene	0.5	1.20E-06	lb/MMscf	2.32E-06	No
Chrysene	0.5	1.80E-06	lb/MMscf	3.48E-06	No
Dibenzo(a,h)anthracene	0.5	1.20E-06	lb/MMscf	2.32E-06	No
Fluoranthene	0.5	3.00E-06	lb/MMscf	5.80E-06	No
Fluorene	0.5	2.80E-06	lb/MMscf	5.41E-06	No
Indo(1,2,3-cd)pyrene	0.5	1.80E-06	lb/MMscf	3.48E-06	No
Phenanthrene	0.5	1.70E-05	lb/MMscf	3.29E-05	No
Pyrene	0.5	5.00E-06	lb/MMscf	9.66E-06	No
Total POM	0.5	4.64E-05	lb/MMscf	8.97E-05	No
Dioxin / Furans					
Total Dioxins	0.5	-	-		-
1,2,3,4,6,7,8 - HpCDF	0.5	-	-		-
1,2,3,4,7,8,9 - HpCDF	0.5	-	-		-
1,2,3,4,7,8 - HxCDF	0.5	-	-		-
1,2,3,6,7,8 - HxCDF	0.5	-	-		-
1,2,3,7,8,9 - HxCDF	0.5	-	-		-
2,3,4,6,7,8 - HxCDF	0.5	-	-		-
1,2,3,4,7,8 - HxCDD	0.5	-	-		-
1,2,3,6,7,8 - HxCDD	0.5	-	-		-
1,2,3,7,8,9 - HxCDD	0.5	-	-		-
1,2,3,4,6,7,8 - HpCDD	0.5	-	-		-
1,2,3,4,6,7,8,9 - OCDF	0.5	-	-		-
1,2,3,4,6,7,8,9 - OCDD	0.5	-	-		-
1,2,3,7,8 - PeCDF	0.5	-	-		-
2,3,4,7,8 - PeCDF	0.5	-	-		-
1,2,3,7,8 - PeCDD	0.5	-	-		-
2,3,7,8 - TCDF	0.5	-	-		-
2,3,7,8 - TCDD	0.5	-	-		-

EU003 Fossil Fuel-fired Steam Generator #3

Fuel Consumption and Fuel Characteristics		
Natural Gas	**Potential[1]**	
Fuel Heating Value	1,020	Btu/scf
Fuel Usage	7,708,800	MMBtu/yr
Fuel Usage	7,558	MMscf/yr
Sulfur Content		%

1. Potential fuel consumption and fuel characteristics based on permitted limits in Title V Permit No. 1210003-005-AV. Potential heating values based on standard fuel higher heating values listed in AP-42.

EU003 Emissions From Natural Gas

Pollutant	Reporting Threshold (tpy)	Natural Gas Emission Factor		Potential Emissions (tpy)	Above Reporting Threshold?
CPM	5	5.70	lb/MMscf	21.54	Yes
PM2.5	5	1.90	lb/MMscf	7.18	Yes
TBAC	5	-	-		-
NH3	5	3.20	lb/MMscf	12.09	Yes
1,1,1-Trichloroethane	0.5	-	-		-
2-Methylnaphthalene	0.5	2.40E-05	lb/MMscf	9.07E-05	No
3-Methylchloranthrene	0.5	1.80E-06	lb/MMscf	6.80E-06	No
7,12-Dimethylbenz(a)anthracene	0.5	1.60E-05	lb/MMscf	6.05E-05	No
Acetaldehyde	0.5	9.00E-04	lb/MMscf	3.40E-03	No
Acetophenone	0.5	-	-		-
Acrolein	0.5	8.00E-04	lb/MMscf	3.02E-03	No
Benzene	0.5	1.70E-03	lb/MMscf	6.42E-03	No
Benzyl Chloride	0.5	-	-		-
Biphenyl	0.5	-	-		-
Bis(2-ethylhexyl)phthalate (DEHP)	0.5	-	-		-
Bromoform	0.5	-	-		-
1,3-Butadiene	0.5	-	-		-
Carbon Disulfide	0.5	-	-		-
2-Chloroacetophenone	0.5	-	-		-
Chlorobenzene	0.5	-	-		-
Chloroform	0.5	-	-		-
Cumene	0.5	-	-		-
Cyanide	0.5	-	-		-
Dichlorobenzene	0.5	1.20E-03	lb/MMscf	4.53E-03	No
2,4-Dinitrotoluene	0.5	-	-		-
Dimethyl sulfate	0.5	-	-		-
Ethylbenzene	0.5	2.00E-03	lb/MMscf	7.56E-03	No
Ethyl chloride	0.5	-	-		-
Ethylene dibromide	0.5	-	-		-
Ethylene dichloride	0.5	-	-		-
Formaldehyde	0.5	3.60E-03	lb/MMscf	1.36E-02	No
Hexachlorobenzene	0.5	-	-		-
Hexane	0.5	1.30E-03	lb/MMscf	4.91E-03	No
HCl	0.5	1.24E-05	lb/MMBtu	4.78E-02	No
HF	0.5	-	-		-
Isophorone	0.5	-	-		-
Methyl bromide	0.5	-	-		-
Methyl chloride	0.5	-	-		-
Methyl hydrazine	0.5	-	-		-
Methyl methacrylate	0.5	-	-		-
Methyl tert butyl ether	0.5	-	-		-
Methylene chloride	0.5	-	-		-
Naphthalene	0.5	3.00E-04	lb/MMscf	1.13E-03	No
Phenol	0.5	-	-		-
Propionaldehyde	0.5	-	-		-
Poplylein Oxide	0.5	-	-		-
Styrene	0.5	-	-		-
Tetrachloroethylene	0.5	-	-		-
Toluene	0.5	10	lb/trillion Btu	3.85E-02	No
o-Xylene	0.5	-	-		-
Vinyl acetate	0.5	-	-		-

Metal HAP					
Antimony	0.5	-	-		
Arsenic	0.5	0.23	lb/trillion Btu	8.87E-04	No
Beryllium	0.5	0.01	lb/trillion Btu	3.85E-05	No
Cadmium	0.5	0.04	lb/trillion Btu	1.54E-04	No
Chromium	0.5	1.10	lb/trillion Btu	4.24E-03	No
Chromium VI	0.5	-	-		-
Cobalt	0.5	0.08	lb/trillion Btu	3.08E-04	No
Lead	0.25	0.40	lb/trillion Btu	1.54E-03	No
Manganese	0.5	0.40	lb/trillion Btu	1.54E-03	No
Mercury	0.5	8.00E-04	lb/trillion Btu	3.08E-06	No
Nickel	0.5	2.40	lb/trillion Btu	9.25E-03	No
Selenium	0.5	0.02	lb/trillion Btu	7.71E-05	No
POM					
					-
Acenaphthene	0.5	1.80E-06	lb/MMscf	6.80E-06	No
Acenaphthylene	0.5	1.80E-06	lb/MMscf	6.80E-06	No
Anthracene	0.5	2.40E-06	lb/MMscf	9.07E-06	No
Benz(a)anthracene	0.5	1.80E-06	lb/MMscf	6.80E-06	No
Benzo(b)fluoranthene	0.5	1.80E-06	lb/MMscf	6.80E-06	No
Benzo(k)fluoranthene	0.5	1.80E-06	lb/MMscf	6.80E-06	No
Benzo(g,h,i)perylene	0.5	1.20E-06	lb/MMscf	4.53E-06	No
Benzo(a)pyrene	0.5	1.20E-06	lb/MMscf	4.53E-06	No
Chrysene	0.5	1.80E-06	lb/MMscf	6.80E-06	No
Dibenzo(a,h)anthracene	0.5	1.20E-06	lb/MMscf	4.53E-06	No
Fluoranthene	0.5	3.00E-06	lb/MMscf	1.13E-05	No
Fluorene	0.5	2.80E-06	lb/MMscf	1.06E-05	No
Indo(1,2,3-cd)pyrene	0.5	1.80E-06	lb/MMscf	6.80E-06	No
Phenanthrene	0.5	1.70E-05	lb/MMscf	6.42E-05	No
Pyrene	0.5	5.00E-06	lb/MMscf	1.89E-05	No
Total POM	0.5	4.64E-05	lb/MMscf	1.75E-04	No
Dioxin / Furans					
Total Dioxins	0.5	-	-		-
1,2,3,4,6,7,8 - HpCDF	0.5	-	-		-
1,2,3,4,7,8,9 - HpCDF	0.5	-	-		-
1,2,3,4,7,8 - HxCDF	0.5	-	-		-
1,2,3,6,7,8 - HxCDF	0.5	-	-		-
1,2,3,7,8,9 - HxCDF	0.5	-	-		-
2,3,4,6,7,8 - HxCDF	0.5	-	-		-
1,2,3,4,7,8 - HxCDD	0.5	-	-		-
1,2,3,6,7,8 - HxCDD	0.5	-	-		-
1,2,3,7,8,9 - HxCDD	0.5	-	-		-
1,2,3,4,6,7,8 - HpCDD	0.5	-	-		-
1,2,3,4,6,7,8,9 - OCDF	0.5	-	-		-
1,2,3,4,6,7,8,9 - OCDD	0.5	-	-		-
1,2,3,7,8 - PeCDF	0.5	-	-		-
2,3,4,7,8 - PeCDF	0.5	-	-		-
1,2,3,7,8 - PeCDD	0.5	-	-		-
2,3,7,8 - TCDF	0.5	-	-		-
2,3,7,8 - TCDD	0.5	-	-		-

EU004 Combustion Turbine Peaking Unit No. 1

Fuel Consumption and Fuel Characteristics		
No. 2 Fuel Oil	**Potential[1]**	
Fuel Heating Value	140	MMBtu/Mgal
Fuel Usage	1,108,500	MMBtu/yr
Fuel Usage	7,918	Mgal/yr
Sulfur Content		%

1. Potential fuel consumption and fuel characteristics based on permitted limits in Title V Permit No. 1210003-005-AV. Potential heating values based on standard fuel higher heating values listed in AP-42.

EU004 Emissions From No. 2 Fuel Oil

Pollutant	Reporting Threshold (tpy)	No. 2 Fuel Oil Emission Factor		Potential Emissions (tpy)	Above Reporting Threshold?
CPM	5	4.70E-03	(lb/MMBtu)	2.60	No
PM2.5	5	3.87E-03	(lb/MMBtu)	2.14	No
TBAC	5	-	-		-
NH3	5	6.62	(lb/Mgal)	26.21	Yes
1,1,1-Trichloroethane	0.5	-	-		-
2-Methylnaphthalene	0.5	-	-		-
3-Methylchloranthrene	0.5	-	-		-
7,12-Dimethylbenz(a)anthracene	0.5	-	-		-
Acetaldehyde	0.5	-	-		-
Acetophenone	0.5	-	-		-
Acrolein	0.5	-	-		-
Benzene	0.5	5.50E-05	(lb/MMBtu)	3.05E-02	No
Benzyl Chloride	0.5	-	-		-
Biphenyl	0.5	-	-		-
Bis(2-ethylhexyl)phthalate (DEHP)	0.5	-	-		-
Bromoform	0.5	-	-		-
1,3-Butadiene	0.5	1.60E-05	(lb/MMBtu)	8.87E-03	No
Carbon Disulfide	0.5	-	-		-
2-Chloroacetophenone	0.5	-	-		-
Chlorobenzene	0.5	-	-		-
Chloroform	0.5	-	-		-
Cumene	0.5	-	-		-
Cyanide	0.5	-	-		-
Dichlorobenzene	0.5	-	-		-
2,4-Dinitrotoluene	0.5	-	-		-
Dimethyl sulfate	0.5	-	-		-
Ethylbenzene	0.5	-	-		-
Ethyl chloride	0.5	-	-		-
Ethylene dibromide	0.5	-	-		-
Ethylene dichloride	0.5	-	-		-
Formaldehyde	0.5	2.80E-04	(lb/MMBtu)	1.55E-01	No
Hexachlorobenzene	0.5	-	-		-
Hexane	0.5	-	-		-
HCl	0.5	-	-		-
HF	0.5	-	-		-
Isophorone	0.5	-	-		-
Methyl bromide	0.5	-	-		-
Methyl chloride	0.5	-	-		-
Methyl hydrazine	0.5	-	-		-
Methyl methacrylate	0.5	-	-		-
Methyl tert butyl ether	0.5	-	-		-
Methylene chloride	0.5	-	-		-
Naphthalene	0.5	3.50E-05	(lb/MMBtu)	1.94E-02	No
Phenol	0.5	-	-		-
Propionaldehyde	0.5	-	-		-
Poplylein Oxide	0.5	-	-		-
Styrene	0.5	-	-		-
Tetrachloroethylene	0.5	-	-		-
Toluene	0.5	-	-		-
o-Xylene	0.5	-	-		-
Vinyl acetate	0.5	-	-		-

Metal HAP					
Antimony	0.5	-	-		-
Arsenic	0.5	1.10E-05	(lb/MMBtu)	6.10E-03	No
Beryllium	0.5	3.10E-07	(lb/MMBtu)	1.72E-04	No
Cadmium	0.5	4.80E-06	(lb/MMBtu)	2.66E-03	No
Chromium	0.5	1.10E-05	(lb/MMBtu)	6.10E-03	No
Chromium VI	0.5	-	-		-
Cobalt	0.5	-	-		-
Lead	0.25	1.40E-05	(lb/MMBtu)	7.76E-03	No
Manganese	0.5	7.90E-04	(lb/MMBtu)	4.38E-01	No
Mercury	0.5	1.20E-06	(lb/MMBtu)	6.65E-04	No
Nickel	0.5	4.60E-06	(lb/MMBtu)	2.55E-03	No
Selenium	0.5	2.50E-05	(lb/MMBtu)	1.39E-02	No
POM					
Acenaphthene	0.5	-	-		-
Acenaphthylene	0.5	-	-		-
Anthracene	0.5	-	-		-
Benz(a)anthracene	0.5	-	-		-
Benzo(b)fluoranthene	0.5	-	-		-
Benzo(k)fluoranthene	0.5	-	-		-
Benzo(g,h,i)perylene	0.5	-	-		-
Benzo(a)pyrene	0.5	-	-		-
Chrysene	0.5	-	-		-
Dibenzo(a,h)anthracene	0.5	-	-		-
Fluoranthene	0.5	-	-		-
Fluorene	0.5	-	-		-
Indo(1,2,3-cd)pyrene	0.5	-	-		-
Phenanthrene	0.5	-	-		-
Pyrene	0.5	-	-		-
Total POM	0.5	-	-		-
Dioxin / Furans					
Total Dioxins	0.5	-	-		-
1,2,3,4,6,7,8 - HpCDF	0.5	-	-		-
1,2,3,4,7,8,9 - HpCDF	0.5	-	-		-
1,2,3,4,7,8 - HxCDF	0.5	-	-		-
1,2,3,6,7,8 - HxCDF	0.5	-	-		-
1,2,3,7,8,9 - HxCDF	0.5	-	-		-
2,3,4,6,7,8 - HxCDF	0.5	-	-		-
1,2,3,4,7,8 - HxCDD	0.5	-	-		-
1,2,3,6,7,8 - HxCDD	0.5	-	-		-
1,2,3,7,8,9 - HxCDD	0.5	-	-		-
1,2,3,4,6,7,8 - HpCDD	0.5	-	-		-
1,2,3,4,6,7,8,9 - OCDF	0.5	-	-		-
1,2,3,4,6,7,8,9 - OCDD	0.5	-	-		-
1,2,3,7,8 - PeCDF	0.5	-	-		-
2,3,4,7,8 - PeCDF	0.5	-	-		-
1,2,3,7,8 - PeCDD	0.5	-	-		-
2,3,7,8 - TCDF	0.5	-	-		-
2,3,7,8 - TCDD	0.5	-	-		-

EU004 Combustion Turbine Peaking Unit No. 1

Fuel Consumption and Fuel Characteristics		
Natural Gas	**Potential[1]**	
Fuel Heating Value	1,020	Btu/scf
Fuel Usage	1,108,500	MMBtu/yr
Fuel Usage	1,087	MMscf/yr
Sulfur Content		%

1. Potential fuel consumption and fuel characteristics based on permitted limits in Title V Permit No. 1210003-005-AV. Potential heating values based on standard fuel higher heating values listed in AP-42.

EU004 Emissions From Natural Gas

Pollutant	Reporting Threshold (tpy)	Natural Gas Emission Factor		Potential Emissions (tpy)	Above Reporting Threshold?
CPM	5	7.20E-03	(lb/MMBtu)	3.99	No
PM2.5	5	1.90E-03	(lb/MMBtu)	1.05	No
TBAC	5	-	-		-
NH3	5	6.56	(lb/MMscf)	3.56	No
1,1,1-Trichloroethane	0.5	-	-		-
2-Methylnaphthalene	0.5	-	-		-
3-Methylchloranthrene	0.5	-	-		-
7,12-Dimethylbenz(a)anthracene	0.5	-	-		-
Acetaldehyde	0.5	4.00E-05	(lb/MMBtu)	0.02	No
Acetophenone	0.5				-
Acrolein	0.5	6.40E-06	(lb/MMBtu)	3.55E-03	No
Benzene	0.5	1.20E-05	(lb/MMBtu)	0.01	No
Benzyl Chloride	0.5	-	-		-
Biphenyl	0.5	-	-		-
Bis(2-ethylhexyl)phthalate (DEHP)	0.5	-	-		-
Bromoform	0.5	-	-		-
1,3-Butadiene	0.5	4.30E-07	(lb/MMBtu)	2.38E-04	No
Carbon Disulfide	0.5	-	-		-
2-Chloroacetophenone	0.5	-	-		-
Chlorobenzene	0.5	-	-		-
Chloroform	0.5	-	-		-
Cumene	0.5	-	-		-
Cyanide	0.5	-	-		-
Dichlorobenzene	0.5	-	-		-
2,4-Dinitrotoluene	0.5	-	-		-
Dimethyl sulfate	0.5	-	-		-
Ethylbenzene	0.5	3.20E-05	(lb/MMBtu)	0.02	No
Ethyl chloride	0.5	-	-		-
Ethylene dibromide	0.5	-	-		-
Ethylene dichloride	0.5	-	-		-
Formaldehyde	0.5	7.10E-04	(lb/MMBtu)	0.39	No
Hexachlorobenzene	0.5	-	-		-
Hexane	0.5	-	-		-
HCl	0.5	-	-		-
HF	0.5	-	-		-
Isophorone	0.5	-	-		-
Methyl bromide	0.5	-	-		-
Methyl chloride	0.5	-	-		-
Methyl hydrazine	0.5	-	-		-
Methyl methacrylate	0.5	-	-		-
Methyl tert butyl ether	0.5	-	-		-
Methylene chloride	0.5	-	-		-
Naphthalene	0.5	1.30E-06	(lb/MMBtu)	7.21E-04	No
Phenol	0.5	-	-		-
Propionaldehyde	0.5	-	-		-
Poplylein Oxide	0.5	2.90E-05	(lb/MMBtu)	0.02	No
Styrene	0.5	-	-		-
Tetrachloroethylene	0.5	-	-		-
Toluene	0.5	1.30E-04	(lb/MMBtu)	0.07	No
o-Xylene	0.5	6.40E-05	(lb/MMBtu)	0.04	No
Vinyl acetate	0.5	-	-		-

Metal HAP					
Antimony	0.5	-	-		-
Arsenic	0.5	2.30E-01	(lb/trillion Btu)	1.27E-04	No
Beryllium	0.5	1.00E-02	(lb/trillion Btu)	5.54E-06	No
Cadmium	0.5	4.00E-02	(lb/trillion Btu)	2.22E-05	No
Chromium	0.5	1.10	(lb/trillion Btu)	6.10E-04	No
Chromium VI	0.5	-	-		-
Cobalt	0.5	8.00E-02	(lb/trillion Btu)	4.43E-05	No
Lead	0.25	4.00E-01	(lb/trillion Btu)	2.22E-04	No
Manganese	0.5	4.00E-01	(lb/trillion Btu)	2.22E-04	No
Mercury	0.5	8.00E-04	(lb/trillion Btu)	4.43E-07	No
Nickel	0.5	2.40	(lb/trillion Btu)	1.33E-03	No
Selenium	0.5	2.00E-02	(lb/trillion Btu)	1.11E-05	No
POM					
Acenaphthene	0.5	-	-		-
Acenaphthylene	0.5	-	-		-
Anthracene	0.5	-	-		-
Benz(a)anthracene	0.5	-	-		-
Benzo(b)fluoranthene	0.5	-	-		-
Benzo(k)fluoranthene	0.5	-	-		-
Benzo(g,h,i)perylene	0.5	-	-		-
Benzo(a)pyrene	0.5	-	-		-
Chrysene	0.5	-	-		-
Dibenzo(a,h)anthracene	0.5	-	-		-
Fluoranthene	0.5	-	-		-
Fluorene	0.5	-	-		-
Indo(1,2,3-cd)pyrene	0.5	-	-		-
Phenanthrene	0.5	-	-		-
Pyrene	0.5	-	-		-
Total POM	0.5	-	-		-
Dioxin / Furans					
Total Dioxins	0.5	-	-		-
1,2,3,4,6,7,8 - HpCDF	0.5	-	-		-
1,2,3,4,7,8,9 - HpCDF	0.5	-	-		-
1,2,3,4,7,8 - HxCDF	0.5	-	-		-
1,2,3,6,7,8 - HxCDF	0.5	-	-		-
1,2,3,7,8,9 - HxCDF	0.5	-	-		-
2,3,4,6,7,8 - HxCDF	0.5	-	-		-
1,2,3,4,7,8 - HxCDD	0.5	-	-		-
1,2,3,6,7,8 - HxCDD	0.5	-	-		-
1,2,3,7,8,9 - HxCDD	0.5	-	-		-
1,2,3,4,6,7,8 - HpCDD	0.5	-	-		-
1,2,3,4,6,7,8,9 - OCDF	0.5	-	-		-
1,2,3,4,6,7,8,9 - OCDD	0.5	-	-		-
1,2,3,7,8 - PeCDF	0.5	-	-		-
2,3,4,7,8 - PeCDF	0.5	-	-		-
1,2,3,7,8 - PeCDD	0.5	-	-		-
2,3,7,8 - TCDF	0.5	-	-		-
2,3,7,8 - TCDD	0.5	-	-		-

EU005 Combustion Turbine Peaking Unit No. 2

Fuel Consumption and Fuel Characteristics		
No. 2 Fuel Oil	**Potential[1]**	
Fuel Heating Value	140	MMBtu/Mgal
Fuel Usage	1,108,500	MMBtu/yr
Fuel Usage	7,918	Mgal/yr
Sulfur Content		%

1. Potential fuel consumption and fuel characteristics based on permitted limits in Title V Permit No. 1210003-005-AV. Potential heating values based on standard fuel higher heating values listed in AP-42.

EU005 Emissions From No. 2 Fuel Oil

Pollutant	Reporting Threshold (tpy)	No. 2 Fuel Oil Emission Factor		Potential Emissions (tpy)	Above Reporting Threshold?
CPM	5	4.70E-03	(lb/MMBtu)	2.60	No
PM2.5	5	3.87E-03	(lb/MMBtu)	2.14	No
TBAC	5	-	-		-
NH3	5	6.62	(lb/Mgal)	26.21	Yes
1,1,1-Trichloroethane	0.5	-	-		-
2-Methylnaphthalene	0.5	-	-		-
3-Methylchloranthrene	0.5	-	-		-
7,12-Dimethylbenz(a)anthracene	0.5	-	-		-
Acetaldehyde	0.5	-	-		-
Acetophenone	0.5	-	-		-
Acrolein	0.5	-	-		-
Benzene	0.5	5.50E-05	(lb/MMBtu)	3.05E-02	No
Benzyl Chloride	0.5	-	-		-
Biphenyl	0.5	-	-		-
Bis(2-ethylhexyl)phthalate (DEHP)	0.5	-	-		-
Bromoform	0.5	-	-		-
1,3-Butadiene	0.5	1.60E-05	(lb/MMBtu)	8.87E-03	No
Carbon Disulfide	0.5	-	-		-
2-Chloroacetophenone	0.5	-	-		-
Chlorobenzene	0.5	-	-		-
Chloroform	0.5	-	-		-
Cumene	0.5	-	-		-
Cyanide	0.5	-	-		-
Dichlorobenzene	0.5	-	-		-
2,4-Dinitrotoluene	0.5	-	-		-
Dimethyl sulfate	0.5	-	-		-
Ethylbenzene	0.5	-	-		-
Ethyl chloride	0.5	-	-		-
Ethylene dibromide	0.5	-	-		-
Ethylene dichloride	0.5	-	-		-
Formaldehyde	0.5	2.80E-04	(lb/MMBtu)	1.55E-01	No
Hexachlorobenzene	0.5	-	-		-
Hexane	0.5	-	-		-
HCl	0.5	-	-		-
HF	0.5	-	-		-
Isophorone	0.5	-	-		-
Methyl bromide	0.5	-	-		-
Methyl chloride	0.5	-	-		-
Methyl hydrazine	0.5	-	-		-
Methyl methacrylate	0.5	-	-		-
Methyl tert butyl ether	0.5	-	-		-
Methylene chloride	0.5	-	-		-
Naphthalene	0.5	3.50E-05	(lb/MMBtu)	1.94E-02	No
Phenol	0.5	-	-		-
Propionaldehyde	0.5	-	-		-
Poplylein Oxide	0.5	-	-		-
Styrene	0.5	-	-		-
Tetrachloroethylene	0.5	-	-		-
Toluene	0.5	-	-		-
o-Xylene	0.5	-	-		-
Vinyl acetate	0.5	-	-		-

Metal HAP					
Antimony	0.5	-	-		-
Arsenic	0.5	1.10E-05	(lb/MMBtu)	6.10E-03	No
Beryllium	0.5	3.10E-07	(lb/MMBtu)	1.72E-04	No
Cadmium	0.5	4.80E-06	(lb/MMBtu)	2.66E-03	No
Chromium	0.5	1.10E-05	(lb/MMBtu)	6.10E-03	No
Chromium VI	0.5	-	-		-
Cobalt	0.5	-	-		-
Lead	0.25	1.40E-05	(lb/MMBtu)	7.76E-03	No
Manganese	0.5	7.90E-04	(lb/MMBtu)	4.38E-01	No
Mercury	0.5	1.20E-06	(lb/MMBtu)	6.65E-04	No
Nickel	0.5	4.60E-06	(lb/MMBtu)	2.55E-03	No
Selenium	0.5	2.50E-05	(lb/MMBtu)	1.39E-02	No
POM					
Acenaphthene	0.5	-	-		-
Acenaphthylene	0.5	-	-		-
Anthracene	0.5	-	-		-
Benz(a)anthracene	0.5	-	-		-
Benzo(b)fluoranthene	0.5	-	-		-
Benzo(k)fluoranthene	0.5	-	-		-
Benzo(g,h,i)perylene	0.5	-	-		-
Benzo(a)pyrene	0.5	-	-		-
Chrysene	0.5	-	-		-
Dibenzo(a,h)anthracene	0.5	-	-		-
Fluoranthene	0.5	-	-		-
Fluorene	0.5	-	-		-
Indo(1,2,3-cd)pyrene	0.5	-	-		-
Phenanthrene	0.5	-	-		-
Pyrene	0.5	-	-		-
Total POM	0.5	-	-		-
Dioxin / Furans					
Total Dioxins	0.5	-	-		-
1,2,3,4,6,7,8 - HpCDF	0.5	-	-		-
1,2,3,4,7,8,9 - HpCDF	0.5	-	-		-
1,2,3,4,7,8 - HxCDF	0.5	-	-		-
1,2,3,6,7,8 - HxCDF	0.5	-	-		-
1,2,3,7,8,9 - HxCDF	0.5	-	-		-
2,3,4,6,7,8 - HxCDF	0.5	-	-		-
1,2,3,4,7,8 - HxCDD	0.5	-	-		-
1,2,3,6,7,8 - HxCDD	0.5	-	-		-
1,2,3,7,8,9 - HxCDD	0.5	-	-		-
1,2,3,4,6,7,8 - HpCDD	0.5	-	-		-
1,2,3,4,6,7,8,9 - OCDF	0.5	-	-		-
1,2,3,4,6,7,8,9 - OCDD	0.5	-	-		-
1,2,3,7,8 - PeCDF	0.5	-	-		-
2,3,4,7,8 - PeCDF	0.5	-	-		-
1,2,3,7,8 - PeCDD	0.5	-	-		-
2,3,7,8 - TCDF	0.5	-	-		-
2,3,7,8 - TCDD	0.5	-	-		-

EU006 Combustion Turbine Peaking Unit No. 3

Fuel Consumption and Fuel Characteristics		
No. 2 Fuel Oil	**Potential[1]**	
Fuel Heating Value	140	MMBtu/Mgal
Fuel Usage	1,108,500	MMBtu/yr
Fuel Usage	7,918	Mgal/yr
Sulfur Content		%

1. Potential fuel consumption and fuel characteristics based on permitted limits in Title V Permit No. 1210003-005-AV. Potential heating values based on standard fuel higher heating values listed in AP-42.

EU006 Emissions From No. 2 Fuel Oil

Pollutant	Reporting Threshold (tpy)	No. 2 Fuel Oil Emission Factor		Potential Emissions (tpy)	Above Reporting Threshold?
CPM	5	4.70E-03	(lb/MMBtu)	2.60	No
PM2.5	5	3.87E-03	(lb/MMBtu)	2.14	No
TBAC	5	-	-		-
NH3	5	6.62	(lb/Mgal)	26.21	Yes
1,1,1-Trichloroethane	0.5	-	-		-
2-Methylnaphthalene	0.5	-	-		-
3-Methylchloranthrene	0.5	-	-		-
7,12-Dimethylbenz(a)anthracene	0.5	-	-		-
Acetaldehyde	0.5	-	-		-
Acetophenone	0.5	-	-		-
Acrolein	0.5	-	-		-
Benzene	0.5	5.50E-05	(lb/MMBtu)	3.05E-02	No
Benzyl Chloride	0.5	-	-		-
Biphenyl	0.5	-	-		-
Bis(2-ethylhexyl)phthalate (DEHP)	0.5	-	-		-
Bromoform	0.5	-	-		-
1,3-Butadiene	0.5	1.60E-05	(lb/MMBtu)	8.87E-03	No
Carbon Disulfide	0.5	-	-		-
2-Chloroacetophenone	0.5	-	-		-
Chlorobenzene	0.5	-	-		-
Chloroform	0.5	-	-		-
Cumene	0.5	-	-		-
Cyanide	0.5	-	-		-
Dichlorobenzene	0.5	-	-		-
2,4-Dinitrotoluene	0.5	-	-		-
Dimethyl sulfate	0.5	-	-		-
Ethylbenzene	0.5	-	-		-
Ethyl chloride	0.5	-	-		-
Ethylene dibromide	0.5	-	-		-
Ethylene dichloride	0.5	-	-		-
Formaldehyde	0.5	2.80E-04	(lb/MMBtu)	1.55E-01	No
Hexachlorobenzene	0.5	-	-		-
Hexane	0.5	-	-		-
HCl	0.5	-	-		-
HF	0.5	-	-		-
Isophorone	0.5	-	-		-
Methyl bromide	0.5	-	-		-
Methyl chloride	0.5	-	-		-
Methyl hydrazine	0.5	-	-		-
Methyl methacrylate	0.5	-	-		-
Methyl tert butyl ether	0.5	-	-		-
Methylene chloride	0.5	-	-		-
Naphthalene	0.5	3.50E-05	(lb/MMBtu)	1.94E-02	No
Phenol	0.5	-	-		-
Propionaldehyde	0.5	-	-		-
Poplylein Oxide	0.5	-	-		-
Styrene	0.5	-	-		-
Tetrachloroethylene	0.5	-	-		-
Toluene	0.5	-	-		-
o-Xylene	0.5	-	-		-
Vinyl acetate	0.5	-	-		-

Metal HAP					
Antimony	0.5	-	-		-
Arsenic	0.5	1.10E-05	(lb/MMBtu)	6.10E-03	No
Beryllium	0.5	3.10E-07	(lb/MMBtu)	1.72E-04	No
Cadmium	0.5	4.80E-06	(lb/MMBtu)	2.66E-03	No
Chromium	0.5	1.10E-05	(lb/MMBtu)	6.10E-03	No
Chromium VI	0.5	-	-		-
Cobalt	0.5	-	-		-
Lead	0.25	1.40E-05	(lb/MMBtu)	7.76E-03	No
Manganese	0.5	7.90E-04	(lb/MMBtu)	4.38E-01	No
Mercury	0.5	1.20E-06	(lb/MMBtu)	6.65E-04	No
Nickel	0.5	4.60E-06	(lb/MMBtu)	2.55E-03	No
Selenium	0.5	2.50E-05	(lb/MMBtu)	1.39E-02	No
POM					
Acenaphthene	0.5	-	-		-
Acenaphthylene	0.5	-	-		-
Anthracene	0.5	-	-		-
Benz(a)anthracene	0.5	-	-		-
Benzo(b)fluoranthene	0.5	-	-		-
Benzo(k)fluoranthene	0.5	-	-		-
Benzo(g,h,i)perylene	0.5	-	-		-
Benzo(a)pyrene	0.5	-	-		-
Chrysene	0.5	-	-		-
Dibenzo(a,h)anthracene	0.5	-	-		-
Fluoranthene	0.5	-	-		-
Fluorene	0.5	-	-		-
Indo(1,2,3-cd)pyrene	0.5	-	-		-
Phenanthrene	0.5	-	-		-
Pyrene	0.5	-	-		-
Total POM	0.5	-	-		-
Dioxin / Furans					
Total Dioxins	0.5	-	-		-
1,2,3,4,6,7,8 - HpCDF	0.5	-	-		-
1,2,3,4,7,8,9 - HpCDF	0.5	-	-		-
1,2,3,4,7,8 - HxCDF	0.5	-	-		-
1,2,3,6,7,8 - HxCDF	0.5	-	-		-
1,2,3,7,8,9 - HxCDF	0.5	-	-		-
2,3,4,6,7,8 - HxCDF	0.5	-	-		-
1,2,3,4,7,8 - HxCDD	0.5	-	-		-
1,2,3,6,7,8 - HxCDD	0.5	-	-		-
1,2,3,7,8,9 - HxCDD	0.5	-	-		-
1,2,3,4,6,7,8 - HpCDD	0.5	-	-		-
1,2,3,4,6,7,8,9 - OCDF	0.5	-	-		-
1,2,3,4,6,7,8,9 - OCDD	0.5	-	-		-
1,2,3,7,8 - PeCDF	0.5	-	-		-
2,3,4,7,8 - PeCDF	0.5	-	-		-
1,2,3,7,8 - PeCDD	0.5	-	-		-
2,3,7,8 - TCDF	0.5	-	-		-
2,3,7,8 - TCDD	0.5	-	-		-

EU006 Combustion Turbine Peaking Unit No. 3

Fuel Consumption and Fuel Characteristics		
Natural Gas	**Potential[1]**	
Fuel Heating Value	1,020	Btu/scf
Fuel Usage	1,108,500	MMBtu/yr
Fuel Usage	1,087	MMscf/yr
Sulfur Content		%

1. Potential fuel consumption and fuel characteristics based on permitted limits in Title V Permit No. 1210003-005-AV. Potential heating values based on standard fuel higher heating values listed in AP-42.

EU006 Emissions From Natural Gas

Pollutant	Reporting Threshold (tpy)	Natural Gas Emission Factor		Potential Emissions (tpy)	Above Reporting Threshold?
CPM	5	7.20E-03	(lb/MMBtu)	3.99	No
PM2.5	5	1.90E-03	(lb/MMBtu)	1.05	No
TBAC	5	-	-		-
NH3	5	6.56	(lb/MMscf)	3.56	No
1,1,1-Trichloroethane	0.5	-	-		-
2-Methylnaphthalene	0.5	-	-		-
3-Methylchloranthrene	0.5	-	-		-
7,12-Dimethylbenz(a)anthracene	0.5	-	-		-
Acetaldehyde	0.5	4.00E-05	(lb/MMBtu)	0.02	No
Acetophenone	0.5				-
Acrolein	0.5	6.40E-06	(lb/MMBtu)	3.55E-03	No
Benzene	0.5	1.20E-05	(lb/MMBtu)	0.01	No
Benzyl Chloride	0.5	-	-		-
Biphenyl	0.5	-	-		-
Bis(2-ethylhexyl)phthalate (DEHP)	0.5	-	-		-
Bromoform	0.5	-	-		-
1,3-Butadiene	0.5	4.30E-07	(lb/MMBtu)	2.38E-04	No
Carbon Disulfide	0.5	-	-		-
2-Chloroacetophenone	0.5	-	-		-
Chlorobenzene	0.5	-	-		-
Chloroform	0.5	-	-		-
Cumene	0.5	-	-		-
Cyanide	0.5	-	-		-
Dichlorobenzene	0.5	-	-		-
2,4-Dinitrotoluene	0.5	-	-		-
Dimethyl sulfate	0.5	-	-		-
Ethylbenzene	0.5	3.20E-05	(lb/MMBtu)	0.02	No
Ethyl chloride	0.5	-	-		-
Ethylene dibromide	0.5	-	-		-
Ethylene dichloride	0.5	-	-		-
Formaldehyde	0.5	7.10E-04	(lb/MMBtu)	0.39	No
Hexachlorobenzene	0.5	-	-		-
Hexane	0.5	-	-		-
HCl	0.5	-	-		-
HF	0.5	-	-		-
Isophorone	0.5	-	-		-
Methyl bromide	0.5	-	-		-
Methyl chloride	0.5	-	-		-
Methyl hydrazine	0.5	-	-		-
Methyl methacrylate	0.5	-	-		-
Methyl tert butyl ether	0.5	-	-		-
Methylene chloride	0.5	-	-		-
Naphthalene	0.5	1.30E-06	(lb/MMBtu)	7.21E-04	No
Phenol	0.5	-	-		-
Propionaldehyde	0.5	-	-		-
Poplylein Oxide	0.5	2.90E-05	(lb/MMBtu)	0.02	No
Styrene	0.5	-	-		-
Tetrachloroethylene	0.5	-	-		-
Toluene	0.5	1.30E-04	(lb/MMBtu)	0.07	No
o-Xylene	0.5	6.40E-05	(lb/MMBtu)	0.04	No
Vinyl acetate	0.5	-	-		-

Metal HAP					
Antimony	0.5	-	-		-
Arsenic	0.5	2.30E-01	(lb/trillion Btu)	1.27E-04	No
Beryllium	0.5	1.00E-02	(lb/trillion Btu)	5.54E-06	No
Cadmium	0.5	4.00E-02	(lb/trillion Btu)	2.22E-05	No
Chromium	0.5	1.10	(lb/trillion Btu)	6.10E-04	No
Chromium VI	0.5	-	-		-
Cobalt	0.5	8.00E-02	(lb/trillion Btu)	4.43E-05	No
Lead	0.25	4.00E-01	(lb/trillion Btu)	2.22E-04	No
Manganese	0.5	4.00E-01	(lb/trillion Btu)	2.22E-04	No
Mercury	0.5	8.00E-04	(lb/trillion Btu)	4.43E-07	No
Nickel	0.5	2.40	(lb/trillion Btu)	1.33E-03	No
Selenium	0.5	2.00E-02	(lb/trillion Btu)	1.11E-05	No
POM					
Acenaphthene	0.5	-	-		-
Acenaphthylene	0.5	-	-		-
Anthracene	0.5	-	-		-
Benz(a)anthracene	0.5	-	-		-
Benzo(b)fluoranthene	0.5	-	-		-
Benzo(k)fluoranthene	0.5	-	-		-
Benzo(g,h,i)perylene	0.5	-	-		-
Benzo(a)pyrene	0.5	-	-		-
Chrysene	0.5	-	-		-
Dibenzo(a,h)anthracene	0.5	-	-		-
Fluoranthene	0.5	-	-		-
Fluorene	0.5	-	-		-
Indo(1,2,3-cd)pyrene	0.5	-	-		-
Phenanthrene	0.5	-	-		-
Pyrene	0.5	-	-		-
Total POM	0.5	-	-		-
Dioxin / Furans					
Total Dioxins	0.5	-	-		-
1,2,3,4,6,7,8 - HpCDF	0.5	-	-		-
1,2,3,4,7,8,9 - HpCDF	0.5	-	-		-
1,2,3,4,7,8 - HxCDF	0.5	-	-		-
1,2,3,6,7,8 - HxCDF	0.5	-	-		-
1,2,3,7,8,9 - HxCDF	0.5	-	-		-
2,3,4,6,7,8 - HxCDF	0.5	-	-		-
1,2,3,4,7,8 - HxCDD	0.5	-	-		-
1,2,3,6,7,8 - HxCDD	0.5	-	-		-
1,2,3,7,8,9 - HxCDD	0.5	-	-		-
1,2,3,4,6,7,8 - HpCDD	0.5	-	-		-
1,2,3,4,6,7,8,9 - OCDF	0.5	-	-		-
1,2,3,4,6,7,8,9 - OCDD	0.5	-	-		-
1,2,3,7,8 - PeCDF	0.5	-	-		-
2,3,4,7,8 - PeCDF	0.5	-	-		-
1,2,3,7,8 - PeCDD	0.5	-	-		-
2,3,7,8 - TCDF	0.5	-	-		-
2,3,7,8 - TCDD	0.5	-	-		-

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