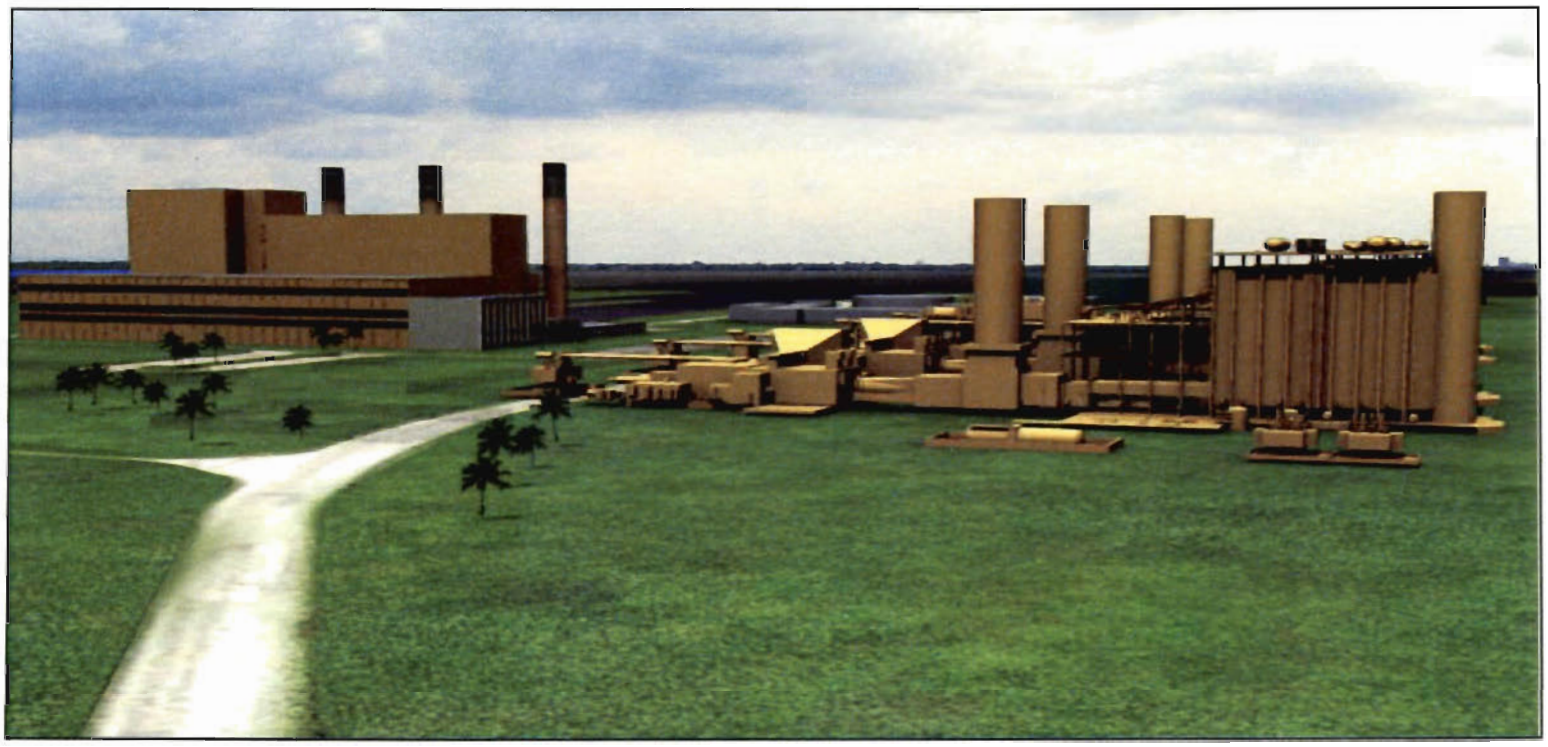
TITLE V PERMIT APPLICATION
BARTOW POWER PLANT



Submitted to:
Florida Department of Environmental Protection

On Behalf of
Florida Power Corporation dba Progress Energy, Florida, Inc.

Progress Energy

Submitted by:

Golder Associates

May 2009

083-89614

From: Origin ID: KYOA (813) 287-1717
Scott Osbourn
GOLDER ASSOCIATES
5100 W. LEMON STREET, SUITE 114

TAMPA, FL 33609

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SHIP TO: (850) 921-9531 BILL SENDER

Mr. Jonathan Holtom
FDEPDARM
2600 BLAIRSTONE RD
MS 5000
TALLAHASSEE, FL 32399

TRK# 0201 7975 6448 6952

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Progress Energy

May 4, 2009

RECEIVED
MAY 05 2009
BUREAU OF AIR REGULATION

Mr. Jonathon Holtom, P.E.
Air Quality Division
Department of Environmental Protection
2600 Blair Stone Road,
MS 5000
Tallahassee, Florida 32399-2400

Re: Application for Air Permit Revision and Renewal
Bartow Power Plant
Facility ID No. 1030011

Project No.: 1030011-015-AC
1030011-016-AV

Dear Mr. Holtom:

Enclosed please find one original and three copies of an application for revision and renewal of the current Title V air permit for the Bartow Power Plant. (1030011-009-AV). This application requests revisions to incorporate conditions related to the repowering project, which were addressed under Air Permit Nos. 1030011-010-AC and 1030011-012-AC. As some of the revisions also reflect requested changes to these referenced air construction permits, it is requested that the Department conduct concurrent processing of the construction and operating permit revisions.

Progress Energy Florida looks forward to working with you on this permitting effort. We hope to meet with you or otherwise discuss specific details of the issues involved at your earliest convenience. If you would like to discuss any issues regarding this application, please contact Mr. Chris Bradley in our St. Petersburg office by telephone at (727) 820-5962 or Mr. Scott Osbourn, P.E. of Golder Associates at (813) 287-1717 in Tampa.

Sincerely,

T. E. Callaghan

Thomas Callaghan
Plant Manager
Bartow CC Power Plant

Enclosures

Cc: Mara Nasca, DEP SW District
Peter Hessling, Pinellas County DEM

Progress Energy Florida, Inc.
P.O Box 14042
St Petersburg, FL 33733

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: **Progress Energy Florida, Inc.**	
2. Site Name: **P. L. Bartow Plant**	
3. Facility Identification Number: **1030011**	
4. Facility Location... Street Address or Other Locator: **Weedon Island** City: **St. Petersburg** County: **Pinellas** Zip Code: **33733**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Chris Bradley, Sr. Environmental Specialist**
2. Application Contact Mailing Address... Organization/Firm: **Progress Energy Florida, Inc.** Street Address: **299 First Avenue North, PEF 903** City: **St. Petersburg** State: **FL** Zip Code: **33701**
3. Application Contact Telephone Numbers... Telephone: **(727) 820 - 5962** ext. Fax: **(727) 820 - 5229**
4. Application Contact E-mail Address: **Chris.Bradley@pgnmail.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 5/5/09	3. PSD Number (if applicable):
2. Project Number(s): 1030011-015-AC 1030011-016-AV	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)

☒ Air construction permit and Title V permit revision, incorporating the proposed project.

☒ 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:

☒ 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

This application is for a Title V renewal and revision. Specifically, this TV revision is to incorporate the permit terms and conditions of the air construction permit (1030011-012-AC and PSD-FL-381A) that authorized construction of the Bartow Repowering Project. The permittee must apply for a TV operation permit no later than 180 days after commencing operation (i.e., 180 days after the commence operation date of November 5, 2008 is May 4, 2009). Therefore, this application is being submitted even though the compliance demonstrations required under the air construction permit have not yet been fully met. Due to these circumstances, this application also includes a Compliance Plan to address those compliance requirements that have yet to be demonstrated.

This application also requests revisions to the lists of unregulated emission units and insignificant activities (see Attachment BA-FI-C8), as well as to address the retirement of fossil fuel steam units 1, 2 and 3 (EU ID Nos. 001, 002 and 003, respectively).

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
001	No. 1 Unit, Fossil Fuel Fired Steam Generator with Electrostatic Precipitator		
002	No. 2 Unit, Fossil Fuel Fired Steam Generator		
003	No. 3 Unit, Fossil Fuel Fired Steam Generator		
004	Bartow-Anclote Pipeline Heating Boiler		
005	Gas Turbine Peaking Unit # P-1		
006	Gas Turbine Peaking Unit # P-2		
007	Gas Turbine Peaking Unit # P-3		
008	Gas Turbine Peaking Unit # P-4		
009	Relocatable Diesel Fired Generator(s)		
038	Unit 4A-- Simple- and Combined Cycle F-Class Combustion Turbine with HRSG Duct Firing		
039	Unit 4B-- Simple- and Combined Cycle F-Class Combustion Turbine with HRSG Duct Firing		
040	Unit 4C-- Simple- and Combined Cycle F-Class Combustion Turbine with HRSG Duct Firing		
041	Unit 4D-- Simple- and Combined Cycle F-Class Combustion Turbine with HRSG Duct Firing		
042	Unit 5-- Simple-Cycle F-Class Combustion Turbine		
043	Auxiliary Boiler rated at 99 MMBtu/hr		
044	Five Gas-Fired Process Heaters		
045	Two Nominal 3,500,000 Gallon Distillate Oil Storage Tanks		
046	One Nominal 300 HP Diesel-Fueled Emergency Fire Pump		

Application Processing Fee

Check one: ☐ Attached - Amount: $_____ ☒ Not Applicable

APPLICATION INFORMATION

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: ( ) - ext. 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 INFORMATION

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: **Thomas Callaghan, 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, CAIR source, or Hg Budget source.

3. Application Responsible Official Mailing Address...
Organization/Firm: **Progress Energy Florida, Inc.**
Street Address: **299 First Avenue North, BR 44**
City: **St. Petersburg** State: **FL** Zip Code: **33701**

4. Application Responsible Official Telephone Numbers...
Telephone: **(727) 827 - 6161** ext. Fax: **(727) 827 - 6298**

5. Application Responsible Official E-mail Address:

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 5/4/09 Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **Scott H. Osbourn, Senior Consultant**
   Registration Number: **57557**
2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates, Inc.**
   Street Address: **5100 West Lemon Street, Suite 114**
   City: **Tampa** State: **FL** Zip Code: **33609**
3. Professional Engineer Telephone Numbers...
   Telephone: **(813) 287-1717** ext. 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.

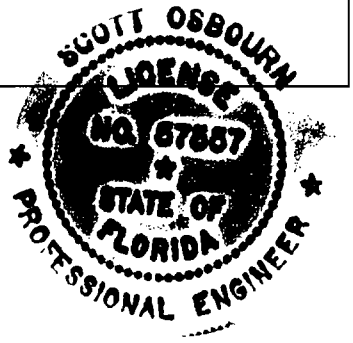
(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application 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 ☒, 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 Date 5/4/09

(seal)



* 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) **343.87** North (km) **3082.69**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **27° 51' 41" N** Longitude (DD/MM/SS) **82° 36' 6" W**	
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: **The new Project consists of one nominal 1,279 MW power block with four CT/HRSG trains and one simple-cycle CT at an additional 190 MW. See Scope of Application and the PSD report.**			

Facility Contact

1. Facility Contact Name: **Terese Sanchez, Sr. Environmental Specialist**
2. Facility Contact Mailing Address... Organization/Firm: **Progress Energy Florida, Inc.** Street Address: **299 First Avenue North, BR 44** City: **St. Petersburg** State: **FL** Zip Code: **33701**
3. Facility Contact Telephone Numbers: Telephone: **(727) 827 - 6107** ext. Fax: **(727) 827 - 6298**
4. Facility Contact E-mail Address: **terese.sanchez@pgnmail.com**

Facility Primary Responsible Official

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 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. [x] Title V Source	
4. [x] 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. [x] 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:

Item 6—While the current facility is characterized as a major source of HAPs, PEF believes that the facility will be a minor HAP source when EUSGU Nos. 1, 2 and 3 cease operations under the attached Compliance Plan.

Item 8—The CTs and HRSG Duct Burners are subject to 40 CFR 60, NSPS Subpart KKKK.

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
PM	**A**	**N**
PM10	**A**	**N**
SO2	**A**	**N**
NOx	**A**	**N**
CO	**A**	**N**
VOC	**A**	**N**
HAPs	**B**	**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: **BA-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: **BA-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: **BA-FI-C3*** [ ] Previously Submitted, Date:_____

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location:
   [x] Attached, Document ID: **BA-FI-C4*** [ ] 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

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)
   [x] Attached, Document ID: **BA-FI-C5*** ☐ 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)
   [x] Attached, Document ID: **BA-FI-C6***
   ☐ Not Applicable (revision application with no change in applicable requirements)

3. Compliance Report and Plan: (Required for all initial/revision/renewal applications)
   [x] Attached, Document ID: **BA-FI-C7**
   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
   [x] Not Applicable

5. Verification of Risk Management Plan Submission to EPA: (If applicable, required for initial/renewal applications only)
   ☐ Attached, Document ID:_____ [x] Not Applicable

6. Requested Changes to Current Title V Air Operation Permit:
   [x] Attached, Document ID: **BA-FI-C8** ☐ 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: **BA-FI-C9** [ ] 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: **BA-FI-C10** [ ] Previously Submitted, Date:_____
   [ ] Not Applicable (not a CAIR source)

3. Hg Budget Part (DEP Form No. 62-210.900(1)(c)):
   [ ] Attached, Document ID:_____ [ ] Previously Submitted, Date:_____
   [x] Not Applicable (not a Hg Budget unit)

Additional Requirements Comment

(*) indicates to also refer to the PSD Report (Attachment BA-FI-C11) for additional information.

The Acid Rain Part application also includes a revised Certificate of Representation.

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.

EMISSIONS UNIT INFORMATION
Section [1] of [15]
No. 1 Unit, FFFSG w/ ESP

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:

No. 1 Unit, Fossil Fuel Fired Steam Generator with Electrostatic Precipitator

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		**30-Sep-1958**	**49**

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

[x] Acid Rain Unit

[x] CAIR Unit

[ ] Hg Budget Unit

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: **120 MW**

11. Emissions Unit Comment: **Unit No. 1 is a front-fired fossil fuel steam generator which produces 120 megawatts of electric power.**

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

1. Control Equipment/Method Description: **Electrostatic Precipitator (high efficiency 95-99.9%)**
2. Control Device or Method Code: **10**

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: **1,220 million Btu/hr**	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	
24 hours/day	**7** days/week
52 weeks/year	**8,760** hours/year
6. Operating Capacity/Schedule Comment:	
Maximum heat input based on permit limit firing No.6 fuel oil.	

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: **EU1**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **300 feet**	7. Exit Diameter: **9 feet**
8. Exit Temperature: **312 °F**	9. Actual Volumetric Flow Rate: **488,000 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): **342.9** North (km): **3082.6**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) **27° 51' 37" N** Longitude (DD/MM/SS) **82° 36' 42" W**	
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 3

1. Segment Description (Process/Fuel Type): **No. 6 Fuel Oil**		
2. Source Classification Code (SCC): **101-004-01**	3. SCC Units: **1,000 Gallons Residual Oil (No. 6) Burned**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2.5**	8. Maximum % Ash: **0.1**	9. Million Btu per SCC Unit: **152**
10. Segment Comment:		

Segment Description and Rate: Segment 2 of 3

1. Segment Description (Process/Fuel Type): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **101-005-01**	3. SCC Units: **1,000 Gallons Distillate Oil (No. 1 and 2) Burned**	
4. Maximum Hourly Rate: **8.841**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.5**	8. Maximum % Ash: **0.1**	9. Million Btu per SCC Unit: **138**
10. Segment Comment: **Distillate fuel oil is used as a pilot fuel for startup, shutdown and malfunction. Heat content-HHV.**		

Segment Description and Rate: Segment 3 of 3

1. Segment Description (Process/Fuel Type): **On-speciation used oil**		
2. Source Classification Code (SCC): **101-013-02**	3. SCC Units: **1,000 Gallons Waste Oil Burned**	
4. Maximum Hourly Rate: **8.841**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2.5**	8. Maximum % Ash: **0.9**	9. Million Btu per SCC Unit: **138**
10. Segment Comment: **Used oil specification: Arsenic 5 PPM, Cadmium 2 PPM, Chromium 10 PPM, Lead 100 PPM, Total Halogens 1000 PPM, PCB 50 ppm.14.85 million gal/12 month limit for all 3 generators**		

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
PM/PM10	10		EL
SO2			EL
NOx			NS
CO			NS
VOC			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: **PM/PM10**	2. Total Percent Efficiency of Control: **99**
3. Potential Emissions: **122.0** lb/hour **534.4** 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** Reference: **Permit Limit**	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:

0.1 lb/MMBtu x 1,220 MMBtu/hr = 122 lbs/hr.

122 lbs/hr x 8,760 hr/yr / 2,000 lb/ton = 534.36 = 534.4 tons/yr

11. Potential, Fugitive, and Actual Emissions Comment:
The emission limit is 0.1 lb/mmBtu for 21 hrs/24 hrs and 0.3 lb/mmBtu for 3 hrs/ 24 hrs.

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: **0.3 lbs/MMBtu**	4. Equivalent Allowable Emissions: **366** lb/hour tons/year
5. Method of Compliance: **Test not required if fuel oil is fired <400 hrs/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **During the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.**	

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: **0.1 lbs/MMBtu**	4. Equivalent Allowable Emissions: **122.0** lb/hour **534.4** tons/year
5. Method of Compliance: **Test not required if fuel oil is fired <400 hrs/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **During normal operations.**	

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: **SO2**	2. Total Percent Efficiency of Control: **99**
3. Potential Emissions: **3,355** lb/hour **14,695** tons/year	4. Synthetically Limited? ☐ Yes [x] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2.75 lb/MMBtu** Reference: **Permit Limit**	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:

2.75 lb/MMBtu x 1,220 MMBtu/hr = 3,355 lbs/hr.

3,335 lbs/hr x 8,760 hr/yr / 2,000 lb/ton = 14,694.9 = 14,695 tons/yr

11. Potential, Fugitive, and Actual Emissions Comment:
Permit limits maximum sulfur content in No. 6 fuel oil to 2.5%.

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: **2.75 lbs/MMBtu**	4. Equivalent Allowable Emissions: **3,355** lb/hour **14,695** tons/year
5. Method of Compliance: **EPA Method 6 or 6C if exceedences of SO2 standard is occuring.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.405, 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: **2.5-percent sulfur in fuel**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.405, 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: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **526.2** lb/hour **2,305** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **67 lb/ 1000 Gal** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 67 lb/ 1000 Gal x 7.854 Kgal/hr = 526.2 lb/hr

TPY = 526.2 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 2,305 tons/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions calculated by multiplying annual fuel use limit by emission factor specified in the permit.

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 1**

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): **There is no allowable NOx limit.**	

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: **39.27** lb/hour **172** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **5 lb/ 1000 Gal** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 5 lb/ 1000 Gal x 7.854 Kgal/hr = 39.27 lb/hr

TPY = 39.27 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 172 tons/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions calculated by multiplying annual fuel use limit by emission factor specified in the permit.

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 1**

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): **There is no allowable CO limit.**	

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: **5.969** lb/hour **26** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.76 lb/ 1000 Gal** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.76 lb/ 1000 Gal x 7.854 Kgal/hr = 5.969 lb/hr

TPY = 5.969 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 26 tons/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions calculated by multiplying annual fuel use limit by emission factor specified in the permit.

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 1**

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): **There is no allowable VOC limit.**	

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: **VE40**	2. Basis for Allowable Opacity: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **40 %** Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment: **During normal operations. Test not required if fuel oil is fired <400 hrs /yr.**	

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:	
5. Visible Emissions Comment: **During the 3-hrs in any 24 hr period allowed for boiler cleaning (soot blowing) and load change. Test not required if fuel oil is fired <400 hrs /yr.**	

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 2**

1. Parameter Code: **VE (opacity)**	2. Pollutant(s): **PM, SO2**
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: **DURAG** Model Number: **DR281-AV**	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Inactive**	

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

1. Parameter Code: **VE (opacity)**	2. Pollutant(s): **VE**
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: **DURAG/ENVIROPLAN** Model Number: **CEMOP-281**	Serial Number: **29858**
5. Installation Date:	6. Performance Specification Test Date: **06-DEC-94**
7. Continuous Monitor Comment: **Active**	

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: **BA-EU1-I1** [ ] 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: **BA-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: **NA** [ ] 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: **BA-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: **NA** [ ] Previously Submitted, Date _____
   [ ] Not Applicable

6. Compliance Demonstration Reports/Records:
   [X] Attached, Document ID: **BA-EU1-I6**
   Test Date(s)/Pollutant(s) Tested: **7/21-23/2008 PM, VE and SO_2**
   [ ] 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

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: **BA-EU1-I7**
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:

No. 2 Unit, Fossil Fuel Fired Steam Generator

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		**19-Aug-1961**	**49**

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

[X] Acid Rain Unit

[ ] CAIR Unit

[ ] Hg Budget Unit

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: **120 MW**

11. Emissions Unit Comment: **Unit No. 2 is a tangential-fired fossil fuel steam generator which produces 120 megawatts of electric power.**

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:

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: **1,317 million Btu/hr**	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input based on permit limit firing No.6 fuel oil.**	

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: **EU2**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **300 feet**	7. Exit Diameter: **9 feet**
8. Exit Temperature: **305°F**	9. Actual Volumetric Flow Rate: **392,488 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): **342.4** North (km): **3082.6**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) **27° 51' 37" N** Longitude (DD/MM/SS) **82° 37' 0" W**	
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 4

1. Segment Description (Process/Fuel Type): **No. 6 Fuel Oil**		
2. Source Classification Code (SCC): **101-004-04**	3. SCC Units: **1,000 Gallons Residual Oil (No. 6) Burned**	
4. Maximum Hourly Rate: **8.778**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2.5**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **152**
10. Segment Comment: **Heat Content is HHV**		

Segment Description and Rate: Segment 2 of 4

1. Segment Description (Process/Fuel Type): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **101-005-01**	3. SCC Units: **1,000 Gallons Distillate Oil (No. 1 and 2) Burned**	
4. Maximum Hourly Rate: **9.543**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.5**	8. Maximum % Ash: **0.1**	9. Million Btu per SCC Unit: **138**
10. Segment Comment: **Distillate fuel oil is used as a pilot fuel for startup, shutdown and malfunction. Heat content-HHV.**		

Segment Description and Rate: Segment 3 of 4

1. Segment Description (Process/Fuel Type): **Propane**		
2. Source Classification Code (SCC): **101-010-02**	3. SCC Units: **1,000 Gallons Propane Burned**	
4. Maximum Hourly Rate: **14.552**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **81**
10. Segment Comment: **Used to light off ignitors.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **4** of **4**

1. Segment Description (Process/Fuel Type): **On-speciation used oil**		
2. Source Classification Code (SCC): **101-013-02**	3. SCC Units: **1,000 Gallons Waste Oil Burned**	
4. Maximum Hourly Rate: **9.543**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2.5**	8. Maximum % Ash: **0.9**	9. Million Btu per SCC Unit: **138**
10. Segment Comment: **Used oil specification: Arsenic 5 PPM, Cadmium 2 PPM, Chromium 10 PPM, Lead 100 PPM, Total Halogens 1000 PPM, PCB 50 ppm.14.85 million gal/12 month limit for all 3 generators**		

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
PM/PM10			**EL**
SO2			**EL**
NOx			**NS**
CO			**NS**
VOC			**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: **PM/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **131.7** lb/hour **576.9** 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** Reference: **Permit Limit**	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:

0.1 lb/MMBtu x 1,317 MMBtu/hr = 131.7 lbs/hr.

131.7 lbs/hr x 8,760 hr/yr / 2,000 lb/ton = 576.9 tons/yr

11. Potential, Fugitive, and Actual Emissions Comment:

The emission limit is 0.1 lb/mmBtu for 21 hrs/24 hrs and 0.3 lb/mmBtu for 3 hrs/ 24 hrs.

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: **0.3 lbs/MMBtu**	4. Equivalent Allowable Emissions: **395.1** lb/hour tons/year
5. Method of Compliance: **Test not required if fuel oil is fired <400 hrs/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **During the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.**	

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: **0.1 lbs/MMBtu**	4. Equivalent Allowable Emissions: **131.7** lb/hour **576.9** tons/year
5. Method of Compliance: **Test not required if fuel oil is fired <400 hrs/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **During normal operations.**	

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: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3622** lb/hour **15,863** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2.75 lb/MMBtu** Reference: **Permit Limit**	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:

2.75 lb/MMBtu x 1,317 MMBtu/hr = 3,621.75 = 3,622 lbs/hr.

3,622 lbs/hr x 8,760 hr/yr / 2,000 lb/ton = 15,863 tons/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Permit limits maximum sulfur content in No. 6 fuel oil to 2.5%.

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: **2.75 lbs/MMBtu**	4. Equivalent Allowable Emissions: **3,622** lb/hour **18,863** tons/year
5. Method of Compliance: **EPA Method 6 or 6C if exceedences of SO2 standard is occurring.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.405, 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: **2.5-percent sulfur in fuel**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.405, 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: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **368.67** lb/hour **1,615** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **42 lb/ 1000 Gal** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 42 lb/ 1000 Gal x 8.778 Kgal/hr = 368.67 lb/hr

TPY = 368.67 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 1,615 tons/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions calculated by multiplying annual fuel use limit by emission factor specified in the permit.

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 1**

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): **There is no allowable NOx limit.**	

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: **43.9** lb/hour **192** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **5 lb/ 1000 Gal** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 5 lb/ 1000 Gal x 8.778 Kgal/hr = 43.9 lb/hr

TPY = 43.9 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 192 tons/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions calculated by multiplying annual fuel use limit by emission factor specified in the permit.

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 1**

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): **There is no allowable CO limit.**	

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: **6.67** lb/hour **29** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.76 lb/ 1000 Gal** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.76 lb/ 1000 Gal x 8.778 Kgal/hr = 6.67 lb/hr

TPY = 6.67 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 29 tons/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions calculated by multiplying annual fuel use limit by emission factor specified in the permit.

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 1**

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): **There is no allowable VOC limit.**	

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: **VE40**	2. Basis for Allowable Opacity: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **40 %** Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment: **During normal operations. Test not required if fuel oil is fired <400 hrs /yr.**	

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:	
5. Visible Emissions Comment: **During the 3-hrs in any 24 hr period allowed for boiler cleaning (soot blowing) and load change. Test not required if fuel oil is fired <400 hrs /yr.**	

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 **2**

1. Parameter Code: **VE (opacity)**	2. Pollutant(s): **PM, SO2**
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: **DURAG** Model Number: **DR281-AV**	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Inactive**	

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

1. Parameter Code: **VE (opacity)**	2. Pollutant(s): **VE**
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: **CEMOP-281**	Serial Number: **29852**
5. Installation Date: **02-DEC-94**	6. Performance Specification Test Date: **02-DEC-94**
7. Continuous Monitor Comment: **Active** **Rule 40 CFR 72.6**	

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: **BA-EU2-I1** [ ] 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: **BA-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: **NA** [ ] 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: **BA-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: **NA** [ ] Previously Submitted, Date _____
   [X] Not Applicable

6. Compliance Demonstration Reports/Records:
   [X] Attached, Document ID: **BA-EU2-I6**
   Test Date(s)/Pollutant(s) Tested: **7/25/2008 PM, VE and SO_2**
   [ ] 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

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: **BA-EU1-I7**
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.

EMISSIONS UNIT INFORMATION
Section [3] of [15]
No. 3Unit, FFFSG

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:
No. 3 Unit, Fossil Fuel Fired Steam Generator

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		**25-Jul-1963**	**49**

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

[x] Acid Rain Unit

[ ] CAIR Unit

[ ] Hg Budget Unit

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: **225 MW**

11. Emissions Unit Comment: **Unit No. 3 is a tangential-fired fossil fuel steam generator which produces 225 megawatts, of electric power.**

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:

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: **2,211 million Btu/hr**	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	
24 hours/day	**7** days/week
52 weeks/year	**8,760** hours/year
6. Operating Capacity/Schedule Comment:	
Maximum heat input based on permit limit firing No. 6 fuel oil (2,266 MMBtu/hr for natural gas).	

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: **EU3**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **300 feet**	7. Exit Diameter: **11 feet**
8. Exit Temperature: **275 °F**	9. Actual Volumetric Flow Rate: **646,648 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): **343.4** North (km): **3082.6**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) **27° 51' 37" N** Longitude (DD/MM/SS) **82° 37' 0" W**	
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 5

1. Segment Description (Process/Fuel Type): **No. 6 Fuel Oil**		
2. Source Classification Code (SCC): **101-004-04**	3. SCC Units: **1,000 Gallons Residual Oil (No. 6) Burned**	
4. Maximum Hourly Rate: **14.546**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2.5**	8. Maximum % Ash: **0.1**	9. Million Btu per SCC Unit: **152**
10. Segment Comment: **Heat content-HHV.**		

Segment Description and Rate: Segment 2 of 5

1. Segment Description (Process/Fuel Type): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **101-005-01**	3. SCC Units: **1,000 Gallons Distillate Oil (No. 1 and 2) Burned**	
4. Maximum Hourly Rate: **16.022**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.5**	8. Maximum % Ash: **0.1**	9. Million Btu per SCC Unit: **138**
10. Segment Comment: **Distillate fuel oil is used as a pilot fuel for startup, shutdown and malfunction. Heat content-HHV.**		

Segment Description and Rate: Segment 3 of 5

1. Segment Description (Process/Fuel Type): **Propane**		
2. Source Classification Code (SCC): **101-010-02**	3. SCC Units: **1,000 Gallons Propane Burned**	
4. Maximum Hourly Rate: **24.431**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **81**
10. Segment Comment: **Used to light off ignitors.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

Segment Description and Rate: Segment **4** of **5**

1. Segment Description (Process/Fuel Type): **On-speciation used oil**		
2. Source Classification Code (SCC): **101-013-02**	3. SCC Units: **1,000 Gallons Waste Oil Burned**	
4. Maximum Hourly Rate: **16.022**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2.5**	8. Maximum % Ash: **0.9**	9. Million Btu per SCC Unit: **138**
10. Segment Comment: **Used oil specification: Arsenic 5 PPM, Cadmium 2 PPM, Chromium 10 PPM, Lead 100 PPM, Total Halogens 1000 PPM, PCB 50 ppm.14.85 million gal/12 month limit for all 3 generators**		

Segment Description and Rate: Segment **5** of **5**

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **101-006-04**	3. SCC Units: **Million Cubic Feet Natural Gas Burned**	
4. Maximum Hourly Rate: **2.158**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,050**
10. Segment Comment: **Heat content- HHV. Sulfur content - 1 grain/100 cf**		

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
PM/PM10			EL
SO2			EL
NOx			NS
CO			NS
VOC			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: **PM/PM10**	2. Total Percent Efficiency of Control: **99**
3. Potential Emissions: **221.1** lb/hour **968.4** 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** Reference: **Permit Limit**	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:

0.1 lb/MMBtu x 2,211 MMBtu/hr = 221.1 lbs/hr.

221.1 lbs/hr x 8,760 hr/yr / 2,000 lb/ton = 968.4 tons/yr

11. Potential, Fugitive, and Actual Emissions Comment:

The emission limit is 0.1 lb/mmBtu for 21 hrs/24 hrs and 0.3 lb/mmBtu for 3 hrs/ 24 hrs.

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: **0.3 lbs/MMBtu**	4. Equivalent Allowable Emissions: **663.3** lb/hour tons/year
5. Method of Compliance: **Test not required if fuel oil is fired <400 hrs/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **During the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.**	

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: **0.1 lbs/MMBtu**	4. Equivalent Allowable Emissions: **221.1** lb/hour **968.4** tons/year
5. Method of Compliance: **Test not required if fuel oil is fired <400 hrs/yr.**	
6. Allowable Emissions Comment (Description of Operating Method): **During normal operations.**	

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: **SO2**	2. Total Percent Efficiency of Control: **99**
3. Potential Emissions: **6,080** lb/hour **26,631** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2.75 lb/MMBtu** Reference: **Permit Limit**	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:

2.75 lb/MMBtu x 2,211 MMBtu/hr = 6,080 lbs/hr.

6,080 lbs/hr x 8,760 hr/yr / 2,000 lb/ton = 26,631 tons/yr

11. Potential, Fugitive, and Actual Emissions Comment:
Permit limits maximum sulfur content in No. 6 fuel oil to 2.5%.

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: **2.75 lbs/MMBtu**	4. Equivalent Allowable Emissions: **6,080** lb/hour **26,631** tons/year
5. Method of Compliance: **EPA Method 6 or 6C if exceedences of SO2 standard is occurring.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.405, 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: **2.5-percent sulfur in fuel**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.405, 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: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **619.16** lb/hour **2,712** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **42 lb/1000 gal** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 42 lb/1000 gal x 14.742 Kgal/hr = 619.16 lb/hr

TPY = 619.16 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 2,712 tons/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions based on No. 6 fuel oil firing. Emission factor specified in the permit. For Natural gas emission factor is 550 lb/mmcf.

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): **There is no allowable NOx limit.**	

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: **73.71** lb/hour **323** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **5 lb/1000 gal** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 5 lb/1000 gal x 14.742 Kgal/hr = 73.71 lb/hr

TPY = 73.71 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 323 tons/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions based on No. 6 fuel oil firing. Emission factor specified in the permit. Emission factor is the same for NG.

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): **There is no allowable CO limit.**	

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: **11.2** lb/hour **49** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.76 lb/1000 gal** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.76 lb/1000 gal x 14.742 Kgal/hr = 11.2 lb/hr

TPY = 11.2 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 49 tons/yr

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions based on No. 6 fuel oil firing. Emission factor specified in the permit. For Natural gas emission factor is 1.4 lb/mmcf.

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): **There is no allowable VOC limit.**	

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: **VE40**	2. Basis for Allowable Opacity: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **40 %** Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment: **During normal operations. Test not required if fuel oil is fired <400 hrs /yr.**	

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:	
5. Visible Emissions Comment: **During the 3-hrs in any 24 hr period allowed for boiler cleaning (soot blowing) and load change. Test not required if fuel oil is fired <400 hrs /yr.**	

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 2**

1. Parameter Code: **VE (opacity)**	2. Pollutant(s): **PM, SO2**
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: **DURAG** Model Number: **DR281-AV**	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Inactive**	

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

1. Parameter Code: **VE (opacity)**	2. Pollutant(s): **VE**
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: **DURAG/ENVIROPLAN** Model Number: **CEMOP-281**	Serial Number: **29858**
5. Installation Date:	6. Performance Specification Test Date: **06-DEC-94**
7. Continuous Monitor Comment: **Active**	

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: **BA-EU3-I1** [ ] 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: **BA-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: **NA** [ ] 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: **BA-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: **NA** [ ] Previously Submitted, Date _____
[X] Not Applicable

6. Compliance Demonstration Reports/Records:
[X] Attached, Document ID: **BA-EU3-I6**
Test Date(s)/Pollutant(s) Tested: **5/21/2008**
PM, VE and SO_2
[ ] 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

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: **BA-EU1-I7**
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:

Bartow-Anclote Pipeline Heating Boiler

3. Emissions Unit Identification Number: **004**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**01-Jun-1974**	**49**

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

[ ] Acid Rain Unit

[ ] CAIR Unit

[ ] Hg Budget Unit

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

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:

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: **15.5 million Btu/hr**	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	
24 hours/day	**7** days/week
52 weeks/year	**8,760** hours/year
6. Operating Capacity/Schedule Comment:	

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: **EU4**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **30** feet	7. Exit Diameter: **3** feet
8. Exit Temperature: **515** °F	9. Actual Volumetric Flow Rate: **7,220** 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): **342.4** North (km): **3082.6**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) **27° 51' 37" N** Longitude (DD/MM/SS) **82° 37' 0" W**	
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **3**

1. Segment Description (Process/Fuel Type): **New No. 2 Fuel Oil**		
2. Source Classification Code (SCC): **102-005-02**	3. SCC Units: **1,000 Gallons Distillate Oil Burned**	
4. Maximum Hourly Rate: **0.112**	5. Maximum Annual Rate: **983.9**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.5**	8. Maximum % Ash: **0.1**	9. Million Btu per SCC Unit: **138**
10. Segment Comment:		

Segment Description and Rate: Segment **2** of **3**

1. Segment Description (Process/Fuel Type): **Liquified Petroleum Gas (Propane)**		
2. Source Classification Code (SCC): **102-010-02**	3. SCC Units: **1,000 Gallons Propane Burned**	
4. Maximum Hourly Rate: **0.191**	5. Maximum Annual Rate: **1,676.3**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **81**
10. Segment Comment:		

Segment Description and Rate: Segment **3** of **3**

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **102-006-02**	3. SCC Units: **Million Cubic Feet Natural Gas Burned**	
4. Maximum Hourly Rate: **1.43**	5. Maximum Annual Rate: **12,527**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.00015**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,050**
10. Segment Comment: **Sulfur content; 1 grain/100cf**		

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
CO			NS
NOx			NS
PM/PM10			NS
VOC			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: **7.8** lb/hour **34.2** tons/year	4. Synthetically Limited? ☐ Yes [x] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.5 percent sulfur in fuel** Reference: **Permit Limit**	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:

142 lb/1000 gal fuel x 0.5 percent sulfur x 110 gal/hr = 7.81 lb/hr

7.81 lb/hr x 8,760 hr/yr /2,000 lb/ton = 34.2 tons/year

11. Potential, Fugitive, and Actual Emissions Comment:

0.5% S by weight

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 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.5 % sulfur in fuel**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: **Fuel analysis provided by vendor upon each fuel delivery.**	
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: **0.55** lb/hour **2.41** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:	
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: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.2** lb/hour **9.64** tons/year	4. Synthetically Limited? ☐ Yes [x] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:	
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: **PM/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.22** lb/hour **0.96** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:	
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.

<u>**Allowable Emissions**</u> 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):	

<u>**Allowable Emissions**</u> 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):	

<u>**Allowable Emissions**</u> 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: **0.04** lb/hour **0.18** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	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:	
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):	

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:	
5. Visible Emissions Comment: **During normal operations. Test not required if fuel oil is fired <400 hrs/yr.**	

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:	
5. Visible Emissions Comment: **During the 3-hrs in any 24 hr period allowed for boiler cleaning (soot blowing) and load change. Test not required if fuel oil is fired <400 hrs/yr.**	

H. CONTINUOUS MONITOR INFORMATION

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

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:	

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: **BA-EU4-I1** [ ] 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: **BA-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: **NA** [ ] 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)
   [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date _____
   [X] 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: **BA-EU4-I6**
   Test Date(s)/Pollutant(s) Tested: **2/2/2009**
   VE
   [ ] 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

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: [x] Attached, Document ID: : **BA-EU1-I8**
2. Compliance Assurance Monitoring: ☐ Attached, Document ID: _____ [x] Not Applicable
3. Alternative Methods of Operation: ☐ Attached, Document ID: _____ [x] Not Applicable
4. Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: _____ [x] 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.

3. Description of Emissions Unit Addressed in this Section:

Gas Turbine Peaking Unit #P-1

3. Emissions Unit Identification Number: **005**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**14-Jun-1972**	**49**

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

[ ] Acid Rain Unit

[ ] CAIR Unit

[ ] Hg Budget Unit

9. Package Unit: **General Electric**
Manufacturer: Model Number: **MS7000**

10. Generator Nameplate Rating: **56 MW**

11. Emissions Unit Comment:

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:

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: **714 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:	

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:	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **45** feet	7. Exit Diameter: **17.9** feet
8. Exit Temperature: **930**°F	9. Actual Volumetric Flow Rate: **1,043,297** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Stack exit is rectangular, 20.67 ft. x 12.17 ft.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **No. 2 Fuel Oil**		
2. Source Classification Code (SCC): **201-001-01**	3. SCC Units: **1,000 Gallons Distillate Oil (Diesel) Burned**	
4. Maximum Hourly Rate: **5.174**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **S content limit is not federally enforceable.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **201-002-01**	3. SCC Units: **Million Cubic Feet Natural Gas Burned**	
4. Maximum Hourly Rate: **714**	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
SO2			EL
CO			NS
NOx			NS
PM/PM10			NS
VOC			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: **360.6** lb/hour **1579.3** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: **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:

1.01(S) lb/MMBtu x714 MMBtu/hr = 360.6 lb/hr
360.57 lb/hr x 8,760 hr/yr/2,000 lb/ton = 1579.3 TPY.

11. Potential, Fugitive, and Actual Emissions Comment:

S= 0.5 % S by wt. Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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 1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.5-percent sulfur in fuel**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): **Basis for allowable emissions: AO 52-253215A. Sulfur content limit is not federally enforceable.**	

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: **34.27** lb/hour **150** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.048 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.048 lb/MMBtu x 714 MMBtu/hr = 34.27 lb/hr
TPY = 34.27 lb/hr x 8,760 hr/yr/2,000 lb/ton = 150 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **498.37** lb/hour **2,183** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.698 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.698 lb/MMBtu x 714 MMBtu/hr = 498.37 lb/hr
TPY = 498.37 lb/hr x 8,760 hr/yr/2,000 lb/ton = 2,183 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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: **PM/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **43.55** lb/hour **191** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.061 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.061 lb/MMBtu x 714 MMBtu/hr = 43.55 lb/hr
TPY = 43.55 lb/hr x 8,760 hr/yr/2,000 lb/ton = 191 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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: **12.13** lb/hour **53** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.017 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.017 lb/MMBtu x 714 MMBtu/hr = 12.13 lb/hr
TPY = 12.13 lb/hr x 8,760 hr/yr/2,000 lb/ton = 53 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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):	

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: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **20%** Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
4. Visible Emissions Comment: **Test not required if fuel oil is fired <400 hrs /yr.**	

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 ___ 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:	

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: **BA-EU5-I1** [ ] 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: **BA-EU5-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: **NA** [ ] 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)
   [ ] Attached, Document ID: **NA** [ ] 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: **BA-EU5-I6**
   Test Date(s)/Pollutant(s) Tested: **2/4/2009 VE**
   [ ] 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

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: **BA-EU1-I7**
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.

1. Description of Emissions Unit Addressed in this Section:

Gas Turbine Peaking Unit #P-2

3. Emissions Unit Identification Number: **006**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**14-Jun-1972**	**49**

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

[ ] Acid Rain Unit

[ ] CAIR Unit

[ ] Hg Budget Unit

9. Package Unit: **General Electric**
Manufacturer: Model Number: **MS7000**

10. Generator Nameplate Rating: **56 MW**

11. Emissions Unit Comment:

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:

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: **714 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:	

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:	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **45** feet	7. Exit Diameter: **17.9** feet
8. Exit Temperature: **930**°F	9. Actual Volumetric Flow Rate: **1,043,297** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Stack exit is rectangular, 20.67 ft. x 12.17 ft.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **No. 2 Fuel Oil**		
2. Source Classification Code (SCC): **201-001-01**	3. SCC Units: **1,000 Gallons Distillate Oil (Diesel) Burned**	
4. Maximum Hourly Rate: **5.174**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **S content limit is not federally enforceable.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **201-002-01**	3. SCC Units: **Million Cubic Feet Natural Gas Burned**	
4. Maximum Hourly Rate: **714**	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
SO2			EL
CO			NS
NOx			NS
PM/PM10			NS
VOC			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: **360.6** lb/hour **1579.3** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: **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:

1.01(S) lb/MMBtu x714 MMBtu/hr = 360.6 lb/hr
360.57 lb/hr x 8,760 hr/yr/2,000 lb/ton = 1579.3 TPY.

11. Potential, Fugitive, and Actual Emissions Comment:

S= 0.5 % S by wt. Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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 1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.5-percent sulfur in fuel**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): **Basis for allowable emissions: AO 52-253215A. Sulfur content limit is not federally enforceable.**	

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: **34.27** lb/hour **150** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.048 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.048 lb/MMBtu x 714 MMBtu/hr = 34.27 lb/hr
TPY = 34.27 lb/hr x 8,760 hr/yr/2,000 lb/ton = 150 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **498.37** lb/hour **2,183** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.698 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.698 lb/MMBtu x 714 MMBtu/hr = 498.37 lb/hr
TPY = 498.37 lb/hr x 8,760 hr/yr/2,000 lb/ton = 2,183 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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: **PM/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **43.55** lb/hour **191** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.061 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.061 lb/MMBtu x 714 MMBtu/hr = 43.55 lb/hr
TPY = 43.55 lb/hr x 8,760 hr/yr/2,000 lb/ton = 191 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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: **12.13** lb/hour **53** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.017 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.017 lb/MMBtu x 714 MMBtu/hr = 12.13 lb/hr
TPY = 12.13 lb/hr x 8,760 hr/yr/2,000 lb/ton = 53 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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):	

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: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **20%** Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
2. Visible Emissions Comment: **Test not required if fuel oil is fired <400 hrs /yr.**	

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 ___ 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:	

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: **BA-EU5-I1** [ ] 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: **BA-EU5-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: **NA** [ ] 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)
   [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date _____
   [X] 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: **BA-EU5-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

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: **BA-EU1-I7**
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.

1. Description of Emissions Unit Addressed in this Section:

Gas Turbine Peaking Unit #P-3

3. Emissions Unit Identification Number: **007**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**14-Jun-1972**	**49**

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

[ ] Acid Rain Unit

[ ] CAIR Unit

[ ] Hg Budget Unit

9. Package Unit: **General Electric**
Manufacturer: Model Number: **MS7000**

10. Generator Nameplate Rating: **56 MW**

11. Emissions Unit Comment:

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:

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: **714 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:	

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:	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **45** feet	7. Exit Diameter: **17.9** feet
8. Exit Temperature: **930**°F	9. Actual Volumetric Flow Rate: **1,043,297** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Stack exit is rectangular, 20.67 ft. x 12.17 ft.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **No. 2 Fuel Oil**		
2. Source Classification Code (SCC): **201-001-01**	3. SCC Units: **1,000 Gallons Distillate Oil (Diesel) Burned**	
4. Maximum Hourly Rate: **5.174**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **S content limit is not federally enforceable.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **201-002-01**	3. SCC Units: **Million Cubic Feet Natural Gas Burned**	
4. Maximum Hourly Rate: **714**	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
SO2			EL
CO			NS
NOx			NS
PM/PM10			NS
VOC			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: **360.6** lb/hour **1579.3** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: **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:

1.01(S) lb/MMBtu x714 MMBtu/hr = 360.6 lb/hr
360.57 lb/hr x 8,760 hr/yr/2,000 lb/ton = 1579.3 TPY.

11. Potential, Fugitive, and Actual Emissions Comment:

S= 0.5 % S by wt. Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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 1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.5-percent sulfur in fuel**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): **Basis for allowable emissions: AO 52-253215A. Sulfur content limit is not federally enforceable.**	

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: **34.27** lb/hour **150** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.048 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.048 lb/MMBtu x 714 MMBtu/hr = 34.27 lb/hr
TPY = 34.27 lb/hr x 8,760 hr/yr/2,000 lb/ton = 150 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **498.37** lb/hour **2,183** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.698 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.698 lb/MMBtu x 714 MMBtu/hr = 498.37 lb/hr
TPY = 498.37 lb/hr x 8,760 hr/yr/2,000 lb/ton = 2,183 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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: **PM/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **43.55** lb/hour **191** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.061 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.061 lb/MMBtu x 714 MMBtu/hr = 43.55 lb/hr
TPY = 43.55 lb/hr x 8,760 hr/yr/2,000 lb/ton = 191 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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: **12.13** lb/hour **53** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.017 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.017 lb/MMBtu x 714 MMBtu/hr = 12.13 lb/hr
TPY = 12.13 lb/hr x 8,760 hr/yr/2,000 lb/ton = 53 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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):	

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: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **20%** Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
2. Visible Emissions Comment: **Test not required if fuel oil is fired <400 hrs /yr.**	

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 ___ 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:	

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: **BA-EU5-I1** [ ] 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: **BA-EU5-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: **NA** [ ] 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)
   [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date _____
   [X] 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: **BA-EU5-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

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: [X] Attached, Document ID: **BA-EU1-I7**
2. Compliance Assurance Monitoring: ☐ Attached, Document ID: _____ [X] Not Applicable
3. Alternative Methods of Operation: ☐ Attached, Document ID: _____ [X] Not Applicable
4. Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: _____ [X] 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.

1. Description of Emissions Unit Addressed in this Section:

Gas Turbine Peaking Unit #P-4

3. Emissions Unit Identification Number: **008**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**14-Jun-1972**	**49**

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

[ ] Acid Rain Unit

[ ] CAIR Unit

[ ] Hg Budget Unit

9. Package Unit: **General Electric**
Manufacturer: Model Number: **MS7000**

10. Generator Nameplate Rating: **56 MW**

11. Emissions Unit Comment:

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:

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: **714 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:	

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:	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **45** feet	7. Exit Diameter: **17.9** feet
8. Exit Temperature: **930**°F	9. Actual Volumetric Flow Rate: **1,043,297** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Stack exit is rectangular, 20.67 ft. x 12.17 ft.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **No. 2 Fuel Oil**		
2. Source Classification Code (SCC): **201-001-01**	3. SCC Units: **1,000 Gallons Distillate Oil (Diesel) Burned**	
4. Maximum Hourly Rate: **5.174**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **S content limit is not federally enforceable.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **201-002-01**	3. SCC Units: **Million Cubic Feet Natural Gas Burned**	
4. Maximum Hourly Rate: **714**	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
SO2			EL
CO			NS
NOx			NS
PM/PM10			NS
VOC			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: **360.6** lb/hour **1579.3** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: **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:

1.01(S) lb/MMBtu x714 MMBtu/hr = 360.6 lb/hr
360.57 lb/hr x 8,760 hr/yr/2,000 lb/ton = 1579.3 TPY.

11. Potential, Fugitive, and Actual Emissions Comment:

S= 0.5 % S by wt. Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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 1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.5-percent sulfur in fuel**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): **Basis for allowable emissions: AO 52-253215A. Sulfur content limit is not federally enforceable.**	

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: **34.27** lb/hour **150** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.048 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.048 lb/MMBtu x 714 MMBtu/hr = 34.27 lb/hr
TPY = 34.27 lb/hr x 8,760 hr/yr/2,000 lb/ton = 150 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **498.37** lb/hour **2,183** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.698 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.698 lb/MMBtu x 714 MMBtu/hr = 498.37 lb/hr
TPY = 498.37 lb/hr x 8,760 hr/yr/2,000 lb/ton = 2,183 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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: **PM/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **43.55** lb/hour **191** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.061 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.061 lb/MMBtu x 714 MMBtu/hr = 43.55 lb/hr
TPY = 43.55 lb/hr x 8,760 hr/yr/2,000 lb/ton = 191 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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: **12.13** lb/hour **53** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.017 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code: **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:

Lb/hr = 0.017 lb/MMBtu x 714 MMBtu/hr = 12.13 lb/hr
TPY = 12.13 lb/hr x 8,760 hr/yr/2,000 lb/ton = 53 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions are calculated by multiplying the maximum heat input rate by EF specified in permit.

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):	

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: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **20%** Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
2. Visible Emissions Comment: **Test not required if fuel oil is fired <400 hrs /yr.**	

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 ___ 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:	

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: **BA-EU5-I1** [ ] 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: **BA-EU5-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: **NA** [ ] 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)
   [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date _____
   [X] 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: **BA-EU5-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

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: **BA-EU1-I7**
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.

1. Description of Emissions Unit Addressed in this Section:

Relocatable diesel generator(s)

3. Emissions Unit Identification Number: **009**

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

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

[ ] Acid Rain Unit

[ ] CAIR Unit

[ ] Hg Budget Unit

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: **2.46 MW**

11. Emissions Unit Comment: **Relocatable diesel generator(s) will have a maximum (combined) heat input of 25.74 MMBtu/hr while being fueled by 186.3 gallons of new No. 2 fuel oil per hour with a maximum (combined) rating of 2460 kw. The generators may be relocated to any of the following facilities: Crystal River Plant, Bartow Plant, Higgins Plant, Bayboro Plant, Wildwood Reclamation Facility, Hines Energy Complex, and/or Anclote Power Plant.**

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:

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: **25.74 million Btu/hr**	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: hours/day weeks/year	days/week **2,970** hours/year

6. Operating Capacity/Schedule Comment:

The hours of operation expressed as "engine-hours" shall not exceed 2,970 hours in any consecutive 12 month period. The total hours of operation expressed as "engine-hours" shall be the summation of the individual hours of operation of each generator.

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:	2. Emission Point Type Code:	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code:	6. Stack Height: feet	7. Exit Diameter: feet
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	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): **No. 2 Fuel Oil**		
2. Source Classification Code (SCC): **201-001-01**	3. SCC Units: **1,000 Gallons Distillate Oil (Diesel) Burned**	
4. Maximum Hourly Rate: **0.186**	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **Only No.2 fuel oil with a maximum sulfur content of 0.5% by weight, shall be fired in the diesel generators.**		

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
SO2			EL
NOx			EL

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: lb/hour tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.5% sulfur by weight** Reference: **Permit Limit**	7. Emissions Method Code:
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:	
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 **1 of 1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.5-percent sulfur in fuel**	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: lb/hour **<40** tons/year	4. Synthetically Limited? [x] Yes [ ] No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code: **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: **Vendor spec sheet.**	
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: **PSD Avoidance**	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): **< 40 TPY**	

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: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **20%** Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
7. Visible Emissions Comment: **Test not required if fuel oil is fired <400 hrs /yr.**	

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 ___ 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:	

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: **BA-EU9-I1** [ ] 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: **BA-EU5-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)
   [X] Attached, Document ID: **NA** [ ] 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)
   [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date _____
   [X] 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:
   [ ] Attached, Document ID: _____
   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: _____
   [X] 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

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: **BA-FI-I7**
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:

Four identical Siemens F Class, SGT6-PAC-5000F CT/HRSGs with duct firing.

3. Emissions Unit Identification Number: **038, 039, 040, and 041**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A	**12/1/06**		**49**

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

[X] Acid Rain Unit

[ ] CAIR Unit

[ ] Hg Budget Unit

9. Package Unit:
Manufacturer: **Siemens** Model Number: **SGT6-PAC-5000F**

10. Generator Nameplate Rating: **190 MW (each CT)**

11. Emissions Unit Comment: **Total nominal capacity of 1,279 MW consisting of 4 CTs, 4 duct fired HRSGs, and one steam turbine (4 x 4 x 1 configuration).**

Emissions Unit Control Equipment/Method: Control **1** of **2**

1. Control Equipment/Method Description: **Natural Gas** • **Combined cycle – SCR**
2. Control Device or Method Code: **25**

Emissions Unit Control Equipment/Method: Control **2** of **2**

1. Control Equipment/Method Description: **Distillate Fuel Oil** • **Water injection** **Combined cycle - SCR**
2. Control Device or Method Code: **28, 65**

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: **(see Appendix A of PSD Report)**	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	
24 hours/day	**7** days/week
52 weeks/year	**8,760** hours/year

8. Operating Capacity/Schedule Comment:

Appendix A of the PSD Report shows the maximum heat input at ISO conditions and base load for both natural gas and distillate oil firing. Appendix A of PSD Report also includes performance at various turbine inlet temperatures and loads.

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: **See PSD Report**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Exhausts through the HRSG stack during combined-cycle operation and through the bypass stack during simple-cycle operation. Stack height is equal for HRSG and bypass stacks (120 ft). The stack diameter is 22 ft for the bypass mode and 18 ft for the HRSG stacks.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **120** feet	7. Exit Diameter: **18/22** feet
8. Exit Temperature: **See PSD Report** °F	9. Actual Volumetric Flow Rate: **See PSD Report** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: **See PSD Report** dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Tables 2-3 through 2-6 of the PSD Report show the emission point characteristics at ISO conditions and base load for each CT/HRSG. Appendix A of the PSD Report has emission point characteristics for various turbine inlet temperatures and operating loads.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Distillate (No. 2) Fuel Oil**		
2. Source Classification Code (SCC): **201-001-01**	3. SCC Units: **1,000 Gallons Used**	
4. Maximum Hourly Rate: **13.4**	5. Maximum Annual Rate: **13,373**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**
10. Segment Comment: **Million British Thermal Units (Btu) per SCC unit = 129.9 (rounded to 130). Based on 7.1 pounds per gallon (lb/gal); LHV = 18,514 Btu/lb ISO conditions; 1,000 hours per year (hr/yr) operation. See Section 2.0 in PSD Report for fuel usage of other loads and conditions.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **201-002-01**	3. SCC Units: **Million cubic feet**	
4. Maximum Hourly Rate: **1.9**	5. Maximum Annual Rate: **16,693 (per CT)**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **933 LHV**
10. Segment Comment: **Based on 933 Btu/cf (LHV); ISO conditions and 8,760 hr/yr operation. See Section 2.0 in PSD Report for fuel usage of other loads and conditions.**		

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
PM			NS
PM_{10}			NS
SO_2			NS
NO_X	025, 028	065	EL
CO			EL
VOC			EL

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: **See PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD Report** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	7. Emissions Method Code: **2**
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 PSD Report, Section 2.0, Tables 2-3 through 2-6, and Appendix A.**	
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 **1 of 2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **Annual VE test: EPA Method 9; if > 400 hrs oil firing.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: See PSD Report, Section 2.0, Tables 2-5 and 2-6, and Appendix A.**	

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: **10% opacity**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **Annual VE test: EPA Method 9.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas firing: See PSD Report, Section 2.0, Tables 2-3 and 2-4, and Appendix A.**	

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: **See PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD Report** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	7. Emissions Method Code: **2**
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 PSD Report, Section 2.0, Tables 2-3 through 2-6, and Appendix A.**	
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 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **Annual VE test: EPA Method 9; if > 400 hrs oil firing.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil-firing: See PSD Report, Section 2.0, Tables 2-5 and 2-6, and Appendix A.**	

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: **10% opacity**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **Gas-firing: See PSD Report, Section 2.0, Tables 2-3 and 2-4, and Appendix A.**	
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: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **See PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD Report** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	7. Emissions Method Code: **2**
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 PSD Report, Section 2.0, Tables 2-3 through 2-6, and Appendix A.**	
11. Potential Fugitive and Actual Emissions Comment: **Emission factor: 2 grains Sulfur (S) per 100 SCF gas; 0.05% S oil. See PSD Report, Section 2.0 and Appendix A.**	

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: **0.05% S oil**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **Fuel sampling.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **2 grains/100 SCF**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: **Fuel sampling.**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural gas-firing CT with duct firing. See PSD Report Section 2.0 and Appendix A.**	

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: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **See PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD Report** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	7. Emissions Method Code: **2**
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 PSD Report, Section 2.0, Tables 2-3 through 2-6, and Appendix A.**	
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 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **42 ppmvd**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Methods 20 and 7E; CEM – 24-hr block average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Requested allowable emissions at 15% O_2. Oil-firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **15 ppmvd**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Methods 20 and 7E; CEM – 24-hr block average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Requested allowable emissions at 15% O_2. Gas-firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **See PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD Report** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	7. Emissions Method Code: **2**
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 PSD Report, Section 2.0, Tables 2-3 through 2-6, and Appendix A.**	
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 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **See PSD Table 2-5 and 2-6.**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Method 10; base load; if > 400 hrs oil firing. CEM – 24-hr block average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **See PSD Table 2-3 and 2-4.**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Method 10; base load. CEM – 24-hr block average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas-firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **See PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD Report** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	7. Emissions Method Code:
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 PSD Report, Section 2.0, Tables 2-3 through 2-6, and Appendix A.**	
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 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **See PSD Table 2-5 and 2-6.**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Methods 18, 25, or 25A; base load.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **See PSD Table 2-3 and 2-4.**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Methods 18, 25, or 25A; base load.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas-firing: See PSD Report, Section 2.0 and Appendix A.**	

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: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **20%** Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
9. Visible Emissions Comment: **FDEP Rule 62-296.320(4)(b)1, F.A.C. requires 20 percent opacity. Excess emissions per Rule 62-210.700, F.A.C.**	

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 **2**

1. Parameter Code: **EM**	2. Pollutant(s): **NO_X**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR Part 75. NO_X monitoring includes diluent monitor (O_2 or CO_2).**	

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

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM monitor anticipated pursuant to previous BACT determinations.**	

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: **PSD Report** *[ ] 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: **PSD Report** *[ ] 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)
   [X] Attached, Document ID: **PSD Report** *[ ] 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)
   [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date _____
   [X] 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: **BA-EU10-I6**
   Test Date(s)/Pollutant(s) Tested: **See Compliance Plan**
   [ ] Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____
   [ ] To be Submitted, Date (if known): _____
   Test Date(s)/Pollutant(s) Tested: _____
   [X] 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

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: **PSD Report***_
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

(*) **Indicates to refer to the PSD Report (BA-FI-C11) for additional information.**

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.

3. Description of Emissions Unit Addressed in this Section:

One Siemens F Class, SGT6-PAC-5000F CT operating in simple-cycle mode.

3. Emissions Unit Identification Number: **042**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A	**12/1/06**		**49**

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

[X] Acid Rain Unit

[ ] CAIR Unit

[ ] Hg Budget Unit

9. Package Unit:
Manufacturer: **Siemens** Model Number: **SGT6-PAC-5000F**

10. Generator Nameplate Rating: **(See Section 2.0 and Appendix A of PSD Report)**

11. Emissions Unit Comment: **Total nominal capacity of 190 MW consisting of 1 CT operating in simple-cycle mode.**

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description: **Distillate Fuel Oil** • **Water injection**
2. Control Device or Method Code: **28**

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: **(see Appendix A of PSD Report)**	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	
24 hours/day	**7** days/week
52 weeks/year	**8,760** hours/year

10. Operating Capacity/Schedule Comment:

Appendix A of PSD Report (Attachment BA-FI-C11) shows the maximum heat input at ISO conditions and base load. Appendix A also has performance at various turbine inlet temperatures and loads.

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: **See PSD Report**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Exhausts through CT stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **120** feet	7. Exit Diameter: **22** feet
8. Exit Temperature: **See PSD Report** °F	9. Actual Volumetric Flow Rate: **See PSD Report** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: **See PSD Report** dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Tables in Section 2.0 of the PSD Report (Attachment BA-FI-C11) show the emission point characteristics at ISO conditions and base load. Appendix A of the PSD Report has emission point characteristics for various turbine inlet temperatures and operating loads.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Distillate (No. 2) Fuel Oil**		
2. Source Classification Code (SCC): **201-001-01**	3. SCC Units: **1,000 Gallons Used**	
4. Maximum Hourly Rate: **13.4**	5. Maximum Annual Rate: **13,373**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**
10. Segment Comment: **Million British Thermal Units (Btu) per SCC unit = 129.9 (rounded to 130). Based on 7.1 pounds per gallon (lb/gal); LHV = 18,514 Btu/lb ISO conditions; 1,000 hours per year (hr/yr) operation. See Section 2.0 in PSD Report for fuel usage of other loads and conditions.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **201-002-01**	3. SCC Units: **Million cubic feet**	
4. Maximum Hourly Rate: **1.9**	5. Maximum Annual Rate: **16.693 (per CT)**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **933 LHV**
10. Segment Comment: **Based on 933 Btu/cf (LHV); ISO conditions and 8,760 hr/yr operation. See Section 2.0 in PSD Report for fuel usage of other loads and conditions.**		

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
PM			NS
PM_{10}			NS
SO_2			NS
NO_X	028		EL
CO			EL
VOC			EL

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: **See PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD Report** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	7. Emissions Method Code: **2**
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 PSD Report, Section 2.0 and Appendix A.**	
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 **1 of 2**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **Annual VE test: EPA Method 9; if > 400 hrs oil firing.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **10% opacity**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **Annual VE test: EPA Method 9.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **See PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD Report** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	7. Emissions Method Code: **2**
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 PSD Report, Section 2.0 and Appendix A.**	
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 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **Annual VE test: EPA Method 9; if > 400 hrs oil firing.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil-firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **10% opacity**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **Gas-firing: See PSD Report, Section 2.0 and Appendix A.**	
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: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **See PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD Report** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	7. Emissions Method Code: **2**
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 PSD Report, Section 2.0 and Appendix A.**	
11. Potential Fugitive and Actual Emissions Comment: **Emission factor: 2 grains Sulfur (S) per 100 SCF gas; 0.05% S oil. See PSD Report, Section 2.0 and Appendix A.**	

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: **0.05% S oil**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **Fuel sampling.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **2 grains/100 SCF**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: **Fuel sampling.**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural gas-firing CT with duct firing. See PSD Report Section 2.0 and Appendix A.**	

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: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **See PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD Report** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	7. Emissions Method Code: **2**
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 PSD Report, Section 2.0 and Appendix A.**	
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 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **42 ppmvd @ 15% O2**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Methods 20 and 7E; CEM – 24-hr block average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil-firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **15 ppmvd @ 15% O2**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Methods 20 and 7E; CEM – 24-hr block average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas-firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **See PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD Report** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	7. Emissions Method Code: **2**
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 PSD Report, Section 2.0 and Appendix A.**	
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 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **See PSD Report**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Method 10; base load; if > 400 hrs oil firing. CEM – 24-hr block average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **See PSD Table 2-3 and 2-4.**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Method 10; base load. CEM – 24-hr block average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas-firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **See PSD Report** lb/hour **See PSD Report** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD Report** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	7. Emissions Method Code:
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 PSD Report, Section 2.0 and Appendix A.**	
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 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **See PSD Table 2-4.**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Methods 18, 25, or 25A; base load.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **See PSD Table 2-2.**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Methods 18, 25, or 25A; base load.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas-firing: See PSD Report, Section 2.0 and Appendix A.**	

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: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **20%** Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
11. Visible Emissions Comment: **FDEP Rule 62-296.320(4)(b)1, F.A.C. requires 20 percent opacity. Excess emissions per Rule 62-210.700, F.A.C.**	

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 **2**

1. Parameter Code: **EM**	2. Pollutant(s): **NO_X**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR Part 75. NO_X monitoring includes diluent monitor (O_2 or CO_2).**	

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

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM monitor anticipated pursuant to previous BACT determinations.**	

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: **PSD Report** * [ ] 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: **PSD Report** * [ ] 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)
[X] Attached, Document ID: **PSD Report** * [ ] 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)
[ ] Attached, Document ID: _____ [ ] Previously Submitted, Date _____
[X] 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:
[ ] Attached, Document ID: _____
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: _____
_____
[X] 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

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: **PSD Report** *_
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

(*) **Indicates to refer to the PSD Report (BA-FI-C11) for additional information.**

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: **Natural gas fired steam boiler rated at 99 MMBtu/hr. The boiler provides steam for periods of combustion turbine startup or quick startup out of a short-term shutdown.**

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
	Prior to 3/2010		**49**

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

[ ] Acid Rain Unit

[ ] CAIR Unit

[ ] Hg Budget Unit

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment: **The emissions unit is regulated under NSPS – 40 CFR 60, Subpart Dc, Standards and Performance for Small Industrial-Commercial-Institutional Steam Generating Units, adopted and incorporated by reference in Rule 62-204.800(8), F.A.C.**

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:

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: **99** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	**7** days/week **1,000** hours/year
6. Operating Capacity/Schedule Comment: **The boiler provides steam for periods of combustion turbine startup or quick startup out of a short-term shutdown.**	

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: **See PSD Report**	2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:

Auxiliary Boiler Stack

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code: **V**	6. Stack Height: **60** feet	7. Exit Diameter: **2.75** feet
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: **29,000** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	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): **Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million cubic feet**	
4. Maximum Hourly Rate: **0.096**	5. Maximum Annual Rate: **96.9**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1030 HHV**
10. Segment Comment: **Based on 99 MMBtu/hr; 1,000 hr/yr**		

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
PM/PM10			NS
SO_2			WP
NO_X			EL
CO			NS
VOC			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: **PM/PM_{10}**	2. Total Percent Efficiency of Control:	
3. Potential Emissions: **0.18** lb/hour **0.09** tons/year		4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year		
6. Emission Factor: **1.90 lb/10^6 cf gas – filterable PM** Reference: **EPA 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: **See PSD Report, Section 2.0, Table 2-8 and Appendix A.**		
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 **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.90 lb/10^6 cf gas – filterable PM**	4. Equivalent Allowable Emissions: **0.18** lb/hour **0.09** tons/year
5. Method of Compliance: **Natural Gas Combustion**	
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: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.55** lb/hour **0.28** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2 grain S/100 scf-gas** Reference:	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: **See PSD Report, Section 2.0, Table 2-8 and Appendix A.**	
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 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2 grain S/100 scf-gas**	4. Equivalent Allowable Emissions: **0.55** lb/hour **0.28** tons/year
5. Method of Compliance: **Natural Gas Combustion**	
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: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **4.85** lb/hour **2.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.049 lb/MMBtu** Reference: **EPA 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: **See PSD Report, Section 2.0, Table 2-8 and Appendix A.**	
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 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.049 lb/MMBtu**	4. Equivalent Allowable Emissions: **4.85** lb/hour **2.4** tons/year
5. Method of Compliance: **Natural Gas Combustion**	
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: **8.15** lb/hour **4.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.082 lb/MMBtu** Reference: **EPA 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: **See PSD Report, Section 2.0, Table 2-8 and Appendix A.**	
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 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.082 lb/MMBtu**	4. Equivalent Allowable Emissions: **8.15** lb/hour **4.1** tons/year
5. Method of Compliance: **Natural Gas Combustion**	
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: **0.53** lb/hour **0.27** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.005 lb/MMBtu** Reference: **EPA 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: **See PSD Report, Section 2.0, Table 2-8 and Appendix A.**	
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 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.005 lb/MMBtu**	4. Equivalent Allowable Emissions: **0.53** lb/hour **0.27** tons/year
5. Method of Compliance: **Natural Gas Combustion**	
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: **VE99**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance:	
4. Visible Emissions Comment: **FDEP Rule 62-210.700(1), F.A.C.; allowed for 2-hours (120 minutes) per 24 hours for startup, shutdown, and malfunction.**	

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 ___ 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:	

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: **PSD Report*** [ ] 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: **PSD Report*** [ ] 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: _____ [ ] 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)
   [ ] Attached, Document ID: _____ [ ] Previously Submitted, Date _____
   [X] 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:
   [ ] Attached, Document ID: _____
   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: _____
   _____
   [X] 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

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: [x] Attached, Document ID: : **PSD Report***
2. Compliance Assurance Monitoring: ☐ Attached, Document ID: _____ [x] Not Applicable
3. Alternative Methods of Operation: ☐ Attached, Document ID: _____ [x] Not Applicable
4. Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: _____ [x] Not Applicable

Additional Requirements Comment

(*) **Indicates to refer to the PSD Report (BA-FI-C11) for additional information.**

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)

[ ] 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).

[X] 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.

5. Description of Emissions Unit Addressed in this Section:

Five natural gas-fired gas heaters, each rated at 3 MMBtu/hr. The heaters are used heat the natural gas before the gas is fired in the combustion turbines.

3. Emissions Unit Identification Number: **042**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A	**12/1/06**		**49**

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

[ ] Acid Rain Unit

[ ] CAIR Unit

[ ] Hg Budget Unit

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

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:

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:	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	**7** days/week **8,760** hours/year

12. Operating Capacity/Schedule Comment:

The heaters are used to heat the natural gas before the gas is fired in the combustion turbines.

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: **See PSD Report**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Each Gas Heater has its own stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **60** feet	7. Exit Diameter: **2** feet
8. Exit Temperature: **500** °F	9. Actual Volumetric Flow Rate: **4,950** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: **See PSD Report** dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	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): **Natural Gas**		
2. Source Classification Code (SCC): **201-002-01**	3. SCC Units: **Million cubic feet**	
4. Maximum Hourly Rate: **0.00289**	5. Maximum Annual Rate: **25.3 (per CT)**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1040 LHV**
10. Segment Comment: **Based on 3 MMBtu/hr, 8,760 hr/yr, per gas heater.**		

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
PM			NS
SO_2			WP
NO_X			NS
CO			NS
VOC			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: **PM/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.005** lb/hour **0.024** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **1.9 lb MMscf gas filterable PM** Reference: **EPA AP42**	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: **Per gas heater. See PSD Report, Table 2-9.**	
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 **1 of 1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.9 lb/MMscf of gas filterable PM**	4. Equivalent Allowable Emissions: **0.005** lb/hour **0.024** tons/year
5. Method of Compliance: **Natural Gas Combustion**	
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: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.016** lb/hour **0.072** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2 grains S/100 scf of gas** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	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: **Per gas heater. See PSD Report, Table 2-9.**	
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 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2 grain S / 100 scf of gas**	4. Equivalent Allowable Emissions: **0.016** lb/hour **0.072** tons/year
5. Method of Compliance: **Natural Gas Combustion.**	
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: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.29** lb/hour **1.3** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **100 lb/MMscf of gas** Reference: **EPA AP42**	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: **Per gas heater. See PSD Report, Table 29.**	
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 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **100 lb/MMscf of gas**	4. Equivalent Allowable Emissions: **0.29** lb/hour **1.3** tons/year
5. Method of Compliance: **Natural Gas Combustion**	
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: **0.24** lb/hour **1.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **84 lb/MMscf of gas** Reference: **EPA AP42.**	7. Emissions Method Code: **2**
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: **Per gas heater. See PSD Report, Table 2-9.**	
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 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **84 lb/MMscf of gas**	4. Equivalent Allowable Emissions: **0.24** lb/hour **1.1** tons/year
5. Method of Compliance: **Natural Gas Combustion.**	
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: **0.02** lb/hour **0.07** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **5.5 lb/MMscf of gas** Reference: **EPA AP-42**	7. Emissions Method Code:
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: **Per gas heater. See PSD Report, Table 2-9.**	
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 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **5.5 lb/MMscf of gas**	4. Equivalent Allowable Emissions: **0.02** lb/hour **0.07** tons/year
5. Method of Compliance: **Natural Gas Combustion**	
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: **VE99**	2. Basis for Allowable Opacity: [x] Rule [ ] Other
3. Allowable Opacity: Normal Conditions: **%** Exceptional Conditions: **100%** Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **None**	
13. Visible Emissions Comment: **FDEP Rule 62-210.700(2),allowed for 2-hours (120 minutes) per 24 hours startup, shutdown, and malfunction.**	

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 ___ 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:	

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: **PSD Report** * [ ] 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: **PSD Report** * [ ] 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)
[X] Attached, Document ID: **PSD Report** * [ ] 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)
[ ] Attached, Document ID: _____ [ ] Previously Submitted, Date _____
[X] 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:
[ ] Attached, Document ID: _____
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: _____
[X] 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

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: **PSD Report***
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

(*) **Indicates to refer to the PSD Report (BA-FI-C11) for additional information.**

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.

EMISSIONS UNIT INFORMATION
Section [14] of [15]
Two Distillate Oil Storage Tanks

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)

[ ] 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).

[X] 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.

[X] 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 nominal 3.5 MMgal Distillate Oil Storage Tanks**

3. Emissions Unit Identification Number: **045**

4. Emissions Unit Status Code:	5. Commence Construction Date: **1/29/07**	6. Initial Startup Date: **11/5/08**	7. Emissions Unit Major Group SIC Code:

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

[ ] Acid Rain Unit

[ ] CAIR Unit

[ ] Hg Budget Unit

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

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:

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: million Btu/hr		
4. Maximum Incineration Rate: pounds/hr tons/day		
5. Requested Maximum Operating Schedule:		
	24 hours/day	7 days/week
	52 weeks/year	8,760 hours/year
6. Operating Capacity/Schedule Comment:		

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:	2. Emission Point Type Code:	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code:	6. Stack Height: feet	7. Exit Diameter: feet
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	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 __ 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:		

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
VOC			

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: lb/hour tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
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:	
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):	

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 __ 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:	

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 ___ 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:	

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)
   ☐ Attached, Document ID: _____ ☐ 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)
   ☐ Attached, Document ID: _____ ☐ 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: _____ ☐ 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)
   ☐ Attached, Document ID: _____ ☐ 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 _____
   ☐ Not Applicable

6. Compliance Demonstration Reports/Records:
   ☐ Attached, Document ID: _____
   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: _____ ☐ Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

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: _____
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.

6. Description of Emissions Unit Addressed in this Section:

One – 300 HP diesel fuel-fired internal combustion engine (emergency fire pump).

3. Emissions Unit Identification Number: **042**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A	**12/1/06**		**49**

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

[ ] Acid Rain Unit

[ ] CAIR Unit

[ ] Hg Budget Unit

9. Package Unit:
Manufacturer: **Clarke/John Deere** Model Number: **JW6H-UF58**

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
The addition of a diesel-fired emergency fire pump reflects a change in the project design that occurred after the initial air application was submitted. This 300 HP Clarke/John Deere engine will meet all requirements of the new NSPS (*Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*), recently promulgated on July 11, 2006 in *Federal Register, Volume 71, Number 132.*

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description: **Good Combustion Practice – Diesel fuel fired.**
2. Control Device or Method Code: **NA**

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: **2.1** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	
24 hours/day	**7** days/week
52 weeks/year	**500** hours/year

14. Operating Capacity/Schedule Comment:

Maximum heat input based on fuel heating value of 150,000 Btu/gal.

The emergency generator will not be subject 40 CFR 63 Subpart ZZZZ, the Reciprocating Internal Combustion Engine (RICE) MACT Rule since it will be used for emergency purposes and qualify for the exemption, as described below:

Emergency Generator - Any stationary RICE that operates in an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility is interrupted, *or stationary RICE used to pump water in case of fire or flood,* etc. Emergency stationary RICE may be operated for the purpose of maintenance checks and readiness testing provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of the emergency stationary RICE in emergency situations and for routine testing and maintenance. Emergency stationary RICE may also operate an additional 50 hours per year in non-emergency situations.

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: **Adjacent to PB 4**	2. Emission Point Type Code:	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **15** feet	7. Exit Diameter: **0.5** feet
8. Exit Temperature: **866** °F	9. Actual Volumetric Flow Rate: **1,642** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	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): **Diesel fuel combustion**		
2. Source Classification Code (SCC):	3. SCC Units: **1000 gallons**	
4. Maximum Hourly Rate: **0.014**	5. Maximum Annual Rate: **7.0**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **150**
10. Segment Comment: **Maximum annual rate based on estimated 500 hr / yr operation.**		

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
PM/PM10			EL
CO			EL
NMHC+NOx			EL

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/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.15** lb/hour **0.04** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.23 g/HP-hr** Reference: **John Deere, 2006**	7. Emissions Method Code: **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:	
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 **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.23 g/HP-hr**	4. Equivalent Allowable Emissions: **0.15** lb/hour **0.04** tons/year
5. Method of Compliance: **Diesel fuel combustion**	
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: **0.67** lb/hour **0.17** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **1.01 g/hp-hr** Reference: **John Deere, 2006**	7. Emissions Method Code: **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: **Annual emissions based on 500 hr/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 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.01 g/hp-hr**	4. Equivalent Allowable Emissions: **0.67** lb/hour **0.17** tons/year
5. Method of Compliance: **Diesel Fuel Combustion.**	
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: **NMHC+NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3.7** lb/hour **0.93** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **5.52 g/HP-hr** Reference: **John Deere, 2006**	7. Emissions Method Code: **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:	
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 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **5.52 g/HP-hr**	4. Equivalent Allowable Emissions: **3.7** lb/hour **0.93** tons/year
5. Method of Compliance: **Diesel Fuel Combustion**	
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 __ 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:	
15. Visible Emissions Comment:	

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 ___ 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:	

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)
   ☐ Attached, Document ID: _____ ☒ Previously Submitted, Date **July 31, 2006**

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)
   ☐ Attached, Document ID: _____ ☒ Previously Submitted, Date **July 31, 2006**

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: _____ ☐ 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)
   ☐ Attached, Document ID: _____ ☐ 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 _____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records:
   ☐ Attached, Document ID: _____
   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: _____ ☒ Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

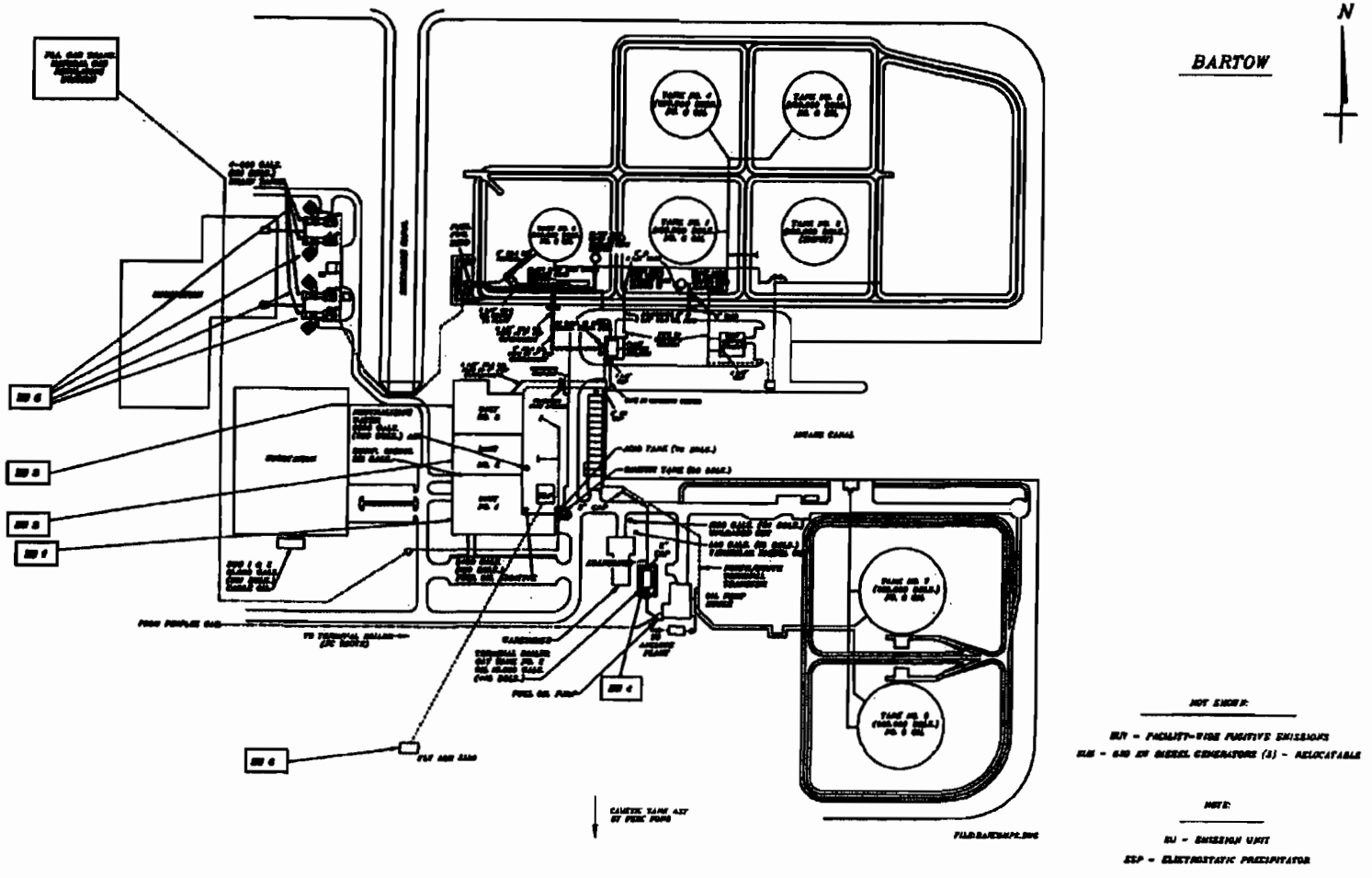
1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☐ Attached, Document ID: _____ ☐ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID: _____ ☐ 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

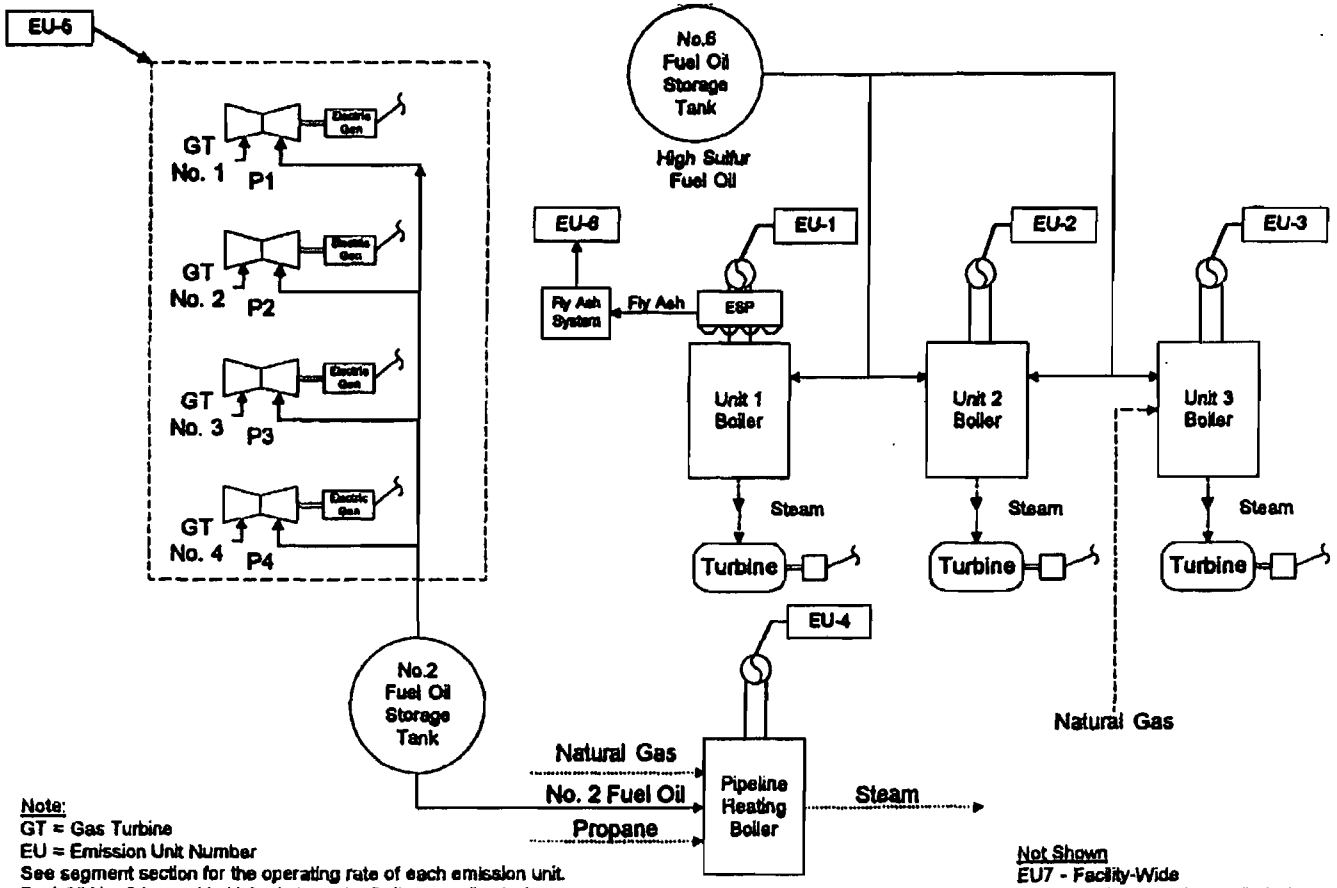
1. Identification of Applicable Requirements: ☐ Attached, Document ID: _____
2. Compliance Assurance Monitoring: ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Alternative Methods of Operation: ☐ Attached, Document ID: _____ ☒ Not Applicable
4. Alternative Modes of Operation (Emissions Trading):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

Additional Requirements Comment

FACILITY INFORMATION



CLIENT/PROJECT **Progress Energy Florida, Inc**			TAMPA, FLORIDA **Golder Associates**				TITLE **Facility Plot Plan P. L. Bartow Plant**			
DRAWN	CHECKED	REVIEWED	DATE 4/16/2009	NOT TO SCALE	FILE NO.	Job No. 083-89614	DWG NO.	SUBTITLE	REV. NO.	**BA-FI-C1**



Note:
GT = Gas Turbine
EU = Emission Unit Number
See segment section for the operating rate of each emission unit.
Fuel Oil No. 2 is used in Units 1, 2, and 3 Boilers as pilot fuel.
On-spec used oil can be fired in Units 1, 2 and 3
Propane is used in Units 2 and 3 for flame stabilization.

Not Shown
EU7 - Facility-Wide
- Fugitive/Deminimis Emissions
EU8 - 820 KW Diesel Generators(3)
- *relocatable*

CLIENT/PROJECT **Progress Energy Florida, Inc**			TAMPA, FLORIDA Golder Associates				TITLE **Process Flow Diagram P. L. Bartow Plant**			
DRAWN	CHECKED	REVIEWED	DATE 4/16/2009	NOT TO SCALE	FILE NO.	Job No. 083-89614	DWG NO.	SUBTITLE	REV. NO.	**BA-FI-C2**

ATTACHMENT BA-FI-C3

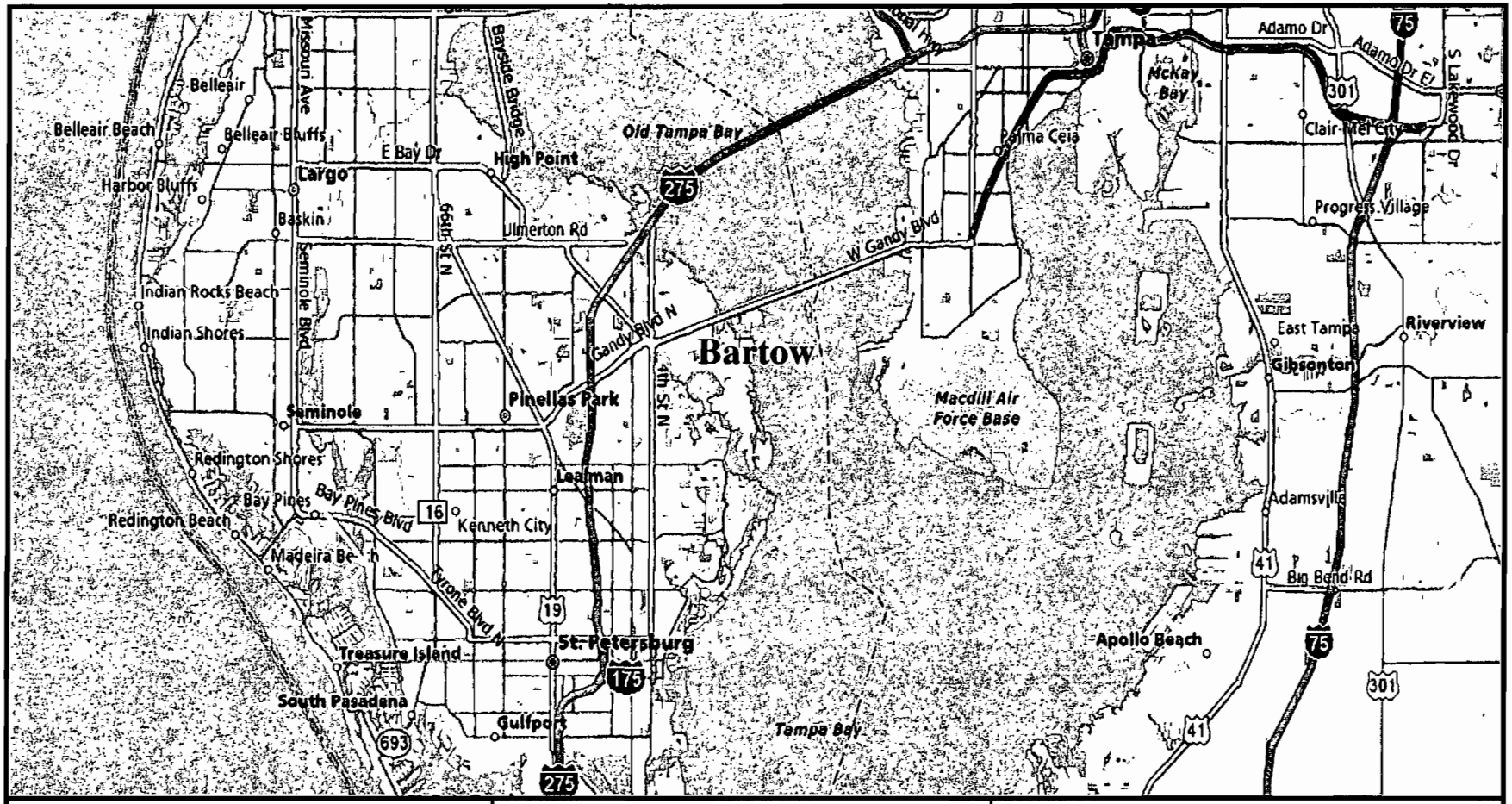
PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

The facility has negligible amounts of unconfined particulate matter as a result of the operation of the facility. Potential examples of particulate matter include:

- Fugitive dust from paved and unpaved roads, and
- Fugitive particulates from the use of bagged chemical products.

Operational measures are undertaken at the facility which also minimize particulate emissions, in accordance with 62-296.310(3), F.A.C.:

- Maintenance of paved areas as needed,
- Regular mowing of grass and care of vegetation, and
- Limiting access to plant property by unnecessary vehicles.



CLIENT/PROJECT **Progress Energy Florida, Inc**			TAMPA, FLORIDA **Golder Associates**				TITLE **Area Map P. L. Bartow Plant**			
DRAWN	CHECKED	REVIEWED	DATE 4/16/2009	SCALE Not to Scale	FILE NO.	Job No. 083-89614	DWG NO.	SUBTITLE	REV. NO.	**BA-FI-C4**

ATTACHMENT BA-FI-C5

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

Progress Energy Florida	**FINAL Permit No.:** 1030011-009-AV
P. L. Bartow Plant	**Facility ID No.:** 1030011

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210300(3)(a), F.A.C., Categorical Exemptions, or that meet the criteria specified in Rule 62-210.300(3)(b)l., 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 pernutting under Rules 62-210300(3)(a) and (b)l., 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 he 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 62-210300(3)(a) and (b)l., 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 andlor activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

Brief Description of Emissions Units and/or Activities

~~1. Water Laboratory solvent use and hood chemical analyses for water~~
~~2. Water Laboratory flammable chemical storage cabinet~~
3. General Boiler Building fire protection equipment
4. Flammable liquid cabinets Site wide
5. Plant and South Terminal Fire suppression foam
6. Site utilization of sand blasters, drill presses, welding machines, lathes, hand-held tools, etc.
7. Large equipment outdoor sandblasting
8. Steam release during boiler blow-downs
9. General Site surface coating 4 0 gallons per day
10. General Site brazing, soldering and welding
~~11. Unit 1 Fly Ash Handling System~~
12. Lawn mowing and landscaping activities
13. Use of solvents
14. Painting and painting related cleanup
15. Use of products in the aerosol form
16. Use of small, portable generators and pumps
17. Pressure washing of machinery and buildings
18. Earth moving activities
19. Heavy equipment (backhoe, forklift, cranes, etc.)

ATTACHMENT BA-FI-C6
Identification of Applicable Requirements

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Mr. Harry Sideris
Plant Manager
Progress Energy Florida, Inc.
1601 Weedon Island Drive
St. Petersburg, FL 33702

Title V Permit Renewal No. **1030011-009-AV**
P.L. Bartow Power Plant
Pinellas County
Facility ID No. 1030011

Enclosed is FINAL Title V Permit Renewal Number **1030011-009-AV** for the P.L. Bartow Power Plant, located at 1601 Weedon Island Drive, St. Petersburg, Pinellas County, issued pursuant to Chapter 403, Florida Statutes (F.S.).

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

http://www.dep.state.fl.us/air/permitting.htm

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

Executed in Tallahassee, Florida.

Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

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

Harry Sideris, Progress Energy Florida, Inc.*
Scottt Osbourn, P.E., Golder Associates, 5100 West Lemon Street, Suite 114, Tampa, FL 33609
Jerry Kissel, DEP-SWD
Gary Robbins, Pinellas County
U.S. EPA, Region 4 (INTERNET E-mail Memorandum)

12/27/04 cc: Sunl Air File
Reading File

Clerk Stamp

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

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

FINAL PERMIT DETERMINATION

I. Comment(s).

The PROPOSED Title V Permit Renewal was posted on the Department's web site on November 10, 2004, for review by U.S. EPA's Region 4 Office in Atlanta. As of close of business on December 23, 2004, *no comments had been received from EPA.*

II. Conclusion.

The permitting authority hereby issues the FINAL Permit Renewal No. **1030011-009-AV** as proposed.

SENDER: COMPLETE THIS SECTION

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

1. Article Addressed to:

Mr. Harry Sideris
Plant Manager
Progress Energy Florida, Inc.
1601 Weedon Island Drive
St. Petersburg, Florida 33702

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Don Brown ☐ Agent ☐ Addressee

B. Received by (Printed Name)

C. Date of Delivery 12-29-4

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

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

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7004 1350 0000 1910 2997

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

7004 1350 0000 1910 2997

U.S. Postal Service™
CERTIFIED MAIL™ RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

For delivery information visit our website at www.usps.com®
Mr. Harry Sideris, Plant Manager OFFICIAL USE

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

Sent To
Mr. Harry Sideris, Plant Manager
Street, Apt. No.; or PO Box No.
1601 Weedon Island Drive
City, State, ZIP+4
St. Petersburg, Florida 33702

PS Form 3800, June 2002 See Reverse for Instructions

STATEMENT OF BASIS

Progress Energy Florida
P. L. Bartow Plant
Facility ID No.: 1030011
Pinellas County

Title V Air Operation Permit Renewal
FINAL Permit No.: 1030011-009-AV

The initial Title V Air Operation Permit, No. 1030011-002-AV, was effective on January 1, 2000. 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 operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

This facility consists of three fossil fuel fired steam generators subject to Phase II Acid Rain, a pipeline heating boiler, four gas turbine peaking units and relocatable diesel generators that can be located at various Florida Power Corporation power plants, as needed.

Unit No. 1 is a front-fired, fossil fuel steam generator which produces 120 megawatts, electric power. The maximum heat input rate is 1,220 million Btu per hour and the unit fires No. 2 through No. 6 fuel oil, and on-specification used oil. Particulate matter emissions are controlled by a General Electric Services, Inc. Model 1-BAB1.2X37(9)36.0-434-4.3P electrostatic precipitator consisting of five fields in depth. The ESP was designed to operate when utilizing a coal/oil mixture which is no longer burned by Progress Energy Florida. The permittee was authorized to redesign the existing electrostatic precipitator (ESP) from three mechanical fields to two mechanical fields. The original design was based on a primary fuel mixture of 50% coal and 50% fuel oil. As coal is no longer an authorized fuel, the new design will be based on No. 6 fuel oil. The ESP inlet design conditions include:

Gas Flow Rate: 488,000 acfm (308,830 dscfm)
Gas Temperature: 250° F to 320° F
Gas Pressure: -2 to - 4 inches w.c.
Gas moisture content: 6% to 8% by volume

The redesign leaves the first mechanical field vacant to provide uniform gas flow to the second and third mechanical fields. A new perforated plate will be added to the inlet to the second mechanical field. The gas passage width was increased to allow for more durable rigid discharge electrodes that replaced current wire electrodes. New transformer rectifiers were installed to provide the increased voltage required for the new rigid electrodes. The design is based on the following critical operating parameters:

Total Collecting Plate Area: 92,711 square feet (based on actual 11 inch gas passage width)
Treatment length: 21 feet
Aspect Ratio: 0.57
Specific Collecting Area (SCA): 190 square feet per 1000 acfm (based on 11 inch gas passage width)
Gas Velocity: 4.0 feet per second
Treatment Time: 5.2 seconds

The redesigned ESP is expected to provide emission rates equal to or better than the original design and lower than reported in recent stack tests. Because Unit 1 is oil fired and this unit is capable of meeting the applicable particulate matter and opacity limits in Conditions A.5., A.6., A.7., and A.8. without the use of the ESP, the provisions of 40 CFR Part 64 (Compliance Assurance Monitoring) do not apply [40 CFR

64.2(b)(ii)]. A Durag Model 281 Continuous Emissions Monitor for opacity with a recorder is used for continual observation of stack opacity. Unit 1 began commercial service in 1958.

Unit No. 2 is a tangential-fired fossil fuel fired steam generator which produces 120 megawatts, electric power. The maximum heat input rate is 1,317 million Btu per hour and the unit fires No. 2 through No. 6 fuel oil, on-specification used oil, and propane. Emissions from Unit No. 2 are uncontrolled. Unit 2 began commercial service in 1961.

Unit No. 3 is a tangential-fired fossil fuel fired steam generator which produces 225 megawatts, electric power. The maximum heat input rate is 2,211 million Btu per hour and the unit fires No. 2 through No. 6 fuel oil, on-specification used oil, natural gas, and propane. Emissions from Unit No. 3 are uncontrolled. Unit 3 began commercial service in 1963.

This permit renewal includes some changes to the Initial Title V permit as described below.

The applicant wanted to revise Appendix U-1, List of Unregulated Emissions Units and/or Activities, to reflect the current status of those emissions units. The changes are not considered significant.

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

Based on the Title V permit renewal application received July 2, 2004, this facility is a major source of hazardous air pollutants (HAPs).

Progress Energy Florida
P. L. Bartow Plant
Facility ID No.: 1030011
Pinellas County

Title V Air Operation Permit Renewal

FINAL Permit No.: 1030011-009-AV

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

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

Compliance Authority:
Pinellas County Department of Environmental Management
Air Quality Division
300 South Garden Avenue
Clearwater, Florida 34616
Telephone: 813/464-4422
Fax: 813/464-4420

Title V Air Operation Permit Renewal

FINAL Permit No.: 1030011-009-AV

Table of Contents

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

Permittee:
Progress Energy Florida
100 Central Avenue, Mail Code BB1A
St. Petersburg, Florida 33701

FINAL Permit No.: 1030011-009-AV
Facility ID No.: 1030011
SIC No(s).: 49, 4911
Project: Title V Air Operation Permit Renewal

This permit renewal is for the operation of P. L. Bartow Plant. This facility is located at 1601 Weedon Island Drive, St. Petersburg, Pinellas County; UTM Coordinates: Zone 17, 342.4 km East and 3,082.6 km North; Latitude: 27° 52' 10" North and Longitude: 82° 35' 59" 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 operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
APPENDIX TV-4, TITLE V CONDITIONS version dated 02/12/02
APPENDIX SS-1, STACK SAMPLING FACILITIES version dated 10/07/96
TABLE 297.310-1, CALIBRATION SCHEDULE version dated 10/07/96
Alternate Sampling Procedure: ASP Number 97-B-01
OGC Order No. 86-1577
OGC Order No. 87-1261
OGC Order No. 96-A-01
PROGRESS ENERGY FLORIDA BARTOW PLANT UNIT #1 ELECTROSTATIC PRECIPITATOR OPERATION AND MAINTENANCE PLAN dated August 2003
Phase II Acid Rain Application/Compliance Plan received July 2, 2004.

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

Michael G. Cooke, Director
Division of Air Resource Management

MGC/sa

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of three fossil fuel fired steam generators subject to Phase II Acid Rain, a pipeline heating boiler, four gas turbine peaking units and relocatable diesel generators that can be located at various Progress Energy Florida power plants, as needed.

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

Based on the Title V permit renewal application received July 2, 2004, this facility is a major source of hazardous air pollutants (HAPs).

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

E.U. ID No.	Brief Description
-001	No. 1 Unit, Fossil Fuel Fired Steam Generator with Electrostatic Precipitator
-002	No. 2 Unit, Fossil Fuel Fired Steam Generator
-003	No. 3 Unit, Fossil Fuel Fired Steam Generator
-004	Bartow-Anclote Pipeline Heating Boiler
-005	Gas Turbine Peaking Unit #P-1
-006	Gas Turbine Peaking Unit #P-2
-007	Gas Turbine Peaking Unit #P-3
-008	Gas Turbine Peaking Unit #P-4
-001	Relocatable Diesel Fired Generator(s) [Facility ID No. 7775047]

Unregulated Emissions Units and/or Activities
{See Appendix U-1}

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

Subsection C. Relevant Documents.

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

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

These documents are on file with the permitting authority:
Initial Title V Air Operation Permit effective January 1, 2000
Application for a Title V Air Operation Permit Revision received May 2, 2003
Title V Permit Renewal Application received on July 2, 2004
DRAFT Title V Permit Renewal clerked on September 29, 2004
PROPOSED Title V Permit Renewal was posted on November 10, 2004

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. APPENDIX TV-4, TITLE V CONDITIONS, is a part of this permit.
{Permitting note: APPENDIX TV-4, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}

2. **Not federally enforceable.** General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

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

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

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

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

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

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

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

compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.

"Nothing was deemed necessary and ordered at this time."

[Rule 62-296.320(1)(a), F.A.C.]

8. Emissions of Unconfined Particulate Matter. Pursuant to Rules 62-296.320(4)(c)1., 3. & 4., F.A.C., reasonable precautions to prevent emissions of unconfined particulate matter at this facility include the following requirements (see Condition 57. of APPENDIX TV-4, TITLE V CONDITIONS):
The following requirements are "not federally enforceable":

a. Maintenance of paved areas as needed;
b. Regular mowing of grass and care of vegetation; and,
c. Limiting access to plant property by unnecessary vehicles.

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

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

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

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

11. The permittee shall submit all compliance related notifications and reports required of this permit to the Pinellas County Department of Environmental Management (PCDEM) office.

Pinellas County Department of Environmental Management
Air Quality Division
300 South Garden Avenue
Clearwater, Florida 34616
Telephone: 727/464-4422
Fax: 727/464-4420

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

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

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

Section III. Emissions Unit(s) and Conditions.

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

E.U. ID No.	Brief Description
-001	No. 1 Unit, Fossil Fuel Fired Steam Generator with Electrostatic Precipitator
-002	No. 2 Unit, Fossil Fuel Fired Steam Generator
-003	No. 3 Unit, Fossil Fuel Fired Steam Generator

Unit No. 1 is a front-fired, fossil fuel steam generator which produces 120 megawatts, electric power. The maximum heat input rate is 1,220 million Btu per hour and the unit fires No. 2 through No. 6 fuel oil, and on-specification used oil. Particulate matter emissions are controlled by a General Electric Services, Inc. Model 1-BAB1.2X37(9)36.0-434-4.3P electrostatic precipitator consisting of five fields in depth. The permit application indicates this ESP was designed to operate when utilizing a coal/oil mixture which is no longer burned by Progress Energy Florida. The permittee was authorized to redesign the existing electrostatic precipitator (ESP) from three mechanical fields to two mechanical fields. The original design was based on a primary fuel mixture of 50% coal and 50% fuel oil. As coal is no longer an authorized fuel, the new design will be based on No. 6 fuel oil. The ESP inlet design conditions include:

Gas Flow Rate: 488,000 acfm (308,830 dscfm)
Gas Temperature: 250° F to 320° F
Gas Pressure: -2 to - 4 inches w.c.
Gas moisture content: 6% to 8% by volume

The redesign leaves the first mechanical field vacant to provide uniform gas flow to the second and third mechanical fields. A new perforated plate will be added to the inlet to the second mechanical field. The gas passage width was increased to allow for more durable rigid discharge electrodes that replaced current wire electrodes. New transformer rectifiers were installed to provide the increased voltage required for the new rigid electrodes. The design is based on the following critical operating parameters:

Total Collecting Plate Area: 92,711 square feet (based on actual 11 inch gas passage width)
Treatment length: 21 feet
Aspect Ratio: 0.57
Specific Collecting Area (SCA): 190 square feet per 1000 acfm (based on 11 inch gas passage width)
Gas Velocity: 4.0 feet per second
Treatment Time: 5.2 seconds

The redesigned ESP is expected to provide emission rates equal to or better than the original design and lower than reported in recent stack tests. Because Unit 1 is oil fired and this unit is capable of meeting the applicable particulate matter and opacity limits in Conditions A.5., A.6., A.7., and A.8. without the use of the ESP, the provisions of 40 CFR 64 do not apply [40 CFR 64.2(b)(ii)]. A Durag Model 281 Continuous Emissions Monitor for opacity with a recorder is used for continual observation of stack opacity. Unit 1 began commercial service in 1958.

Unit No. 2 is a tangential-fired fossil fuel fired steam generator which produces 120 megawatts, electric power. The maximum heat input rate is 1,317 million Btu per hour and the unit fires No. 2 through No. 6 fuel oil, on-specification used oil, and propane. Emissions from Unit No. 2 are uncontrolled. Unit 2 began commercial service in 1961.

Unit No. 3 is a tangential-fired fossil fuel fired steam generator which produces 225 megawatts, electric power. The maximum heat input rate is 2,211 million Btu per hour and the unit fires No. 2 through No. 6 fuel oil, on-specification used oil, natural gas, and propane. Emissions from Unit No. 3 are uncontrolled. Unit 3 began commercial service in 1963.

{Permitting note(s): The emissions units are regulated under Acid Rain, Phase II; Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input; Rule 62-296.700, F.A.C., Reasonably Available Control Technology (RACT) Particulate Matter; and, Rule 62-296.702, F.A.C., Fossil Fuel Steam Generators.}

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

Essential Potential to Emit (PTE) Parameters

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

E.U. ID No.	MMBtu/hr Heat Input	Fuel
-001	1,220	new No. 2 through 6 fuel oil
	1,220	On-specification used oil
-002	1,317	new No. 2 through 6 fuel oil
	1,317	On-specification used oil
-003	2,211	new No. 2 through 6 fuel oil
	2,266	Natural gas
	2,211	On-specification used oil
	2,266	Natural gas and new No. 6 fuel oil and/or on-specification used oil with a maximum of 2,211 MMBtu/hr from the new No. 6 fuel oil and/or on-specification used oil

[Rules 62-4.160(2), 62-210.200(PTE), 62-296.405 and 62-296.702, F.A.C.]

{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 specific condition **A.24.**
[Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation. Fuels. The only fuels allowed to be burned are:

E.U. ID No.	Fuel
-001	new No. 2 through 6 fuel oil
	On-specification used oil
-002	new No. 2 through 6 fuel oil
	On-specification used oil
	Propane
-003	new No. 2 through 6 fuel oil
	Natural gas
	On-specification used oil
	Propane

Each emissions unit may burn the allowed fuels either alone or in any combination. On-Specification used oil containing any quantifiable levels of PCBs can only be fired when the emissions unit is at normal operating temperatures.
[Rule 62-213.410, F.A.C.; and, 40 CFR 761.20(e)(3)]
{Permitting Note: 40 CFR 761.20, dated March 18, 1996, defines "quantifiable level" of PCBs as greater than or equal to 2 parts per million.}

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

Emission Limitations and Standards

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

{Permitting Note: 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. Visible emissions shall not exceed 40 percent opacity.
[Rules 62-296.405(1)(a) and 62-296.702(2)(b), F.A.C.; and, OGC Order Nos. 86-1577, 87-1261, & 96-A-01]

A.6. Visible Emissions - Soot Blowing and Load Change. Visible emissions resulting from boiler cleaning (soot blowing) and load change shall be permitted provided the duration of such excess emissions shall not exceed 3 hours in any 24-hour period and visible emissions shall not

exceed 60 percent opacity, and providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of the excess emissions shall be minimized.

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

Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6) - minute periods, during the 3-hour period of excess emissions allowed under this subparagraph, for boiler cleaning and load changes, at units which have installed and are operating, or have committed to install or operate, continuous opacity monitors.

Particulate matter emissions shall not exceed an average of 0.3 lb. per million Btu heat input during the 3-hour period of excess emissions allowed by this subparagraph.

[Rules 62-210.700(3) and 62-296.702(2)(b), F.A.C.]

A.7. Particulate Matter. Particulate matter emissions during steady state operations shall not exceed the following, as measured by applicable compliance methods (see specific condition **A.20.**):

E.U. ID No.	lb/MMBtu heat input	lb/ hr	Tons per Year
-001	0.1	122.0	534.4
-002	0.1	131.7	576.9
-003	0.1	221.1	968.6

[Rules 62-296.405(1)(b), 62-296.700(4)(b) and 62-296.702(2)(a), F.A.C.]

A.8. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of the following during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

E.U. ID No.	lb/MMBtu heat input	lb/ hr
-001	0.3	366.0
-002	0.3	395.1
-003	0.3	663.3

[Rules 62-210.700(3) and 62-296.700(4)(b), F.A.C.]

A.9. Sulfur Dioxide. When burning liquid fuel, sulfur dioxide emissions shall not exceed 2.75 pounds per million Btu heat input, as measured by applicable compliance methods.

[Rule 62-296.405(1)(c)1.j., F.A.C.]

A.10. Sulfur Dioxide - Sulfur Content. The new No. 6 fuel oil sulfur content shall not exceed 2.5 percent, by weight. The sulfur content of the on-specification used oil shall not exceed 2.5 percent by weight. See specific condition **A.22.**

[Rule 62-296.405(1)(e)3., F.A.C.; and, AO 52-216412, AO 52-216413 & AO 52-233149]

A.11. "On-Specification" Used Oil. Only "on-specification" used oil shall be fired in these units. The quantity of on-specification used oil fired in emissions units -001, -002 and -003 shall

not exceed a total of 14.85 million gallons per consecutive 12-month period and 2.475 million gallons per month. "On-specification" used oil is defined as used oil that meets the 40 CFR 279 (Standards for the Management of Used Oil) specifications listed below. Used oil that does not meet all of the following specifications is considered "off-specification" oil and shall not be fired.

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°F minimum
PCBs	less than 50 ppm**

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

** Used oil shall not be blended to meet this requirement.

[40 CFR 279.11; 40 CFR 761.20; and, AO 52-216412, AO 52-216413 & AO 52-233149]

A.12. "On-Specification" Used Oil. Before accepting from each marketer the first shipment of on-specification used oil with a PCB concentration above the detectable level, the permittee shall provide each marketer with a one-time written and signed notice certifying that the permittee will burn the used oil in a qualified combustion device. The notice must state that EPA or a RCRA-delegated state agency has been given a description of the used oil management activities at the facility and that an industrial boiler or furnace will be used to burn the used oil with PCB concentrations above the detectable level. The description of the used oil management activities shall be submitted to the Administrator, Hazardous Waste Regulation Section, Florida Department of Environmental Protection, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

[40 CFR 279.61 and 40 CFR 761.20(e)(3)(ii)]

A.13. "On-Specification" Used Oil. Each shipment or on-site generated batch of used oil shall be sampled and analyzed for the constituents listed in specific condition **A.11.** A claim that the used oil does not contain quantifiable levels of PCBs must be documented by analysis or other information. The first person making the claim that the used oil does not contain PCBs is responsible for furnishing the documentation. The documentation can be tests, personal or special knowledge of the source and composition of the used oil, or a certification from the person generating the used oil claiming that the used oil contains no detectable PCBs.

[40 CFR 761.20(e)(2); and, Rule 62-4.070(3), F.A.C.]

Excess Emissions

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS or NESHAP provision.}

A.14. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

A.15. 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.16. 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.17. Sulfur Dioxide. **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.** This protocol is allowed because the emissions unit does not have an operating flue gas desulfurization device. See specific conditions **A.10., A.21. and A.22.**
[Rule 62-296.405(1)(f)1.b., F.A.C.]

A.18. 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.]

Test Methods and Procedures

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

A.19. Visible emissions. The test method for visible emissions shall be:
a. E.U. ID Nos. -001, -002 and -003 EPA Method 9, incorporated in Chapter 62-297, F.A.C.
b. E.U. ID No. -001 Continuous opacity monitor.
[Rule 62-296.702(3)(a), F.A.C.; and, AO 52-233149]

A.20. 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., 62-297.401 and 62-296.702(3)(b), F.A.C.]

A.21. 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.** See specific conditions **A.10. and A.22.**
[Rules 62-213.440, 62-296.405(1)(e)3. and 62-297.401, F.A.C.; and, AO 52-216412, AO 52-216413 & AO 52-233149]

A.22. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition, or ASTM D1552-95 or an equivalent method after Department approval.
[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

A.23. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate

determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

A.24. Operating Rate During Testing. Testing of emissions shall be conducted while firing new No. 6 fuel oil or new No. 6 fuel oil/on-specification used oil with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.; and, AO 52-216412, AO 52-216413 & AO 52-233149]

A.25. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

A.26. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet. **See specific condition A.20.**
(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle

and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.
(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, attached as part of this permit.
(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

A.27. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

A.28. 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.

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 for more than 400 hours other than during startup.

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

a. Did not operate; or

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

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

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

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

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

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

9. The owner or operator shall notify the PCDEM, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the

test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

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

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

A.29. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
[Rule 62-297.310(7)(a)4., F.A.C.]

A.30. Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
[Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

Record keeping and Reporting Requirements

A.31. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the PCDEM in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the PCDEM.
[Rule 62-210.700(6), F.A.C.]

A.32. Submit to the PCDEM 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.33. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the PCDEM on the results of each such test.
(b) The required test report shall be filed with the PCDEM 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 PCDEM to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

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

21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

A.34. Not federally enforceable. Special Recordkeeping Requirements: The owner or operator shall obtain, make, and keep the following records related to the use of used oil:

(1) The gallons of on-specification used oil burned each month. (This record shall be completed no later than the fifteenth day of the succeeding month.)
(2) The total gallons of on-specification used oil burned in the preceding calendar year.
(3) The name and address of all marketers delivering used oil to the facility.
(4) Copies of the marketer certifications, if obtained, and any supporting information.
(5) Documentation that the used oil contains less than 2 ppm PCBs, if claimed, including the name and address of the person making the claim.
(6) Results of the analyses required above.
(7) A copy of the notice to EPA and a copy of the one-time written notice provided to each marketer.

These records shall be recorded in a permanent form suitable for inspection by the PCDEM upon request, and shall be retained for at least a five year period.
[40 CFR 279.61; 40 CFR 761.20(e); and, Rule 62-213.440(1)(b)2.b., F.A.C.]

A.35. The permittee shall include in the "Annual Operating Report for Air Pollutant Emitting Facility" a statement of the total quantity of on-specification used oil fired during the calendar year.
[Rule 62-4.070(3), F.A.C.; and, AO 52-216412, AO 52-216413 & AO 52-233149]

A.36. Compliance with the oil sulfur content and the sulfur dioxide emissions limitations of specific conditions **A.9.** and **A.10.** shall be documented by the permittee through submittal of quarterly reports of the Bartow Plant monthly average fuel oil sulfur content, heat content and the resulting sulfur dioxide emission rate in pounds per million Btu heat input. These quarterly reports shall be submitted to PCDEM within 30 days of the end of each calendar quarter.
[Rule 62-4.070(3), F.A.C.; and, AO 52-216412, AO 52-216413 & AO 52-233149]

A.37. Not Federally Enforceable. Submit to the Air Section of PCDEM each calendar year on or before March 1, a completed "Annual Operating Report for Air Pollutant Emitting Facility" form for the preceding calendar year. Until further notice by the Department the permittee shall calculate particulate matter emissions by multiplying the particulate matter stack test results by the hours of operation. Other annual emissions shall be determined by multiplying the annual fuel use by the following emissions factors:

E.U. ID No. -001

Pollutant	No. 6 fuel oil (lb/1000 gal)
SO_2	157(S)
CO	5
NO_X	67
VOC	0.76

E.U. ID No. -002		
Pollutant	No. 6 fuel oil (lb/1000 gal)	
SO_2	157(S)	
CO	5	
NO_X	42	
VOC	0.76	
E.U. ID No. -003		
Pollutant	No. 6 fuel oil (lb/1000 gal)	Natural Gas (lb/MMcf)
SO_2	157(S)	0.6
CO	5	5
NO_X	42	550
VOC	0.76	1.4

[AO 52-216412, AO 52-216413 & AO 52-233149]

A.38. COMS for Periodic Monitoring. The owner or operator is required to install continuous opacity monitoring systems (COMS) pursuant to 40 CFR Part 75. The owner or operator shall maintain and operate COMS and shall make and maintain records of opacity measured by the COMS, for purposes of periodic monitoring.
[Rule 62-213.440, F.A.C.]

Miscellaneous Requirements

A.39. Process Parameters.

	E.U. ID No. -001	E.U. ID No. -002	E.U. ID No. -003
Heat Input Rate	1,220 MMBtu/hr (maximum)	1,317 MMBtu/hr (maximum)	2,266 MMBtu/hr (maximum)
Fuel	New No. 6 fuel oil with a sulfur content of 2.5%, by weight (maximum) and on-specification used oil with a sulfur content of 2.5%, by weight (maximum)	New No. 6 fuel oil with a sulfur content of 2.5%, by weight (maximum) and on-specification used oil with a sulfur content of 2.5%, by weight (maximum)	New No. 6 fuel oil with a sulfur content of 2.5%, by weight (maximum) and on-specification used oil with a sulfur content of 2.5%, by weight (maximum) (also natural gas when available)
Fuel Firing Rate	7,854 gal/hr (187 BBL/hr) new No. 6 fuel oil and/or on-specification used oil (maximum)	8,778 gal/hr (209 BBL/hr) new No. 6 fuel oil and/or on-specification used oil (maximum)	14,742 gal/hr (351 BBL/hr) new No. 6 fuel oil and/or on-specification used oil, 2.2 MMcf/hr natural gas (maximum)
Ash Content	As sampled	As sampled	As sampled
Steam Temperature	1,000°F	1,000°F	1,000°F
Steam Pressure	1,850 psi	1,850 psi	2,050 psi

Steam Flow Rate	900,000 lb/hr	919,600 lb/hr	1,423,500 lb/hr
Stack Height	300 ft	300 ft	300 ft
Boiler Manufacturer	Babcock & Wilcox	Combustion Engineering	Combustion Engineering
Burner Arrangement	Front fired	Tangential fired	Tangential fired

Inspection and Maintenance Program.

(a) Scheduled during major outages: Boilers, controls, auxiliaries, burners and duct work are to be inspected and repaired as necessary. All parts are to be inspected, cleaned and replaced as necessary.
(b) Scheduled during non-peak load periods in Spring and Fall: This schedule is affected by forced outage requirements.
(c) The following operating parameters are to be continuously monitored and maintained at appropriate levels to produce efficient fuel combustion:

1. fuel flow rate
2. fuel temperature
3. fuel pressure
4. air flow rate
5. steam flow rate
6. steam temperature
7. steam pressure

(d) Plant operators are to monitor, adjust and record the following operating parameters at least once per day to assure efficient plant operation:

1. temperatures (superheat, reheat, and fuel)
2. flows (steam, feed water, and fuel)
3. unit load

(e) Fuel oil quality is to be checked prior to delivery and a daily sample taken each day the facility is operated for a monthly composite analysis. Fuel oil analysis (by ASTM Methods) is to be analyzed for the following:

1. heat content (Btu/gal)
2. sulfur content (%S by weight)
3. density
4. API gravity

Records of inspection, maintenance, and performance parameters shall be retained a minimum of five years and shall be mad available for inspection upon request.
[Rule 62-296.700 (6)(d), F.A.C.; and, AO 52-216412, AO 52-216413 & AO 52-233149]

A.40. E.U. ID No. -001 Operation and Maintenance Plan. The rebuilt General Electric Services, Inc. Model 1-BAB1.2X37(9)36.0-434-4.3P electrostatic precipitator shall be operated and maintained in accordance with the PROGRESS ENERGY FLORIDA BARTOW PLANT UNIT #1 ELECTROSTATIC PRECIPITATOR OPERATION AND MAINTENANCE PLAN dated August 2003 and on file with the Department. The O&M Plan documentation logs shall be maintained for a minimum of five years and made available for inspection upon request. At a minimum, the O&M Plan shall include:

1. The operating parameters of the control device.
2. A timetable of routine weekly, bi-weekly, or monthly observations of the pollution control device.

3. A list of the type and quantity of the required spare parts which are stored on the premises for the pollution control device.
4. A record log which shows at a minimum when maintenance was performed, what maintenance was performed, and by whom.

[Rule 62-296.700(6), F.A.C.; and, Pinellas County Code, Section 58-128]

A.41. PSD Applicability Report: The permittee shall maintain information demonstrating that the project (1030011-007-AC) did not result in any significant net emissions increase of particulate matter, which is defined in Rule 62-212.400(2)(e), F.A.C., as follows:

Net Emissions Increase. A modification to a facility results in a net emissions increase when, for a pollutant regulated under the Act, the sum of all of the contemporaneous creditable increases and decreases in the actual emissions of the facility, including the increase in emissions of the modification itself and any increases and decreases in quantifiable fugitive emissions, is greater than zero.

Significant Net Emissions Increase. A significant net emissions increase of a pollutant regulated under the Act is a net emissions increase equal to or greater than the applicable significant emission rate listed in Table 212.400-2, Regulated Air Pollutants – Significant Emission Rates.

The permittee shall submit an annual report to the Department of such information for a period of 5 years representative of normal post-change operations of the unit (within the period not longer than 10 years following the change). For an existing electric utility steam-generating unit, actual emissions of the unit following a physical or operational change shall equal the representative actual annual emissions of the unit following the physical or operational change. The following definition of "representative actual annual emissions" found in 40 CFR 52.21(b)(33) is adopted and incorporated by reference in Rule 62-204.800, F.A.C.

Representative actual annual emissions means the average rate, in tons per year, at which the source is projected to emit a pollutant for the two-year period after a physical change or change in the method of operation of a unit, (or a different consecutive two-year period within 10 years after that change, where the Administrator determines that such period is more representative of normal source operations), considering the effect any such change will have on increasing or decreasing the hourly emissions rate and on projected capacity utilization. In projecting future emissions the Administrator shall:

(i) Consider all relevant information, including but not limited to, historical operational data, the company's own representations, filings with the State or Federal regulatory authorities, and compliance plans under title IV of the Clean Air Act; and

(ii) Exclude, in calculating any increase in emissions that results from the particular physical change or change in the method of operation at an electric utility steam generating unit, that portion of the unit's emissions following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole.

Each required annual report shall be submitted to the Department prior to March 1st and shall quantify operations for the previous calendar year(s).

[1030011-007-AC]

Section III. Emissions Unit(s) and Conditions.

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

E.U. ID No.	Brief Description
-004	Bartow-Anclote Pipeline Heating Boiler

The Bartow-Anclote Pipeline Heating Boiler is used to heat fuel oil being transferred from the Bartow Plant to the Anclote Plant. The boiler's maximum heat input rate is 15.5 million Btu per hour firing natural gas, No. 2 fuel oil, or propane. Emissions from the boiler are uncontrolled.

{Permitting note(s): The emissions unit is regulated under Rule 62-296.406, F.A.C., Fossil Fuel Steam Generators with Less than 250 million Btu per Hour Heat Input}

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

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. The maximum operation heat input rate is 15.5 million Btu per hour. [Rules 62-4.160(2), 62-210.200(PTE) and 62-296.406, F.A.C.]

{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.}

B.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **B.16.** [Rule 62-297.310(2), F.A.C.]

B.3. Methods of Operation. Fuels. This boiler is permitted to fire only the following fuels and at the maximum rates shown:

Fuel	Maximum % Sulfur	Maximum MMBtu/hr	Maximum Fuel Usage
Natural Gas	- -	15.5	15 Mcf/hr
No. 2 Fuel Oil*	0.5% by weight	15.5	110 gal/hr
Propane	- -	15.5	191 gal/hr

* New No. 2 fuel oil only (waste or recycled oil is not allowed)
[Rule 62-213.410, F.A.C.; and, AO 52-244478]

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

Emission Limitations and Standards

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

{Permitting Note: Unless otherwise specified, the averaging times for Specific Conditions **B.5.**-**B.6.** are based on the specified averaging time of the applicable test method.}

B.5. Visible Emissions. Visible emissions shall not exceed 20 percent opacity, except for one two-minute period per hour during which opacity shall not exceed 40 percent.
[Rule 62-296.406(1), F.A.C.; and, AO 52-244478]

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

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

Visible emissions above 60 percent opacity shall be allowed for not more than 4, six (6) minute periods, during the 3-hour period of excess emissions allowed by the subparagraph, for boiler cleaning or load changes, at units which have installed and are operating, or have committed to install and operate, continuous opacity monitors.
[Rule 62-210.700(3), F.A.C.]

B.7. Sulfur Dioxide - Sulfur Content. The new No. 2 fuel oil sulfur content shall not exceed 0.5 percent, by weight. See specific condition **B.15.**
[Rule 62-296.406(3), F.A.C.; and, AO 52-244478]

Excess Emissions

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS or NESHAP provision.}

B.8. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

B.9. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

B.10. 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.11. 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.]

Test Methods and Procedures

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

B.12. Visible emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. See specific condition **B.13.**
[Rules 62-213.440 and 62-297.401, F.A.C.]

B.13. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.
2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards

(e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:

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

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

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

B.14. Sulfur Dioxide. **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.** This protocol is allowed because the emissions unit does not have an operating flue gas desulfurization device. See specific conditions **B.7.** and **B.15.**
[Rule 62-296.406(3), F.A.C.]

B.15. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition, or ASTM D1552-95 or an equivalent method after Department approval.
[Rules 62-213.440 and 62-297.440, F.A.C.]

B.16. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

B.17. Applicable Test Procedures.

(a) Required Sampling Time.

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

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate

matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

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

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

B.18. 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.

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 for more than 400 hours other than during startup.

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

a. Did not operate; or

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

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

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

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

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

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

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

(b) Special Compliance Tests. When the PCDEM, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the

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

B.19. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
[Rule 62-297.310(7)(a)4., F.A.C.]

B.20. Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
[Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

Record keeping and Reporting Requirements

B.21. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify PCDEM in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by PCDEM.
[Rule 62-210.700(6), F.A.C.]

B.22. All recorded data shall be maintained on file by the Source for a period of five years.
[Rule 62-213.440, F.A.C.]

B.23. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the PCDEM on the results of each such test.
(b) The required test report shall be filed with the PCDEM 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 PCDEM to determine if the test was properly conducted and the test

results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

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

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

Section III. Emissions Unit(s) and Conditions.

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

E.U. ID No.	Brief Description
-005	Gas Turbine Peaking Unit #P-1
-006	Gas Turbine Peaking Unit #P-2
-007	Gas Turbine Peaking Unit #P-3
-008	Gas Turbine Peaking Unit #P-4

The four gas turbines are natural gas and/or No. 2 fuel oil fired combustion turbines manufactured by General Electric (model number MS7000) and are designated as Gas Turbine Peaking Units #P-1, #P-2, #P-3 and #P-4. The manufacturers fuel flow and heat input ratings for each turbine are 5,174 gallons per hour of No. 2 fuel oil, or 714 million cubic feet per hour of natural gas (corresponds to approximately 714 million Btu per hour , at 59 degrees F). The actual heat input rate of the turbine is a function of the ambient temperature. These combustion turbines are used as peaking units during peak demand times to run a nominal 56 MW generator (each). Emissions from the combustion turbines are uncontrolled.

{Permitting notes: These emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required. These emissions units are not subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. Each combustion turbine has its own stack. Each combustion turbine began commercial operation in 1972.}

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	MMBtu/hr Heat Input	Fuel Type
P-1	714	Natural Gas
	714	No. 2 Fuel Oil
P-2	714	Natural Gas
	714	No. 2 Fuel Oil
P-3	714	Natural Gas
	714	No. 2 Fuel Oil
P-4	714	Natural Gas
	714	No. 2 Fuel Oil

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

{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.}

C.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **C.13.** [Rule 62-297.310(2), F.A.C.]

C.3. Methods of Operation - Fuels. Only natural gas and/or new No. 2 fuel oil shall be fired in the combustion turbines. New No. 2 fuel oil is defined as fuel oil that has been refined from crude oil and has not been used and which may or may not contain additives.
[Rule 62-213.410(1), F.A.C.; and, AO 52-253215A, AO 52-253216A, AO 52-253217A, and AO 52-253218A]

C.4. Hours of Operation. These emissions units may operate continuously, i.e., 8,760 hours/year.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, AO 52-253215A, AO 52-253216A, AO 52-253217A, and AO 52-253218A]

Emission Limitations and Standards

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

{Permitting Note: Unless otherwise specified, the averaging time for Specific Condition **C.5.** is based on the specified averaging time of the applicable test method.}

C.5. Visible Emissions. Visible emissions from each turbine shall not be equal to or greater than 20 percent opacity.
[Rule 62-296.320(4)(b)1., F.A.C.; and, AO 52-253215A, AO 52-253216A, AO 52-253217A, and AO 52-253218A]

C.6. Not federally enforceable. Sulfur Dioxide - Sulfur Content. The sulfur content of the No. 2 fuel oil shall not exceed 0.5 percent, by weight.
[AO 52-253215A, AO 52-253216A, AO 52-253217A, and AO 52-253218A]

Excess Emissions

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS or NESHAP provision.}

C.7. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by PCDEM for longer duration.
[Rule 62-210.700(1), F.A.C.]

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

Monitoring of Operations

C.9. Not federally enforceable. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis provided by the vendor upon each fuel delivery. See specific condition **C.12.**
[Rule 62-213.440, F.A.C.]

C.10. 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.]

Test Methods and Procedures

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

C.11. The test method for visible emissions shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C.
[Rules 62-204.800, 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.]

C.12. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or latest edition, or ASTM D1552-95 or an equivalent method after Department approval.
[Rules 62-213.440 and 62-297.440, F.A.C.]

C.13. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100

percent of the peak heat input rate based on the average turbine inlet temperature during the test. The peak heat input rate is defined by a graph of Fuel Heat Input verses Ambient Temperature for each gas turbine. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity (i.e., at less than 90 percent of the maximum operation rate allowed by the permit); in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted, provided however, operations do not exceed 100 percent of the maximum operation rate allowed by the permit. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2), F.A.C.; and, AO 52-253215A, AO 52-253216A, AO 52-253217A, and AO 52-253218A]

C.14. Applicable Test Procedures.
(a) Required Sampling Time.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
[Rule 62-297.310(4)(a)2.c., F.A.C.]

C.15. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
a. Did not operate; or
b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
a. Visible emissions, if there is an applicable standard;
b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead

compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

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

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

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

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

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

C.16. Visible Emissions Testing - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:

a. only gaseous fuels; or

b. gaseous fuels in combination with any amount of liquid fuels for less than 400 hours per year; or

c. only liquid fuels for less than 400 hours per year.

[Rules 62-297.310(7)(a)4. & 8., F.A.C.]

Recordkeeping and Reporting Requirements

C.17. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the PCDEM in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.

[Rule 62-210.700(6), F.A.C.]

C.18. Test Reports.

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

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

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

C.19. Not Federally Enforceable. Operating Reports. The annual operating report shall be based on the following:
(a) The Btu heating value, sulfur content (percent by weight), API gravity and density of the fuel being fired in the peaking units, shall be based on a weighted 12-month average (calendar year) and be calculated from the fuel delivery receipts and the vendors fuel oil analysis.
(b) Until further notice by the PCDEM, Progress Energy Florida shall calculate annual emissions (pounds per hour and tons per year), for the Annual Operating Report, by multiplying the total million Btu from fuel usage by the following emissions factors:

	Emissions Factors for No. 2 Fuel Oil Pound per MMBtu
Particulate Matter (PM)	0.061 (Total)
PM_{10}	0.48 PM
Carbon Monoxide	0.048
Sulfur Dioxide	1.01(S)
Nitrogen Oxides	0.698
Hydrocarbons (TOC)	0.017

"S" denotes sulfur content, percent by weight. The sulfur dioxide emissions shall be based on a weighted 12-month average "S" value.
[AO 52-253215A, AO 52-253216A, AO 52-253217A, and AO 52-253218A]

Section III. Emissions Unit(s) and Conditions.

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

Facility ID No.	E.U. ID No.	Brief Description
7775047	-001	Relocatable diesel generator(s) will have a maximum (combined) heat input of 25.74 MMBtu/hour while being fueled by 186.3 gallons of new No. 2 fuel oil per hour with a maximum (combined) rating of 2460 kilowatts. Emissions from the generator(s) are uncontrolled.

The generators may be relocated to any of the following facilities:

1. Crystal River Plant, Powerline Road, Red Level, Citrus County.
2. Bartow Plant, Weedon Island, St. Petersburg, Pinellas County.
3. Higgins Plant, Shore Drive, Oldsmar, Pinellas County.
4. Bayboro Plant, 13th Ave. & 2nd St. South, St. Petersburg, Pinellas County.
5. Wildwood Reclamation Facility, State Road 462, 1 mi. east of U.S. 301, Wildwood, Sumter County.
6. Hines Energy Complex, County Road 555, 1 mi. southwest of Homeland, Polk County.
7. Anclote Power Plant, 1729 Baileys Road, Holiday, Pasco County

{Permitting notes: These emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required. Each generator has its own stack. This section of the permit is only applicable when the generator(s) is (are) located at the Bartow Facility.}

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

Essential Potential to Emit (PTE) Parameters

D.1. Permitted Capacity. The maximum (combined) heat input rate shall not exceed 25.74 million Btu per hour.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

D.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **D.12.**
[Rule 62-297.310(2), F.A.C.]

D.3. Methods of Operation - Fuels. Only new No. 2 fuel oil with a maximum sulfur content of 0.5%, by weight, shall be fired in the diesel generator(s).
[Rule 62-213.410, F.A.C.; and, AC 09-202080.]

D.4. Hours of Operation. The hours of operation expressed as "engine-hours" shall not exceed 2970 hours in any consecutive 12 month period. The total hours of operation expressed as "engine-hours" shall be the summation of the individual hours of operation of each generator. [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, AC 09-202080.]

Emission Limitations and Standards

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

{Permitting Note: Unless otherwise specified, the averaging time for specific condition **D.5.** is based on the specified averaging time of the applicable test method.}

D.5. Visible Emissions. Visible emissions from each generator shall not be equal to or greater than 20 percent opacity.
[Rule 62-296.320(4)(b)1., F.A.C.; and, AC 09-202080.]

Excess Emissions

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS or NESHAP provision.}

D.6. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

D.7. 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

D.8. Fuel Sulfur Analysis. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis provided by the vendor or permittee upon each fuel delivery. See specific conditions **D.3.** and **D.11.**
[Rule 62-213.440, F.A.C.]

D.9. 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.]

Test Methods and Procedures

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

D.10. The test method for visible emissions shall be EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C.
[Rules 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.]

D.11. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-94, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-95, or the latest edition(s), or ASTM D1552-95 or an equivalent method after Department approval.
[Rules 62-213.440 and 62-297.440, F.A.C.]

D.12. Operating Rate During Testing. Testing of emissions shall be conducted with the generator(s) operating at 90 to 100 percent of the maximum fuel firing rate for each generator. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity (i.e., at less than 90 percent of the maximum operation rate allowed by the permit); in this case, subsequent emissions unit operations may be limited to 110 percent of the test load until a new test is conducted, provided however, operations do not exceed 100 percent of the maximum operation rate allowed by the permit. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Failure to submit the actual operating rate may invalidate the test.
[Rules 62-297.310(2), F.A.C.; and, AC 09-202080.]

D.13. Applicable Test Procedures.
(a) Required Sampling Time.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

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

[Rule 62-297.310(4)(a)2.c., F.A.C.]

D.14. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

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

a. Did not operate; or

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

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

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

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. For each generator located in Pinellas County, FPC shall provide the same notification to the Air Quality Division of the PCDEM.

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

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

[Rule 62-297.310(7), F.A.C.; SIP approved; and, AO 09-205952.]

D.15. Visible Emissions Testing - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning liquid fuels for less than 400 hours per year.
[Rules 62-297.310(7)(a)4. & 8., F.A.C.]

D.16. After each relocation, each generator shall be tested within 30 days of startup for opacity and the fuel shall be analyzed for the sulfur content. See specific conditions **D.3.**, **D.5.**, and **D.8.**
[Rules 62-4.070(3) and 62-297.310(7)(b),F.A.C.; and, AO 09-205952.]

Recordkeeping and Reporting Requirements

D.17. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, the owner or operator shall notify PCDEM, if a generator is located in Pinellas County, in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the PCDEM.
[Rule 62-210.700(6), F.A.C.]

D.18. Test Reports.
(a) Each generator shall be tested on an annual basis within 30 days of the date October 25.
(b) 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.
(c) The required test report shall be filed with the Southwest District Office and the Air Quality Division of the Pinellas County Department of Environmental Management, if a generator is located in Pinellas County, as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(d) The test reports for a unit that has been relocated shall be submitted to the Southwest District Office and the Air Quality Division of the PCDEM, if a generator is located in Pinellas County, within 45 days of testing.
[Rule 62-297.310(8), F.A.C.; and, AO 09-25952.]

D.19. To demonstrate compliance with specific condition **D.4.**, records shall indicate the daily hours of operation for each of the generators, the daily hours of operation expressed as "engine-hours" and the cumulative total hours of operation expressed as "engine-hours" for each month. The records shall be maintained for a minimum of 5 years and made available to the Southwest District Office and the Air Quality Division of the PCDEM upon request.
[Rules 62-213.440 and 62-297.310(8), F.A.C.; and, AO 09-205952.]

D.20. To demonstrate compliance with specific condition **D.3.**, records of the sulfur content, in percent by weight, of all the fuel burned shall be kept based on either vendor provided as-delivered or as-received fuel sample analysis. The records shall be maintained for a minimum of 5 years and made available to the Southwest District Office and the Air Quality Division of the PCDEM upon request.
[Rule 62-297.310(8), F.A.C.; and, AC 09-202080.]

Source Obligation

D.21. Specific conditions in construction permit AC 09-202080, limiting the "engine hours", were accepted by the applicant to escape Prevention of Significant Deterioration new source review. If Progress Energy Florida requests a relaxation of any of the federally enforceable emission limits in this permit, the relaxation of limits may be subject to the preconstruction review requirements of Rule 62-212.400(5), F.A.C., as though construction had not yet begun. [Rule 62-212.400(2)(g), F.A.C.; and, AC 09-202080.]

D.22. Progress Energy Florida shall notify the Department's Southwest District Office, in writing, at least 15 days prior to the date on which any diesel generator is to be relocated. The notification shall specify the following;

a. which generator, by serial number, is being relocated,
b. which location the generator is being relocated from and which location it is being relocated to, and
c. the approximate startup date at the new location.

If a diesel generator is to be relocated within Pinellas County, then Progress Energy Florida shall provide the same notification to the Air Quality Division of the PCDEM.
[Rule 62-4.070(3), F.A.C.; and, AC 09-202080]

Section IV. This section is the Acid Rain Part.

Operated by: Progress Energy Florida
ORIS code: 634

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

E.U. ID No.	Brief Description
-001	No. 1 Unit, Fossil Fuel Fired Steam Generator with Electrostatic Precipitator
-002	No. 2 Unit, Fossil Fuel Fired Steam Generator
-003	No. 3 Unit, Fossil Fuel Fired Steam Generator

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

a. DEP Form No. 62-210.900(1)(a), dated December 22, 1995

[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

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

E.U. ID No.	EPA ID	Year	2005	2006	2007	2008	2009
-001	01	**SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73**	2805*	2805*	2805*	2805*	2805*
-002	02	**SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73**	2961*	2961*	2961*	2961*	2961*
-003	03	**SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73**	5428*	5428*	5428*	5428*	5428*

*The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the USEPA under Table 2 or 3 of 40 CFR 73.

A.3. Emission Allowances. Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.
1. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.
2. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.
3. Allowances shall be accounted for under the Federal Acid Rain Program.
[Rule 62-213.440(1)(c), F.A.C.]

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

A.5. Where an applicable requirement of the Act is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator.
[40 CFR 70.6(a)(1)(ii); and, Rule 62-210.200, Definitions - Applicable Requirements, F.A.C.]

A.6. Comments, notes, and justifications: none

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

Progress Energy Florida
P. L. Bartow Plant

FINAL Permit No.: 1030011-009-AV
Facility ID No.: 1030011

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. Water Laboratory solvent use and hood-chemical analyses for water
2. Water Laboratory flammable chemical storage cabinet
3. General Boiler Building fire protection equipment
4. Flammable liquid cabinets – Site wide
5. Plant and South Terminal – Fire suppression foam
6. Site utilization of sand blasters, drill presses, welding machines, lathes, hand-held tools, etc.
7. Large equipment outdoor sandblasting
8. Steam release during boiler blow-downs
9. General Site surface coating <6.0 gallons per day
10. General Site brazing, soldering and welding
11. Unit 1 Fly Ash Handling System
12. Lawn mowing and landscaping activities
13. Use of solvents
14. Painting and painting related cleanup
15. Use of products in the aerosol form
16. Use of small, portable generators and pumps
17. Pressure washing of machinery and buildings
18. Earth moving activities

Appendix H-1: Permit History

Progress Energy Florida
P. L. Bartow Plant

FINAL Permit No.: 1030011-009-AV
Facility ID No.: 1030011

E.U. ID No.	Description	Permit No.	Effective Date	Expiration Date	Project Type [1]
All	Facility	1030011-002-AV	01/01/2000	12/31/2004	Initial
-001	No. 1 Unit, Fossil Fuel Fired Steam Generator with Electrostatic Precipitator	1030011-005-AC	09/04/1998	09/04/2003	Construction (mod.)
-001	No. 1 Unit, Fossil Fuel Fired Steam Generator with Electrostatic Precipitator	1030011-006-AC	12/29/1999	12/29/2004	Construction (mod.)
-001	No. 1 Unit, Fossil Fuel Fired Steam Generator with Electrostatic Precipitator	1030011-007-AC	10/28/2002	05/01/2003	Construction (mod.)
-001	No. 1 Unit, Fossil Fuel Fired Steam Generator with Electrostatic Precipitator	1030011-008-AV	03/11/2004	12/31/2004	Revision

[1] Project Type (select one): Title V: Initial, Revision, Renewal, or Admin. Correction; Construction (new or mod.); or, Extension (AC only).
[2] Change to an actual date, which is day 55 from the date of posting the PROPOSED Permit for EPA review (see confirmation e-mail from Tallahassee) or the date that EPA confirms resolvement of any objections.

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

Progress Energy Florida
P. L. Bartow Plant

FINAL Permit No.: 1030011-009-AV
Facility ID No.: 1030011

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

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

E.U. ID No.	Brief Description of Emissions Units and/or Activity
001	Fuel Storage - Tank No. #1 (7) N. Terminal - 6,354,768 gallons No. 6 fuel oil
002	Fuel Storage - Tank No. #2 (8) N. Terminal– 6,369,342 gallons No. 6 fuel oil
003	Fuel Storage - Tank No. #3 (9) N. Terminal– 6,329, 232 gallons No. 6 fuel oil
004	Fuel Storage - Tank No. #4(10) N. Terminal– 8,447,544 gallons No. 6 fuel oil
005	Fuel Storage - Tank No. #6(11) N. Terminal - 4,118,142 gallons No. 2 fuel oil
006	Fuel Storage - Tank No. #T1(12) S. Terminal– 10,540,740 gallons No. 6 fuel oil
007	Fuel Storage - Tank No. #T2(13) S. Terminal– 10,542,294 gallons No. 6 fuel oil
008	Fuel Storage (1R1) - 1,008 gallons unleaded gasoline
009	Fuel Storage (6) - 550 gallons diesel - vehicle
010	Fuel Storage - Tank No. #12 - 300 gallons diesel - emergency fire pump
011	Tank No. #13 - 300 gallons diesel - emergency generator
012	Tank No. #16 - 5,460 gallons magnesium hydroxide fuel additive
013	Tank No. FOA - 6,100 gallons calcium nitrate fuel additive
014	Gas Turbine 1, 2, 3, and 4 - Lube oil vent with demister
015	Gas Turbine 1, 2, 3, and 4 - Underground 2,600 gallon lube oil storage tank
016	Gas Turbine 1 (2R1), 2 (3R1), 3 (4R1), and 4 (5R1) – 2,000 gallon waste oil storage tank
017	General Site - Two, 500 gallon propane gas tanks for Unit 2 and 3 ignitors

(#) = DEP assigned tank number

Table 1-1, Summary of Air Pollutant Standards and Terms

Progress Energy Florida
Bartow Plant

FINAL Permit No.: 1030011-009-AV
Facility ID No.: 1030011

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]	No. 1 Unit, Fossil Fuel Fired Steam Generator with Electrostatic Precipitator
[-002]	No. 2 Unit, Fossil Fuel Fired Steam Generator
[-003]	No. 3 Unit, Fossil Fuel Fired Steam Generator

			Allowable Emissions			Equivalent Emissions*			
Pollutant Name	Fuel(s)	Hours/Year	Standard(s)	lbs./hour	TPY	lbs./hour	TPY	Regulatory Citation(s)	See permit condition(s)
PM [EU-001]	All	8,760	0.1 lb/MMBtu	122.0	534.4			Rules 62-296.405(1)(b), 62-296.700(4)(b) & 62-296.702(2)(a)	A.7.
PM [EU-002]	All	8,760	0.1 lb/MMBtu	131.7	576.9			Rules 62-296.405(1)(b), 62-296.700(4)(b) & 62-296.702(2)(a)	A.7.
PM [EU-003]	All	8,760	0.1 lb/MMBtu	221.1	968.6			Rules 62-296.405(1)(b), 62-296.700(4)(b) & 62-296.702(2)(a)	A.7.
PM [EU-001]	All	8,760	0.3 lb/MMBtu	366.0				Rules 62-210.700(3) & 62-296.700(4)(b)	A.8.
PM [EU-002]	All	8,760	0.3 lb/MMBtu	395.1				Rules 62-210.700(3) & 62-296.700(4)(b)	A.8.
PM [EU-003]	All	8,760	0.3 lb/MMBtu	663.3				Rules 62-210.700(3) & 62-296.700(4)(b)	A.8.
SO_2 [EU-001]	Liquid	8,760	2.75 lb/MMBtu			3,355.0	14,694.9	Rule 62-296.405(1)(c)1.j.	A9.
SO_2 [EU-002]	Liquid	8,760	2.75 lb/MMBtu			3,621.75	15,863.28	Rule 62-296.405(1)(c)1.j.	A9.
SO_2 [EU-003]	Liquid	8,760	2.75 lb/MMBtu			6,080.25	26,631.5	Rule 62-296.405(1)(c)1.j.	A9.
SO_2	Liquid	8,760	2.5% by weight sulfur					Rule 62-296.405(1)(e)3.	A10.
VE	All	8,760	40% opacity					Rule 62-296.405(1)(a) & OGC Orders 86-1577 & 87-1261	A.5.
VE	All	3 hr/24 hr	60% opacity					Rule 62-210.700(3)	A.6.

Notes:
* The "Equivalent Emissions" listed are for informational purposes only.

[electronic file name: 10300111.xls]

Table 1-1, Summary of Air Pollutant Standards and Terms

Progress Energy Florida
Bartow Plant

FINAL Permit No.: 1030011-009-AV
Facility ID No.: 1030011

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]	Bartow-Anclote Pipeline Heating Boiler

			Allowable Emissions			Equivalent Emissions*			
Pollutant Name	Fuel(s)	Hours/Year	Standard(s)	lbs./hour	TPY	lbs./hour	TPY	Regulatory Citation(s)	See permit condition(s)
SO_2	Liquid	8,760	0.5% by weight sulfur			8.52	37.34	Rule 62-296.406(3)	B.7.
VE	All	8,760	20% except 40% 2 min/hr					Rule 62-296.406(1)	B.5.
VE	All	3 hr/24 hr	60% opacity					Rule 62-210.700(3)	B.6.

Notes:
* The "Equivalent Emissions" listed are for informational purposes only.

[electronic file name: 10300111.xls]

Table 1-1, Summary of Air Pollutant Standards and Terms

Progress Energy Florida
Bartow Plant

FINAL Permit No.: 1030011-009-AV
Facility ID No.: 1030011

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
[-005]	Gas Turbine Peaking Unit #P-1
[-006]	Gas Turbine Peaking Unit #P-2
[-007]	Gas Turbine Peaking Unit #P-3
[-008]	Gas Turbine Peaking Unit #P-4

			Allowable Emissions			Equivalent Emissions*			
Pollutant Name	Fuel(s)	Hours/Year	Standard(s)	lbs./hour	TPY	lbs./hour	TPY	Regulatory Citation(s)	See permit condition(s)
SO_2	Liquid	8,760	0.5% by weight sulfur			392.7	1,720.0	AO52-253215A, 253216A, 253217A & 253218A	C.6.
VE	All	8,760	20% opacity					Rule 62-296.320(4)(b)1.	C.5.

Notes:
* The "Equivalent Emissions" listed are for informational purposes only.

[electronic file name: 10300111.xls]

Table 1-1, Summary of Air Pollutant Standards and Terms

Progress Energy Florida
Bartow Plant

FINAL Permit No.: 1030011-009-AV
Facility ID No.: 1030011

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
[-xxx]	Relocatable Diesel Fired Generator(s)

			Allowable Emissions			Equivalent Emissions*			
Pollutant Name	Fuel(s)	Hours/Year	Standard(s)	lbs./hour	TPY	lbs./hour	TPY	Regulatory Citation(s)	See permit condition(s)
SO_2	Liquid	2,970	0.5% by weight Sulfur			14.16	21.02	Applicant request & AC09-202080	D.4. & D.6.
VE	All	2,970	20% opacity					Applicant request & AO09-205952	D.5.

Notes:
* The "Equivalent Emissions" listed are for informational purposes only.

[electronic file name: 10300111.xls]

Table 2-1, Summary of Compliance Requirements

Progress Energy Florida
Bartow Plant

FINAL Permit No.: 1030011-009-AV
Facility ID No.: 1030011

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]	No. 1 Unit, Fossil Fuel Fired Steam Generator with Electrostatic Precipitator
[-002]	No. 2 Unit, Fossil Fuel Fired Steam Generator
[-003]	No. 3 Unit, Fossil Fuel Fired Steam Generator

Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS**	See permit condition(s)
VE EU[-001]	All	EPA Method 9	Annual***	3/16 & 9/16	60 min	Yes	A.19., A.29.and A.30.
VE EU[-002 & -003]	All	EPA Method 9	Annual	5/28 & 4/28	60 min		A.19.and A.30.
PM EU[-001]	All	EPA Method 17, 5, 5B or 5F	Annual***	3/16 & 9/16	1 hr		A.20., A.29.and A.31.
PM EU[-002 & -003]	All	EPA Method 17, 5, 5B or 5F	Annual	5/28 & 4/28	1 hr		A.20.and A.31.
SO_2	Liquid	EPA Method 6, 6A, 6B, or 6C; or fuel analysis	Annual	w/ PM test	1 hr		A.21.and A.22.
Used oil	On-specification	EPA SW-846	each batch				A.11., A.12., A.13., & 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
*** Changed from 6 months to annual based on Administrative Order RTF No. 96-A-01 dated Feb. 10, 1997

Table 2-1, Summary of Compliance Requirements

Progress Energy Florida
Bartow Plant

FINAL Permit No.: 1030011-009-AV
Facility ID No.: 1030011

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]	Bartow-Anclote Pipeline Heating Boiler

Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS**	See permit condition(s)
VE	All	DEP Method 9	Annual	31-May	30 min		**B.12., B.13 and B.19.**
SO_2	Liquid	ASTM Methods	each delivery				**B.14. & B.15.**

Notes:
* The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
**CMS [=] continuous monitoring system

[electronic file name: 10300112.xls]

Table 2-1, Summary of Compliance Requirements

Progress Energy Florida
Bartow Plant

FINAL Permit No.: 1030011-009-AV
Facility ID No.: 1030011

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
[-005]	Gas Turbine Peaking Unit #P-1
[-006]	Gas Turbine Peaking Unit #P-2
[-007]	Gas Turbine Peaking Unit #P-3
[-008]	Gas Turbine Peaking Unit #P-4

Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS**	See permit condition(s)
VE	All	EPA Method 9	Annual	1-Feb	30 min		C.11. & C.16.
SO_2	Liquid	ASTM Methods	each delivery				C.12.

Notes:
* The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
**CMS [=] continuous monitoring system

[electronic file name: 10300112.xls]

Table 2-1, Summary of Compliance Requirements

Progress Energy Florida
Bartow Plant

FINAL Permit No.: 1030011-009-AV
Facility ID No.: 1030011

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
[-xxx]	Relocatable Diesel Fired Generator(s)

Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS**	See permit condition(s)
VE		EPA Method 9	Annual	30 days from startup	30 min		D.11.
SO_2	Liquid	ASTM Methods	each delivery				D.12.

Notes:
* The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
**CMS [=] continuous monitoring system

[electronic file name: 10300112.xls]

Acid Rain Part Application

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

This submission is: Renewal

STEP 1
Identify the source by plant name, State, and ORIS code

Plant Name	Bartow	State	FL	ORIS Code	634

STEP 2

Enter the unit ID# for every Acid Rain unit at the Acid Rain source in column "a." For new units, enter the requested information in columns "c" and "d."

a Unit ID#	b Unit will hold allowances in accordance with 40 CFR 72.9(b)(1)	c New Units Commence Operation Date	d New Units Monitor Certification Deadline
1	Yes	No	
2	Yes	No	
3	Yes	No	
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		
	Yes		

Bartow
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 Department 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 Department; 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.

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 Department:
(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,

Bartow
Plant Name (from Step 1)

STEP 3, Cont'd.

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, 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

Read the certification statement, sign, and date

Certification

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	J. Michael Kennedy Q.E.P.	
Signature	J. Michael Kennedy	Date 4/26/04

THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

In the matter of:	)	
	)	
Petition for Reduction in Quarterly Particulate Emissions Compliance Testing	)	OGC File No. 87-1261
	)	
FLORIDA POWER CORPORATION, Bartow Unit 2,	)	
	)	
Petitioner	)	
	)	

ORDER

On May 4, 1987, the Petitioner, Florida Power Corporation, filed a Petition for Reduction in the Frequency of Particulate Matter Emissions Compliance Testing pursuant to Florida Administrative Code Rule 17-2.600(5)(b)1. for the following fossil fuel-fired steam generating unit:

BARTOW UNIT 2

Pursuant to Florida Administrative Code Rule 17-2.600(5)(b)1., Petitioner has conducted semi-annual particulate matter emissions compliance tests. Florida Administrative Code Rule 17-2.600(5)(b)1. provides that the Department may reduce the frequency of particulate matter testing upon a demonstration that the particulate matter standard of 0.1 pounds per million Btu heat input has been regularly met. The petition and supporting documentation submitted by Petitioner indicate that, since December 21, 1982, Petitioner has regularly met the particulate matter standard. It is therefore,

ORDERED that the Petition for Reduction in the Frequency of Particulate Matter Emissions Compliance Testing is GRANTED, and that:

1. Petitioner's generating unit Bartow Unit 2 shall be

required to conduct one steady-state particulate matter emissions compliance test annually and one particulate matter emissions compliance test annually under soot blowing conditions.

2. Bartow Unit 2 shall be subject to a steady-state visible emissions limiting standard of forty (40) percent opacity (number 2 of the Ringlemann Chart).

3. This order supercedes all conflicting conditions relating to frequency of particulate matter emissions compliance testing contained in operating permit A052-56650 for Bartow Unit 2.

4. The Department, or its designee, if after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emissions standard in Chapter 17-2 or in a permit issued pursuant to Chapter 17-2 is being violated, may require additional tests for particulate matter emissions pursuant to Florida Administrative Code Rule 17-2.700(2)(b).

Persons whose substantial interests are affected by the Department's above proposed agency action may petition for an administrative determination (hearing) in accordance with Section 120.57, Florida Statutes. The petition must conform to the requirements of Chapters 17-103 and 28-5, Florida Administrative Code, and must be filed (received) in the Department's Office of General Counsel, 2600 Blair Stone Road, Tallahasse, Florida 32399-2400, within twenty-one (21) days of publication of this notice. Failure to file a petition within the twenty-one (21) days constitutes a waiver of any right such person has to an administrative determination (hearing) pursuant to Section

120.57, Florida Statutes.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the proposed agency action. Therefore, persons who may not desire to file a petition may want to intervene in the proceeding. A petition for intervention must be filed pursuant to Rule 28-5.207, Florida Administrative Code, at least five (5) days before the final hearing and must be filed with the Hearing Officer if one has been assigned, at the Division of Administrative Hearings, Department of Administration, 2009 Apalachee Parkway, Tallahassee, Florida 32301. If no Hearing Officer has been assigned, the petition is to be filed with the Department's Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Failure to petition to intervene within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, Florida Statutes.

DONE AND ORDERED this 12th day of October, 1987, in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION

DALE TWACHTMANN
Secretary

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(904) 488-4805

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

Clerk

10-13-87
Date

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

In the Matter of: Petition for Reduction in Semiannual Particulate Emissions Compliance Testing, Bartow Unit No. 3; Florida Power Corporation Petitioner.	)	OGC File No. 86-1577

ORDER

On February 18, 1986, the Petitioner, Florida Power Corporation, filed a Petition for Reduction in the Frequency of Particulate Emissions Compliance Testing pursuant to Florida Administrative Code Rule 17-2.600(5)(b)1. for the following fossil fuel steam generating unit:

Bartow Unit No. 3

Pursuant to Florida Administrative Code Rule 17-2.600(5)(b)1., and by Order dated November 7, 1982, Petitioner has conducted semiannual particulate emission compliance tests. Florida Administrative Code Rule 17-2.600(5)(b)1. provides that the Department may reduce the frequency of particulate testing upon a demonstration that the particulate standard of 0.1 pound per million Btu heat input has been regularly met. The petition and supporting documentation submitted by Petitioner indicate that, since January 26, 1982, Petitioner has regularly met the particulate standard. It is therefore,

ORDERED that the Petition for Reduction in the Frequency of Particulate Emissions Compliance Testing in GRANTED. Petitioner may immediately commence testing on an annual basis. Test results from the first regularly scheduled compliance test conducted in FY 87 (October 1, 1986 - September 30, 1987), provided the results of that test meet the particulate standard and the 40% opacity standard, shall be accepted as results from the first annual test. Failure of Bartow Unit No.3 to meet

either the particulate standard or the 40% opacity standard in the future shall constitute grounds for revocation of this authorization.

Persons whose substantial interests are affected by the above proposed agency action have a right, pursuant to Section 120.57, Florida Statutes, to petition for an administrative determination (hearing) on the proposed action. The Petition must conform to the requirements of Chapters 17-103 and 28-5, Florida Administrative Code, and must be filed (received) with the Department's Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within fourteen (14) days of publication of this notice. Failure to file a petition within the fourteen (14) days constitutes a waiver of any right such person has to an administrative determination (hearing) pursuant to Section 120.57, Florida Statutes.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the proposed agency action. Persons whose substantial interests will be affected by any decision of the Department have the right to intervene in the proceeding. A petition for the intervention must be filed pursuant to Model Rule 28-5.207, Florida Administrative Code, at least five (5) days before the final hearing and be filed with the Hearing Officer if one has been assigned at the Division of Administrative Hearings, Department of Administration, 2009 Apalachee Parkway, Tallahassee, Florida 32301. If no Hearing Officer has been assigned, the petition is to filed with the Department's Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Failure to petition to intervene within the allowed time frame constitues a

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing ORDER has been furnished by United States Mail to J.A. Hancock, Vice President, Fossil Operations, Florida Power Corporation, Post Office Box 14042, St. Petersburg, Florida 33733; on this 17 day of December, 1986, in Tallahassee, Florida.

E. Gary Early
Assistant General Counsel

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida
32399-2400
Telephone (904)488-9730

Florida Department of Environmental Protection

Memorandum

TO: Michael G. Cooke

THRU: Trina L. Vielhauer
Al Linero

FROM: Syed Arif

DATE: December 27, 2004

SUBJECT: FINAL Permit Project No.: 1030011-009-AV
Progress Energy Florida, Inc.
P.L. Bartow Power Plant
Pinellas County

Attached is the final permit package for the Title V Permit Renewal for this facility. As of close of business on December 23, 2004, *no comments had been received from EPA.*

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

AAL/sa

Attachments

Friday, Barbara

To: 'sosbourn@golder.com'; Waters, Jason; grobbins@co.pinellas.fl.us

Cc: Arif, Syed

Subject: Final Title V Permit Renewal No.: 1030011-009-AV - Progress Energy Florida, Inc. - P.L. Bartow Power Plant

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

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

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

Progress Energy

RECEIVED
AUG 20 2003
BUREAU OF AIR REGULATION

August 13, 2003

Mr. Scott M Sheplak, P.E.
Florida Department of Environmental Protection
Bureau of Air Regulation
Mail Station: #5505
2600 Blair Stone Road
Tallahassee, Florida 32399

Dear Mr. Sheplak:

Re: Progress Energy Florida Bartow Plant – Unit 1 Electrostatic Precipitator Operation and Maintenance Plan Information

The Department and the Pinellas County Department of Environmental Management have previously reviewed Progress Energy Florida's Title V permit application concerning the Bartow facility's electrostatic precipitator. Progress Energy Florida subsequently received a letter from the Department, dated June 11, 2003, requesting additional information to be included in the electrostatic precipitator's operation and maintenance plan.

As suggested in the Department's letter, I request that the Title V Permit be revised in the name of Progress Energy Florida, Inc.

Enclosed please find the revised operation and maintenance plan incorporating the Department's and County's comments.

Please contact Matt Lydon (727) 826-4152 if you have any questions.

Sincerely,

Brenda Brickhouse
Bartow Plant Manager

Cc: Wayne Martin, PCDEM

Progress Energy Florida • Bartow Steam Plant
1601 Weedon Island Drive • St. Petersburg, Florida 33702
727-827-6100

PROGRESS ENERGY FLORIDA
BARTOW PLANT UNIT #1 ELECTROSTATIC PRECIPITATOR
OPERATION AND MAINTENANCE PLAN
August 2003

DESCRIPTION

This cold-side precipitator is a two-chambered Buell unit built in 1982. The unit was designed to treat a gas volume of 488,000 acfm at 300° F under negative pressure. As of October 2002, this unit was rebuilt. There are two mechanical and five electrical fields in the direction of gas flow. There are 30 gas passes per chamber, formed by 36' high collecting plates 11" apart. Plates in the third (outlet) mechanical fields of each chamber are 12' wide, while those in the second (center) field are 9' wide. The first field is vacant. The discharge electrodes are RDE-1 rigid electrodes with emitter pins on 3" centers.

Electrical power is supplied through five dual-bushing transformer/rectifier sets, each of which is controlled by a BHA, SQ-300 automatic voltage controller, rated at 480 V, 240 A primary and 45 kV, 1800 mA secondary.

Cleaning of the precipitator internals is accomplished by a total of 154 BHA manufactured EGR impact rappers controlled by a BHA, PRC-100 Rapper controls. Collected ash is shed into 12 hoppers, which are equipped with Dynatrol hopper level detector probes and Chromalox heaters.

EQUIPMENT SPECIFICATIONS

Original Manufacturer – General Electric Environmental Services, Inc.
Rebuild Manufacturer – BHA Group, Inc.
Precipitator: Model 1-BAB1.2x37(9)36.0-434-4.3P

Number of Electrical Fields	5
Number of Bus Sections	14
Number of Gas Passes	60
Plate Height	36'
Emitting Electrodes	rigid electrode
Automatic Voltage Controller	BHA SQ-300
Electrode Cleaning Methods:	
Emitting System	impact rappers
Collecting System	impact rappers
Electrode Cleaning Controller	PRC-100

DESIGN PARAMETERS

Fuel Type	No. 6 Fuel Oil
Flue Gas Volume	488,000 acfm
Gas Velocity	4.07 fps
Normal Flue Gas Exit Temperature	300° F
Fly Ash Removal Efficiency for No. 6 Fuel Oil	98%

PROCESS PARAMETERS

Plant operators monitor and may adjust the following Bartow Plant Unit 1 parameters at least once per day to assure efficient plant operations:

- Pressures (furnace, superheat, and reheat)
- Temperatures (superheat, reheat, and fuel)
- Flows (steam, feedwater, and fuel); and
- Unit load

RAPPER FREQUENCY AND DURATION

- Rapper frequency, plate – 8 half cycles
- Rapper duration, plate – 1 rap – cycle time 8:27:330 (plates 4)
- Rapper duration, plate – 1 rap – cycle time 13:27:330 (plates 5)
- Rapper duration, plate – 1 rap – cycle time 35:14:660 (plates 6&7)
- Rapper duration, plate – 1 rap – cycle time 49:34:660 (plates 8&9)
- Rapper duration, plate – 1 rap – cycle time 60:07:330 (plates 10)

Please Note: These rapper parameters are <u>NOT</u> set parameters.

OPERATIONAL CHECKS

The following parameters are checked and recorded each day of precipitator operation:

- Transformer/rectifier primary voltage (110 to 300 V)
- Secondary voltage – 50 kV
- Transformer/rectifier primary current (20 to 80 A AC)
- Transformer/rectifier secondary current (0.07 to 0.54 A DC)
- Transformer/rectifier spark rates (0 to 30 sparks/min.)

Other parameters, listed below, are monitored during precipitator operation but not recorded. These parameters are alarmed locally (in the precipitator control room) and there is continuous monitoring by an alarm to the main control room, as a 'Precipitator Trouble' alarm.

Precipitator Control Room:

Checks for Alarms:

- Transformer/rectifier low voltage – Alarms at 50V and 10 kV
- Transformer/rectifier over current – Alarms at 300A and 22502 MA
- Transformer/rectifier high oil temperature – Alarms at 50 deg. C
- Control cubicle fan failure

- Insulator heater system failure
- Rapper control cabinet loss of power
- Purge system airflow failure
- Purge system fan failure
- Control room high temperature
- Hopper heaters low temperature
- Hopper ash level high

Other Checks:

- Check for rapper faults on WinRap program on precipitator controls computer
- Check that transformer control cubical fans are in operation.
- Check for transformer/rectifier trips on local switch cabinet.
- Check AVC (WinDac) precipitator controls computer for abnormal conditions daily.
- Check for leaks through doors, manholes, etc. on the 2nd, 4th, and 8th floors at least monthly.

MAINTENANCE PLAN

The majority of precipitator maintenance is done during planned unit outages. Planned outages generally occur every two years. Unplanned unit outages occur due to some type of failure or operational problem with either the precipitator or the steam unit. Unplanned unit outages required due to steam unit performance may also be an opportunity to perform precipitator maintenance. Whether an unplanned outage is necessitated by precipitator performance will depend on the type and significance of precipitator equipment failure. Such a decision depends on the engineering judgement of responsible Progress Energy personnel.

Outage related maintenance work may include the following:

- Complete precipitator cleaning and inspection, depending on time lapse since last complete inspection.
- Inspection and repair as needed of transformer rectifiers.
- Inspections and repair as needed of hoppers and hopper heaters.
- Cleaning of transformer/rectifier set, support and rapper insulators.
- Replace gaskets on doors and manholes as needed
- Weld repair of plates as needed to repair areas of corrosion.
- Properly align rigged electrodes, plates, and frames internally.

Maintenance activities are documented on several forms. Attached are samples of a Trouble Report form and the computerized maintenance planned or completed report format from the Productivity Measurement System.

SPARE PARTS

The following is a list of major items stocked. There are many other small parts not listed such as clips, fuses, lighting fixtures, etc. Quantities and spare parts carried vary with time of year, determination of need as equipment ages and economic reorder quantities (i.e.: pricing in quantities).

PART	QUANTITY
Hopper heater	29
Insulator shaft - Alumina	2
Insulator support	7
SQ-300 AVC controller	1
EGR rapper assembly	1
EGR rapper coil assembly	2
EGR rapper gaskets	6
Adjusting Bolt	2
Rapper Boot Seals	5
Rapper boot seal clamps	15
Insulator shaft – Porcelain	1
Heater element	5
Rapper steering diode assembly	1
Fuses	6
PRC-100 rapper Triac board	1
PRC-100 rapper power module	1
PRC-100 rapper IFB board	1

PROGRESS ENERGY - BARTOW STEAM PLANT
ESP WORK LOG (Work orders history)

Passport Information Portal - Query Results
For Information Only. PassPort is the Application of Record.
WORK ORDERS AND WORK ORDER TASKS (Facility: BAR --- Date: 8/11/2003 4:18:57 PM)

Wo_Facility	Wt_Unit	Wo_Work_Order_Nbr	Wt_System_Code	Wt_Wo_Tsk_Status	Wo_Description		Wo_Planner	Wo_Start_Date	Wt_Completion_Date
BAR	1	439137	BA	85	U1/EL/PRECIP RAPPER B164 IN ALARM "SHORT"		BETSAE	20030728	20030811
BAR	1	443208	BA	50	K/M/U1/PRECIP. VENT LINE IS PLUGGED		HENDEL	20030808	20030808
BAR	1	437336	BA	85	PRECIPITATOR RAPPER SYSTEM TROUBLE SYSTEM CURRENT IS TO HI		BETSAE	20030724	20030807
BAR	1	427545	BA	85	M/U1 RECONFIGURE 90 DEGREE FILTER BAG DUMPSTER ATTACHMENT		BOYDRO		20030801
BAR	1	413916	BA	85	M/W12 GAS RECIRC DMPRS		BOYDRO		20030801
BAR	1	427311	BA	85	M/W2 CLN ASH TRANS PIPE		BOYDRO		20030729
BAR	1	437535	BA	85	K/U1 INSTALL LINERS IN BLUE ASH BOX'S		BOYDRO		20030725
BAR	1	422269	BA	85	I&C /U1 #1 AND #1A IK'S NEED AIR ISOLATION VALVES		PAULDA	20030617	20030725
BAR	1	361359	BA	85	M/U1 PRECIP STEEL RUSTED OUT "A" OUTLET STRUCTURE		BOYDRO		20030725
BAR	1	427544	BA	85	M/U1 PRECIP FLEX HOSE TO FLYASH DUMPSTER KINKED		BOYDRO	20030629	20030721
BAR	1	294067	BA	85	M/W48 FLYASH AIR TK MAINT		BOYDRO		20030717
BAR	1	294067	BA	85	M/W48 FLYASH AIR TK MAINT		BOYDRO		20030717
BAR	1	409028	BA	50	M/U1 ASH TRANSPORT PIPE COLLAPSED IN TWO AREAS		BOYDRO		20030716
BAR	1	431204	BA	85	K/M/U1/PRECIP.---T-108 WILL NOT PRESSURIZE- INSPECT		HENDEL	20030709	20030715
BAR	1	433367	BA	85	EL/U1 PRECIPITATOR		BETSAE		20030714
BAR	1	409288	BA	85	I/PRECIP/WORK ON PC LOGIC		PAULDA	20030516	20030710
BAR	1	421469	BA	85	M/W2 CLN ASH TRANS PIPE		FISHER		20030708
BAR	1	423275	BA	85	J/U1 REMOVE ASH FROM BLUE BOX "D"		BOYDRO		20030707
BAR	1	409020	BA	85	I/U1/PRECIP INSTRUMENT AIR FILTERS NEED TO BE CHANGED		PAULDA		20030707
BAR	1	410269	BA	85	M/W2 CLN ASH TRANS PIPE		BOYDRO		20030702
BAR	1	409028	BA	50	M/U1 ASH TRANSPORT PIPE COLLAPSED IN TWO AREAS		BOYDRO		20030701
BAR	1	421855	BA	85	I/U1 T-109 TRANSPORT AIR REGULATOR BLOWING OUT VENT		PAULDA		20030626
BAR	1	369420	BA	85	M/U1 FLYASH DUMPSTER CONTAINMENT AREA, REPLACE BULLARD		BOYDRO	20030204	20030626
BAR	1	424757	BA	85	K/M/U1/ FLYASH DUMPSTER "VACUUM" VENT LINE TO BOILER.		HENDEL	20030623	20030623
BAR	1	380793	BA	85	M/W12 1A&1B ID FAN DMPRS		BOYDRO		20030623
BAR	1	416042	BA	85	M/W2 CLN ASH TRANS PIPE		BOYDRO		20030620
BAR	1	404521	BA	85	M/W2 CLN ASH TRANS PIPE		BOYDRO		20030617
BAR	1	361359	BA	85	M/U1 PRECIP STEEL RUSTED OUT "A" OUTLET STRUCTURE		BOYDRO		20030617
BAR	1	409034	BA	85	I/U1 T-109 TRANSPORT AIR REGULATOR BLOWING OUT VENT		PAULDA	20030515	20030616
BAR	1	380794	BA	85	M/W12 GAS RECIRC DMPRS		BOYDRO		20030610
BAR	1	417005	BA	85	M/U1 "A" A/H HIGH DIFF. NEEDS WASHING		BOYDRO		20030609
BAR	1	402375	BA	85	M/U1 INSTALL REMAINING CASTELL-KEY LOCKS.		BOYDRO		20030609

Facility: BAR BARTOW PLANT
WR Originator: SAVAGM SAVAGE JR. M F
Unit : 1 Project :
W/O Type: CO TSK PRI: 4 W/O Dspln: K
Planner : HENDEL HENDERSON L L
W/O Title : K/M/U1/PRECIP. VENT LINE IS PLUGGED
W/O Task Title: K/M/U1/PRECIP. VENT LINE IS PLUGGED

Task Dspln : K Due By: 08/08/03

Work Order Package
(Single Work Order)
00443208 01

Rpt : TIPMC11
Date: 08/11/03

Page: 1

Work Order Task Written To

Facility : BAR Unit : 1 Sys: BA PMT:
Equipment : PIP BA1BA3020000000 Component:
Work Item : Eqt. List: Review Reqd:
Equip. Tag: BA1-PRECIPITATOR-PIPING Alt:
Catalog ID: Job Type : CO UCR:A UTC :
Name : BA1 PRECIPITATOR PIPING
Location :
Crew :
Resource Type: PERS Resource Code: FINT Qty: 1 Duration:
Cost Centr: 60953D Activity : User Def:
Percentage: 100.000 Acct No. : 00 20016145 W0300
CPM Proj : NONSCHED Network Reference:

Work Order Task Instructions

PRECIP.--VENT LINE TO THE BOILER IS PLUGGED.
PLEASE INVESTIGATE AND RETURN TO SERVICE ASAP.

Rework/Approval

Deficiency Tag No.: Loc: Tag Removed:
ReWork Job : Comments:

Task Requirements

FAC.	REG/REQ	VALUE	COMMENTS
BAR	ASBESTOS		
BAR	CLR REQ		
BAR	FIRE PROT		
BAR	HOTWRK PMT		
BAR	INSU		
BAR	NDE REQ		
BAR	PMT		
BAR	SCAFFOLD		
BAR	SECURITY		
BAR	WELD DOC		

Facility: BAR BARTOW PLANT
W. Originator: SAVAGM SAVAGE JR. M F
Unit : 1 Project :
W/O Type: CO TSK PRI: 4 W/O Dspln: K
Planner : HENDEL HENDERSON L L
W/O Title : K/M/U1/PRECIP. VENT LINE IS PLUGGED
W/O Task Title: K/M/U1/PRECIP. VENT LINE IS PLUGGED

Task Dspln : K Due By: 08/08/03

Work Order Package

00443208 01

Rpt : TIPMC11
Date: 08/11/03

Authorization

Start Permission : _____ _ _ Date: _____ ____

Failure/Action Taken/As Found

Failure Category Code (F/NF) _____
Action Taken Category Code: _____
As Found Sub Category Code: (1-5) _____

Deficiency Tag Loc:

Deficiency Marker or Tag: _____
Removed (Y/N) _____

Work Completion Signatures

Name	Function/Dept.	Date

Comments: _____
(rework?) _____

Rework Reason/Cause

		(Y/N)
CT	COMPONENT FAILED	_
I W	INCOMPLETE WORK FROM MAINTENANCE	_
N/A	NON APPLICABLE	_

Date: _____
Comments: _____

Facility: BAR BARTOW PLANT
WR Originator: SAVAGM SAVAGE JR. M F
Unit : 1 Project :
W/O Type: CO TSK PRI: 4 W/O Dspln: K
Planner : HENDEL HENDERSON L L
W/O Title : K/M/U1/PRECIP. VENT LINE IS PLUGGED
W/ Task Title: K/M/U1/PRECIP. VENT LINE IS PLUGGED

Task Dspln : K Due By: 08/08/03

Work Order Package

00443208 01

Rpt : TIPMC11
Date: 08/11/03

Completion Comments on Work Performed

Completion Comments Required : Y

Comments: _____

Comments: _____

Comments: _____

Continued on Additional Sheets? : _____

***** E N D O F R E P O R T *****

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an
Application for Air Permit by:

Florida Power Corporation dba
Progress Energy Florida, Inc.
100 Central Avenue, Mail Code BP39
St. Petersburg, Florida 33701

Authorized Representative: Mr. Rufus Jackson

DEP File No.: 1030011-010-AC
Permit No. PSD-FL-381
P.L. Bartow Power Plant
Repowering Project
Pinellas County

Enclosed is the Final Permit Number PSD-FL-381 (1030011-010-AC) to construct/install a 1280 MW natural gas-fueled combined cycle unit system and a 195 MW natural gas-fueled simple cycle unit at the P.L. Bartow Power Plant at Weedon Island in St Petersburg, Pinellas County. The project includes and requires the shutdown of three existing residual oil-fueled steam electrical generating units. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final Permit) and all copies were sent electronically (with Received Receipt) before the close of business on 1/29/07 to the person(s) listed:

Rufus Jackson, PEF: rufus.jackson@pgnmail.com
Scott Osbourn, P.E., Golder: sosbourn@golder.com
Ann Quillian, P.E., PEF: ann.quillian@pgnmail.com
Dee Morse, NPS: dee_morse@nps.gov
Meredith Bond, U.S. FWS: meredith_bond@fws.gov
Peter Hessling, PCDEM: phesslin@pinellascounty.org
Jim Little, EPA: little.james@epa.gov
Mara Nasca, DEPSWD: mara.nasca@dep.state.fl.us
Mayor, City of St. Petersburg: mayor@stpete.org
Administrator, Pinellas County: sspratt@pinellascounty.org

Clerk Stamp

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

(Clerk) 1/29/07 (Date)

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

PERMITTEE

Florida Power Corporation dba.
Progress Energy Florida, Inc.
100 Central Avenue, Mail Code BP39
St. Petersburg, Florida 33701

Authorized Representative:
Mr. Rufus Jackson

DEP File No. 1030011-010-AC
Permit No. PSD-FL-381
PEF P.L. Bartow Power Plant
Plant Repowering Project
Pinellas County
SIC No. 4911
Expires: March 31, 2010

PROJECT AND LOCATION

This permit authorizes the construction of one nominal 1,280 megawatt (MW) combined cycle unit and one nominal 195 MW simple cycle unit at the Progress Energy Florida (PEF) P.L. Bartow Power Plant located at 1601 Weedon Island Drive, St. Petersburg, Pinellas County.

Three existing fossil fuel fired steam generators designated as Units 1, 2 and 3 with a total nominal capacity of 465 MW will be shut down as part of this project.

The UTM coordinates are Zone 17, 342.4 km East and 3,082.6 km North.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Parts 60 and 63 of the Code of Federal Regulations. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

Joseph Kahn, Director
Division of Air Resource Management

1/26/07
(Date)

FINAL DETERMINATION

Florida Power Corporation dba
Progress Energy Florida, Inc.
Bartow Plant Repowering Project
DEP File No.: PSD-FL-381 (1030011-010-AC)

An Intent to Issue an Air Construction Permit was sent to Florida Power Corporation doing business as Progress Energy Florida, Inc. (the Company). The project is to construct a natural gas-fueled combined cycle unit and a natural gas-fueled simple cycle unit with a total nominal electrical generating capacity of 1475 megawatts at the P.L. Bartow Power Plant at Weedon Island in St. Petersburg, Pinellas County.

The Company will permanently shut down three residual oil-fueled steam electrical generating units at the facility thus generating contemporaneous emissions reductions for several pollutants including nitrogen oxides (NO_X), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}) and sulfuric acid mist (SAM). A determination of Best Available Control Technology (BACT) was required pursuant to Rule 62-212.400(6), Florida Administrative Code for emissions of carbon monoxide (CO) and volatile organic compounds (VOC).

The Public Notice of Intent to Issue Air Construction Permit was published in the St. Petersburg Times on December 13, 2006. The proof of the Public Notice was received by the Department on January 3, 2007.

No comments were received from the public or the reviewing agencies with the exception of some minor comments regarding the numbering of emission units received from the Pinellas County Department of Environmental Management (the County). No requests for a public meeting or an administrative hearing were received.

Comments were received from the Company regarding the Draft Permit. Their comments are related to:

- Minor changes in the description of the project;
- Numeration of the emissions points (same as the County's comments);
- The compliance, monitoring and reporting requirements of the Federal New Source Performance Standards (NSPS) and the Department's BACT requirements; and
- Clarification on the permitting language of some conditions.

The comments from the Company are paraphrased below in *italics* and are followed by the Department's responses (in regular script) and permit changes shown in underlined (additions) and ~~strikethrough~~ (deletions) format:

1. Section I. Facility and Project Description

   Comment:

   The pipeline heating boiler and the relocatable diesel generator(s) are considered to be regulated emission units (see Sections III.B. and III.D. of Title V Permit 1030011-009-AV). The language in this paragraph is such that it includes these two emission units in the unregulated/insignificant emissions units. Please correct.

   Response:

   The Department will correct the facility description regarding the mentioned existing equipment as described by the Company and consistent with the Title V Operation Permit.

2. Section I. Facility and Project Description (Page 2) and Emissions Units Description Table (Page 6)

Comment:

The emission unit ID numbers listed are already assigned to unregulated emission units at the site. Please correct them with the emission unit ID numbers that would be generated by the ARMS database. These new emission unit ID numbers are expected to begin with number 038. The emission unit ID numbers are already assigned and should be changed.

Response:

The Department concurs with the Company's and the County's requests to correct the ID numbers to reflect the ones that will actually be assigned by the Department's Air Resource Management System (ARMS). The numeration of the new emissions units authorized by this permit will be numbered from 038 to 046.

3. Section III. A. Condition 3. NESHAP Requirements

Comment:

Please find attached a copy of an electronic mail message from EPA that confirms that the gas-fired stationary combustion turbine definition is based on actual hours of fuel oil burning operation per calendar year. Though the Bartow Repowering project is requesting the total aggregate limitation of 5000 hours per year of distillate oil firing, until which time the site exceeds the 1000 hours in a calendar year 40 CFR 63, Subpart YYYY would not apply.

Response:

The Company requested an aggregate total permitted usage of distillate fuel oil of 5000 hours per year in the original application. The Department reasonably concluded when reviewing the application that during some years distillate fuel use by the facility will actually exceed 1000 hours and that Subpart YYYY, a rule for the control of hazardous air pollutants from stationary combustion turbines, will apply.

The Department believes a project-specific determination is necessary before considering removal of the otherwise applicable rule provisions. The Department contacted EPA Region 4 and its staff will provide a project-specific determination.

The Department will review and if necessary revise the condition in accordance with EPA's future written project-specific guidance on the matter. The Company does not wish to take a lower limit on fuel oil use than the requested 5000 hours. Because the Company wishes to receive the permit promptly, the Department will proceed with final issuance and will re-open the permit after receiving the requested project-specific guidance.

4. Section III. A. Condition 8. Selective Catalytic Reduction Systems

Comment:

Please change the first sentence to align with the last sentence of the same condition that the SCR system operation is not required when NO_x emission limits are met without their use. This change is as follows: "Selective Catalytic Reduction Systems: The permittee is authorized to ~~shall~~ install, tune, operate, and maintain a selective catalytic reduction (SCR) system within each HRSG to control NO_x emissions from each of the four CT/Duct-fired HRSGs comprising the combined cycle unit."

Response:

The Department agrees with the comment. The project avoided the requirements for the Prevention of Significant Deterioration (PSD) and a BACT determination for NO_X by shutting down older and more polluting units and complying with a separate new rule (40 CFR 60, Subpart KKKK) that limits NO_X emissions to 15 parts per million (ppm) when burning gas and 42 ppm when burning fuel oil. The Department has reasonable assurance that the 15 and 42 ppm NO_X limits will be achieved by the whether or not SCR (i.e. ammonia injection) systems are employed. ~~Therefore installation of~~ SCR systems is authorized and (as already indicated in the permit) their operation is not required. Section III. A. Condition 8 is changed as follows:

Selective Catalytic Reduction Systems: The permittee is authorized to ~~shall~~ install, tune, operate, and maintain a selective catalytic reduction (SCR) system within each HRSG to control NO_X emissions from each of the four CT/Duct-fired HRSGs comprising the combined cycle unit. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions. Operation of the SCR systems is not required when the NO_X emission limits can be met without their use. [Application No. 1030011-010-AC; Design, and 62-210.650 (Circumvention), F.A.C.]

5. Section III. A. Condition 12. Permitted Capacity- Combustion Turbines

Comment:

Please correct the typo in the first sentence of Condition 12 as follows: "Permitted Capacity - Combustion Turbines: The nominal heat input rate excluding steam for power augmentation to each CT is 1,972 MMBtu per hour when firing natural gas and 1,876 MMBtu per hour when firing distillate fuel oil based on a compressor inlet air temperature of 59° F, the ~~lower~~ higher heating value (HHV) of each fuel, and 100% load)...."

Response:

The Department agrees with the comment. By specifying the higher heating value, the requested correction will actually reduce the stated "nominal heat input rate". Section III. A. Condition 12 is corrected as follows:

Permitted Capacity - Combustion Turbines: The nominal heat input rate excluding steam for power augmentation to each CT is 1,972 MMBtu per hour when firing natural gas and 1,876 MMBtu per hour when firing distillate fuel oil based on a compressor inlet air temperature of 59° F, the ~~lower~~ higher heating value (HHV) of each fuel, and 100% load. Heat input rates will vary depending upon CT characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(Definitions - PTE), F.A.C.]

6. Section III. A. Condition 14. (opening paragraph) Temporary Simple Cycle Operation of Two CTs Prior to Permanent Shutdown of Units 1, 2, and 3

Comment:

The second sentence of the opening paragraph limits operation to only the initially chosen CTs. If one or both of these initial CTs were to have operational and logistical problems, it would result in the need to operate one of the other two CTs in its place. Please change this language to address such a scenario, but still limits to only two CTs operated during this temporary period;

Response:

The Department will not change this condition at this time. The Company can request a modification of this permit in the future with a more complete assessment of the scenario(s) envisioned and the impacts on emissions and preservation of "netting" to avoid PSD.

7. Section III. A. Condition 14.a. (second bullet) Temporary Simple Cycle Operation of Two CTs Prior to Permanent Shutdown of Units 1, 2, and 3

Comment:

Restriction on SC Operation, second Bullet. The thirty (30) calendar day time limit to complete the certification of the NO_X CEMS under 40 CFR 75 will be difficult to meet, as there may be initial operational and logistical problems. PEF is requesting that the time frame be changed to 30 ***operating*** *days to complete the certification.*

Response:

It is not certain that the two subject combustion turbines will actually operate 30 calendar days in simple cycle prior to the permanent shutdown of residual fuel oil fired Units 1, 2 and 3. Therefore the requested change opens up the possibility that there will not be sufficient data to confirm that the project will comply with the requirement to limit NO_X emissions to less than 39 tons during the temporary simple cycle operation period.

The Department will modify the requirement to reflect 30 operating days but will also require that the certification be accomplished within 60 calendar days. Taken together, the requirements will comply with 40 CFR 75 – Continuous Emission Monitoring and with the Department's reasonable assurance provisions. The Department will modify Section III. A. Condition 14.a. (second bullet) as follows:

Temporary Simple Cycle Operation of Two CTs Prior to Permanent Shutdown of Units 1, 2 and 3: The permittee may select any two of the five new CTs to be operated as simple cycle units prior to shutdown of Units 1, 2 and 3. The restrictions included in this condition apply only to those CTs chosen, and only during the described period. Once selected, only those CTs chosen may be operated prior to shutdown of Units 1, 2 and 3 in accordance with the following restrictions:

a. *Restriction on SC Operation*:

- The combined operation of the two CTs shall not exceed 1,100 hours.
- A NO_X CEMS shall be installed and operating in each stack prior to startup of the CTs in order to collect and record data for the purpose of demonstrating compliance with this requirement. Notwithstanding the relative accuracy test audit (RATA) grace period described in 40 CFR 75 Appendix B, the NO_X CEMS shall be fully certified in accordance with the requirements of 40 CFR 75 (including a RATA), within 30 ~~calendar~~ operating days but not later than 60 calendar days after ~~of~~ startup of the CTs.
- Total emissions of NO_X from the two CTs shall not exceed 39 tons during all operation including startups, shutdowns and malfunctions as measured and recorded by the required NO_X continuous emissions monitoring systems (CEMS) during the temporary period. Data recorded before and after CEMS certification shall be included in the calculation.

The rest of this condition remains unchanged.

8. Section III. A. Condition 15.b. and 15.c. Restricted Operation

Comment:

Please make the following suggested changes to the distillate oil CT firing as well as the DB operation. Also, please change the similar language in the fourth paragraph in Section I. General Information – Facility and Project Description (Page 2 of draft permit). Note the comments in items 4 and 15 of this correspondence.

"...b. Distillate oil firing is limited to ~~1,000 hours per CT (i.e.~~ 5,000 hours total aggregate for all five CTs~~)~~ during any consecutive 12-month period.

" c. Operation of the DBs is limited to ~~2,434 hours per DB (i.e.~~ 9,736 hours aggregate for four DBs~~)~~ during any consecutive 12-month period...."

Response:

The language in the permit is consistent with the public notice for this project that states:

"Low sulfur (0.05 percent sulfur) distillate fuel oil will be allowed as backup fuel for 1000 hours per year per each of five CTGs. The gas-fueled duct burner within each of four HRSGs may operate 2,434 hours per year and each CTG may be operated in power (steam) augmentation mode for 1,688 hours per year."

The Department will not change this condition at this time. The Company can request a modification of this permit in the future with a more complete assessment of the scenario(s) envisioned and the impacts on emissions and preservation of "netting" to avoid PSD.

9. Section III. A. Condition 16.a. Methods of Operation Simple Cycle (SC) Operation

Comment:

Please correct the typographical error by changing the last word of Condition 16.a. from "below" to "above."

Response:

The Department does not believe a change is necessary since the word "below" refers to the Condition 16.b. that immediately follows Condition 16.a.

10. Section III. A. Condition 17 New Source Performance Standards for NOx

Comment:

Table 1 of 40 CFR 60, Subpart KKKK and Condition 17 specify the NO_x emission limitations in ppmvd @ 15% O_2 also Condition 32 specifies that the CEMS final results be expressed in ppmvd @ 15% O_2. However §60.4350(c) states, "Correction of measured NO_X concentrations to 15% O_2 is not allowed." This appears to be a conflicting requirement. Please clarify in the permit language whether the NO_X CEMS data should be corrected to 15% O_2 or not.

Response:

The Department acknowledges that correction of NO_X emissions concentrations to 15 percent oxygen (% O_2) is not allowed under the mentioned rule for the purposes of demonstrating compliance with that rule. Reliance upon the uncorrected NO_X concentrations as specified in the mentioned rule will actually decrease the theoretical NO_X emissions by a presently unknown value for the present project.

The Department will change all references to the NO_X limit throughout the permit to reflect that the allowable and measured concentrations are not and should not be corrected to 15% O_2. This will have the effect of reducing the potential to emit NO_X by several hundred tons per year.

Condition 17, Table Footnote b is modified as follows:

b. A CEMS for NO_X shall be installed on the CT stacks and on the HRSG stacks. Correction to 15% O_2 is not allowed consistent with the provisions of 40 CFR 60, Subpart KKKK.

11. Section III. A. Condition 18.d. Best Available Control Technology (BACT) Emissions Standards for CO and VOC

Comment:

As the project moves into combined cycle operation, PEF expects to run in simple cycle infrequently. Currently, FDEP requirements allow for a test waiver if liquid or solid fuel is burned for less than 400 hour per year, see Rule 62-297.310(7)(a)5, F.A.C. PEF is requesting similar language such that an annual compliance test could be waived if the unit did not operate in simple cycle mode for greater than 400 hours per year.

Response:

The Department acknowledges the comment; however no changes are needed. This section of Rule 62-297.310(7)(a)5, F.A.C. refers to particulate matter test and not to volatile organic compounds (VOC) or carbon monoxide (CO). These units are inherently very low emitters of particulate matter and are not subject to testing. Instead they are subject to visible emissions testing as surrogate for PM.

Rule 62-297.310(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 start up, for a total of more than 400 hours."

12. Section III. A. Condition 20.c. Measures to Limit Particulate Emissions (PM/PM_{10}/Fine Particulate Matter) – Ammonia Slip

Comment:

Please add 40 CFR 63 Appendix A – Method 320 as an alternative test method for ammonia.

Response:

The Department agrees with the comment and Method 320 is added as an alternative method. Section III, Condition No. 20.c. is modified as follows:

c. *Ammonia Emissions (Slip) Limits*: Ammonia emissions shall be limited to 5 ppmvd @15% O_2. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Methods CTM-027 or 320.

The rest of this condition remains unchanged.

13. Section III. A. Condition 25. Allowable Data Exclusions

Comment:

Per the permit for PEF's Hines Energy Complex, the limitations and data exclusions are on a 24-hour block period. The current language does not specify 24-hour block average, though the BACT CEMS emission limitation is on a block average basis in Condition 18 and 24-hour block average is defined in Condition 32. Please change the language to reflect a 24-hour block average.

Response:

The Department believes that it is not necessary to modify this condition since the 24-hr block average is already defined and is a requisite of the BACT emission limits for the selected pollutant.

14. Section III. A. Condition 25.e. Allowable Data Exclusions - Fuel Switching

Comment:

The draft permit allows CEMs data exclusion of 2 hours per 24-hour period for fuel switching. Based on operating experience at PEF's Hines Energy Complex it has been observed that the Siemens F-Class CTs' fuel switch operation occurs at low loads in either fuel switch direction, which is different from the GE equivalent CTs. Also with recent increased hurricane activity, PEF has observed the need to be prepared to burn fuel oil in case of natural gas curtailment. The original equipment manufacturer of the Hines Energy Complex has recommended that a fuel switch be performed twice per month per CT. This enables the equipment associated with the fuel oil system to remain in working order and be ready for use during a possible curtailment.

PEF is requesting that the CEMs data exclusion for a fuel switch be 2 hours per fuel switch. However, PEF is not asking for a change to the limitation on the amount fuel oil burned.

~~Response~~:

The Department will need operating data from the manufacturer to consider this change. The Company can apply for a permit modification to address this issue after compiling the required data.

15. Section III. A. Condition 27 Test Methods

Comment:

Please add 40 CFR 63 Appendix A – Method 320 as an alternative test method.

Response:

The request is acceptable. The table in Condition 27 that lists test methods will be modified to reflect the additional procedure called "Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy".

16. Section III. A. Condition 31 CEMS Systems

Comment:

Please consider clarifying the language in the last sentence of the opening paragraph to note that the one working day excess emissions notification does not include excluded data. See the following: "CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO from the HRSG stacks and NO_X from all stacks in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions which after the application of Condition 25 (allowable data exclusions) are in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority."

Response:

The Department does not believe a change is necessary since the full conditions (25 and 31) as written are self explanatory. A revision in Item 18 below further clarifies the matter.

17. Section III. A. Condition 36.b. Fuel Sulfur Methods – Distillate Fuel Oil Sulfur Limit

Comment:

Please make the following change to the fuel sulfur analysis recordkeeping requirements: "b. Distillate Fuel Oil Sulfur Limit: Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods or other Department approved methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor or other fuel sulfur analysis performed on each delivery. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content."

Response:

The Department accepts the suggestion and modifies Section III.A. Condition 36.b as follows:

b. *Distillate Fuel Oil Sulfur Limit*: Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods or other Department approved methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor or other fuel sulfur analysis performed on each delivery. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

The rest of the condition remains unchanged.

18. Section III. A. Condition 38.b. Excess Emissions Reporting – SIP Quarterly Permit Limits Excess Emissions Reports

Comment:

See item 16 above regarding application of Condition 25 and excess emissions reporting. Please clarify the language in this condition as to the reporting of excess emissions that are outside the allowable data exclusion. Please consider the following: "SIP Quarterly Permit Limits Excess Emissions Report: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit and have not been excluded per Condition 25. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter."

Response:

The Department will not change Condition 38.b. as requested. However, the Department will clarify that excluded data should be provided with the Quarterly Report. This condition will be modified as follows:

b. SIP Quarterly Permit Limits Excess Emissions Report: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. A summary of data excluded from SIP compliance calculations should also be provided.

The rest of the condition remains unchanged.

19. Section III. B. Emission Unit Description

Comment:

See item 2 above. The emission unit ID numbers are already assigned and should be changed.

Response:

See the Department's response to Comment No.2 above.

20. Section III. B. Condition 4. Equipment

Comment:

Please remove the last three words of Condition 4. The natural gas supply is for more than just the CTs. The suggested change is as follows: "Equipment: The permittee is authorized to install, operate, and maintain one auxiliary boiler with a maximum design heat input of 99 MMBtu/hr (85,000 lb/hr) to produce steam during start up of the CTs and five 3 MMBtu/hr process heaters for the purpose of heating the natural gas supply ~~to the CTs~~."

Response:

The Department accepts the suggestion and modifies Section III. B. Condition 4 as follows:

Equipment: The permittee is authorized to install, operate, and maintain one auxiliary boiler with a maximum design heat input of 99 MMBtu/hr (85,000 lb/hr) to produce steam during start up of the CTs and five 3 MMBtu/hr process heaters for the purpose of heating the natural gas supply ~~to the CTs~~. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

21. Section III. C and D. Emission Unit Description

Comment:

See item 2 above. The emission unit ID numbers are already assigned and should be changed.

Response:

See the Department's response to Comment No.2 above.

22. Section III. D. Condition 5. Authorized Fuel.

Comment:

The language listing the ASTM methods to be used for fuel sampling analysis should be changed to allow for future changes of the rules listing approved ASTM methods. Suggested change is as follows: "More recent versions of these methods or other Department approved methods may be used...."

Response:

The Department accepts the suggestion and modifies Section III. D. Condition 5 as follows:

Authorized Fuel: This unit shall fire low sulfur fuel oil (or superior fuel), which shall contain no more than 0.05% sulfur by weight. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods or other Department approved methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content

CONCLUSION

The final action of the Department will be to issue the permit with the changes as noted above.

FACILITY AND PROJECT DESCRIPTION

Progress Energy Florida operates the Bartow Plant, which is an existing power plant (SIC No. 4911). The plant currently consists of:

- Three fossil fuel fired steam generating units designated as Units 1, 2 and 3 that produce 120, 120 and 225 megawatts (MW) of electrical power respectively;
- Four simple cycle units designated as Gas Combustion Turbine Peaking Units Nos. P-1, P-2, P-3 and P-4 each of which has a nominal capacity of 56 MW;
- Additional emissions units include a pipeline heating boiler and relocatable diesel generators; and
- Miscellaneous unregulated/insignificant emissions units and/or activities including fuel storage tanks and gas tanks that can be located at various PEF power plants. These units are listed in Appendix U of the current Title V Permit.

The project is a plant repowering that includes the construction of a nominal 1,280 MW gas-fired combined cycle unit system ("4-on-1") and a nominal 195 MW gas-fired simple cycle unit. The project includes and requires the shutdown of the three fossil fuel fired steam generating units (Units 1, 2 and 3) resulting in a net decrease in all PSD pollutants except for carbon monoxide (CO) and volatile organic compounds (VOC).

The combined cycle unit system will consist of: four Model SGT6-5000F combustion turbine-electrical generators (CT-electrical generators) with a nominal rating of 215 MW at ISO conditions when practicing power augmentation; four duct-fired heat recovery steam generators (HRSG's) each equipped with a selective catalytic reduction (SCR) reactor and a nominal 500 million Btu per hour (MMBtu/hr) duct burner; and a single nominal 420 MW steam-electrical generator (STG). Each CT within the combined cycle unit system will be permitted to operate in simple cycle by directing the exhaust to a bypass stack instead of the respective HRSG. Thus the project will include eight stacks measuring approximately 120 feet in height.

All CTs will be equipped with evaporative coolers to condition incoming air at high ambient temperatures and wet injection capability for nitrogen oxides control when firing fuel oil or when practicing power augmentation. Each CT will be allowed to fire backup low sulfur (<0.05% S) distillate fuel oil for 1,000 hours per year (hr/yr). The new units are designated as Units 4 and Unit 5.

The simple cycle CT-electrical generator will have a nominal rating of 195 MW at ISO conditions and will exhaust through its own 120 foot stack.

Additional ancillary equipment will include: five natural gas fired fuel heaters; two diesel fuel storage tanks; one auxiliary steam boiler; and a diesel fueled emergency fire pump.

This permit authorizes the installation the following new equipment in conjunction with the permanent shutdown of Units 1, 2, and 3.

E.U. ID	Emission Unit Description
038	Unit 4A – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
039	Unit 4B – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
040	Unit 4C – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
041	Unit 4D – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
042	Unit 5 – One 195 MW (ISO) Combustion Turbine
043	One Nominal 85,000 lb/hr (99 MMBtu/hr) Auxiliary Boiler
044	4 ~~Five~~ Nominal 3 MMBtu/hr Gas-fired Process Heaters
045	Two Nominal 3,500,000 gallon Distillate Fuel Oil Storage Tanks
046	One Nominal 300 horsepower Diesel-fueled Emergency Fire Pump

REGULATORY CLASSIFICATION

Title I, Section 111, Clean Air Act, Standards of Performance for New Stationary Sources

The proposed project is subject to the following New Source Performance Standards of 40 CFR 60:

- Subpart KKKK - Standards of Performance for Stationary Combustion Turbines. This rule also covers duct burners that are incorporated into combined cycle projects,
- Subpart Dc which applies to Small Industrial, Commercial, or Institutional Boilers, and
- Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Title I, Section 112, Clean Air Act, National Emissions Standards for Hazardous Air Pollutants (NESHAP)

The proposed project is subject to the following National Emissions Standards for Hazardous Air Pollutants:

- 40 CFR 63, Subpart YYYY – NESHAP for Stationary Combustion Turbines.
- 40 CFR 63, Subpart DDDDD – NESHAP for Industrial, Commercial, or Institutional Boiler or Process Heater. Applies to auxiliary boiler and gas heaters.

Title I, Part C, Clean Air Act, Prevention of Significant Deterioration (PSD)

The facility is located in an area that is designated as "attainment", "maintenance", or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is classified as a "Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input", which is one of the facility categories with the PSD applicability threshold of 100 tons per year (TPY). Potential emissions of at least one regulated pollutant exceed 100 TPY per year, therefore the facility is classified as a "Major Stationary Source" with respect to Rule 62-212.400 F.A.C.

Title IV, Clean Air Act, Acid Rain Provisions

The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V, Clean Air Act, Permits

The facility is a Title V or "Major Source" of air pollution because the potential emissions of at least one regulated pollutant exceed 100 tons per year or because it is a Major Source of HAP. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

Clean Air Interstate Rule (CAIR)

The new combustion turbine-electrical generators may be subject to CAIR pending finalization of DEP rules.

Florida Power Plant Siting Act (Siting)

The facility was not certified pursuant to Siting under 403.501-519, F.S. or Chapter 62-17, F.A.C. The proposed project is not subject to Siting because there will be no net increase in steam-generated electrical power. [Design; Letter from Applicant Dated December 19, 2005]

RELEVANT DOCUMENTS

The following relevant documents are not a part of this permit, but helped form the basis for this permitting action:

- Air Construction Permit application received July 31, 2006;
- Department's Request for Additional Information dated August 30, 2006;
- Progress additional information received October 2 and October 26, 2006;
- Intent to Issue, Draft Air Construction Permit, and Technical Evaluation distributed December 13, 2006; and
- Final Determination distributed concurrently with Final Air Construction Permit.

1. Permitting Authority: All documents related to applications for permits to construct, modify, or operate emissions units at this facility shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such related documents shall also be submitted to the Compliance Authority.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Quality Division of the Pinellas County Department of Environmental Management Office at 300 South Garden Avenue, Clearwater, Florida 34616.

3. Appendices: The following Appendices are attached as part of this permit: Appendix A (NSPS and NESHAP Subpart A – Identification of General Provisions); Appendix CF (Citation Format); Appendix GC (General Conditions); and Appendix CC (Common Conditions); Appendix IIII (NSPS Subpart IIII Provisions – Internal Combustion Engines); Appendix KKKK (NSPS Subpart KKKK Provisions - Combustion Turbines and Duct Burners); Appendix YYYY (NESHAP Subpart YYYY Provisions – Combustion Turbines); Appendix BD (BACT Determination); Appendix DDDDD (NESHAP Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, or Institutional Boiler or Process Heater); Appendix Dc (NSPS Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units); Appendix XS (Semiannual NSPS Excess Emissions Report).

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in general accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and Title 40, Parts 60 and 63 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

5. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

6. Modifications: The permittee shall notify the Compliance Authority upon commencement of construction. No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

7. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit. The owner or operator of a phased construction project shall adhere to the procedures provided in 40 CFR 52.21(j)(4), adopted and by reference in Rule 62-204.800, F.A.C. For good cause, the permittee may request that this PSD air construction permit be extended.
[Rules 62-4.070(4), 62-4.080, 62-210.300(1), 62-212.400(12)(a) and 62-212.400(10)(d), F.A.C.]

8. Source Obligation: At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification. [Rule 62-212.400(12)(b), F.A.C.]

9. Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. This permit does not specify the Acid Rain program requirements. These will be included in the Title V air operation permit. [40 CFR 72]

10. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the appropriate Permitting Authority with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

11. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(3), F.A.C.]

A. Combined Cycle Unit 4 and Simple Cycle Unit 5 (EU-038, 039, 040, 041 and 042)

This section of the permit addresses the following emissions unit.

E.U. ID	Emissions Units Comprising Combined Cycle Unit 4
038	Unit 4A – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
039	Unit 4B – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
040	Unit 4C – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
041	Unit 4D – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
042	Unit 5 – One 195 MW (ISO) Combustion Turbine

APPLICABLE STANDARDS AND REGULATIONS

1. PSD Applicability and BACT Determinations: The Rules for the Prevention of Significant Deterioration (PSD) of Air Quality apply to this project and Best Available Control Technology (BACT) determinations were made for carbon monoxide (CO) and volatile organic compounds (VOC).

   See Appendix BD of this permit for a summary of the final BACT determinations.
   [Rules 62-210.200 (Definitions) and 62-212.400, F.A.C.]

   {Permitting Note: The repowering project does not trigger PSD or require a BACT determination for NO_Y, SO_2, sulfuric acid mist or PM/PM_{10} because emissions reductions from the permanent shutdown of existing fossil fueled steam generating Units 1, 2 and 3 will exceed emissions increases from the project by values greater than the respective significant emissions rates.}

2. NSPS Requirements: Each CT shall comply with all applicable requirements of 40 CFR 60, listed below, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   a. *Subpart A - General Provisions*, including:

   - 40 CFR 60.7, Notification and Record Keeping
   - 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

   b. Subpart KKKK - Standards of Performance for Stationary Combustion Turbines: These provisions were finalized on July 6, 2006 and include requirements applicable to duct burners located in HRSGs.

3. NESHAP Requirements: The CTs are subject to 40 CFR 63, Subpart A - Identification of General Provisions and 40 CFR 63, Subpart YYYY - National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Turbines.

EQUIPMENT AND CONTROL TECHNOLOGY

4. Combustion Turbines (CTs): The permittee is authorized to install, tune, operate, and maintain five Model SGT6-5000F CT-electrical generator sets. Each CT shall include an automated control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system, evaporative inlet air-cooling system and a nominal 120 foot exhaust stack for simple cycle operation.
   [Application No. 1030011-010-AC; Design]

5. Heat Recovery Steam Generators (HRSGs): The permittee is authorized to install, operate, and maintain four new duct-fired HRSGs that recover exhaust heat energy from four of the CTs and deliver steam to a nominal 420 MW steam turbine electrical generator. Each HRSG shall be equipped with a nominal 120 foot

exhaust stack for combined cycle operation. [Application No. 1030011-010-AC; Design]

6. DLN Combustion: The permittee shall install, operate and maintain Dry Low NO_X (DLN) systems to control NO_X emissions from each CT when firing natural gas. Prior to the initial emissions performance tests required for each CT, the DLN combustors and automated combustion turbine control system shall be tuned without a selective catalytic reduction (SCR) system in operation to achieve the permitted CO, VOC and NO_X levels for simple cycle operation. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations or industry standards.
[Application No. 1030011-010-AC; Design]

7. Water Injection: The permittee shall install, operate, and maintain a water injection system to reduce NO_X emissions from each CT when firing distillate fuel oil. Prior to the initial emissions performance tests, the water injection system shall be tuned without an SCR system in operation to achieve the NO_X value for simple cycle operation. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations or industry standards. [Application No. 1030011-010-AC; Design]

8. Selective Catalytic Reduction Systems: The permittee is authorized to install, tune, operate, and maintain a selective catalytic reduction (SCR) system within each HRSG to control NO_X emissions from each of the four CT/Duct-fired HRSGs comprising the combined cycle unit. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions. Operation of the SCR systems is not required when the NO_X emission limits can be met without their use.
[Application No. 1030011-010-AC; Design, and 62-210.650 (Circumvention), F.A.C.]

9. Oxidation Catalyst Systems: The permittee shall design and build the project to facilitate future installation of an oxidation catalyst system within each HRSG to control CO and VOC emissions from each of the four CTs/Duct-fired HRSGs comprising the combined cycle unit. The permittee may install oxidation catalyst during project construction or, after notifying the Department, at a future date as described in Specific Condition 18.f. [Rule 62-4.070(3) F.A.C.]

10. Ammonia Storage: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.
[Rule 62-4.070 F.A.C.]

PERFORMANCE RESTRICTIONS

11. Authorized Fuels: Each CT shall fire only natural gas and distillate oil. The maximum sulfur content of natural gas shall not exceed 2.0 grains of sulfur per 100 standard cubic feet of natural gas. The maximum sulfur content of distillate oil shall not exceed 0.05% by weight.
[Design; Rules 62-4.070 and 62-210.200 (Definitions – PTE), F.A.C.; 40 CFR 60, Subpart KKKK]

12. Permitted Capacity - Combustion Turbines: The nominal heat input rate excluding steam for power augmentation to each CT is 1,972 MMBtu per hour when firing natural gas and 1,876 MMBtu per hour when firing distillate fuel oil based on a compressor inlet air temperature of 59° F, the higher heating value (HHV) of each fuel, and 100% load. Heat input rates will vary depending upon CT characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(Definitions - PTE), F.A.C.]

13. Permitted Capacity - Duct Burners: The total nominal heat input rate to the duct burners (DBs) located within each HRSG is 500 MMBtu per hour based on the higher heating value (HHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(Definitions - PTE), F.A.C.]

14. Temporary Simple Cycle Operation of Two CTs Prior to Permanent Shutdown of Units 1, 2 and 3: The permittee may select any two of the five new CTs to be operated as simple cycle units prior to shutdown of Units 1, 2 and 3. The restrictions included in this condition apply only to those CTs chosen, and only during the described period. Once selected, only those CTs chosen may be operated prior to shutdown of Units 1, 2 and 3 in accordance with the following restrictions:

    a. *Restriction on SC Operation*:

    - The combined operation of the two CTs shall not exceed 1,100 hours.
    - A NO_X CEMS shall be installed and operating in each stack prior to startup of the CTs in order to collect and record data for the purpose of demonstrating compliance with this requirement. Notwithstanding the relative accuracy test audit (RATA) grace period described in 40 CFR 75 Appendix B, the NO_X CEMS shall be fully certified in accordance with the requirements of 40 CFR 75 (including a RATA), within 30 operating days but not later than 60 calendar days after startup of the CTs.
    - Total emissions of NO_X from the two CTs shall not exceed 39 tons during all operation including startups, shutdowns and malfunctions as measured and recorded by the required NO_X continuous emissions monitoring systems (CEMS) during the temporary period. Data recorded before and after CEMS certification shall be included in the calculation.
    - Each CT shall be stack tested to demonstrate initial compliance with the applicable Subpart KKKK NO_X emission standard for each fuel to be fired. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit. Data collected during the above described RATA may be used to satisfy this 60-day test requirement provided all requirements of 40 CFR 60.8 and Subpart KKKK are met.
    - The BACT emissions standards of specific condition 18 do not apply to these CTs prior to Unit 1, 2 and 3 shutdown. Following shutdown of Units 1, 2 and 3 all restrictions of this permit apply, including the BACT limits of specific condition 18.

    b. *Restriction on CC Operation*: No combined cycle operation of any unit is allowed prior to permanent shutdown of Units 1, 2, and 3.

    c. *Monthly Operations Summary*: By the 10th calendar day of each month, the permittee shall record the following in a written or electronic log for each CT for the previous month of operation: fuel consumption, hours of operation, NO_X emissions in total tons for the month, and NO_X emissions in total tons for the described restricted period of operation. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D.

    {Permitting note: The limitation on total NO_X emissions and adherence to the emissions standards in Specific Conditions 18, 19 and 20 along with the compliance and recordkeeping requirements of this condition will effectively ensure that emissions increases of all PSD pollutants from the selected CTs operated in SC mode prior to Unit 1, 2 and 3 shutdown will be less than their respective Significant Emissions Rates per Rule 62-210.200 (Definitions-SER), F.A.C.}

    [Rules 62-4.070(3), 62-210.200(PTE) and 62-212.400(12)(PSD Avoidance), F.A.C.; 40 CFR 60.8, and 40 CFR Subpart KKKK]

15. Restricted Operation: The permittee shall not exceed the following parameters following shutdown of Units 1, 2 and 3:
    a. The hours of operation of the CTs are not limited (8,760 hours per year).
    b. Distillate oil firing is limited to 1,000 hours per CT (i.e. 5,000 hours total aggregate for all five CTs) during any consecutive 12-month period.
    c. Operation of the DBs is limited to 2,434 hours per DB (i.e. 9,736 hours aggregate for four DBs) during any consecutive 12-month period.
    d. Power (steam) augmentation shall be limited to 1,688 hours per CT during any consecutive 12-month period.
    e. Other than startup, shutdown, fuel switching or documented malfunction the CTs shall operate above 70% load during simple cycle operation.
16. Methods of Operation: Subject to the restrictions and requirements of this permit, the CTs may operate under the following methods of operation after shutdown of Units 1, 2 and 3
    a. *Simple Cycle (SC) Operation:* All five CTs may operate in simple cycle (SC) mode whereby the turbine exhaust gas (TEG) exits through or is diverted to a stack unassociated with a DB-fired HRSG. This method of operation will be an infrequent occurrence for the four CTs that will typically operate in combined cycle mode as described below.
    b. *Combined Cycle (CC) Operation*: The four CTs associated with combined cycle Unit 4 may operate in combined cycle (CC) mode whereby the TEG is exhausted to their respective duct-fired HRSGs for energy recovery in order to raise steam to drive the single steam turbine-electrical generator (STG) subject to the restrictions of this permit.
    c. *Inlet Conditioning*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling systems may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power.
    d. *Duct Firing*: The DB within each HRSG may be fired with natural gas to reheat the TEG in order to provide additional steam to the STG or the CTs for power augmentation.
    e. *Power augmentation:* Power (Steam) Augmentation (PA): Steam for PA is taken from the HRSG and is introduced into the CT compressor discharge, thus increasing the power produced by the expander portion of the turbine.

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

EMISSIONS STANDARDS

17. New Source Performance Standards for NO_X: Emissions of NO_X shall not exceed the following emission limits for each CT or CT/DB-fired HRSG determined pursuant to 40 CFR 60, Subpart KKKK.

Pollutant	Fuel	Method of Operation [a]	CEMS [b] Rolling Average ppmvd (uncorrected)
NO_X [c]	Oil	CT (SC)	42 on 4-hour basis
		CT (CC)	42 on 30-operating days basis
	Gas	CT (SC)	15 on 4-hour basis
		CT (CC)	15 on 30-operating days basis
		CT & DB	

a. CT (SC) means operation of CT in simple cycle mode. CT(CC) means operation of CT in combined cycle without use of the DB. CT & DB means operation in combined cycle mode and using the DB.

b. A CEMS for NO_X shall be installed on the CT stacks and on the HRSG stacks. Correction to 15% O_2 is not allowed consistent with the provisions of 40 CFR 60, Subpart KKKK.

c. Compliance with the continuous NO_X standards shall be demonstrated based on data collected by the required CEMS.

. Refer to Appendix KKKK of this permit for the full NSPS requirements. [40 CFR 60, Subpart KKKK]

18. Best Available Control Technology (BACT) Emissions Standards for CO and VOC: Emissions of VOC and CO shall not exceed the following emission limits for each CT or CT/DB-fired HRSG.

Pollutant	Fuel	Method of Operation [a]	Stack Test, 3-Run Average		CEMS [c] Block Average
			ppmvd @ 15% O_2	lb/hr [b]	ppmvd @ 15% O_2
Unit 4 HRSG Stacks					
CO	Oil	CT	8.0	40.4	8.0, 24-hr [d] 6, 12-month [f]
	Gas	CT	4.1	20.8	
		CT & DB	7.6	38.3	
VOC [e,g]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	
		CT & DB	1.5	3.8	
Unit 5CT and Unit 4 Bypass Stacks					
CO	Oil	CT	8.0	40.4	Not Applicable
	Gas	CT	4.1	20.8	
VOC [e]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	

a. CT means operation of a combustion turbine (CT) in simple cycle or in combined cycle without use of the duct burner (DB). CT & DB means operation in combined cycle mode and using the DB.

b. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

c. CEMS for CO are required only on the HRSG stacks. Other than startup, shutdown, fuel switching or documented malfunction the CT shall operate above 70% load during simple cycle operation.

d. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS on the HRSG stacks. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, or duct burner modes. Separate CO tests shall be conducted under simple cycle mode on the CT stacks.

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

f. Rolling Average. Enforcement discretion may be exercised for up to 12 months with respect to the 6 ppmvd @15% O_2 limit for any CT/Duct-fired HRSG upon notification by the permittee of intent to install oxidation catalyst. The permittee shall have 12 months to complete the oxidation catalyst installation. From time of

notification to installation of the catalyst all partial or complete calendar months shall be excluded from the 12-month rolling average.

g. Compliance with the CO CEMS based limits shall be deemed as compliance with the VOC limit.

[Rule 62-210.200(Definitions – BACT) and 62-212.400 F.A.C.]

19. New Source Performance Standard for SO_2: Pursuant to §60.4330(a)(2), SO_2 emissions are limited in NSPS Subpart KKKK by a prohibition on the firing of any fuels that contain total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input. Refer to Appendix KKKK of this permit for the full NSPS requirements. [40 CFR 60, Subpart KKKK]

20. Measures to Limit Particulate Emissions (PM/PM_{10}/Fine Particulate Matter): The following measures and limitations, in conjunction with decreases from other units, effectively limit combined annual PM/PM_{10} emissions to a level that ensures net emissions increases are well below the significant emission rate at which PSD applies and a subsequent BACT determination is required. These measures also minimize fine particulate emissions and formation:

    a. *Fuel Sulfur Limits*: The sulfur concentration shall be limited to 2 grains per 100 standard cubic feet of natural gas. The sulfur concentration in the distillate fuel oil used shall be limited to 0.05 percent. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content.

    b. *Visible Emissions*: Visible emissions shall not exceed 10 percent opacity for each 6-minute block average. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.23

    c. *Ammonia Emissions (Slip) Limits*: Ammonia emissions shall be limited to 5 ppmvd @15% O_2. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Methods TM-027 or 320.

    [62-212.400(12)(PSD Avoidance)]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 18 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS or Acid Rain programs.}

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

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

23. Definitions

    a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions. [Rule 62-210.200(245), F.A.C.]

    b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.
    [Rule 62-210.200(230), F.A.C.]

c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(159), F.A.C.]

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

25. Allowable Data Exclusions: As per the procedures in this condition, limited amounts of CO CEMS emissions data may be excluded from the corresponding SIP-based compliance demonstration, provided that best operational practices to minimize emissions are adhered to and the duration of data excluded is minimized. As provided by the authority in Rule 62-210.700(5), F.A.C., these conditions replace the provisions in Rule 62-210.700(1), F.A.C. For each CT/HRSG system, excess emissions resulting from startup, shutdown, and documented malfunctions shall not exceed two hours in any 24-hour period except for the specific cases listed below. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

    a. *Steam Turbine/HRSG System Cold Startup*: For cold startup of the steam turbine system, up to 8 hours of excess emissions from any CT/HRSG system may be excluded in any 24-hour period. A cold "startup of the steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

    {Permitting Note: During a cold startup of the steam turbine system, each CT/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}

    b. *Shutdown Combined Cycle Operation*: For shutdown of the combined cycle operation, up to 3 hours in any 24-hour period of excess emissions from any CT/HRSG system can be excluded.

    c. *CT/HRSG System Cold Startup*: For cold startup of a CT/HRSG system, up to 4 hours in any 24-hour period can be excluded. "Cold startup of a CT/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

    d. *Simple Cycle CT Startup*: For startup of a CT for the purpose of operation in simple cycle mode, up to 1 hour in any 24-hour period of excess emissions can be excluded.

    e. *Fuel Switching*: For fuel switching, up to 2 hours in any 24-hour period can be excluded.

26. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least 7 days that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail.
[Design; Rule 62-4.070(3), F.A.C.]

EMISSIONS PERFORMANCE TESTING

27. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

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

No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

28. Initial Compliance Determinations: Each CT shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. Reference method data collected during the required Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the initial CO and NO_X compliance tests. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO mass rate emissions standards. CO and NO_X emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, oxidation catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

29. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour and 12-month CO emission standards, and the NO_X emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any RATA on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion and oxidation catalyst operation, which reduces emissions of particulate matter and volatile organic compounds. [Rule 62-212.400 (BACT), F.A.C.]

30. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each CT shall be tested to demonstrate compliance with the emission standards for visible emissions. CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the CO standards. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run.

{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions. The Department retains the right to require VOC testing for the reasons such as exceedance of the CO limit or those given in Appendix SC, Special Compliance Tests.}

[Rules 62-212.400, 62-210.200 (243) (BACT), 62-4.070 (3) and 62-297.310(7)(a)4, F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

31. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO from the HRSG stacks and NO_X from all stacks in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.
    a. *CO Monitors.* The CO monitors shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A within 60 calendar days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.
    b. *NO_X Monitors.* Each NO_X monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.
    c. *Diluent Monitors.* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO is monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

32. CEM Data Requirements:

- *Data Collection*: Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd of CO corrected to 15% oxygen and as ppmvd of NO_X (uncorrected). The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions.

- *Valid Hour*: Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values.

- *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of all available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR Part 75, subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]

- *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CO CEMS compliance demonstration subject to the provisions of Condition Nos. 25 and 26 of this section. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, fuel switches, DLN tuning) may be used for the appropriate exclusion periods. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

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

[Rules 62-4.070(3) and 62-212.400(12), F.A.C.; 40 CFR 75]

33. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system by the time of the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate and, as applicable for fuel oil firing, the water-to-fuel ratio, that are consistent with the documented flow rate for the CT load condition. [Rules 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

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

35. Monthly Operations Summary: By the 10th calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each CT for the previous month of operation: fuel consumption, hours of operation, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D.
[Rules 62-4.070(3), 62-212.400, 62-210.200 (38) and 62-210.200 (243)(BACT), F.A.C.]

36. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    a. *Natural Gas Sulfur Limit*: Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81. More recent versions of these methods or other Department approved methods may be used.

    b. *Distillate Fuel Oil Sulfur Limit*: Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods or other Department approved methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor or other fuel sulfur analysis performed on each delivery. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

    The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

37. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.].

38. Excess Emissions Reporting:

    a. *Malfunction Notification:* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess

emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

b. *SIP Quarterly Permit Limits Excess Emissions Report*: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. A summary of data excluded from SIP compliance calculations should also be provided.

c. *NSPS Semi-Annual Excess Emissions Reports*: Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions of the applicable NSPS that occurred during the previous semi-annual period.

{Note: If there are no periods of excess emissions as defined in NSPS Subpart KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7 and Subpart KKKK]

39. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the fuel oil storage tank for use in the Annual Operating Report. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
043	One Large Gaseous-fueled Auxiliary Boiler (99 MMBTU/hr and 85,000 lb/hr)
044	Five Small Gaseous-fueled Process Heaters (3 MMBtu/hr)

APPLICABLE STANDARDS AND REGULATIONS

1. PSD and BACT Applicability: The Rules for the Prevention of Significant Deterioration (PSD) of Air Quality apply to this project and require BACT determinations for carbon monoxide (CO) and volatile organic compounds (VOC) for these emissions units.

   [Rule 62-212.400, F.A.C.]

2. NESHAP Subpart DDDDD Applicability: The 99 MMBTU/hr (85,000 lb/hr) auxiliary boiler is subject to all applicable requirements of 40 CFR 63, Subpart DDDDD, which applies to an industrial, commercial, or institutional boiler or process heater as defined in Sec. 63.7575 that is located at, or is part of, a major source of HAP as defined in Sec. 40 CFR 63.2.

   [40 CFR 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, or Institutional Boiler or Process Heater]

3. NSPS Subpart Dc Applicability: The 99 MMBTU/hr (85,000 lb/hr) auxiliary boiler is subject to all applicable requirements of 40 CFR 60, Subpart Dc which applies to Small Industrial, Commercial, or Institutional Boiler. Specifically, this emission unit shall comply with 40 CFR60.48c Reporting and Recordkeeping Requirements.

   [Rule 62-204.800(7)(b) and 40 CFR 60, Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, attached as Appendix Dc]

EQUIPMENT, CAPACITIES AND LIMITATIONS ON OPERATION

4. Equipment: The permittee is authorized to install, operate, and maintain one auxiliary boiler with a maximum design heat input of 99 MMBtu/hr (85,000 lb/hr) to produce steam during start up of the CTs and five 3 MMBtu/hr process heaters for the purpose of heating the natural gas supply.
   [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

5. Hours of Operation: The hours of operation of the limited use gas-fueled auxiliary boiler shall not exceed 1,000 hours per year. The gas-fueled process heaters are allowed to operate continuously (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C. and 40 CFR 63.7575]

EMISSIONS, FUELS AND TESTING REQUIREMENTS

6. Auxiliary Boiler Emissions Limits:

CO (BACT, Subpart DDDDD)	VOC (BACT)
0.08 lb/MMBtu, 400 ppmvd @3% O_2	10% Opacity, Natural Gas Specification of 2 gr S/100 SCF

   [Rule 62-212.400, F.A.C.; 40 CFR 60, Subpart Dc; 40 CFR 63, Subpart DDDDD]

7. Auxiliary Boiler Testing Requirements: This unit shall be stack tested to demonstrate initial compliance with the emission standards for CO and visible emissions. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each combined cycle unit.

   [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 63.7]

8. Auxiliary Boiler Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}

9. Annual CO Performance Test for Auxiliary Boilers: Pursuant to 40 CFR 63.7515(e) permittee shall conduct an annual CO test according to Sec. 63.7520. Each annual performance test must be conducted between 10 and 12 months after the previous performance test.

   [40 CFR 63.7515 and Rule 62-204.800(11)(b)84. F.A.C.]

10. Natural Gas Fired Process Heaters Emissions Limits:

CO (BACT)	VOC (BACT)
0.08 lb/MMBtu	10% Opacity, Natural Gas Specification of 2 gr S/100 SCF

   [Rule 62-212.400, F.A.C.]

11. Natural Gas Fired Process Heaters Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO and visible emissions. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each combined cycle unit. As an alternative, a Manufacturer certification of emissions characteristics of the purchased model that are at least as stringent as the BACT values can be used to fulfill this requirement.

    [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

12. Natural Gas Fired Process Heaters Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}

NOTIFICATION, REPORTING AND RECORDS

13. Notification: Initial notification is required for the limited use 99 MMBtu/hr gas-fueled auxiliary boiler. Initial notification is not required for the five small gas-fueled 3 MMBtu/hr process heaters. [40 CFR 63.9, 40 CFR 63.7506(c) and Rule 62-204.800(11)(b) F.A.C.]

14. Reporting: The permittee shall maintain records of the amount of natural gas used in the heaters and auxiliary boilers. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3] F.A.C.]

C. Distillate Fuel Oil Storage Tanks (EU-045)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
045	Two Nominal 3.5 million gallon distillate fuel oil storage tanks

APPLICABLE STANDARDS AND REGULATIONS

1. PSD and BACT Applicability: The Rules for the Prevention of Significant Deterioration (PSD) of Air Quality apply to this project and require BACT determinations for volatile organic compounds (VOC) for these emissions units.

NSPS APPLICABILITY

2. NSPS Subpart Kb Applicability: The distillate fuel oil tanks are not subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb. [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]

EQUIPMENT, CAPACITIES AND USAGE

3. Equipment: The permittee is authorized to install, operate, and maintain two 3.5 million gallon distillate fuel oil storage tank designed to provide low sulfur fuel oil to the gas turbines. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

4. Hours of Operation: The hours of operation are not restricted (8760 hours per year). [Applicant Request and Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING AND RECORDS

5. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for each storage tank for use in the Annual Operating Report. [Rule 62-4.070(3) F.A.C]

6. Fuel Oil Records: The permittee shall keep readily accessible records showing the maximum true vapor pressure of the stored liquid. The maximum true vapor pressure shall be less than 3.5 kPa. Compliance with this condition may be demonstrated by using the information from the respective Material Safety Data Sheets (MSDS) for the low sulfur fuel oil stored in the tanks. [Rule 62-4.070(3) and 62-212.400, F.A.C.]

D. Emergency Diesel Fire Pump (EU-046)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
046	One nominal 300-hp emergency diesel fire pump engine and 500 gallon fuel oil storage tank.

APPLICABLE STANDARDS AND REGULATIONS

1. PSD and BACT Applicability: The Rules for the Prevention of Significant Deterioration (PSD) of Air Quality apply to this project and require BACT determinations for carbon monoxide (CO) and volatile organic compounds (VOC) for these emissions units.

2. NSPS Subpart IIII Applicability: This fire pump engine is an Emergency Stationary Compression Ignition Internal Combustion Engine (Stationary ICE) and is subject to 40 CFR 60, Subpart IIII. It shall comply with 40 CFR 60, Subpart IIII only to the extent that the regulations apply to the emissions unit and its operations (e.g. fire pumps, horsepower, model year selected).

   [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines].

EQUIPMENT, CAPACITIES AND USAGE

3. Equipment: The permittee is authorized to install, operate, and maintain one diesel engine driven fire pump (approximately 300 hp) and an associated 500 gallon fuel oil storage tank.

4. Hours of Operation: The fire pump may operate in response to emergency conditions and 40 non-emergency hours per year for maintenance testing.
   [Applicant Request; Rule 62-210.200 (PTE), F.A.C.

EMISSIONS, FUELS AND TESTING REQUIREMENTS

5. Authorized Fuel: This unit shall fire low sulfur fuel oil (or superior fuel), which shall contain no more than 0.05% sulfur by weight. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

   Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods or other Department approved methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

6. Fire Pump Engine Emissions Limits:

   The following limits apply based on the size category of the fire pump located at the facility.

Size (hp)	CO (BACT, IIII)	NMHC*+NO_X (BACT for VOC, IIII)	PM
175 and greater	2.6 gm/bhp-hr	7.8 gm/bhp-hr	0.40

   Note 1. Non-Methane Hydrocarbons (NMHC) are surrogate for VOC.

7. Fire Pump Engine Certification: Manufacturer certification shall be provided to the Department in lieu of actual testing. [Rule 62-212.400 (BACT), F.A.C. and 40 CFR 60.4211]

SECTION 4. APPENDICES

CONTENTS

CITATION FORMATS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001"identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

SECTION 4. APPENDIX A

GENERAL PROVISIONS, SUBPART A FOR NSPS AND NESHAP

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

NESHAP - SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a National Emission Standards for Hazardous Air Pollutants of 40 CFR 63 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 63.1 Applicability.

§ 63.2 Definitions.

§ 63.3 Units and abbreviations.

§ 63.4 Prohibited Activities and Circumvention.

§ 63.5 Preconstruction Review and Notification Requirements.

§ 63.6 Compliance with Standards and Maintenance Requirements.

§ 63.7 Performance Testing Requirements.

§ 63.8 Monitoring Requirements.

GENERAL PROVISIONS, SUBPART A FOR NSPS AND NESHAP

§ 63.9 Notification Requirements.

§ 63.10 Recordkeeping and Reporting Requirements.

§ 63.11 Control Device Requirements.

§ 63.12 State Authority and Delegations.

§ 63.13 Addresses of State Air Pollution Control Agencies and EPA Regional Offices.

§ 63.14 Incorporation by Reference.

§ 63.15 Availability of Information and Confidentiality.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

Refer to the Draft BACT proposal discussed in the initial Technical Evaluation for this project and to the Final Determination issued with the Final permit for the rationale regarding the following BACT determination

Department's DRAFT BACT Summary for Combustion Turbines and Duct Burners

Emissions from each gas turbine shall not exceed the values given in the following table.

Pollutant	Fuel	Method of Operation [a]	Stack Test, 3-Run Average		CEMS [c] Block Average
			ppmvd @ 15% O_2	lb/hr [b]	ppmvd @ 15% O_2
Unit 4 HRSG Stacks					
CO	Oil	CT	8.0	40.4	8.0, 24-hr [d] 6, 12-month [f]
	Gas	CT	4.1	20.8	
		CT & DB	7.6	38.3	
VOC [e,g]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	
		CT & DB	1.5	3.8	
Unit 5CT and Unit 4 Bypass Stacks					
CO	Oil	CT	8.0	40.4	Not Applicable
	Gas	CT	4.1	20.8	
VOC [e]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	

a. CT means operation of a combustion turbine (CT) in simple cycle or in combined cycle without use of the duct burner (DB). CT & DB means operation in combined cycle mode and using the DB.

b. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

c. CEMS for CO are required only on the HRSG stacks. Other than startup, shutdown, fuel switching or documented malfunction the CT shall operate above 70% load during simple cycle operation.

d. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS on the HRSG stacks. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, or duct burner modes. Separate CO tests shall be conducted under simple cycle mode on the CT stacks.

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

f. Rolling Average. Enforcement discretion may be exercised for up to 12 months with respect to the 6 ppmvd @15% O_2 limit for any CT/Duct-fired HRSG upon notification by the permittee of intent to install oxidation catalyst. The permittee shall have 12 months to complete the oxidation catalyst installation. From time of notification to installation of the catalyst all partial or complete calendar months shall be excluded from the 12-month rolling average.

g. Compliance with the CO CEMS based limits shall be deemed as compliance with the VOC limit.

Given the 24-hour and annual BACT CO limits, it is reasonable to expect that formaldehyde emissions will be less than 0.091 ppmvd @15% O_2. This value is equal to the applicable formaldehyde limit of Part 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (CT MACT). Siemens test data supplied by the applicant includes values less than 0.006 ppmvd @15% O_2 for the F class engine at base load without an oxidation catalyst.

Department's DRAFT BACT Summary for Auxiliary Boiler and Gas Heaters

The CO BACT limit for the fuel heaters and the auxiliary boiler is 0.08 lb CO/MMBtu (equates to approximately 84 lb CO/MMscf). A requirement for the exclusive use of natural gas and a 10 % opacity limit is BACT for VOC.

Department's DRAFT BACT Summary for Emergency Fired Pump

The Department's BACT for the emergency fire pump (175 HP or greater) is compliance with the NSPS standards for CO and VOC and use of 0.05% sulfur fuel oil.

SECTION 4. APPENDIX GC
GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. 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.

2. 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.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and 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 or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. 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.

5. 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 Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or 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.

7. 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 a reasonable time, access to the premises, where the permitted activity is located or conducted to:

   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. 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.

8. 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:

   a. A description of and cause of non-compliance; and

   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

   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.

9. 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 403.73 and 403.111, Florida

Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. 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.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, 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.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (X);
    b. Determination of Prevention of Significant Deterioration (X);
    c. Compliance with New Source Performance Standards (X); and
    d. Compliance with National Emission Standards for Hazardous Air Pollutants for Source Categories (X).

14. The permittee shall comply with the following:

    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 or this permit. These materials shall be retained at least three 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;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.

15. 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 that 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.

SECTION 4. APPENDIX CC
COMMON CONDITIONS

{Permitting Note: Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the facility.}

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

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

5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permitee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]

6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]

7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]

8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]

9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

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

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

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

13. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

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

    c. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

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

14. Determination of Process Variables

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

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

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

15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C.

16. Test Notification: The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator. [Rule 62-297.310(7)(a)9, F.A.C.]

17. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

18. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the

test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

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

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

RECORDS AND REPORTS

19. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]
20. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

A 99 MMBTu/hr (85,000 lb/hr) auxiliary boiler will serve the combined cycle unit system to produce steam during start up of the CTs. The auxiliary boiler is regulated as Emissions Unit 043. The provisions of this Subpart may be provided in full upon request.

{Note: Only applicable definitions have been included.}

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units which meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam ch a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Natural gas means (1) a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane, or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835-86, 87, 91, or 97, "Standard Specification for Liquefied Petroleum Gases" (incorporated by reference -- see § 60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

§ 60.42c Standard for sulfur dioxide.

§ 60.43c Standard for particulate matter.

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

§ 60.46c Emission monitoring for sulfur dioxide

§ 60.47c Emission monitoring for particulate matter.

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by § 60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

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

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

On July 6, 2006, EPA published the final NSPS Subpart KKKK (40 CFR 60) provisions for combustion turbines in the Federal Register. Although not yet adopted by Rule 62-204.800(8), F.A.C., the combustion turbines shall comply with the applicable federal requirements. These combustion gas turbines are regulated as Emissions Units 038, 039, 040, 041 and 042.

Source: Federal Register dated 7/6/06

Introduction
60.4300 What is the purpose of this subpart?

Applicability
60.4305 Does this subpart apply to my stationary combustion turbine?
60.4310 What types of operations are exempt from these standards of performance?

Emission Limits
60.4315 What pollutants are regulated by this subpart?
60.4320 What emission limits must I meet for nitrogen oxides (NOX)?
60.4325 What emission limits must I meet for NOX if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?
60.4330 What emission limits must I meet for sulfur dioxide (SO2)?

General Compliance Requirements
60.4333 What are my general requirements for complying with this subpart?

Monitoring
60.4335 How do I demonstrate compliance for NOX if I use water or steam injection?
60.4340 How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?
60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?
60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?
60.4355 How do I establish and document a proper parameter monitoring plan?
60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?
60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?
60.4370 How often must I determine the sulfur content of the fuel?

Reporting
60.4375 What reports must I submit?
60.4380 How are excess emissions and monitor downtime defined for NOX?
60.4385 How are excess emissions and monitoring downtime defined for SO2?
60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?
60.4395 When must I submit my reports?

Performance Tests
60.4400 How do I conduct the initial and subsequent performance tests, regarding NOX?
60.4405 How do I perform the initial performance test if I have chosen to install a NOX-diluent CEMS?
60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?
60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

Definitions
60.4420 What definitions apply to this subpart?

Table 1 to Subpart KKKK of Part 60-Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

The combustion gas turbines are subject to the applicable requirements of the 40 CFR 63, Subpart YYYY. The provisions of this Subpart may be provided in full upon request. These combustion gas turbines are regulated as Emissions Unit 038, 039, 040, 041 and 042.

Applicability of NESHAP Subpart YYYY

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

Staying of the Rule

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

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

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

Requirements

The applicable requirements in Subpart YYYY are:

§ 63.6145 What notifications must I submit and when?

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

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

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

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

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

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

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

SECTION 4. APPENDIX DDDDD
NESHAPS REQUIREMENTS FOR INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS AND PROCESS HEATERS

The auxiliary 99 MMBtu/hr boiler and the process heaters are subject to the applicable requirements of this 40 CFR 63, Subpart DDDDD. These emission units are regulated as E.U. 043 and 044 respectively. The provisions of this Subpart may be provided in full upon request.

Source: Federal Register Dated 9/12/04

What This Subpart Covers
63.7480 What is the purpose of this subpart?
63.7485 Am I subject to this subpart?
63.7490 What is the affected source of this subpart?
63.7491 Are any boilers or process heaters not subject to this subpart?
63.7495 When do I have to comply with this subpart?

Emission Limits and Work Practice Standards
63.7499 What are the subcategories of boilers and process heaters?
63.7500 What emission limits, work practice standards, and operating limits must I meet?

General Compliance Requirements
63.7505 What are my general requirements for complying with this subpart?
63.7506 Do any boilers or process heaters have limited requirements?
63.7507 What are the health-based compliance alternatives for the hydrogen chloride (HCl) and total selected metals (TSM) standards?

Testing, Fuel Analyses, and Initial Compliance Requirements
63.7510 What are my initial compliance requirements and by what date must I conduct them?
63.7515 When must I conduct subsequent performance tests or fuel analyses?
63.7520 What performance tests and procedures must I use?
63.7521 What fuel analyses and procedures must I use?
63.7522 Can I use emission averaging to comply with this subpart?
63.7525 What are my monitoring, installation, operation, and maintenance requirements?
63.7530 How do I demonstrate initial compliance with the emission limits and work practice standards?

Continuous Compliance Requirements
63.7535 How do I monitor and collect data to demonstrate continuous compliance?
63.7540 How do I demonstrate continuous compliance with the emission limits and work practice standards?
63.7541 How do I demonstrate continuous compliance under the emission averaging provision?

Notifications, Reports, and Records
63.7545 What notifications must I submit and when?
63.7550 What reports must I submit and when?
63.7555 What records must I keep?
63.7560 In what form and how long must I keep my records?

Other Requirements and Information
63.7565 What parts of the General Provisions apply to me?
63.7570 Who implements and enforces this subpart?
63.7575 What definitions apply to this subpart?

Tables to Subpart DDDDD of Part 63
Table 1 to Subpart DDDDD of Part 63--Emission Limits and Work Practice Standards
Table 2 to Subpart DDDDD of Part 63--Operating Limits for Boilers and Process Heaters With Particulate Matter Emission Limits
Table 3 to Subpart DDDDD of Part 63--Operating Limits for Boilers and Process Heaters With Mercury Emission Limits and Boilers and Process Heaters That Choose to Comply With the Alternative Total Selected Metals Emission Limits
Table 4 to Subpart DDDDD of Part 63--Operating Limits for Boilers and Process Heaters With Hydrogen Chloride Emission Limits
Table 5 to Subpart DDDDD of Part 63--Performance Testing Requirements
Table 6 to Subpart DDDDD of Part 63--Fuel Analysis Requirements
Table 7 to Subpart DDDDD of Part 63--Establishing Operating Limits
Table 8 to Subpart DDDDD of Part 63--Demonstrating Continuous Compliance
Table 9 to Subpart DDDDD of Part 63--Reporting Requirements
Table 10 to Subpart DDDDD of Part 63--Applicability of General Provisions to Subpart DDDDD (See Appendix B)

Appendices to Subpart DDDDD
Appendix A to Subpart DDDDD--Methodology and Criteria for Demonstrating Eligibility for the Health-Based Compliance Alternatives Specified for the Large Solid Fuel Subcategory
Appendix B to Subpart DDDDD--Applicability of General Provisions to Subpart DDDDD

The emergency fired pump is subject to the applicable requirements of 40 CFR 60, Subpart IIII. This unit is regulated as emissions unit (E.U.) 046. The provisions of this Subpart may be provided in full upon request.

Source Federal Register Dated 7/11/06. EFECTIVE 9/11/06

Subpart IIII–Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

What This Subpart Covers
60.4200 Am I subject to this subpart?

Emission Standards for Manufacturers
60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?
60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?
60.4203 How long must my engines meet the emission standards if I am a stationary CI internal combustion engine manufacturer?

Emission Standards for Owners and Operators
60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Fuel Requirements for Owners and Operators
60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

Other Requirements for Owners and Operators
60.4208 What is the deadline for importing and installing stationary CI ICE produced in the previous model year?
60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

Compliance Requirements
60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?
60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

Testing Requirements for Owners and Operators
60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?
60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Notification, Reports, and Records for Owners and Operators
60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

Special Requirements
60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?
60.4216 What requirements must I meet for engines used in Alaska?

60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

General Provisions
60.4218 What parts of the General Provisions apply to me?

Definitions
60.4219 What definitions apply to this subpart?

Tables to Subpart IIII of Part 60
Table 1 to Subpart IIII of Part 60--Emission Standards for Stationary Pre-2007 Model Year Engines with a displacement of < 10 liters per cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and with a displacement of < 10 liters per cylinder
Table 2 to Subpart IIII of Part 60--Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE < 37 KW (50 HP) and with a Displacement of < 10 liters per cylinder
Table 3 to Subpart IIII of Part 60--Certification Requirements for Stationary Fire Pump Engines
Table 4 to Subpart IIII of Part 60--Emission Standards for Stationary Fire Pump Engines
Table 5 to Subpart IIII of Part 60--Labeling and Recordkeeping Requirements for New Stationary Emergency Engines
Table 6 to Subpart IIII of Part 60--Optional 3-Mode Test Cycle for Stationary Fire Pump Engines
Table 7 to Subpart IIII of Part 60--Requirements for Performance Tests for Stationary CI ICE with a displacement of >=30 liters per cylinder
Table 8 to Subpart IIII of Part 60--Applicability of General Provisions to Subpart IIII

SECTION 4. APPENDIX XS
SEMIANNUAL NSPS EXCESS EMISSIONS REPORT

FIGURE 1. SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant *(Circle One)*: SO_2 NO_X TRS H_2S CO Opacity

Reporting period dates: From _____ to _____

Company: _____

Emission Limitation: _____

Address: _____

Monitor Manufacturer: _____

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 emissions ____	2. Total CMS Downtime ____
3. Total duration of excess emissions x (100) / [Total source operating time] ____ %[2]	3. [Total CMS Downtime] x (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 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes since the last in CMS, process or controls.

I certify that the information contained in this report is true, accurate, and complete.

Name: _____

Signature: _____ *Date*: _____

Title: _____

FINAL DETERMINATION

PERMITTEE

Florida Power Corporation dba
Progress Energy Florida (PEF)
1601 Weedon Island Drive
St. Petersburg, Florida 33711

PERMITTING AUTHORITY

Florida Department of Environmental Protection (Department)
Division of Air Resource Management
Bureau of Air Regulation, Special Projects Section
2600 Blair Stone Road, MS #5505
Tallahassee, Florida 32399-2400

PROJECT

Air Permit No. PSD-FL-381A
Project No. 1030011-012-AC
Bartow Repowering Project Permit Modifications
Progress Energy Florida (PEF) Bartow Power Plant

The project is to modify PSD permit [reference: DEP File No. 1030011-010-AC (PSD-FL-381)] that authorized the replacement of the three residual fuel oil-fired steam electrical generators with a natural gas-fueled combined cycle unit and a natural gas-fueled simple cycle unit. The key modification to this PSD permit is the elimination of an interim period during which the four combustion turbines that comprise the combined cycle unit (presently under construction) can operate in simple cycle (higher emitting) mode. This project does not trigger PSD.

NOTICE AND PUBLICATION

The Department distributed a Notice of Intent to Issue Air Permit package on September 8, 2008. The applicant published the Public Notice of Intent to Issue Air Permit in the St. Petersburg Times on September 15. The Department received the proof of publication on September 25.

COMMENTS

No comments on the Draft Permit were received from the applicant, the public, the Pinellas County Department of Environmental Management Air Quality Division, the Department's Southwest District Office, the EPA Region 4 Office, the National Park Service or the U.S. Fish and Wildlife Service.

Clarification Regarding Condition 6:

The Department added a note to Condition 6 regarding the tuning of combustors. The drafted language striking VOC from the condition (as originally drafted) could have been misconstrued to infer that tuning prior to initial testing does not seek to insure compliance with the VOC emission limit. Instead of striking VOC from the condition, a note will be added indicating that testing is not required during tuning. VOC testing to demonstrate compliance with the applicable limit is nevertheless required by permit conditions.

CONCLUSION

The final action of the Department is to issue the permit as noted during the public notice period.

Florida Department of Environmental Protection
Bob Martinez Center
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

October 1, 2008

Electronically Sent – Received Receipt Requested

Thomas.Lawery@pgnmail.com
Mr. Thomas Lawery, Plant Manager
P.L. Bartow Power Plant
Florida Power Corporation dba
Progress Energy Florida (PEF)
1601 Weedon Island Drive
St. Petersburg, Florida 33711

Re: DEP File No. 1030011-012-AC (PSD-FL-381A)
P.L. Bartow Power Plant Repowering Project
Modification of Interim Operation Modes

Dear Mr. Lawery:

On May 6, 2008, PEF submitted a permit modification application requesting changes to certain specific conditions of the air construction permit [reference: DEP File No. 1030011-010-AC (PSD-FL-381)] that authorized the replacement of the three residual fuel oil-fired steam electrical generators with a natural gas-fueled combined cycle unit and a natural gas-fueled simple cycle unit.

The key requested modification to the permit is the elimination of an interim period during which the four combustion turbines that comprise the combined cycle unit (presently under construction) can operate in simple cycle (higher emitting) mode. The requests were assessed in the Department's Technical Evaluation and Preliminary Determination issued on September 8, 2008.

The following sections or conditions in Permit No. 1030011-010-AC (PSD-FL-381) are hereby modified as shown below in strike through (~~strike through~~) and double underline format.

Section III, Subsection A, Emissions Unit Table

The title of the table shall now read:

Emissions Units Comprising Combined Cycle Unit 4 and Simple Cycle Unit 5.

(The rest of the table is unchanged)

6. DLN Combustion: The permittee shall install, operate and maintain Dry Low NO_x (DLN) systems to control NO_x emissions from each CT when firing natural gas. Prior to the initial emissions performance tests required for each CT, the DLN combustors and automated combustion turbine control system shall be tuned without a selective catalytic reduction (SCR) system in operation to achieve the permitted CO, VOC and NO_x levels for simple cycle operation. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations or industry standards.

{Permitting Note: Specific VOC testing is not required during the tuning conducted prior to the initial compliance test.}

14. Deleted in accordance with Permit Modification 1030011-012-AC.
~~Temporary Simple Cycle Operation of Two CTs Prior to Permanent Shutdown of Units 1, 2 and 3: The permittee may select any two of the five new CTs to be operated as simple cycle units prior to shutdown of Units 1, 2 and 3. The restrictions included in this condition apply only to those CTs chosen, and only during the described period. Once selected, only those CTs chosen may be operated prior to shutdown of Units 1, 2 and 3 in accordance with the following restrictions:~~

~~a. *Restriction on SC Operation*:~~

- ~~The combined operation of the two CTs shall not exceed 1,100 hours.~~
- ~~A NO_x CEMS shall be installed and operating in each stack prior to startup of the CTs in order to collect and record data for the purpose of demonstrating compliance with this requirement. Notwithstanding the relative accuracy test audit (RATA) grace period described in 40 CFR 75 Appendix B, the NO_x CEMS shall be fully certified in accordance with the requirements of 40 CFR 75 (including a RATA), within 30 operating days but not later than 60 calendar days after startup of the CTs.~~
- ~~Total emissions of NO_x from the two CTs shall not exceed 39 tons during all operation including startups, shutdowns and malfunctions as measured and recorded by the required NO_x continuous emissions monitoring systems (CEMS) during the temporary period. Data recorded before and after CEMS certification shall be included in the calculation.~~
- ~~Each CT shall be stack tested to demonstrate initial compliance with the applicable Subpart KKKK NO_x emission standard for each fuel to be fired. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit. Data collected during the above described RATA may be used to satisfy this 60 day test requirement provided all requirements of 40 CFR 60.8 and Subpart KKKK are met.~~
- ~~The BACT emissions standards of specific condition 18 do not apply to these CTs prior to Unit 1, 2 and 3 shutdown. Following shutdown of Units 1, 2 and 3 all restrictions of this permit apply, including the BACT limits of specific condition 18.~~

~~b. *Restriction on CC Operation:* No combined cycle operation of any unit is allowed prior to permanent shutdown of Units 1, 2, and 3.~~

~~c. *Monthly Operations Summary*: By the 10th calendar day of each month, the permittee shall record the following in a written or electronic log for each CT for the previous month of operation: fuel consumption, hours of operation, NO_x emissions in total tons for the month, and NO_x emissions in total tons for the described restricted period of operation. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D.~~

~~*{Permitting note: The limitation on total NO_x emissions and adherence to the emissions standards in Specific Conditions 18, 19 and 20 along with the compliance and recordkeeping requirements of this condition will effectively ensure that emissions increases of all PSD pollutants from the selected CTs operated in SC mode prior to Unit 1, 2 and 3 shutdown will be less than their respective Significant Emissions Rates per Rule 62-210.200 (Definitions-SER), F.A.C.}*~~

~~[Rules 62-4.070(3), 62-210.200(PTE) and 62-212.400(12)(PSD Avoidance), F.A.C.; 40 CFR 60.8, and 40 CFR Subpart KKKK]~~

15. Restricted Operation: The permittee shall not exceed the following parameters following shutdown of Units 1, 2 and 3:

    a. The hours of operation of the CTs are not limited (8,760 hours per year).

    b. Distillate oil firing is limited to ~~1,000 hours per CT (i.e.~~ 5,000 hours total aggregate for all five CTs~~)~~ (based on an average of 1,000 hours per CT) during any consecutive 12-month period.

    c. Operation of the DBs is limited to ~~2,434 hours per DB (i.e.~~ 9,736 hours aggregate for four DBs~~)~~ (based on an average of 2,434 hours per DB) during any consecutive 12-month period.

    d. Power (steam) augmentation shall be limited to 6,752 hours aggregate for the four CTs comprising Unit 4 (based on an average of 1,688 hours per CT during any consecutive 12-month period.

    e. Other than startup, shutdown, fuel switching or documented malfunction ~~the CTs, shall operate above 70% load during simple cycle operation.~~ simple cycle CT operations shall be at a load not less than 45% or that load at which compliance was demonstrated at initial, whichever is higher.

16. Methods of Operation: Subject to the restrictions and requirements of this permit, the CTs may commence commercial operation and thereafter operate under the following methods of operation after ~~shutdown of~~ Units 1, 2 and 3 cease commercial operation:

    {Commence commercial operation means to have begun to generate electricity for sale, including the sale of test generation.}

    (The rest of Condition 16 is unchanged)

Condition 17, Footnote b. will be modified as follows:

    b. A CEMS for NO_X shall be installed on the CT stacks and on the HRSG stacks. Correction to 15% O_2 is required ~~not allowed~~ consistent with the provisions of 40 CFR 60, Subpart KKKK.

    (The rest of Condition 17 is unchanged)

Condition 18, Footnote c. will be modified as follows:

    c. CEMS for CO are required only on the HRSG stacks. Other than startup, shutdown, fuel switching or documented malfunction ~~the CTs, shall operate above 70% load during simple cycle operation.~~ simple cycle CT operations shall be at a load not less than 45% or that load at which compliance was demonstrated at initial, whichever is higher.

    (The rest of Condition 18 is unchanged)

What load was testing done at?

Condition 20.a. will be modified as follows:

    a. *Visible Emissions*: Visible emissions shall not exceed 10 percent opacity for each 6-minute block average. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.~~23~~.

    (The rest of Condition 20 is unchanged)

Condition 25.d. will be modified as follows:

    b. *Simple Cycle CT Startup*: For startup of a CT for the purpose of operation in simple cycle mode, up to 1 hour or 60 minutes of CEMS data in any 24-hour period of excess emissions can be excluded.

    (The rest of Condition 25 is unchanged)

27. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

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

No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

28. Initial Compliance Determinations: Each CT shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. Reference method data collected during the required Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the initial CO and NO_X compliance tests. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO mass rate emissions standards. With appropriate flow measurements (or fuel measurements and approved F-factors), the EPA Method 25A instrumental data may be used to demonstrate initial compliance with the VOC mass rate emissions standards. CO and NO_X emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, oxidation catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

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

a. *CO Monitors.* The CO monitors shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A within 60 calendar days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60~~ and shall be based on a continuous sampling train~~. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.

b. *NO_X Monitors.* Each NO_X monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_X monitor shall be performed using EPA ~~Method 20 or~~ 7E in Appendix A of 40 CFR 60.

c. *Diluent Monitors.* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where $\underline{NO_X}$ and CO are ~~is~~ monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

Condition 32, first bullet will be modified as follows:

32. CEM Data Requirements:

- *Data Collection*: Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd of $\underline{NO_X}$ and CO corrected to 15% oxygen ~~and as ppmvd of NO_X (uncorrected)~~. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions.

(The rest of Condition 32 is unchanged)

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

Executed in Tallahassee, Florida.

Joseph Kahn, Director
Division of Air Resource Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Final Permit Modification was sent by electronic mail (or a link to these documents made available electronically on a publicly available server) with received receipt requested before the close of business on 10/1/08 to the persons listed below:

cc: Thomas Lawery, PEF: thomas.lawery@pgnmail.com
Chris Bradley, PEF: chris.bradley@pgnmail.com
Scott Osbourn, P.E., Golder: sosbourn@golder.com
Dee Morse, NPS: dee_morse@nps.gov
Meredith Bond, U.S. FWS: meredith_bond@fws.gov
Kathleen Forney: forney.kathleen@epa.gov
Mara Nasca, DEPSWD: mara.nasca@dep.state.fl.us
Mayor, City of St. Petersburg: mayor@stpete.org
Administrator, Pinellas County: sspratt@pinellascounty.org
Peter Hessling, PCDEM: phesslin@pinellascounty.org
Victoria Gibson, DEP BAR: victoria.gibson@dep.state.fl.us

Clerk Stamp

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

(Clerk) 10/1/08 (Date)

Memorandum

Florida Department of
Environmental Protection

TO: Joseph Kahn, Division of Air Resource Management

THROUGH: Trina Vielhauer, Bureau of Air Regulation
A. A. Linero, Special Projects Section

FROM: Teresa Heron, Special Projects Section T.H

DATE: September 30, 2008

SUBJECT: DEP File Nos. 1030011-012-AC (PSD-FL-381A)
P.L. Bartow Power Plant Repowering Project
Modification of Permit – Removal of Interim Operating Mode

The Final Permit for this project is attached for your approval and signature. The project authorizes the modification of the original PSD permit to eliminate the interim period during which the four combustion turbines that comprise the combined cycle unit (presently under construction) can operate in simple cycle (higher emitting) mode. The existing P.L. Bartow Power Plant is located at 1601 Weedon Island Drive in St. Petersburg, Pinellas County, Florida.

We recommend your approval of the attached Final Permit for this project.

Attachments

STATEMENT OF BASIS

Progress Energy, P.L. Bartow Power Plant
Facility ID No. 1030011
Pinellas County

Final Permit No. 1030011-013-AV

Title V Air Operation Permit Revision

CAIR Part

PROJECT DESCRIPTION

On May 7, 2008, the applicant submitted a CAIR Part Form in order to incorporate the Clean Air Interstate Rule provisions into Title V air operation permit No. 1030011-009-AV.

On July 11, 2008, the D.C. Circuit Court issued a remand & vacatur order of the CAIR regulations. Due to the vacatur status, the processing of the CAIR Part was stopped. On December 23, 2008 the D.C. Circuit Court issued a remand without vacatur order of the CAIR regulations. The processing of the revision request to incorporate the Clean Air Interstate Rule provisions into the Title V air operation permit is hereby resumed.

FACILITY DESCRIPTION

This existing facility consists of three fossil fuel fired steam generators designated as Unit Nos. 1, 2 & 3, four gas turbine peaking units designated as Gas Turbine Peaking Unit #P-1, P-2, P-3, & P-4, relocatable diesel generators and a pipeline heating boiler. The generators commenced operations in 1958, 1961, 1963, respectively and the peaking units commenced operation in 1972.

PROCESSING SCHEDULE AND RELATED DOCUMENTS

Application for a Title V Air Operation Permit Revision received on May 7, 2008.
Draft/Proposed Permit posted on web site on June 26, 2008.
Public Notice published on January 28, 2009.
Proof of Publication of Public Notice received on February 2, 2009.
Notification to U.S. EPA Region 4 of Publication of Public Notice on February 3, 2009.

PROJECT REVIEW

CAIR Part

- The CAIR Part Form is now a part of this permit and has been incorporated as Section V., CAIR Part Form. This section identifies the units that must comply with the standard requirements and special provisions set forth in the CAIR Part Form.
- The identification numbers on the CAIR Part Form for the units were incorrect. The EPA unit identification numbers under the acid rain program for the units have already been established.

CONCLUSION

This project revises Title V air operation permit No. 1030011-009-AV, which was effective January 1, 2005. This Title V air operation permit revision is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210 and 62-213, Florida Administrative Code (F.A.C.). In accordance with the terms and conditions of this permit, the above named permittee is hereby authorized to operate the facility as shown on the application and approved drawings, plans, and other documents, on file with the permitting authority.

Clean Air Interstate Rule (CAIR).

Operated by: Progress Energy
Plant Name: P.L. Bartow Power Plant
ORIS Code: 0634

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

E.U. ID No.	EPA Unit ID#	Brief Description
-001	01	No. 1 Unit, Fossil Fuel Fired Steam Generator with Electrostatic Precipitator
-002	02	No. 2 Unit, Fossil Fuel Fired Steam Generator
-003	03	No. 3 Unit, Fossil Fuel Fired Steam Generator
-005	TBE	Gas Turbine Peaking Unit #P-1
-006	TBE	Gas Turbine Peaking Unit #P-2
-007	TBE	Gas Turbine Peaking Unit #P-3
-008	TBE	Gas Turbine Peaking Unit #P-4
-038	TBE	Unit 4A – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
-039	TBE	Unit 4B – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
-040	TBE	Unit 4C – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
-041	TBE	Unit 4D – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator

"TBE" - to be established

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 section. [Chapter 62-213, F.A.C. and Rule 62-210.200, F.A.C.]

Clean Air Interstate Rule (CAIR) Part

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

This submission is: ☑ New ☐ Revised ☐ Renewal

STEP 1

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

Plant Name: P.L. BARTOW POWER PLANT	State: Florida	ORIS or EIA Plant Code: 0634

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
EU001	X	X	X		
EU002	X	X	X		
EU003	X	X	X		
EU005	X	X	X		
EU006	X	X	X		
EU007	X	X	X		
EU008	X	X	X		
EU038	X	X	X	06/01/09	05/25/09
EU039	X	X	X	06/01/09	05/25/09
EU040	X	X	X	06/01/09	05/25/09
EU041	X	X	X	06/01/09	05/25/09

DEP Form No. 62-210.900(1)(b) – Form
Effective: 3/15/06

1

P.L. BARTOW POWER 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.

P.L. BARTOW POWER 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.

P.L. BARTOW POWER 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, 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.

P.L. BARTOW POWER 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: Brenda Brickhouse	Title: Director, Environmental Services Section
Company Owner Name FLORIDA POWER CORPORATION DBA PROGRESS ENERGY FLORIDA, INC.	
Phone: 727.820.5153	E-mail Address: Brenda.Brickhouse@pgnmail.com
Signature	Date 4/21/08

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

5

ATTACHMENT BA-FI-C7
Compliance Report and Plan

ATTACHMENT BA-FI-C7

COMPLIANCE PLAN

Background

Florida Power Corporation dba Progress Energy Florida, Inc. (PEF) repowered its existing P.L. Bartow Power Plant (Facility ID No. 1030011) in Pinellas County, Florida. The project site is approximately 675 acres in size and presently contains the existing P.L. Bartow Power Plant. The site is located in eastern Pinellas County on Tampa Bay at 1601 Weedon Island Drive, St. Petersburg, Pinellas County; UTM Coordinates: Zone 17, 342.4 km East and 3,082.6 km North; Latitude: 27° 52' 10" North and Longitude: 82° 35' 59" West.

The permittee must apply for a TV operation permit no later than 180 days after commencing operation (i.e., 180 days after the commence operation date of November 5, 2008 is May 4, 2009). Therefore, this application is being submitted even though the compliance demonstrations required under the air construction permit (1030011-012-AC and PSD-FL-381A) have not yet been fully completed. Due to these circumstances, this application also includes this Compliance Plan to address those compliance requirements that have yet to be demonstrated.

Repowering Project

This Compliance Plan addresses the repowering project (the Project) at the Bartow Power Plant. The three existing boilers (EU ID Nos. 001, 002 and 003) will be replaced with a 4-on-1 combined cycle power block. This power block configuration consists of four combustion turbines (CTs), with associated heat recovery steam generators (HRSGs), exhausting to one steam turbine (ST) generator. Also, the Project includes duct burner (DB) firing, power augmentation (PA), and evaporative cooling, resulting in an estimated increase of 827 MW (winter) over the existing plant's capacity.

A separate generating unit, a fifth CT in a simple cycle mode, nominally rated at 190 MW (winter), as well as the fifth of five fuel gas heaters, have not yet been constructed. However, these units are addressed in this air application, as they remain in PEF's plans for the site. An auxiliary boiler, nominally rated at 99 MMBtu/hr, was included in the initial air application and air construction permit, but has also not yet been constructed. This unit may also be required for future site operation and is, therefore, addressed in the TV application for revision and renewal.

PEF is aware that authorization to construct will expire if construction is not commenced within 18 months of receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. PEF began construction on the Project within 18 months of permit issuance and there has not been any gap in continuous construction. Finally, if the current construction permit expiration date (March 31, 2010) does not provide sufficient time to complete construction, perform required testing, submit test reports

and submit a supplemental application to the Department, PEF is aware that, for good cause, the PSD air construction permit expiration date may be extended.

As stated previously, this application is being submitted even though the compliance demonstrations required under the air construction permit (1030011-012-AC and PSD-FL-381A) have not yet been fully completed. There are several attachments to this Compliance Plan to summarize the compliance requirements that have been addressed, as well as those compliance requirements that have yet to be demonstrated. Attached is a table entitled *"Construction and Startup Activity Requirements"*, which includes the action item or underlying requirement, the associated permit condition, the due date description and any applicable comment regarding this item (e.g., the item submittal or completion date, etc.). In addition, attached is a *"Master Testing Matrix"* that summarizes those items completed, those that are underway and those that are yet to be initiated.

Existing Unit Retirement

The existing Bartow Power Plant (Facility ID No. 1030011) consists of three fossil fuel-fired electric utility steam generating units (EUSGUs), a pipeline heating boiler, four gas turbine peaking units and as-needed relocatable diesel generator(s). A brief description of the existing EUSGUs to be retired is provided below.

Unit No. 1 (Emissions Unit No. -001) is a front-fired, fossil fuel steam generator which produces 120 megawatts of electric power. The maximum heat input rate is 1,220 million British thermal units per hour (MMBtu/hr) and the unit fires No. 2 through No. 6 fuel oil, and on-specification used oil. Unit 1 began commercial service in 1958.

Unit No. 2 (Emissions Unit No. -002) is a tangential-fired fossil fuel fired steam generator which produces 120 megawatts of electric power. The maximum heat input rate is 1,317 million Btu per hour and the unit fires No. 2 through No. 6 fuel oil, on-specification used oil, and propane. Unit 2 began commercial service in 1961.

Unit No. 3 (Emissions Unit No. -003) is a tangential-fired fossil fuel fired steam generator which produces 225 megawatts of electric power. The maximum heat input rate is 2,211 million Btu per hour and the unit fires No. 2 through No. 6 fuel oil, on-specification used oil, natural gas, and propane. Unit 3 began commercial service in 1963.

Permit No. 1030011-012-AC, Condition 16, indicates that the new CTs (the Project) may commence commercial operation after the existing Units 1, 2 and 3 cease commercial operation. Therefore, in order to meet the projected in-service date for the Project of June 1, 2009, these three EUSGUs would be required to cease operation on that date. The four existing gas turbine peaking units (Emissions Unit Nos. -005 through -008), as well as the pipeline heating boiler (Emissions Unit No. -004), are unaffected by this project and will remain after the project is complete. Finally, the revised lists of unregulated emission units and insignificant activities reflect the retirement of other ancillary equipment, as well as the correction of previous errors.

Air Quality Regulatory Submittal Activities – Construction and Startup
FL DEP Air Permit No. PSD-FL-381

Progress Energy/Florida Power Corporation
P. L. Bartow Power Plant Repowering Project – Units 4A, 4B, 4C, and 4D
St. Petersburg, Pinellas County, Florida

Revision 04/24/09

CONSTRUCTION AND STARTUP ACTIVITY REQUIREMENTS

1	Letter Notification – Commencement of Construction (Units 4A-4D)	40 CFR Part 60 §60.7(a)(1)	≤ 30 days after commencement of construction	Submitted on 02/08/07
2*	Letter Notification – Anticipated Commercial Operation (Units 4A-4D)	40 CFR Part 75 §75.61(a)(2)(i)	≥ 45 days prior to anticipated commercial operation (synch-to-grid)	Submitted on 07/25/08
3	Letter Notification – Actual Startup (Units 4A-4D)	40 CFR Part 60 §60.7(a)(3)	≤ 15 days after actual startup	SU letter (4A bypass): Submitted 12/10/08 SU letter (4B bypass): Submitted 11/07/08 SU letter (4C bypass): Submitted 12/02/08 SU letter (4D bypass): Submitted 12/30/08 SU letter (Units 4A -4D HRSG): Submitted as a single merged letter on 03/07/09
4*	Letter Notification – Actual Commercial Operation (Units 4A-4D)	40 CFR Part 75 §75.61(a)(2)(ii)	≤ 7 days after actual commercial operation (synch-to-grid)	CCO letter (4A): Submitted 12/09/08 CCO letter (4B): Submitted 11/07/08 CCO letter (4C): Submitted 11/24/08 CCO letter (4D): Submitted 12/23/08
5	NSPS/BACT compliance testing protocol (Units 4A-4D)	No specific requirement	≥ 30 days prior to [anticipated] compliance testing	NSPS test protocol (bypass) submitted 10/22/08 NSPS test protocol (HRSG) submitted 04/09/09
6	CO CEMS certification testing protocol (Units 4A-4D)	No specific requirement	≥ 21 days prior to [anticipated] certification testing	Submitted on 10/03/08

CONSTRUCTION AND STARTUP ACTIVITY REQUIREMENTS *continued*

No.	Action/Item Requirement	Permit Condition	Due Date Description	Comments
7a*	Initial monitoring plan (Units 4A-4D)	40 CFR Part 75 §75.62(a); §75.53(e); §75.53(f); §75.73(e)	≥ 21 days prior to [anticipated] certification testing *[changed from 45 to 21 days effective 01/24/08]*	Submitted on 09/24/08
7b*	Acid Rain/NO_x CEMS certification testing protocol (Units 4A-4D)	40 CFR Part 75 §75.53(e)(2)(i)		Submitted on 09/24/08
8*	Notice of anticipated NO_x CEMS certification testing dates (Units 4A-4D)	40 CFR Part 75 §75.61(a)(1)(i); §75.20(g)(2)	≥ 21 days prior to [anticipated] testing; ≥ 7 days prior to revised actual test date (if applicable)	Submitted on 10/09/08
9	Notice of anticipated CO CEMS certification testing dates (Units 4A-4D)	FL DEP CC 16; §60.8(d)	≥ 15 days prior to [anticipated] [RATA] testing	Submitted on 04/09/09
10	Notice of anticipated NSPS/BACT compliance testing dates (Units 4A-4D)	FL DEP CC 16; §60.8(d) and §60.7(a)(5)	≥ 15 days prior to [anticipated] testing; ≥ 7 days prior to revised actual test date	Submitted on 10/07/08
11*	QA Plan (CEMS SOP) (Units 4A-4D)	40 CFR Part 75 Appendix B, §1; Acid Rain Program Policy Manual Question Nos. 11-1 and 11-2	As of the date that CEMS certification testing is commenced	Must be maintained on-site. Not required to submit. Will combine with a site-specific PEF CEMS SOP.

CONSTRUCTION AND STARTUP ACTIVITY REQUIREMENTS *continued*

No.	Action/Item Requirement	Permit Condition	Due Date Description	Comments
12	NSPS/BACT compliance testing	FL DEP Section III.A-27 and 28, III.B-7; 40 CFR Part 60 §60.8(a)	Simple-Cycle Units ≤ 60 days after maximum production [per CT] and ≤ 180 days after startup [per CT] Combined-Cycle Units ≤ 60 days after maximum production [4 CTs + ST] and ≤ 180 days after startup [per CT]	See *"Bartow Repower MasterTesting Matrix"* for testing status (attached)
13	NSPS/BACT compliance testing report (Units 4A-4D)	FL DEP Section III.A-37; FL DEP CC 18; 40 CFR Part 60, §60.8(a)	≤ 45 days after the last sampling run of each test is completed	Compliance test report (byp gas) Submitted on 02/18/09 Compliance test report (byp oil) Submitted on 04/20/09
14*	NO_x (and O_2) CEMS certification testing (Units 4A-4D)	40 CFR Part 75 §75.4(b)(2); FL DEP Section III.A-31	Simple-Cycle Units The earlier of ≤ 90 unit operating days or ≤ 180 calendar days after synch-to-grid Combined-Cycle Units The earlier of ≤ 90 unit operating days or ≤ 180 calendar days after emissions pass through SCR control device	All NO_x certification testing to be performed per 40 CFR Part 75.
14a*	RATA (and bias adjustment factor) *(RATA data anticipated to be used for NO_x compliance demonstration)*	40 CFR Part 75 Appendix A, §6.5; FL DEP Section III.A-31		Stack testing required for RATA portion only (should take ~5 hours per unit)
14b*	Linearity	40 CFR Part 75 Appendix A, §6.2		All NO_x certification testing to be performed per 40 CFR Part 75.
14c*	7-day calibration error (CE) test	40 CFR Part 75 Appendix A, §6.3		All NO_x certification testing to be performed per 40 CFR Part 75.
14d*	Cycle time test	40 CFR Part 75 Appendix A, §6.4		All NO_x certification testing to be performed per 40 CFR Part 75.

CONSTRUCTION AND STARTUP ACTIVITY REQUIREMENTS *continued*

No.	Action/Item Requirement	Permit Condition	Due Date Description	Comments
15*	NO_x (and O_2) CEMS Certification Application Package (Units 4A-4D)	40 CFR Part 75 §75.63, §75.62, and §75.53	≤ 45 days after the completion of all certification tests [§75.63(a)(1)]	Includes Item Nos. 17a-17e
15a*	NO_x CEMS certification report/results (RATA, linearity, 7-day, and cycle time tests)	40 CFR Part 75 §75.59(a)(9); FL DEP Section III.A-31 and 37		Provide hardcopy to FL DEP and US EPA; electronic results to CAMD
15b*	Final monitoring plan	40 CFR Part 75 §75.63(b)		Provide hardcopy to FL DEP and US EPA; electronic version to CAMD
15c*	DAHS verification results	40 CFR Part 75 §75.59(a)(9) and §75.63(a)(2)(iii)	≤ 60 days after the completion of all certification tests [§60.13(c)(2)]	Include with certification report; testing notification not specified
15d1*	Fuel flowmeter calibration and accuracy results (CT gas)	40 CFR Part 75 §75.53(f)(1)		
15d2*	Fuel flowmeter calibration and accuracy results (DB gas)			4 gas + 4 DB + 4 oil meters (Rosemount/Floboss for gas and Micro Motion for oil)
15d3*	Fuel flowmeter calibration and accuracy results (oil)			

CONSTRUCTION AND STARTUP ACTIVITY REQUIREMENTS *continued*

No.	Action/Item Requirement	Permit Condition	Due Date Description	Comments
16	CO CEMS certification testing (Units 4A-4D)	FL DEP Section III.A-31; 40 CFR Part 60 §60.13(c) and Appendices B and F	The earlier of ≤ 60 days after maximum production [4 CTs + ST] and ≤ 180 calendar days after startup *[differs from NSPS definition of ≤ 30 days after compliance testing]*	All CO certification testing to be performed per 40 CFR Part 60. 40 CFR Part 75 does not apply.
16a	RATA (no bias adjustment factor) *(RATA data anticipated to be used for CO compliance demonstration)*	40 CFR Part 60 Appendix B, PS-4A, §13.2		Stack testing required for RATA portion only (should take ~5 hours per unit)
16b	Cylinder Gas Audit (CGA)	40 CFR Part 60 Appendix F, §5.1.2		All CO certification testing to be performed per 40 CFR Part 60.
16c	7-day calibration drift (CD) test	40 CFR Part 60 Appendix B, PS-4A, §13.1		Can now perform over 7 consecutive unit operating days
16d	Response time test	40 CFR Part 60 Appendix B, PS-4A, §13.3		All CO certification testing to be performed per 40 CFR Part 60.
17	CO CEMS certification report/results (RATA, CGA, 7-day, and response time tests)	FL DEP Section III.A-31 and 37	≤ 45 days after the completion of all certification tests (to be consistent with 40 CFR Part 75)	40 CFR Part 60, §60.13(c)(2) allows for 60 days.
18	EDR/MDC preparation and submittal of all record types corresponding to (a) initial NO_x CEMS certification and (b) any applicable quarterly report data	40 CFR Part 75 §75.64(a)	≤ 30 days after end of most recent calendar quarter	This item is yet to be completed.
19	Test observation/QA memo (Units 4A-4D)	Internal GTC requirement, if deemed necessary	At a date agreed upon by RMB/GTC after conclusion of test program	This item is yet to be completed.

CONSTRUCTION AND STARTUP ACTIVITY REQUIREMENTS *continued*

No.	Action/Item Requirement	Permit Condition	Due Date Description	Comments
20	Custom Fuel Analysis Schedule [aka Custom Fuel Monitoring Plan] (Units 4A-4D **sulfur** – gas and oil) *Natural Gas (pipeline)* GCV Btu/scf (monthly) total sulfur gr/100scf (semi-annually) *Fuel Oil (barge)* GCV (Btu/lb), % sulfur, and density (lb/gal), vapor pressure (each time tank is topped off/switched)	FL DEP Section III.A-36; 40 CFR Part 60 §§60.4360 and 4370; 40 CFR Part 75 Appendix D; QA Plan	Fuel sampling begins on or before startup	Anticipated to use same plan/schedule as Hines; provide PNG documentation in NO_x CEMS certification report; 40 CFR Part 75 Appendix D procedures used in lieu of SO_2 CEMS. Fuel sampling procedures to be outlined in Bartow QA Program, as well as air permit.
21a	Notification of Fuel Sulfur Records (gas)	FL DEP Section III.A-36 and III.D-5; 40 CFR Part 75	≥ 21 days prior to [anticipated] certification testing	Submitted on 09/24/08
21b	Notification of Fuel Sulfur Records (oil)	FL DEP Section III.A-36 and III.D-5	Prior to startup (no specific time)	Submitted on 11/07/08
22	Process controls installed/verified to monitor water injection rates (Units 4A-4D)	FL DEP Section III.A-7	Prior to conducting the NSPS/BACT compliance test	40 CFR Part 75 NO_x CEMS used in lieu of water-to-fuel injection predictive monitoring
23a	Process controls installed/verified to monitor ammonia injection rates (Units 4A-4D)	FL DEP Section III.A-8 and 33	Prior to conducting the NSPS/BACT compliance test	Internal
23b	Ammonia meter calibration records (Units 4A-4D)	FL DEP Section III.A-33	Prior to conducting the NSPS/BACT compliance test	Internal
24	Process controls installed/verified to monitor ambient temperature, ambient humidity, and combustor inlet pressure, for any EPA ISO corrections	FL DEP Section III.A-32; 40 CFR Part 60 §60.4350	Prior to conducting the NSPS/BACT compliance test	ISO calculations are no longer required. However, EPA still requires the capability to do so (just in case).

CONSTRUCTION AND STARTUP ACTIVITY REQUIREMENTS *continued*

No.	Action/Item Requirement	Permit Condition	Due Date Description	Comments
25a	Tuning/Integrated Tuning	Siemens requirement	Performed over several weeks prior to compliance testing	Performed over several weeks prior to compliance testing using "semi-certified" CEMS installed each stack.
25b	Tuning/Integrated Tuning Notification	FL DEP Section III.A-26	≥ 7 days prior to tuning	Submitted on 10/07/08
26	Manufacturer's turbine curves *[Heat Input versus Temperature]*	FL DEP Section III.A-12	≤ 45 days after completing testing	Submitted on 02/18/09
27	Auxiliary Boiler compliance testing completed (CO and VE)	FL DEP Section III.B-7	≤ 60 days after maximum production and ≤ 180 days after startup	Initial notification and testing will be conducted upon commencement of construction of the boiler.
28	Process Heater manufacturer certification of emissions characteristics (CO, opacity, and %S content of PNG)	FL DEP Section III.B-11	Not specified. Will submit before startup.	Submitted on 10/07/08
29a	Install gas flowmeters on process heaters	FL DEP Section III.B-14	On or before startup	Internal
29b	Establish natural gas usage records for process heaters	FL DEP Section III.B-14	On or before startup	Must submit on an annual basis.
30a	Records of fuel oil storage tank dimensions, capacity, and annual throughput	FL DEP Section III.C-5	On or before startup	Two (2) total storage tanks. Maintain dimensions/capacity records on site. Submit throughput records on an annual basis.

CONSTRUCTION AND STARTUP ACTIVITY REQUIREMENTS *continued*

No.	Action/Item Requirement	Permit Condition	Due Date Description	Comments
30b	Records of fuel oil storage tank maximum true vapor pressure	FL DEP Section III.C-6	On or before startup	Maintain records on site. Vapor pressure shall be < 3.5 kPa. Will need stock temp and Reid pressure. Add this record to oil fuel analysis.
31	Emergency diesel fire pump manufacturer certification of emissions characteristics (CO, PM, and NMHC+NOx)	FL DEP Section III.D-7; 40 CFR Part 60, NSPS IIII, §§60.4211 and 60.4214	Not specified. Will submit before startup.	Submitted on 10/07/08
32	Thermal and Reliability (T/R) Performance Testing (output, heat rate, and 100-hour reliability)	Siemens requirement	Performed over several days during or after compliance testing	Not to be confused with CEMS certification testing or NSPS/BACT compliance testing.
33	Notification of physical or operational changes to units	40 CFR Part 60 §60.7(a)(4)	≤ 60 days prior to change or as soon as practicable prior to the change	Only submit as/when applicable.
34	MACT Subpart YYYY Requirements (Tentative Initial Notification)	FL DEP Section 4 – Appendix YYYY; 40 CFR Part 63, NESHAP Subpart YYYY, §63.6145(c)	Submitted on 02/27/09	

Notes

1. Unless otherwise noted, submit all required documentation/paperwork/reports to FL DEP's Local Pinellas County Office in Clearwater and FL DEP's Main Office in Tallahassee.
2. Some calendar dates subject to change due to this matrix being a "living schedule" based on anticipated dates.
3. Items Nos. (Column 1) marked with an "*" are those items subject to the federal requirements of US EPA's Acid Rain Program under 40 CFR Part 75. These items should be sent to US EPA Region IV, US EPA CAMD, and FL DEP. All Region IV and DEP submittals are typically hardcopies. All CAMD submittals are typically email/electronic.

ACRONYMS AND ABBREVIATIONS

BACT	Best Available Control Technology	NSPS	New Source Performance Standards
CCO	Commence Commercial Operation (aka synch-to-grid)	NH_3	Ammonia (Slip)
CCU	Combined Cycle Unit (CT + ST)	O_2	Oxygen
COC	Commencement of Construction	PM	Particulate Matter
CEMS	Continuous Emissions Monitoring System(s)	RATA	Relative Accuracy Test Audit
CFR	Code of Federal Regulations	RFP	Request for Proposal (or Quotation)
CO	Carbon Monoxide	SOP	Standard Operating Procedure(s)
CT	Combustion Turbine (also known as Gas Turbine [GT])	SO_2	Sulfur Dioxide
DAHS	Data Acquisition and Handling System	ST	Steam Turbine
EDR	Acid Rain Program Quarterly Electronic Data Report	SU	Startup
MACT	Maximum Achievable Control Technology	TBD	To Be Determined
MDC	US EPA's Monitoring Data Checking Software	VE	Visible Emissions (aka Opacity)
NO_x	Oxides of Nitrogen (NO + NO_2)	VOC	Volatile Organic Compound

CC	Common (aka Standard) Permit Conditions as listed in Air Permit (Appendix CC) issued by FL DEP
EUSC	Emissions Units Specific Conditions as listed in Air Permit (Section III) issued by FL DEP
GC	General Permit Conditions as listed in Air Permit (Appendix GC) issued by FL DEP
KKKK	NSPS Subpart KKKK Requirements for Gas Turbines as listed in Air Permit (Appendix KKKK) issued by FL DEP
YYYY	MACT Subpart YYYY Requirements for Gas Turbines as listed in Air Permit (Appendix YYYY) issued by FL DEP

Testing Phases

Phase I = Tuning
Phase II = NO_x and CO CEMS Certification Testing (includes linearity, 7-day, RATA, and cycle time testing)
Phase III= NSPS/BACT Compliance Testing
Phase IV = Thermal/Reliability Performance Testing & Guarantees

Progress Energy Bartow Repower – Master Testing Matrix

Shaded Items Have Been Completed, Yellow Items Are In Process (as of 04/28/09)

UNIT 4A

Stack	Fuel	Load	Task
Bypass	Gas	High	Compliance Run 1
	Gas	High	Compliance Run 2
	Gas	High	Compliance Run 3
	Gas	Low	Compliance Run 1
	Gas	Low	Compliance Run 2
	Gas	Low	Compliance Run 3
	Oil	High	Compliance Run 1
	Oil	High	Compliance Run 2
	Oil	High	Compliance Run 3
	Oil	Low	Compliance Run 1
	Oil	Low	Compliance Run 2
	Oil	Low	Compliance Run 3
	Gas	High	Stratification Check
	Gas	High	NOx RATA Run 1
	Gas	High	NOx RATA Run 2
	Gas	High	NOx RATA Run 3
	Gas	High	NOx RATA Run 4
	Gas	High	NOx RATA Run 5
	Gas	High	NOx RATA Run 6
	Gas	High	NOx RATA Run 7
	Gas	High	NOx RATA Run 8
	Gas	High	NOx RATA Run 9
	Any	Any	NOx Linearity High Range
	Any	Any	O2 Linearity
	Any	Any	NOx 7-Day High Range [7/7]
	Any	Any	O2 7-Day [7/7]
	Any	Any	NOx Cycle Time
	Any	Any	O2 Cycle Time
HRSG	Gas	High	Compliance Run 1 (DB On)
	Gas	High	Compliance Run 2 (DB On)
	Gas	High	Compliance Run 3 (DB On)
	Gas	High	Compliance Run 1 (DB Off)
	Gas	High	Compliance Run 2 (DB Off)
	Gas	High	Compliance Run 3 (DB Off)
	Oil	High	Compliance Run 1
	Oil	High	Compliance Run 2
	Oil	High	Compliance Run 3
	Gas	High	Stratification Check
	Gas	High	NOx/CO RATA Run 1
	Gas	High	NOx/CO RATA Run 2
	Gas	High	NOx/CO RATA Run 3
	Gas	High	NOx/CO RATA Run 4
	Gas	High	NOx/CO RATA Run 5
	Gas	High	NOx/CO RATA Run 6
	Gas	High	NOx/CO RATA Run 7
	Gas	High	NOx/CO RATA Run 8
	Gas	High	NOx/CO RATA Run 9
	Any	Any	NOx Linearity High Range
	Any	Any	O2 Linearity
	Any	Any	CO CGA High Range
	Any	Any	CO CGA Low Range
	Any	Any	NOx 7-Day High Range [3/7]
	Any	Any	O2 7-Day [3/7]
	Any	Any	CO 7-Day High Range [3/7]
	Any	Any	CO 7-Day Low Range [3/7]
	Any	Any	NOx Cycle Time
	Any	Any	O2 Cycle Time
	Any	Any	CO Response Time

Bypass	Protocols	I		III
	Reports	V	VI	VIII
HRSG	Protocols	II	III	IV
	Reports	VII	IX	X

UNIT 4B

Stack	Fuel	Load	Task
Bypass	Gas	High	Compliance Run 1
	Gas	High	Compliance Run 2
	Gas	High	Compliance Run 3
	Gas	Low	Compliance Run 1
	Gas	Low	Compliance Run 2
	Gas	Low	Compliance Run 3
	Oil	High	Compliance Run 1
	Oil	High	Compliance Run 2
	Oil	High	Compliance Run 3
	Oil	Low	Compliance Run 1
	Oil	Low	Compliance Run 2
	Oil	Low	Compliance Run 3
	Gas	High	Stratification Check
	Gas	High	NOx RATA Run 1
	Gas	High	NOx RATA Run 2
	Gas	High	NOx RATA Run 3
	Gas	High	NOx RATA Run 4
	Gas	High	NOx RATA Run 5
	Gas	High	NOx RATA Run 6
	Gas	High	NOx RATA Run 7
	Gas	High	NOx RATA Run 8
	Gas	High	NOx RATA Run 9
	Any	Any	NOx Linearity High Range
	Any	Any	O2 Linearity
	Any	Any	NOx 7-Day High Range [7/7]
	Any	Any	O2 7-Day [7/7]
	Any	Any	NOx Cycle Time
	Any	Any	O2 Cycle Time
HRSG	Gas	High	Compliance Run 1 (DB On)
	Gas	High	Compliance Run 2 (DB On)
	Gas	High	Compliance Run 3 (DB On)
	Gas	High	Compliance Run 1 (DB Off)
	Gas	High	Compliance Run 2 (DB Off)
	Gas	High	Compliance Run 3 (DB Off)
	Oil	High	Compliance Run 1
	Oil	High	Compliance Run 2
	Oil	High	Compliance Run 3
	Gas	High	Stratification Check
	Gas	High	NOx/CO RATA Run 1
	Gas	High	NOx/CO RATA Run 2
	Gas	High	NOx/CO RATA Run 3
	Gas	High	NOx/CO RATA Run 4
	Gas	High	NOx/CO RATA Run 5
	Gas	High	NOx/CO RATA Run 6
	Gas	High	NOx/CO RATA Run 7
	Gas	High	NOx/CO RATA Run 8
	Gas	High	NOx/CO RATA Run 9
	Any	Any	NOx Linearity High Range
	Any	Any	O2 Linearity
	Any	Any	CO CGA High Range
	Any	Any	CO CGA Low Range
	Any	Any	NOx 7-Day High Range [4/7]
	Any	Any	O2 7-Day [4/7]
	Any	Any	CO 7-Day High Range [4/7]
	Any	Any	CO 7-Day Low Range [4/7]
	Any	Any	NOx Cycle Time
	Any	Any	O2 Cycle Time
	Any	Any	CO Response Time

Bypass	Protocols	I		III
	Reports	V	VI	VIII
HRSG	Protocols	II	III	IV
	Reports	VII	IX	X

UNIT 4C

Stack	Fuel	Load	Task
Bypass	Gas	High	Compliance Run 1
	Gas	High	Compliance Run 2
	Gas	High	Compliance Run 3
	Gas	Low	Compliance Run 1
	Gas	Low	Compliance Run 2
	Gas	Low	Compliance Run 3
	Oil	High	Compliance Run 1
	Oil	High	Compliance Run 2
	Oil	High	Compliance Run 3
	Oil	Low	Compliance Run 1
	Oil	Low	Compliance Run 2
	Oil	Low	Compliance Run 3
	Gas	High	Stratification Check
	Gas	High	NOx RATA Run 1
	Gas	High	NOx RATA Run 2
	Gas	High	NOx RATA Run 3
	Gas	High	NOx RATA Run 4
	Gas	High	NOx RATA Run 5
	Gas	High	NOx RATA Run 6
	Gas	High	NOx RATA Run 7
	Gas	High	NOx RATA Run 8
	Gas	High	NOx RATA Run 9
	Any	Any	NOx Linearity High Range
	Any	Any	O2 Linearity
	Any	Any	NOx 7-Day High Range [7/7]
	Any	Any	O2 7-Day [7/7]
	Any	Any	NOx Cycle Time
	Any	Any	O2 Cycle Time
HRSG	Gas	High	Compliance Run 1 (DB On)
	Gas	High	Compliance Run 2 (DB On)
	Gas	High	Compliance Run 3 (DB On)
	Gas	High	Compliance Run 1 (DB Off)
	Gas	High	Compliance Run 2 (DB Off)
	Gas	High	Compliance Run 3 (DB Off)
	Oil	High	Compliance Run 1
	Oil	High	Compliance Run 2
	Oil	High	Compliance Run 3
	Gas	High	Stratification Check
	Gas	High	NOx/CO RATA Run 1
	Gas	High	NOx/CO RATA Run 2
	Gas	High	NOx/CO RATA Run 3
	Gas	High	NOx/CO RATA Run 4
	Gas	High	NOx/CO RATA Run 5
	Gas	High	NOx/CO RATA Run 6
	Gas	High	NOx/CO RATA Run 7
	Gas	High	NOx/CO RATA Run 8
	Gas	High	NOx/CO RATA Run 9
	Any	Any	NOx Linearity High Range
	Any	Any	O2 Linearity
	Any	Any	CO CGA High Range
	Any	Any	CO CGA Low Range
	Any	Any	NOx 7-Day High Range [4/7]
	Any	Any	O2 7-Day [4/7]
	Any	Any	CO 7-Day High Range [2/7]
	Any	Any	CO 7-Day Low Range [2/7]
	Any	Any	NOx Cycle Time
	Any	Any	O2 Cycle Time
	Any	Any	CO Response Time

Bypass	Protocols	I		III
	Reports	V	VI	VIII
HRSG	Protocols	II	III	IV
	Reports	VII	IX	X

UNIT 4D

Stack	Fuel	Load	Task
Bypass	Gas	High	Compliance Run 1
	Gas	High	Compliance Run 2
	Gas	High	Compliance Run 3
	Gas	Low	Compliance Run 1
	Gas	Low	Compliance Run 2
	Gas	Low	Compliance Run 3
	Oil	High	Compliance Run 1
	Oil	High	Compliance Run 2
	Oil	High	Compliance Run 3
	Oil	Low	Compliance Run 1
	Oil	Low	Compliance Run 2
	Oil	Low	Compliance Run 3
	Gas	High	Stratification Check
	Gas	High	NOx RATA Run 1
	Gas	High	NOx RATA Run 2
	Gas	High	NOx RATA Run 3
	Gas	High	NOx RATA Run 4
	Gas	High	NOx RATA Run 5
	Gas	High	NOx RATA Run 6
	Gas	High	NOx RATA Run 7
	Gas	High	NOx RATA Run 8
	Gas	High	NOx RATA Run 9
	Any	Any	NOx Linearity High Range
	Any	Any	O2 Linearity
	Any	Any	NOx 7-Day High Range [7/7]
	Any	Any	O2 7-Day [7/7]
	Any	Any	NOx Cycle Time
	Any	Any	O2 Cycle Time
HRSG	Gas	High	Compliance Run 1 (DB On)
	Gas	High	Compliance Run 2 (DB On)
	Gas	High	Compliance Run 3 (DB On)
	Gas	High	Compliance Run 1 (DB Off)
	Gas	High	Compliance Run 2 (DB Off)
	Gas	High	Compliance Run 3 (DB Off)
	Oil	High	Compliance Run 1
	Oil	High	Compliance Run 2
	Oil	High	Compliance Run 3
	Gas	High	Stratification Check
	Gas	High	NOx/CO RATA Run 1
	Gas	High	NOx/CO RATA Run 2
	Gas	High	NOx/CO RATA Run 3
	Gas	High	NOx/CO RATA Run 4
	Gas	High	NOx/CO RATA Run 5
	Gas	High	NOx/CO RATA Run 6
	Gas	High	NOx/CO RATA Run 7
	Gas	High	NOx/CO RATA Run 8
	Gas	High	NOx/CO RATA Run 9
	Any	Any	NOx Linearity High Range
	Any	Any	O2 Linearity
	Any	Any	CO CGA High Range
	Any	Any	CO CGA Low Range
	Any	Any	NOx 7-Day High Range [1/7]
	Any	Any	O2 7-Day [1/7]
	Any	Any	CO 7-Day High Range [1/7]
	Any	Any	CO 7-Day Low Range [1/7]
	Any	Any	NOx Cycle Time
	Any	Any	O2 Cycle Time
	Any	Any	CO Response Time

Bypass	Protocols	I		III
	Reports	V(High)	VI+V(Low)	VIII
HRSG	Protocols	II	III	IV
	Reports	VII	IX	X

PROTOCOLS: I = Bypass Compliance (Gas and Oil), II = HRSG Compliance (Gas and Oil), III = Bypass and HRSG NOx CEMS, IV = HRSG CO CEMS

REPORTS: V = Bypass Compliance (Gas), VI = Bypass Compliance (Oil), VII = HRSG Compliance (Gas and Oil), VIII = Bypass NOx CEMS, IX = HRSG NOx CEMS, X = HRSG CO CEMS

Progress Energy

January 23, 2009

Mr. Wayne Martin
Pinellas County Department of Environmental Management
Air Quality Division
300 South Garden Avenue
Clearwater, FL 33756

Re: Florida Power Corporation d/b/a Progress Energy Florida, Inc.
P.L. Bartow Plant
Title V Permit No. 1030011-009-AV
Annual Statement of Compliance

Dear Mr. Martin:

Pursuant to F.A.C. Chapter 62-213.440(3) (a) (2) enclosed please find the Annual Statement of Compliance for the above reference facility.

If you have any questions or would like additional information, please contact Terese Sanchez at (727) 827-6107.

Sincerely,

Thomas Callaghan
Bartow CC Plant Manager

Enclosures

cc: Roselyn Hughes, EPA Region IV
Danielle Henry, FDEP Southwest District

Progress Energy Florida, Inc.
1601 Weedon Island Dr. NE
St. Pete, FL 33702

STATEMENT OF COMPLIANCE - TITLE V SOURCE

RESPONSIBLE OFFICIAL CERTIFICATION

I, the undersigned, am a responsible official (Title V air permit application or responsible official notification form on file with the Department) of the Title V source for which this document is being submitted. With respect to all matters other than Acid Rain program requirements, I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made and data contained in this document are true, accurate, and complete.

T.S. Callaghan — 1/23/09

(Signature of Title V Source Responsible Official) *(Date)*

Name: Thomas Callaghan Title: Bartow Plant Manager

DESIGNATED REPRESENTATIVE CERTIFICATION (only applicable to Acid Rain source)

I, the undersigned, 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.

Patricia O. West — 1/23/09

(Signature of Acid Rain Source Designated Representative) *(Date)*

Name: Patricia O. West Title: Manager, Env. Serv, Energy Supply FL

{Note: Attachments, if required, are created by a responsible official or designated representative, as appropriate, and should consist of the information specified and any supporting records. Additional information may also be attached by a responsible official or designated representative when elaboration is required for clarity. This report is to be submitted to both the compliance authority (DEP district or local air program) and the U.S. Environmental Protection Agency(EPA) (U.S. EPA Region 4, Air and EPCRA Enforcement Branch, 61 Forsyth Street, Atlanta GA 30303).}

Progress Energy

Florida Power Corporation d/b/a Progress Energy Florida, Inc.
P.L. Bartow Plant
Facility ID No. 1030011
Title V Permit No. 1030011-009-AV
Semi-Annual Monitoring Report Deviation Events
July through December 2008

Date	Time	Duration (min)	Parameter	Description
Unit No. 1 (EU ID No. -001)				
07/15/2008	23:00	6	Opacity	Mechanical malfunction: burners
07/16/2008	00:00	12	Opacity	Mechanical malfunction: burners
07/16/2008	1:06	6	Opacity	Mechanical malfunction: burners
12/07/2008	4:48	6	Opacity	Mechanical malfunction: burners
Unit No. 2 (EU ID No. -002)				
07/14/2008	00:48	6	Opacity	Controls malfunction: boiler
08/15/2008	13:36	12	Opacity	Mechanical malfunction: burners
08/23/2008	8:48	6	Opacity	Controls malfunction: fuel
08/26/2008	11:00	6	Opacity	Mechanical malfunction: burners
09/07/2008	8:54	6	Opacity	Controls malfunction: Air/Fan/Dampers
11/04/2008	16:00	6	Opacity	Mechanical malfunction: burners
12/08/2008	12:36	6	Opacity	Mechanical malfunction: burners
Unit No. 3 (EU ID No. -003)				

Note: All of these excess emissions were in compliance with Specific Condition A.14 of the Title V Permit:

A.14. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

Department of Environmental Protection

Division of Air Resources Management

STATEMENT OF COMPLIANCE - TITLE V SOURCE

Facility Owner/Company Name: Progress Energy Florida, Inc.

Site Name: Bartow CT Plant County: Pinellas

Title V Air Operation Permit No.: 1030011-009-AV

REPORTING PERIOD	REPORT DEADLINE*
January 1 through December 31 of 2008 (year)	March 1, 2009

*See Rule 62-213.440(3)(a)2, F.A.C.

COMPLIANCE STATEMENT (Check only one of the following three options)

X A. This facility was in compliance with all terms and conditions of the Title V Air Operation Permit and, if applicable, the Acid Rain Part, and there were no reportable incidents of deviations from applicable requirements associated with any malfunction or breakdown of process, fuel burning or emission control equipment, or monitoring systems during the reporting period identified above.

___ B. This facility was in compliance with all terms and conditions of the Title V Air Operation Permit and, if applicable, the Acid Rain Part; however, there were one or more reportable incidents of deviations from applicable requirements associated with malfunctions or breakdowns of process, fuel burning or emission control equipment, or monitoring systems during the reporting period identified above, which were reported to the Department. For each incident of deviation, the following information is included:

1. Date of report previously submitted identifying the incident of deviation.
2. Description of the incident.

___ C. This facility was in compliance with all terms and conditions of the Title V Air Operation Permit and, if applicable, the Acid Rain Part, EXCEPT those identified in the pages attached to this report. For each item of noncompliance, the following information is included:

1. Emissions unit identification number.
2. Specific permit condition number.
3. Description of the requirement of the permit condition.
4. Basis for the determination of noncompliance (for monitored parameters, indicate whether monitoring was continuous, i.e., recorded at least every 15 minutes, or intermittent).
5. Beginning and ending dates of periods of noncompliance.
6. Identification of the probable cause of noncompliance and description of corrective action or preventative measures implemented.
7. Dates of any reports previously submitted identifying this incident of noncompliance.

Progress Energy Florida
Bartow Combustion Turbines - July 1, 2008 thru December 31, 2008
Malfunction Events

During the second two quarters of calendar year 2008, no deviations occurred for Unit No. 1 No. 2, No. 3, and No. 4.

Date	Time	Duration	Parameter	Description

None to report for the second two quarters of 2008

Progress Energy Florida
Bartow Combustion Turbines - January 1, 2008 thru June 30, 2008
Malfunction Events

During the first two quarters of calendar year 2008, no deviations occurred for Unit No. 1 No. 2, No. 3, and No. 4.

Date	Time	Duration	Parameter	Description

None to report for the first two quarters of 2008

Florida Power Corporation/Progress Energy Florida
2008 Title V Compliance Certification
Reasonable Inquiry Documentation

Plant Name: P.L. Bartow Plant

Title V Permit Number: 1030011-009-AV

1. Were any self-assessments completed during the period? If yes, describe below and attach a copy of the results. See File

2. Were any independent audits completed during the year? If yes, describe below and attach a copy of the results. No

3. For the Title V certification: (Include any comments on a separate attachment)

JS Review the plant files to determine if there were any non-compliant events for the period. This includes but is not limited to:
   a. Were all reports submitted and submitted on time? Yes
   b. Were all test notifications made in a timely manner? Yes
   c. Were all compliance tests completed and results satisfactory? Yes
   d. Were all agency on-site inspections satisfactory? Yes
   e. Were all immediate notifications (verbal or in writing) made on time? Yes

JS Review ESS correspondence and excess emission files to determine if there were any non-compliant events or deviations

JS Review the Title V permit to determine if there are any conditions that might not have been complied with during the year. On a separate attachment, identify any conditions which in your opinion were not met by the plant during the year.

JS Review the excess emission reports and identify all "deviations" to be reported on the annual compliance certification.

JS List below all persons who were contacted during the annual review to determine their knowledge of the compliance status of the facility. Include their name, organization, and basis for their having knowledge of plant compliance status.

C. Dufeny, C. Bradley, G. Schaefer.

Progress Energy

Florida Power Corporation d/b/a Progress Energy Florida, Inc.
P.L. Bartow Plant
Facility ID No. 1030011
Title V Permit No. 1030011-009-AV
Semi-Annual Monitoring Report Deviation Events
January through June 2008

Date	Time	Duration (min)	Parameter	Description
Unit No. 1 (EU ID No. -001)				
02/17/2008	9:42	6	Opacity	Mechanical malfunction: burners
04/06/2008	9:18	6	Opacity	Mechanical malfunction: burners
04/11/2008	12:48	6	Opacity	Other: unknown cause
04/12/2008	7:18	6	Opacity	Other: Turbine control valves stuck swinging boiler.
Unit No. 2 (EU ID No. -002)				
01/02/2008	14:42	6	Opacity	Mechanical malfunction: burners
03/27/2008	12:54	6	Opacity	Mechanical malfunction: burners
03/30/2008	10:30	12	Opacity	Mechanical malfunction: burners
Unit No. 3 (EU ID No. -003)				
01/12/2008	10:24	12	Opacity	Mechanical malfunction: burners
01/28/2008	00:48	6	Opacity	Controls malfunction: boiler

Note: All of these excess emissions were in compliance with Specific Condition A.14 of the Title V Permit:
A.14. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

STATEMENT OF COMPLIANCE - TITLE V SOURCE

REASON FOR SUBMISSION (Check one to indicate why this statement of compliance is being submitted)

✓ Annual Requirement	☐ Transfer of Permit	☐ Permanent Facility Shutdown

REPORTING PERIOD*	REPORT DEADLINE**
January 1 through December 31 of 2008 (year)	March 1, 2008

*The statement of compliance must cover all conditions that were in effect during the indicated reporting period, including any conditions that were added, deleted, or changed through permit revision.
**See Rule 62-213.440(3)(a)2., F.A.C.

Facility Owner/Company Name: Progress Energy Florida, Inc.

Site Name: P.L. Bartow Plant Facility ID No. 1030011-009-AV County: Hillsborough

COMPLIANCE STATEMENT (Check only one of the following three options)

____ A. This facility was in compliance with all terms and conditions of the Title V Air Operation Permit and, if applicable, the Acid Rain Part, and there were no reportable incidents of deviations from applicable requirements associated with any malfunction or breakdown of process, fuel burning or emission control equipment, or monitoring systems during the reporting period identified above.

X B. This facility was in compliance with all terms and conditions of the Title V Air Operation Permit and, if applicable, the Acid Rain Part; however, there were one or more reportable incidents of deviations from applicable requirements associated with malfunctions or breakdowns of process, fuel burning or emission control equipment, or monitoring systems during the reporting period identified above, which were reported to the Department. For each incident of deviation, the following information is included:

1. Date of report previously submitted identifying the incident of deviation.
2. Description of the incident.

____ C. This facility was in compliance with all terms and conditions of the Title V Air Operation Permit and, if applicable, the Acid Rain Part, EXCEPT those identified in the pages attached to this report and any reportable incidents of deviations from applicable requirements associated with malfunctions or breakdowns of process, fuel burning or emission control equipment, or monitoring systems during the reporting period identified above, which were reported to the Department. For each item of noncompliance, the following information is included:

1. Emissions unit identification number.
2. Specific permit condition number (note whether the permit condition has been added, deleted, or changed during certification period).
3. Description of the requirement of the permit condition.
4. Basis for the determination of noncompliance (for monitored parameters, indicate whether monitoring was continuous, i.e., recorded at least every 15 minutes, or intermittent).
5. Beginning and ending dates of periods of noncompliance.
6. Identification of the probable cause of noncompliance and description of corrective action or preventative measures implemented.
7. Dates of any reports previously submitted identifying this incident of noncompliance.

For each incident of deviation, as described in paragraph B. above, the following information is included:

1. Date of report previously submitted identifying the incident of deviation.
2. Description of the incident.

STATEMENT OF COMPLIANCE - TITLE V SOURCE

RESPONSIBLE OFFICIAL CERTIFICATION

I, the undersigned, am the responsible official as defined in Chapter 62-210.200, F.A.C., of the Title V source for which this document is being submitted. With respect to all matters other than Acid Rain program requirements, I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made and data contained in this document are true, accurate, and complete.

Signed by Steam Plant Manager per Gus Schaefer – sent to T. Sanchez 1/13/09
(Signature of Title V Source Responsible Official) *(Date)*

Name: David Karp Title: Plant Manager

DESIGNATED REPRESENTATIVE CERTIFICATION (only applicable to Acid Rain source)

I, the undersigned, 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.

(Signature of Acid Rain Source Designated Representative) *(Date)*

Name: J. Michael Kennedy Title: Principal Environmental Specialist

{Note: Attachments, if required, are created by the responsible official or the designated representative, as appropriate, and should consist of the information specified and any supporting records. Additional information may also be attached by the responsible official or designated representative when elaboration is required for clarity. This report is to be submitted to both the compliance authority (DEP district or local air program) and the U.S. EPA (U.S. EPA Region 4, Air and EPCRA Enforcement Branch, 61 Forsyth Street, Atlanta GA 30303).}

ATTACHMENT BA-FI-C8

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

Progress Energy Florida	**FINAL Permit No.:** 1030011-009-AV
P. L. Bartow Plant	**Facility ID No.:** 1030011

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210300(3)(a), F.A.C., Categorical Exemptions, or that meet the criteria specified in Rule 62-210.300(3)(b)l., 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 pernutting under Rules 62-210300(3)(a) and (b)l., 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 he 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 62-210300(3)(a) and (b)l., 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 andlor activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

Brief Description of Emissions Units and/or Activities

~~1. Water Laboratory solvent use and hood-chemical analyses for water~~
~~2. Water Laboratory flammable chemical storage cabinet~~
3. General Boiler Building fire protection equipment
4. Flammable liquid cabinets - Site wide
5. Plant and South Terminal - Fire suppression foam
6. Site utilization of sand blasters, drill presses, welding machines, lathes, hand-held tools, etc.
7. Large equipment outdoor sandblasting
8. Steam release during boiler blow-downs
9. General Site surface coating 4 0 gallons per day
10. General Site brazing, soldering and welding
~~11. Unit 1 Fly Ash Handling System~~
12. Lawn mowing and landscaping activities
13. Use of solvents
14. Painting and painting related cleanup
15. Use of products in the aerosol form
16. Use of small, portable generators and pumps
17. Pressure washing of machinery and buildings
18. Earth moving activities
19. Heavy Equipment (backhoe, forklifts, cranes, etc.)

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

Progress Energy Florida	**FINAL Permit No.:** 1030011-009-AV
P. L. Bartow Plant	**Facility ID No.:** 1030011

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

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

E.U. ID No.	Brief Description of Emissions Units and/or Activity
~~001~~	~~Fuel Storage - Tank No. #1 (7) N. Terminal - 6,354,768 gallons No. 6 fuel oil~~
~~002~~	~~Fuel Storage - Tank No. #2 (8) N. Terminal - 6,369,342 gallons No. 6 fuel oil~~
~~003~~	~~Fuel Storage - Tank No. #3 (9) N. Terminal - 6,329,232 gallons No. 6 fuel oil~~
018	Fuel Storage - Tank No. 2 (8) and 3 (9) N. Terminal- each 6,369,342 gallons No. 6 fuel oil
~~004~~ 019	Fuel Storage - Tank No. 4 (10) N. Terminal- 8,447,544 gallons No. 6 fuel oil
~~005~~ 020	Fuel Storage -Tank No. 6 (11) N. Terminal - 4,118,142 gallons No. 2 fuel oil
~~006~~	~~Fuel Storage -Tank No. #T1 (12) S. Terminal- 10,540,740 gallons No. 6 fuel oil~~
~~007~~	~~Fuel Storage -Tank No. #T2 (13) S. Terminal- 10,542,294 gallons No. 6 fuel oil~~
021	Fuel Storage -Tank No. T1 (12) and T2 (13) S. Terminal- each 10,542,000 gallons No. 6 fuel oil
~~008~~	~~Fuel Storage (1R1) - 1,008 gallons unleaded gasoline~~
~~009~~	~~Fuel Storage (6) - 550 gallons diesel - vehicle~~
010	General Boiler Building - Tank No. 12 - 300 gallons diesel - emergency fire pump
011	Plant Service Building - Tank No. 13 - ~~300~~ 150 gallons diesel, 175 hp - emergency generator
~~012~~	~~Tank No. #16 - 5,460 gallons magnesium hydroxide fuel additive~~
~~013~~	~~Tank No. FOA - 6,100 gallons calcium nitrate fuel additive~~
~~014~~ 015	Gas Turbine 1, 2, 3, and 4 - Lube oil vent with demister
~~015~~ 016	Gas Turbine 1, 2, 3, and 4 - Underground 2,600 gallon lube oil storage tank
~~016~~ 017	Gas Turbine 1 (2R1), 2 (3R1), 3 (4RI), and 4 (5R1) - each 500 ~~2,000~~ gallon waste oil storage tank
~~017~~	~~General Site - Two, 500 gallon propane gas tanks for Unit 2 and 3 ignitors~~
023	Tank No. CT#01(2R), CT#02(3R), and CT#03(4R), CT#04(5R) - 5,509 gallons waste oil
037	Tank No. Substation #1 and Substation #2 – each 16,002 gallons cable oil
045	Two 3.5 million gallon diesel tanks
---	2,000 gallon diesel tank
---	2,000 gallon unleaded gas tank
---	One 470 gallon diesel tank with emergency fire pump

emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

b. *SIP ~~Quarterly~~ Semi-Annual Permit Limits Excess Emissions Report:* Within 30 days following the end of each ~~calendar quarter~~ semi-annual period, the permittee shall submit a report to the Compliance Authority summarizing periods of CO emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c),Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous ~~quarter~~ semi-annual period. A summary of data excluded from SIP compliance calculations should also be provided.

c. *NSPS Semi-Annual Excess Emissions Reports:* Within thirty (30) days following each calendar semiannual period, the permittee shall submit a report on any periods of excess emissions of the applicable NSPS that occurred during the previous semi-annual period.

{Note: If there are no periods of excess emissions as defined in NSPS Subpart KKKK, a statement to that effect may he submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

[Rules 624.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7 and Subpart KKKK]

39. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the fuel oil storage tank for use in the Annual Operating Report. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year.

[Rule 62-210.370(2), F.A.C.]

ATTACHMENT BA-FI-C9
Acid Rain Part Application (DEP Form No. 62-210.900(1)(a))

Acid Rain Program
Instructions for
Acid Rain Part Application
(40 CFR 72.30 - 72.31 and Rule 62-214.320, F.A.C.)

The Acid Rain Program requires the designated representative to submit an Acid Rain part application for each source with an Acid Rain unit. A complete Certificate of Representation must be received by EPA before the part application is submitted to the title V permitting authority. A complete Acid Rain part application, once submitted, is binding on the owners and operators of the Acid Rain source and is enforceable in the absence of an Acid Rain part until the title V permitting authority either issues an Acid Rain part to the source or disapproves the application.

Please type or print. The alternate designated representative may sign in lieu of the designated representative. If assistance is needed, contact the title V permitting authority.

STEP 1 Use the plant name and ORIS Code listed on the Certificate of Representation for the plant. An ORIS code is a 4 digit number assigned by the Energy Information Agency (EIA) at the U.S. Department of Energy to power plants owned by utilities. If the plant is not owned by a utility but has a 5 digit facility code (also assigned by EIA), use the facility code. If no code has been assigned or if there is uncertainty regarding what the code number is, contact EIA at (202) 287-1730 (for ORIS codes), or (202) 287-1927 (for facility codes).

STEP 2 For column "a," identify each Acid Rain unit at the Acid Rain source by providing the appropriate unit identification numbers, consistent with the unit identification numbers entered on the Certificate of Representation and with unit identification numbers used in reporting to DOE and/or EIA. For new units without identification numbers, owners and operators may assign such numbers consistent with EIA and DOE requirements.

For columns "c" and "d," enter the commence operation date(s) and monitor certification deadline(s) for new units in accordance with 40 CFR 72.2 and 75.4, respectively.

Submission Deadlines

For new units, an initial Acid Rain part application must be submitted to the title V permitting authority 24 months before the date the unit commences operation. Acid rain part renewal applications must be submitted at least 6 months in advance of the expiration of the acid rain portion of a title V permit, or such longer time as provided for under the title V permitting authority's operating permits regulation.

Submission Instructions

Submit this form to the appropriate title V permitting authority. If you have questions regarding this form, contact your local, State, or EPA Regional acid rain contact, or call EPA's Acid Rain Hotline at (202) 564-9620.

Acid Rain Part Application

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

This submission is: Renewal

STEP 1
Identify the source by plant name, State, and ORIS code

Plant Name P. L. BARTOW POWER PLANT State FL ORIS Code 634

STEP 2

Enter the unit ID# for every Acid Rain unit at the Acid Rain source in column "a." For new units, enter the requested information in columns "c" and "d."

a Unit ID#	b Unit will hold allowances in accordance with 40 CFR 72.9©(1)	c New Units Commence Operation Date	d New Units Monitor Certification Deadline
1	Yes	No	
2	Yes	No	
3	Yes	No	
4A	Yes	12/05/2008	
4B	Yes	11/05/2008	
4C	Yes	11/19/2008	
4D	Yes	12/20/2008	

P.L. BARTOW POWER 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 Department 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 Department; 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.

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 Department:
(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,

P.L. BARTOW POWER PLANT
Plant Name (from Step 1)

STEP 3, Cont'd.

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, 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

Read the certification statement, sign, and date

Certification

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	Patricia Q. West	
Signature	Patricia Q. West	Date 4/29/09

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Certificate of Representation

For more information, see instructions and refer to 40 CFR 72.24

This submission is: ☐ New ☑ Revised (revised submissions must be completed in full; see instructions)

This submission includes combustion or process sources under 40 CFR part 74 ☐

STEP 1
Identify the source by plant name, State, and ORIS code.

Plant Name	State	ORIS Code
P. L. BARTOW POWER PLANT	**FL**	**634**

STEP 2
Enter requested information for the designated representative.

Name	**Patricia Q. West**		
Address	**Florida Power Corporation d/b/a Progress Energy Florida, Inc.** **P.O. Box 14042, PEF 903** **St. Petersburg, FL 33733**		
Phone Number	**(727) 820-5739**	Fax Number	**(727) 820-5229**
E-mail address (if available)	**Patricia.West@pgnmail.com**		

STEP 3
Enter requested information for the alternate designated representative, if applicable.

Name	**Brenda E. Brickhouse**		
Address	**Florida Power Corporation d/b/a Progress Energy Florida, Inc.** **P.O. Box 14042, PEF 903** **St. Petersburg, FL 33733**		
Phone Number	**(727) 820-5153**	Fax Number	**(727) 820-5229**
E-mail address (if available)	**Brenda.Brickhouse@pgnmail.com**		

STEP 4
Complete Step 5, read the certifications, and sign and date. For a designated representative of a combustion or combustion or process process source under 40 CFR part 74, the references in the certifications to "affected unit" or "affected units" also apply to the combustion or process source under 40 CFR part 74 and the references to "affected source" also apply to the source at which the source is located.

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the affected source and each affected unit at the source.

I certify that I have given notice of the agreement, selecting me as the 'designated representative' for the affected unit at the source identified in this certificate of representation, in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice.

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and of each affected unit at the source and that each such owner and operator shall be fully bound by my actions, inactions, or submissions.

I certify that I shall abide by any fiduciary responsibilities imposed by the agreement by which I was selected as designated representative or alternate designated representative, as applicable.

I certify that the owners and operators of the affected source and of each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under life-of-the-unit, firm power contractual arrangements, I certify that:

I have given a written notice of my selection as the designated representative or alternate designated representative, as applicable, and of the agreement by which I was selected to each owner and operator of the affected source and of each affected unit at the source; and

Allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement or, if such multiple holders have expressly provided for a different distribution of allowances by contract, that allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

The agreement by which I was selected as the alternate designated representative, if applicable, includes a procedure for the owners and operators of the source and affected units at the source to authorize the alternate designated representative to act in lieu of the designated representative.

Plant Name (from Step 1)
P. L. BARTOW POWER PLANT

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

Patricia D. West Signature (designated representative)	Date 4/29/09
Signature (alternate designated representative)	Date

STEP 5
Provide the name of every owner and operator of the source and each affected unit (or combustion or process source) they own and or operate.

Name **Progress Energy Corporation**					☑ Owner	☑ Operator
ID# **1**	ID# **2**	ID# **3**	ID# **4A**	ID# **4B**	ID# **4C**	ID# **4D**
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

Name					☐ Owner	☐ Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#

ATTACHMENT BA-FI-C10
CAIR Part (DEP Form No. 62-210.900(1)(b))

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: P.L. BARTOW POWER PLANT	State: Florida	ORIS or EIA Plant Code: 0634

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
01	X	X	X	No	
02	X	X	X	No	
03	X	X	X	No	
P1	X	X	X	No	
P2	X	X	X	No	
P3	X	X	X	No	
P4	X	X	X	No	
4A	X	X	X	12/05/2008	
4B	X	X	X	11/05/2008	
4C	X	X	X	11/19/2008	
4D	X	X	X	12/20/2008	

P.L. BARTOW POWER 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.

P.L. BARTOW POWER 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.

P.L. BARTOW POWER 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, 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.

P.L. BARTOW POWER 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 9/29/09

Clean Air Interstate Rule (CAIR) Program

Instructions for CAIR Part Form

(40 CFR 96.121, 96.122, 96.221, 96.222, 96.321, 96.322, and Rule 62-296.470, F.A.C.)

The CAIR Program requires the designated representative or alternate designated representative to submit a CAIR Part form for each source with a CAIR unit. A complete Certificate of Representation must be received by EPA before the CAIR Part form is submitted to the DEP Bureau of Air Regulation.

DEFINITIONS:
"CAIR" – Clean Air Interstate Rule
"CFR" - Code of Federal Regulations
"DOE"- U.S. Department of Energy
"EIA" – U.S. Energy Information Agency
"F.A.C." - Florida Administrative Code
"DEP" - Florida Department of Environmental Protection
"NO_X" – Nitrogen oxides
"ORIS" - Office of Regulatory Information Systems
"SO_2" – Sulfur dioxide

Please type or print. The alternate designated representative may sign in lieu of the designated representative. If assistance is needed, contact the DEP Bureau of Air Regulation at (850) 488-0114.

STEP 1 Use the plant name and ORIS Code listed on the Certificate of Representation for the plant. An ORIS code is a 4-digit number assigned by the EIA at the DOE to power plants owned by utilities. If the plant is not owned by a utility but has a 5-digit plant code (also assigned by EIA), use the plant code. If no code has been assigned or if there is uncertainty regarding what the code number is, contact EIA at (202) 586-2402.

STEP 2 For column "a," identify each CAIR unit at the CAIR source by providing the appropriate unit identification numbers, consistent with the unit identification numbers entered on the Certificate of Representation and with unit identification numbers used in reporting to DOE and/or EIA. For new units without identification numbers, owners and operators may assign such numbers consistent with EIA and DOE requirements. For columns "b," "c," and "d," indicate to which CAIR program(s) each unit is subject by placing an "X" in the column(s). For columns "e" and "f," enter the expected commence commercial operation date(s) and expected monitor certification deadline(s) for new units in accordance with 40 CFR 96.102, 96.202, and 96.302; and 40 CFR 96.170(b), 96.270(b), and 96.370(b), respectively.

STEP 3 Read the standard requirements.

STEP 4 Read the certification statement; provide name, title, owner company name, phone, and e-mail address; sign, and date.

Submission deadlines: See Rule 62-213.420, F.A.C.

Submit this form to:
DEP Bureau of Air Regulation
MS 5505
2600 Blair Stone Rd
Tallahassee, FL 32399-2400

ATTACHMENT BA-FI-C11
PSD Report

Golder Associates

Golder Associates Inc.
5100 West Lemon Street
Suite 114
Tampa, FL USA 33609
Telephone: (813) 287-1717
Fax: (813) 287-1716

PSD PERMIT APPLICATION
BARTOW POWER PLANT
REPOWERING PROJECT

Submitted to:

Florida Department of Environmental Protection

Submitted on behalf of:

Florida Power Corporation dba Progress Energy Florida, Inc.
100 Central Avenue
St. Petersburg, Florida 33701

Submitted by:

Golder Associates Inc.
5100 West Lemon Street
Suite 114
Tampa, Florida 33609

Distribution:

4 Copies	-	Florida Department of Environmental Protection
1 Copy		Progress Energy Florida
1 Copy	-	Golder Associates Inc.

July 2006

053-9576

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPLICATION FORMS

APPENDICES

1.0 INTRODUCTION

Florida Power Corporation dba Progress Energy Florida, Inc. (Progress Energy) is proposing to repower its existing P.L. Bartow Power Plant (Facility ID No. 1030011) in Pinellas County, Florida. The project site is approximately 675 acres in size and presently contains the existing P.L. Bartow Power Plant. The site is located in eastern Pinellas County on Tampa Bay (see Figure 1-1) at 1601 Weedon Island Drive, St. Petersburg, Pinellas County; UTM Coordinates: Zone 17, 342.4 km East and 3,082.6 km North; Latitude: 27° 52' 10" North and Longitude: 82° 35' 59" West.

This application addresses the proposed repowering project (the Project) at the Bartow Power Plant, as well as the addition of a combustion turbine designated for simple cycle (peaking) use only. The three existing boilers will be replaced with a 4-on-1 combined cycle power block. This power block configuration will consist of four combustion turbines (CTs), with associated heat recovery steam generators (HRSGs), exhausting to one steam turbine (ST) generator. Also, the Project includes duct burner (DB) firing, power augmentation (PA), and evaporative cooling, resulting in an estimated increase of 827 MW (winter) over the existing plant's capacity. All of the increased capacity will result from the new non-steam CTs. Since no net increase in *steam-powered* electricity generation will result from this project, it is exempted from licensing requirements under the Florida Electrical Power Plant Siting Act (FPPSA), Chapter 403, Part II, Florida Statutes.

A separate generating unit, a fifth CT in a simple cycle mode, nominally rated at 190 MW (winter), will be installed in addition to the repowering project. No steam-powered generation will result from the peaking unit, therefore the additional peaking unit will also be exempted from the licensing requirements under the FPPSA. Natural gas is the proposed primary fuel, with distillate fuel oil as back up for both the combined cycle power block and the simple cycle peaker.

The Bartow Power Plant operates under Title V Air Operation Permit No. 1030011-009-AV, with an effective date of January 1, 2005 and expiration date of December 31, 2009. This application contains the information required by Rule 62-213.420(3), F.A.C., including FDEP Form No. 62-210.900(1), Effective: 02/02/06, Application for Air Permit – Long Form.

This PSD Report is divided into the following major sections:

- Section 1.0 provides the Project introduction;
- Section 2.0 presents a description of the Bartow Repowering Project, including air emissions and stack parameters;
- Section 3.0 provides a review of the PSD requirements applicable to the Bartow Repowering Project;
- Section 4.0 includes the BACT control technology review;
- Section 5.0 discusses the ambient air monitoring analysis (pre-construction monitoring) required by PSD regulations;
- Section 6.0 presents a summary of the air modeling approach and results used in assessing compliance of the proposed facility with ambient air quality standards (AAQS), and PSD increments; and
- Section 7.0 provides the additional impact analyses for soils, vegetation, and visibility.

2.0 PROJECT DESCRIPTION

The existing Bartow Power Plant (Facility ID No. 1030011) consists of three fossil fuel-fired electric utility steam generating units (EUSGUs), a pipeline heating boiler, four gas turbine peaking units and as-needed relocatable diesel generator(s). The Project consists of repowering the existing EUSGUs with a combined cycle natural gas-fired power block as well as the addition of a separate simple cycle peaking unit. A brief description of the existing EUSGUs to be repowered is provided below.

2.1 Existing Baseline Conditions

Unit No. 1 (Emissions Unit No. -001) is a front-fired, fossil fuel steam generator which produces 120 megawatts of electric power. The maximum heat input rate is 1,220 million British thermal units per hour (MMBtu/hr) and the unit fires No. 2 through No. 6 fuel oil, and on-specification used oil. Unit 1 began commercial service in 1958.

Unit No. 2 (Emissions Unit No. -002) is a tangential-fired fossil fuel fired steam generator which produces 120 megawatts of electric power. The maximum heat input rate is 1,317 million Btu per hour and the unit fires No. 2 through No. 6 fuel oil, on-specification used oil, and propane. Unit 2 began commercial service in 1961.

Unit No. 3 (Emissions Unit No. -003) is a tangential-fired fossil fuel fired steam generator which produces 225 megawatts of electric power. The maximum heat input rate is 2,211 million Btu per hour and the unit fires No. 2 through No. 6 fuel oil, on-specification used oil, natural gas, and propane. Unit 3 began commercial service in 1963.

The four existing gas turbine peaking units (Emissions Unit Nos. -005 through -008) are capable of natural gas and oil-firing. The pipeline heating boiler (Emissions Unit No. -004) operates on natural gas, No. 2 oil or propane. These emission units will be unaffected by this proposed project and will remain after the project is complete.

2.2 New Project Conditions

The Project consists of repowering the Bartow EUSGUs with Siemens F-Class combined cycle technology and utilizes natural gas as the primary fuel with distillate fuel oil as a back-up fuel. The

Project consists of installing four combustion turbines (CTs), four heat recovery steam generators (HRSGs), and one steam turbine (ST) that replace the existing boilers and steam turbines. The Project will consist of the power block, the operations control center and directly associated facilities including an auxiliary boiler, five fuel gas heaters, general services/warehouse building, a gas metering station, and fuel oil unloading and storage facilities. Natural gas will be transported to the site via pipeline, and distillate oil will be trucked and/or barged to the site. The light oil, which will have a maximum sulfur content of 0.05 percent, will be stored onsite in two new aboveground storage tanks, each sized to hold approximately 83,333 barrels (3.5 million gallons).

When the repowering is complete, the site will contain one combined cycle unit in a 4 x 4 x 1 configuration (i.e., a 4-on-1) and produce approximately 1,279 MW winter and 1,159 MW summer, in lieu of the three EUSGUs. The resulting incremental increase in capacity will be approximately 827 MW winter and 715 MW summer, utilizing a 420 MW steam turbine. The additional (fifth CT) peaking unit included in this application would provide another 190 MW during the winter peaking season (175 MW summer). Design information and stack parameters for the proposed power equipment are summarized in Section 2.4.

The proposed combined cycle power block will be equipped with duct burner (DB) firing, power augmentation (PA) and evaporative cooling for increased output. In addition, to provide increased reliability, bypass stacks have been included in the design to allow these units to operate in simple cycle mode if steam turbine or main condenser problems occur that would preclude operation in combined cycle mode. The plant design is expected to allow a steam turbine trip without the loss of the gas turbines. This design provides maximum output, operational ease and system dispatch reliability and flexibility. The various proposed operating modes (i.e., combined cycle, simple cycle with bypass, DB firing, PA and evaporative cooling) are explained further in Section 2.3 below.

The repowering provides significant emission reductions of all criteria pollutants that might be subject to PSD review, except for emissions of carbon monoxide (CO) and volatile organic compounds (VOCs). The Project proposes to use low sulfur fuels; dry low nitrogen oxide (NO_X) burners (DLN); optionally employ selective catalytic reduction (SCR) technology; and employ good combustion practices to minimize emissions of particulate matter (PM), CO and VOCs. The good combustion practices and numerical emission limits proposed for control of CO and VOCs represent BACT for these pollutants. In addition to operation on natural gas, the Project is proposing fuel oil-firing equivalent to 1,000 hours of oil-firing per CT per year at full load.

2.3 Proposed Operating Modes

Combined Cycle Operation- The Project will be configured as a 4-on-1 combined cycle unit for base load service. The CTs will use DLN (dry low-NO_X) combustion technology when firing natural gas and water injection when firing distillate oil to minimize NO_X formation. An SCR system will be installed in each HRSG to further reduce NO_X emissions at the option of Progress Energy, as a means to assist the company in complying with the provisions of the Clean Air Interstate Rule (CAIR). SCR is not otherwise required for PSD or BACT purposes. Natural gas will be the primary fuel, and distillate oil will be the backup fuel. Distillate oil usage will be limited to the equivalent of 1,000 hours per year (hr/yr) per CT at full load.

For the Siemens F-Class CT, the maximum heat input is 2,006 MMBtu/hr (LHV) for each CT when firing natural gas (100-percent capacity, 35°F with power augmentation). The corresponding maximum fuel usage is about 2.0 million cubic feet per hour (MMcf/hr) of natural gas for each CT. Maximum potential annual fuel usage at 59°F turbine inlet temperature would be about 1.79×10^{10} cubic feet per year (cf/yr) of natural gas for each 4-on-1 combined cycle unit using the Siemens F-Class CT.

When buring fuel oil, the maximum heat input is 1,859 MMBtu/hr (LHV) for each Siemens F-Class CT (100-percent capacity, 35°F). Low-sulfur distillate oil will be limited to the equivalent of 1,000 hours per year per CT at full load for the 4-on-1 combined cycle configuration and the fifth CT. For the Siemens F-Class turbines, the maximum fuel use is about 13,400 gallons of fuel oil per hour per CT at 35°F turbine inlet temperature. Annual usage is 13.4 million gallons for each CT operating for 1,000 hours and a turbine inlet temperature of 59°F.

The duct burners for each HRSG will have a maximum natural gas firing rate of 500 MMBtu/hr higher heating value (HHV) or 450 MMBtu/hr lower heating value (LHV). The maximum annual fuel usage for the duct burners is based on 2,434 hr/yr at this heat input. The maximum potential annual natural gas usage for the duct burners is calculated to be about 4.7 billion cf/yr. Natural gas will be the only fuel fired in the duct burners.

Plant performance for each of the CTs under consideration for the Project was developed for natural gas and oil-firing at 100 percent load and turbine inlet temperatures of 35°F, 59°F, 74°F, and 95°F. The 74°F and 95°F cases on natural gas–firing were also considered with PA. Lower load cases were

developed for turbine inlet temperatures of 20°F, 59°F, 74°F, and 90°F for natural gas-firing and 20°F, 59°F, 72°F, and 105°F for fuel oil-firing. These cases are described in Section 2.4.

When firing natural gas, NO_X emissions from the turbines will be controlled using DLN combustors and, optionally the SCR systems, to 15 parts per million or less by volume dry (ppmvd), corrected to 15-percent O_2. When firing low-sulfur distillate oil, all turbines will utilize water injection to reduce NO_X emissions to 42 ppmvd, corrected to 15-percent O_2.

The SCR reactors will be located in each HRSG to provide the proper operating temperature range for the required reaction between ammonia and NO_X to achieve additional NO_X reductions. The ammonia handling system will include diluent air blowers (each sized for 100-percent capacity), ammonia flow control and measurement devices, an ammonia/air mixing chamber, distribution header(s), and an ammonia injection grid (AIG). Overall control of the system will be by a distributed control system (DCS).

The SCR systems will allow Progress Energy the flexibility to achieve NO_X reductions, required for compliance with the Clean Air Interstate Rule (CAIR), in the most prudent and economical manner possible. Specifically, the air quality assessment for this Project was conducted assuming that NO_X emissions would be 15 ppmvd in both simple and combined cycle modes (natural gas-firing), even though the combined cycle power block will be SCR-capable. This application bases NOx emissions during oil-firing on 42 ppmvd. This way, as allowed under the CAIR program, Progress Energy can choose whether to comply with CAIR by means of NO_X reductions from these units or through the purchase of NO_X allowances.

Startup and Shutdown Modes- The start-up, shutdown, and fuel changes in combined cycle operation will require an excess emission allowance greater than two hours provided under the FDEP rules. During cold start-up, the operating load of the CTs is limited by the amount of steam that can be accepted by the steam turbine and will result in excess emissions. The excess emission allowance requested for the Project is similar to that previously proposed for FP&L's West County Project. The 3-on-1 combined cycle configuration associated with that project would have similar steam turbine issues during start-up and shutdown operations. The proposed condition for this project follows:

> *"Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and*

duration of emissions during such incidents. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases.

a. *Steam Turbine/HRSG System Cold Startup:* For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed eight (8) hours in any 24-hour period. A cold "startup of the steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}

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

c. *Steam Turbine/HRSG System Warm Startup:* For warm startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed four (4) hours in any 24-hour period. "Warm startup of the steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting more than 8 hours and less than 48 hours.

d. *Shutdown combined Cycle Operation:* For shutdown of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed three (3) hours in any 24-hour period.

e. *Fuel Switching:* For fuel switching, excess emissions shall not exceed two (2) hours in any 24-hour period.

As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, fuel switching and documented malfunction of the gas turbines or the SCR systems. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]"

By-Pass Damper Mode- In order to provide increased reliability, bypass stacks have been included in the design allowing these units to operate in simple cycle mode if there are steam turbine or main condenser problems that would preclude operation in combined cycle mode. The plant design would allow a steam turbine trip without the loss of the gas turbines. This design provides maximum output,

operational ease and system dispatch reliability and flexibility. The dampers allow future operation in bypass mode, at times when the steam turbine is required to be out of service.

Duct Burner Firing, Power Augmentation and Evaporative Cooling Modes– This 4-on-1 unit design would be used along with auxiliary duct firing for the HRSGs, steam power augmentation (PA) and evaporative cooling for the CT's to provide optimum peaking capacity from the steam turbine generator.

Duct firing was included for a worst case impact assessment. The duct burners for each HRSG associated with the 4-on-1 combined cycle unit will have a maximum firing rate of 500 MMBtu/hr (HHV) or 450 MMBtu/hr (LHV). The maximum annual fuel usage for the duct burners is based on 2,434 hr/yr per duct burner at this heat input. The maximum potential annual natural gas usage for the duct burners is calculated to be about 4.7 billion cf/year.

The CTs will be equipped to operate in power augmentation mode. Power augmentation (PA) is the injection of steam in the CTs when firing natural gas at loads above 95 percent to increase power output. About 1.5 lb steam per lb of fuel is used in this mode of operation. The CTs are proposed to operate 1,688 hours per year per CT in PA mode.

Each CT will have evaporative cooling at the turbine air inlet that reduces the inlet air temperature and increases both the efficiency and power output at elevated ambient temperatures. This cooling system will only operate when the ambient temperature is 59°F or greater and the CTs are operating. This cooling system adds water vapor to the compressor inlet of the CTs, which increases the mass flow of air by evaporative cooling, but does not impact the emissions of regulated pollutants. The CTs can operate with or without the evaporative coolers in service.

Interim Project Configuration- The CTs will be fitted with by-pass stack dampers that allow operation in simple cycle mode for operation currently targeted for December 2008. The HRSGs for these units will be commissioned, along with the remainder of the 4-on-1 power block, at a later date. It was originally envisioned that the existing three EUSGUs would be retired in phases beginning in June 2009. Due to projected power needs during the winter peak demand period, Progress Energy has determined that it will be necessary for the three existing EUSGUs to operate concurrently with up to two of the new CTs in a simple cycle mode until approximately June 2009. At that time, the

entire 4-on-1 power block, including the steam cycle, will commence operation and the existing EUSGUs will be retired.

The PSD applicability assessment that was conducted for the Project was based on the permanent operating scenario, where the existing EUSGUs are retired and the resulting emission reductions will offset the increase in emissions for all pollutants, except for CO and VOCs. Modifications to an existing major facility that results in a significant net emissions increase equal to or exceeding the significant emissions rates (SER) listed in Section 62-212.400, Table 62-212.400-2, F.A.C., is classified as a major modification and will be subject to the PSD preconstruction permitting program for those pollutants that exceed the PSD SERs. The only such emission increases are for CO and VOCs.

The procedures for determining applicability of the PSD permitting program to the Project are specified in Rule 62-212.400(2), F.A.C. For each regulated pollutant, PSD is triggered as a result of a modification at an existing unit if the difference between the projected actual emissions and the baseline actual emissions equals or exceeds the SER for that pollutant, as defined at Rule 62-210.200(243), F.A.C. These emission increases, in tons per year (TPY), are projected on an annual (12-month) basis. Due to the Project phase-in schedule, discussed above, the "permanent" operating scenario will not be in effect until approximately six months from commencement of operation of the initial CT. Therefore, in order to determine PSD applicability for the temporary or interim operating scenario, both the baseline emissions and the future representative actual emissions were projected over a 12-month period (i.e., December 2008- June 2009 for the interim scenario and June 2009-December 2009 for the permanent scenario). This scenario is discussed further in Section 2.4 and the projected emissions are presented in tabular format; however, the following example is presented for NO_X emissions:

- NO_X baseline is 4,043 TPY;
- Six months of operation of existing EUSGUs (December 2008- June 2009) is approximately 50 percent of the baseline (2,022 TPY);
- Six months of operation of the Project (4-on-1 and the 5th CT) from June 2009-December 2009 is approximately 50 percent of the annual estimate for the Project (3,191 TPY) or about 1,596 TPY; and

- Subtracting each of the two above scenarios from the initial NO_X baseline (i.e., 4,043 TPY – 2,022 TPY – 1,596 TPY) leaves a balance of 426 TPY available for operation of the simple cycle CTs in the interim or temporary operating scenario.

Progress Energy anticipates that natural gas will be available for use in these CTs during this interim period, but assumes operation on either natural gas or fuel oil.

2.4 Proposed Source Emissions and Stack Parameters

Without the emission offsets from the retirement of the existing EUSGUs, this proposed project would be a major modification, subject to PSD review. As the existing three steam units will be retired, the proposed Project will use emissions credits from their retirement to net out of PSD review for all PSD pollutants, except for CO and VOCs. Table 2-1 provides a comparison of the existing site's baseline emissions to estimated emissions from the proposed project and summarizes the resulting net increase. The baseline emissions presented in this table were derived from a five-year look back (2001 through 2005) at historical emissions, including a summary of the highest two-year average for each pollutant. Baseline data, based on past Annual Operating Reports (AORs) is presented in a series of tables in Appendix A for each unit for each year. In Table 2-1, a comparison of the net increases (worst case with oil firing of 1,000 hours) to the PSD significant emission thresholds indicates that PSD review is only required for CO and VOCs. In addition, as discussed in the previous section, there will be an interim operating mode of approximately six months, during which there will be an overlap in operation among the three existing units and the new units coming online. Table 2-2 summarizes this proposed interim operating mode and presents the approximate cumulative turbine operating hours that are available (due to the emission reductions that are to be realized from existing unit retirement) without triggering PSD for these pollutants.

Performance, estimated maximum hourly emissions and exhaust information representative of each CT/HRSG option operating at base-load, 80 percent load and 60 percent load conditions are presented in Tables 2-3 and 2-4 for natural gas firing in simple cycle and combined cycle, respectively. Tables 2-5 and 2-6 present the same information for fuel oil firing for base-load, 80 percent load and 65 percent load. Plant performance for each of the CTs was developed for natural gas and oil-firing at 100 percent load and turbine inlet temperatures of 35°F, 59°F, 74°F, and 95°F. The 74°F and 95°F cases on natural gas–firing were also considered with PA. See Appendix A for lower load cases for various turbine inlet temperatures for both natural gas and distillate fuel oil.

The maximum short-term emission rates in pounds per hour (lb/hr) generally occur at base load, 35°F operation, where the CT has the greatest output and greatest fuel consumption. The CTs will be equipped to operate in PA mode, as well as concurrent DB firing with natural gas in the HRSG. Therefore, this analysis assumes that the maximum short-term emission rate occurs at base load, 35°F operation, while in PA mode with DB firing. On an annual basis, this analysis assumes that the CTs will each operate up to 1,688 hours per year in PA mode. In addition, each DB is assumed to be fired up to 2,434 hours per year.

Maximum potential annual emissions for the CTs/HRSGs for regulated air pollutants are based on an ambient temperature of 59°F. To produce the maximum annual emissions, it is assumed that each CT/HRSG would operate for 8,760 hours, of which 7,760 hr/yr are assumed to be natural gas firing with 2,434 hours fired at 100-percent load with maximum duct firing and 1,688 hr/yr of PA per CT. For the remaining 1,000 hr/yr, it is assumed that the CTs would operate on distillate oil.

For ease of review, Table 2-7 summarizes the Project's short-term emission rates (ppmvd and lb/hr) for each pollutant in each of the proposed operating modes for each fuel. The table presents both the maximum short-term rates (usually associated with the lowest turbine inlet temperatures) which were used for assessing worst-case modeled impacts and the short-term rate at ISO conditions (which is typically used to estimate annual tons per year).

Provisions for an auxiliary boiler are included in the Project design to assist in combined cycle startup, if required in the future. Once sufficient quality and quantity of steam is available from the HRSG, steam from the auxiliary boiler is not required. The future steam boiler will be a Nebraska Boiler or equivalent with steam capacity of 85,000 lb/hr and a heat input rating of up to 99 MMBtu/hr. Table 2-8 presents estimated performance and emissions information for the future auxiliary boiler. It was conservatively assumed that the annual operation of the auxiliary boiler would be 1,000 hr/yr for the startup of the Siemens F-Class CTs.

The Project will also include five natural gas-fired fuel heaters. These heaters will utilize a heat transfer fluid for heating the natural gas and be fired with only natural gas. The heat input is estimated to be approximately 3 MMBtu/hr per heater. These heaters will be used as necessary to heat natural gas above the dew point. Table 2-9 presents the estimated performance and emissions for the gas heaters. The annual emissions shown in Table 2-9 are based on 8,760 hours per year (hr/yr), although the actual usage is expected to be lower.

Emission factors for hazardous air pollutants (HAPs) were evaluated based on AP-42, the U.S. Environmental Protection Agency (EPA) Combustion Turbine Emissions Database, and the combustion turbine Maximum Achievable Control Technology (MACT) standards. The HAP emissions are based on the April 2000 revision of EPA's AP-42 emission factors for large stationary combustion turbines. Summaries of the emission factors and emission estimates for fuel oil firing and gas firing are presented in Appendix A.

The MACT standard, 40 CFR 63, Subpart YYYY is potentially applicable to the Project. The existing site is already a major source of HAP emissions since emissions exceed ten tons per year (TPY) of a single HAP and exceed 25 TPY for all HAPs. Since low sulfur distillate oil is proposed to be fired in each CT for up to 1,000 hr/yr, the proposed CTs are defined as "stationary diffusion flame oil-fired combustion turbines" under the Subpart YYYY requirements and would have the potential for an aggregate total above the rule threshold (1,000 hours of oil firing during any calendar year). Actual applicability of Subpart YYYY is based on actual fuel oil used in a calendar year. The proposed project will be required to demonstrate compliance with the combustion turbine MACT of 91-ppbvd formaldehyde corrected to 15-percent oxygen if the aggregate 1,000 hr/yr is exceeded. Based on the applicability of Subpart YYYY, compliance will be determined upon initial operation and annually (40 CFR 63.6120, Table 3).

An emission factor for toluene of 33 lb/10^{12} Btu, for natural gas firing, was developed from the data in the EPA Combustion Turbine Emissions Database. This factor is based on the median value for loads greater than 80 percent. Similar to formaldehyde emission factors, there are no confirmed test data of toluene emissions from F-Class turbines. The recent EPA emission factor, which is based on much smaller turbines than those proposed for this project, suggests toluene emissions from gas turbines of 130 lb/10^{12} Btu when firing natural gas at loads greater than 80 percent. For all loads, the average and median EPA factors are 94 and 19 lb/10^{12} Btu, respectively. Since the median emission factor is about 4 to 5 times lower than the average factor, this clearly points to the large range in toluene emissions and how the individual turbine combustion characteristics can influence the results.

The emission factors for many of the other HAPs were developed by EPA in a manner similar to toluene. For these HAPs, fewer data are available and are also considered not representative of state-of-the-art DLN combustion systems. The use of AP-42 emission factors for HAPs is considered a conservative emissions estimate approach.

The National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63, Subpart DDDDD is applicable to industrial, commercial, or institutional boilers or process heaters. The Boiler MACT defines boiler and process heaters as follows in 40 CFR 63.7575:

> *"Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Waste heat boilers are excluded from this definition."*

> *"Process heater means an enclosed device using controlled flame, that is not a boiler, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to heat transfer material for use in a process material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not directly come into contact with process materials. Process heaters do not include units for comfort heat or space heat, food preparation for on-site consumption, or autoclaves."*

Progress Energy proposes to install one auxiliary boiler rated at 99 MMBtu/hr to produce steam if required to support the Project in the future. The auxiliary boiler will be used only for startup and be limited to 1,000 hours per year of operation. The auxiliary boiler will be subject to the Boiler MACT under the "Limited use Gaseous Fuel" subcategory, which is defined as follows in 40 CFR 63.7575:

> *"Limited use gaseous fuel subcategory includes any watertube boiler or process heater that burns gaseous fuels not combined with any liquid or solid fuels, burns liquid fuel only during periods of gas curtailment or gas supply emergencies, has a rated capacity of greater than 10 MMBtu/hr input, and has a federally enforceable annual average capacity factor of equal to or less than 10 percent."*

New or reconstructed limited use gaseous fuel boilers and process heaters must meet a CO emission limit of 400 ppmvd, corrected to three percent oxygen based on an average of three one-hour runs. The auxiliary boiler proposed for the Project will meet these requirements.

The natural gas heaters are defined as small gaseous fuel units and are not subject to the initial notification or any requirements of the Subpart DDDDD pursuant to 40 CFR 63.7506(c).

2.5 Site Layout, Structures, and Stack Sampling Facilities

A plot plan of the proposed project is presented in Figure 2-1 for the 4-on-1 combined cycle configuration, as well as the fifth stand-alone CT (a simple cycle peaking unit). The dimensions of

the buildings and structures are presented in Section 6.0. Stack sampling facilities will be constructed in accordance with Rule 62-297.310(6), F.A.C.

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal, state, and local air regulatory requirements and their applicability to the Project. These requirements must be satisfied before the proposed facility can begin construction and/or operation.

3.1 National, State, and Local AAQS

The existing applicable national and State of Florida AAQS (ambient air quality standards) are presented in Table 3-1. Primary national AAQS were promulgated to protect the public health with an adequate margin of safety, and secondary national AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in compliance with AAQS are designated as attainment areas. New sources to be located in or near these areas may be subject to more stringent air permitting requirements.

3.2 PSD Requirements

3.2.1 General Requirements

Under federal and Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed, and a pre-construction permit issued. As Florida's EPA approved State Implementation Plan (SIP) includes PSD regulations, the Florida Department of Environmental Protection (FDEP) has PSD approval authority.

A "major facility" is defined as any 1 of 28 named source categories that have the potential to emit 100 TPY or more or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment.

EPA has promulgated regulations providing that certain increases above an air quality baseline concentration level of criteria pollutants such as SO_2, PM_{10}, and NO_2 would constitute significant deterioration of air quality. The EPA class designations and allowable PSD increments are presented

in Table 3-1. Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM_{10}, and NO_2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 51.166, *Prevention of Significant Deterioration of Air Quality*. The State of Florida's PSD regulations are found in Rule 62-212.400, F.A.C. Major new facilities are required to undergo the following analyses related to PSD for each pollutant emitted in significant amounts (see Table 3-2):

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis (monitoring),
4. Source information, and
5. Additional impact analyses.

In addition to these analyses, a new facility also must be reviewed with respect to GEP (good engineering practice) stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

3.2.2 Control Technology Review

Per the control technology review PSD requirements, all applicable federal and state emission-limiting standards must be met, and that the Best Achievable Control Technology (BACT) be applied to control emissions from the source (Rule 62-212.400, F.A.C.). The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the significant emission rate (see Table 3-2).

BACT is defined in Rule 62-210.200(38), F.A.C., as:

> *(a) An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account:*
>
> *1. Energy, environmental and economic impacts, and other costs;*

2. *All scientific, engineering, and technical material and other information available to the Department; and*

3. *The emission limiting standards or BACT determinations of Florida and any other state; determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.*

(b) if the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation.

(c) Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

(d) In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.

BACT requirements were promulgated within the framework of the PSD provisions in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in *Guidelines for Determining Best Available Control Technology (BACT)* (EPA, 1978) and in the *PSD Workshop Manual* (EPA, 1980). These guidelines were issued by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. However, BACT in one area may not be identical to BACT in another area. According to EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, as a

minimum, demonstrate compliance with new source performance standards (NSPS) for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

Historically, a "bottom-up" approach consistent with the BACT Guidelines and the PSD Workshop Manual was used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected. However, EPA developed a concern that the bottom-up approach was not providing the level of BACT decisions originally intended. As a result, in December 1987, the EPA Assistant Administrator for Air and Radiation mandated changes in the implementation of the PSD program, including the adoption of a new "top-down" approach to BACT decision making.

The top-down BACT approach essentially starts with the most stringent (or top) technology and emission limits that have been applied elsewhere to the same or a similar source category. The applicant must next provide a basis for rejecting this technology in favor of the next most stringent technology or propose using it. Rejection of control alternatives may be based on technical or economic infeasibility. Such decisions are made on the basis of physical differences (e.g., fuel type), locational differences (e.g., availability of water), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between the proposed facility and the facility for which the control technique was applied previously, must be justified. EPA has issued a draft guidance document on the top-down approach entitled *Top-Down Best Available Control Technology Guidance Document* (EPA, 1990). FDEP utilizes the "top-down" BACT approach.

3.2.3 Source Impact Analysis

A source impact analysis must be performed for a proposed major source subject to PSD review for each pollutant for which emissions exceed the significant emission rate (Table 3-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAQS

and allowable PSD increments. Designated EPA models normally must be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication *Guideline on Air Quality Models (Revised, November 9th, 2005)*. The source impact analysis for criteria pollutants to address compliance with AAQS and PSD Class II increments may be limited to the new source if the impacts as a result of the new source are below significance impact levels, as presented in Table 3-1.

The EPA has proposed significant impact levels for Class I areas, as follows:

Pollutant	Averaging Time	Proposed EPA PSD Class I Significant Impact Levels ($\mu g/m^3$)
SO_2	3-hour	1
	24-hour	0.2
	Annual	0.1
PM_{10}	24-hour	0.3
	Annual	0.2
NO_2	Annual	0.1

[a] $\mu g/m^3$ = micrograms per cubic meter.

Although these levels have not been officially promulgated as part of the federal PSD regulations and may not be binding for states in performing PSD reviews, the levels serve as a guideline in assessing a source's impact in a Class I area. The EPA action to incorporate Class I significant impact levels in the PSD process is part of implementing NSR (New Source Review) provisions of the 1990 CAA Amendments. Because the process of developing the regulations will be lengthy, EPA believes that the guidance concerning the significant impact levels is appropriate to assist states in implementing the PSD permit process. The FDEP has accepted the use of these significant impact levels.

Various lengths of meteorological data records can be used for impact analysis. A five-year period can be used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. The term "highest, second-highest" (HSH) refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If fewer than

five years of meteorological data are used in the modeling analysis, the highest concentration at each receptor normally must be used for comparison to air quality standards.

The term "baseline concentration" refers to a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition, in the PSD regulations as amended August 7, 1980, baseline concentration means the ambient concentration level that existed in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

1. The actual emissions representative of facilities in existence on the applicable baseline date; and
2. The allowable emissions of major stationary facilities that commenced construction before January 6, 1975, for SO_2 and PM(TSP) concentrations or February 8, 1988, for NO_2 concentrations, but that were not in operation by the applicable baseline date.

The following emissions are not included in the baseline concentration and, therefore, will affect PSD increment consumption.

1. Actual emissions from any major stationary facility on which construction commenced after January 6, 1975, for SO_2 and PM(TSP) concentrations and after February 8, 1988, for NO_2 concentrations; and
2. Actual emission increases and decreases at any stationary facility occurring after the baseline date.

In reference to the baseline concentration, the term "baseline date" actually includes three different dates:

1. The major facility baseline date, which is January 6, 1975, in the cases of SO_2 and PM (TSP) and February 8, 1988, in the case of NO_2.
2. The minor facility baseline date, which is the earliest date after the trigger date on which a major stationary facility or major modification subject to PSD regulations submits a complete PSD application.
3. The trigger date, which is August 7, 1977, for SO_2 and PM (TSP) and February 8, 1988, for NO_2.

The minor source baseline date for SO_2 and PM (TSP) has been set as December 27, 1977, for the entire State of Florida [Rules 62-204.200(22); 62-204.360, F.A.C.]. The minor source baseline for

NO_2 has been set as March 28, 1988 [Rule 62-204.200(22); 62-204.360, F.A.C.]. It should be noted that references to PM (TSP) are also applicable to PM_{10}.

3.2.4 Air Quality Monitoring Requirements

In accordance with requirements of 40 CFR 52.21(m) and Rule 62-212.400(7)(f), F.A.C., any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts.

Ambient air monitoring for a period of up to one year generally is appropriate to satisfy the PSD monitoring requirements. Data for a minimum of four months are required. Existing data from the vicinity of the proposed source may be used, if it meets certain quality assurance requirements; otherwise, additional data may be needed. Guidance in designing a PSD monitoring network is provided in *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA, 1987a).

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that a proposed major stationary facility is exempt from the monitoring requirements with respect to a particular pollutant, if the emissions of the pollutant from the facility would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2 (Rule 62-212.400-3(e), F.A.C.). If a facility's predicted impacts are less than the *de minimis* levels, then preconstruction monitoring is not required.

3.2.5 Source Information/GEP Stack Height

Source information must be provided to adequately describe the proposed facility. The general information required for this facility is presented in Section 2.0.

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant cannot be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). Identical regulations have been adopted by FDEP (Rule 62-210.550, F.A.C.). GEP stack height is defined as the highest of:

1. 65 meters (m); or
2. A height established by applying the formula:

   $$Hg = H + 1.5L$$

   where:

   Hg = GEP stack height,

   H = Height of the structure or nearby structure, and

   L = Lesser dimension (height or projected width) of nearby structure(s); or
3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 kilometer (km). Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula.

3.2.6 Additional Impact Analysis

In addition to air quality impact analyses, PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [Rule 62-212.400(8), F.A.C.]. Impacts as a result of general commercial, residential, industrial, and other growth associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (see Table 3-2).

3.2.7 Air Quality Related Values

An Air Quality Related Value (AQRV) analysis is required to assess the potential impact on AQRVs in PSD Class I areas. The Chassahowitzka Wilderness Area is the closest Class I area to the Bartow Power Plant, and is located about 83 km to the north of the site.

The U.S. Department of the Interior in 1978 administratively defined AQRVs to be:

> *All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.*
>
> *Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside (Federal Register, 1978).*

The AQRVs include visibility, freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent on these communities for habitat. Rare, endemic, threatened, and endangered species of the national park and bioindicators of air pollution (e.g., lichens) must also be evaluated.

3.3 Nonattainment Rules

FDEP has nonattainment provisions (Rule 62-212.500, F.A.C.) that apply to all major new facilities located in a nonattainment area. In addition, for major facilities that are located in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The Bartow Power Plant is located in Pinellas County, which is classified as an attainment area for all criteria pollutants. Therefore, nonattainment new source requirements are not applicable.

3.4 Emission Standards

3.4.1 New Source Performance Standards

The New Source Performance Standards (NSPS) are national emission standards, 40 CFR 60, that apply to specific categories of new sources. As stated in the 1977 Clean Air Act Amendments, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

EPA promulgated new NSPS for Stationary Combustion Turbines (40 CFR 60, Subpart KKKK) that commence construction after February 18, 2005. This new final rule was effective on July 6, 2006. The stationary combustion turbines subject to Subpart KKKK, 40 CFR 60 (i.e., 10 MMBtu/hr or

greater), are exempt from the requirements of 40 CFR 60, Subpart GG for combustion turbines. Heat recovery steam generators and duct burners subject to Subpart KKKK are exempt from the requirements of 40 CFR 60, Subparts Da, Db and Dc for duct burners.

On October 15, 2003, EPA promulgated changes to 40 CFR 60, Subpart Kb that would exempt light oil tanks containing No. 2 light oil by virtue of its vapor pressure (FR Vol. 68, No. 199, Pages 59328-59333).

3.4.1.1 Combustion Turbine

NO_X and SO_2 emissions from all stationary CTs with a heat input at peak load equal to 10.7 gigajoules per hour (10 MMBtu/hr), based on the lower heating value of the fuel fired are limited per 40 CFR 60 Subpart KKKK. NO_X emissions for these proposed CTs (i.e., >850 MMBtu/hr) are limited by Subpart KKKK to 15 ppmvd corrected to 15-percent O_2 and 42 ppmvd corrected to 15-percent O_2 for gas and oil-firing, respectively. SO_2 emissions are limited to using a fuel with a sulfur content of no greater than 0.05 percent and 20 grains of sulfur per 100 standard cubic feet for oil and gas-firing, respectively. These requirements are summarized in Section 4.2. In addition to emission limitations, there are requirements for performance testing and monitoring in 40 CFR Subpart KKKK. There are also applicable notification, reporting, and recordkeeping requirements in the general provisions of 40 CFR Subpart A. These are summarized below:

40 CFR 60.7 Notification and Record Keeping

(a)(1) Notification of the date of construction - 30 days after such date.

(a)(3) Notification of actual date of initial start-up - within 15 days after such date.

(a)(5) Notification of date which demonstrates CEM - not less than 30 days prior to date.

60.7 (b) Maintain records of all start-ups, shutdowns, and malfunctions.

(c) Excess emissions reports – semi-annually by the 30th day following six-month period (required even if no excess emissions occur).

(d) Maintain file of all measurements for two years.

60.8 Performance Tests

(a) must be performed within 60 days after achieving maximum production rate but no later than 180 days after initial start-up.

(d) Notification of Performance tests at least 30 days prior to them occurring.

3.4.1.2 Duct Burner

As stated previously, the Subpart KKKK requirements have replaced the Subpart Da requirements for duct burners associated with a combined cycle project. NO_X emissions are 54 ppm at 15 percent O_2 or 0.86 lb/MW for gas-firing.

3.4.2 National Emission Standards for Hazardous Air Pollutants (MACT Standards)

As discussed in Section 2.3, EPA has promulgated MACT standards for combustion turbines. The 40 CFR 63 Subpart YYYY standard limits formaldehyde emissions to 91 parts per billion (ppb) by volume (dry) corrected to 15-percent oxygen, which is equivalent to about 220 lb/10^{12} Btu when firing natural gas and about 240 lb/10^{12} Btu when firing light oil (see Appendix A). The MACT standard could potentially apply to the Project, if during any calendar year oil use exceeds an aggregate of 1,000 hours for all turbines on the site.

3.4.3 Florida Rules

Florida has adopted the NSPS by reference in Rule 62-204.800(8), F.A.C for stationary gas turbines, duct burners, and volatile organic liquid storage vessels. Therefore, the facility is required to meet the same emissions, performance testing, monitoring, reporting, and record keeping as those described in Section 3.4.1. FDEP has authority for implementing NSPS requirements.

3.4.4 Florida Air Permitting Requirements

The FDEP regulations require any new source to obtain an air permit prior to construction. Major new sources must meet the appropriate requirements as discussed previously. Required permits and approvals for air pollution sources include PSD, NSPS, National Emission Standards for Hazardous Air Pollutants (NESHAP), Permit to Construct, and Permit to Operate. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.210, 62-210.300(1), and 62-212.400, F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A.C.

3.4.5 Local Air Regulations

The Pinellas County Department of Environmental Management is the air compliance authority. There are currently no local air quality regulations more stringent than those at the state level.

3.5 Source Applicability

3.5.1 Area Classification

The Project is located in Pinellas County, which has been designated by EPA and FDEP as an attainment area (includes unclassifiable) for all criteria pollutants. Pinellas County and surrounding counties are designated as PSD Class II areas for SO_2, PM(TSP), and NO_2. The nearest Class I area is the Chassahowitzka Wilderness Area located about 83 km (64 miles) to the north of the Site.

3.5.2 PSD Review

3.5.2.1 Pollutant Applicability

The Bartow Plant is classified as an existing major facility. A modification to an existing major facility that results in a significant net emissions increase equal to or exceeding the significant emissions rates (SER) listed in Section 62-212.400, Table 62-212.400-2, F.A.C., is classified as a major modification and will be subject to the PSD preconstruction permitting program for those pollutants that exceed the PSD SERs.

The procedures for determining applicability of the PSD permitting program to the Project are specified in Rule 62-212.400(2), F.A.C. For each regulated pollutant, PSD is triggered as a result of a modification at an existing unit if the difference between the projected actual emissions and the baseline actual emissions equals or exceeds the SER for that pollutant, as defined at Rule 62-210.200(243), F.A.C.

Net changes in emissions resulting from the Project, as shown in Table 2-1, will not exceed the PSD significant emission rates for SO_2, NO_X, PM/PM_{10}, lead and sulfuric acid mist. In fact, there will be substantial emissions decreases from existing emission levels. Therefore, PSD review is not applicable for these pollutants.

The proposed permit condition offered for consideration related to these pollutants is as follows:

> The applicant shall maintain monthly and submit to the Department on an annual basis for a period of five years from the date the Project is completed, information demonstrating in accordance with Rule 62-212.300(1)(e)(1), F.A.C. that the modification did not result in significant emissions increases of NO_X, SO_2, PM/PM_{10} , lead or sulfuric acid mist , as defined in Rule 62-210.200(234), F.A.C. The emissions computation and reporting shall be based on the requirements of Rule 62-210.370, F.A.C. and based on a tons-per-calendar-year basis.

As shown in Table 2-1, potential net emissions increase from the Project will trigger PSD review for two pollutants, CO and VOCs. Impacts from these pollutants that are predicted to be above the significant impact levels require a modeling analysis incorporating the impacts from other sources. (Note: EPA no longer requires PSD review for HAPs. The pollutants vinyl chloride, asbestos, and beryllium are no longer evaluated in PSD review because they are addressed through the NESHAP program.)

3.5.2.2 Emission Standards

The applicable NSPS for the CTs and for the duct burners is 40 CFR 60, Subpart KKKK. The proposed emissions for the Project will meet or be below the specified limits (see Section 4.2).

The MACT Standard 40 CFR 63, Subpart YYYY may potentially apply to the Project. Information available indicates that the Project will meet the proposed MACT of 91 ppbvd, corrected to 15-percent oxygen for formaldehyde.

3.5.2.3 Ambient Monitoring

Based on the potential emissions increase from the Project (see Table 2-1), a pre-construction ambient monitoring analysis is required for CO and ozone (based on VOC emissions). If the ambient impact of these pollutants is less than the applicable *de minimis* monitoring concentration (100 TPY in the case of VOC), then an exemption from the pre-construction ambient monitoring requirement is available per Rule 62-212.400(3)(e), F.A.C. As shown in Table 6-4, the Project's impacts are predicted to be below the applicable *de minimis* monitoring concentration levels for CO emissions. Therefore, pre-construction monitoring is not required to be submitted.

3.5.2.4 GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 meters or 213 ft high. The stacks for the Project will be 120 ft, and, therefore, do not exceed the GEP stack height. However, as discussed in Section 6.0, Air Quality Modeling Approach, since the stack height is less than GEP, building downwash effects are considered in the modeling analysis.

3.5.3 Other Clean Air Act Requirements

The 1990 Clean Air Act Amendments established the Acid Rain Program to reduce the release of acidic deposition precursors, SO_2 and NO_X. EPA's final regulations were promulgated on January 11, 1993, and included permit provisions (Part 72), allowance system (Part 73), continuous emission monitoring (Part 75), excess emission procedures (Part 77), and appeal procedures (Part 78).

This Acid Rain Program applies to all existing and new utility units except those serving a generator less than 25 MW, existing simple cycle CTs, and certain non-utility facilities; units which fall under the program are referred to as "affected units." The EPA regulations are applicable to the Project for the purposes for obtaining a permit and allowances, as well as emission monitoring. New units are required to obtain Acid Rain permits by submitting a complete application 24 months before the date on which the unit commences operation (e.g., first fire).

The Acid Rain permit would require the units to hold SO_2 emission allowances. These are market-based financial instruments that are equivalent to a prescribed amount of SO_2 emissions. Allowances can be sold, purchased, or traded. Emission limitations established in the Acid Rain Program are presumed to be less stringent than BACT for new units.

Continuous emission monitoring (CEM) for SO_2 and NO_X is required for gas fired and oil fired affected units. When an SO_2 CEM is selected to monitor SO_2 mass emissions, a flow monitor is also required. Alternately, SO_2 emissions may be determined using procedures established in Appendix D, 40 CFR 75 (flow proportional oil sampling or manual daily oil sampling). CO_2 emissions must also be determined either through a CEM (e.g., as a diluent for NO_X monitoring) or calculation. Alternate procedures, test methods, and quality assurance/quality control (QA/QC) procedures for CEM are specified (Part 75, Appendices A through I). The acid rain CEM requirements including QA/QC procedures are, in general, more stringent than those specified in the

NSPS. New units are required to meet these requirements by either January 1, 1995, or not later than 90 days after the unit commences commercial operation, which ever is later.

Finally, on May 12, 2005, EPA promulgated a rule to reduce emissions of SO_2 and NO_X from electric generating units located in 29 eastern states, including Florida. This rule was codified as a revision to Subpart G of 40 CFR Part 51. The stated objective of the Clean Air Interstate Rule (CAIR), is to assist eastern states in achieving attainment with the new, more stringent $PM_{2.5}$ and the 8-hour ozone National Air Quality Standards (NAAQS) by reducing precursor emissions in upwind areas. Progress Energy is proposing this Project, in part, to allow it to reduce NO_X and SO_2 emissions such that it will not have to buy allowances under the CAIR program. Compliance of the Bartow site with Florida's CAIR implementing regulations will be addressed following their finalization, in a separate subsequent application package as required by rules that the Department is promulgating in 2006.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 Applicability

Per the PSD regulations, the Project is required to undergo a control technology review for emissions of CO and VOCs (see Section 3.0). The maximum potential annual emissions of these pollutants from the proposed Siemens F-Class CTs are summarized in Table 2-1.

This section presents the applicable NSPS and the proposed BACT for these pollutants. The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as consideration of EPA's current policy guidelines requiring a "top-down" approach. A BACT determination requires an analysis of the economic, environmental, and energy impacts of the proposed and alternative control technologies. The analysis must, by definition, be specific to the Project (i.e., case-by-case).

4.2 New Source Performance Standards

The applicable NSPS for CTs are codified in 40 CFR 60, Subpart KKKK and summarized in Appendix B. The applicable NSPS emission limits for NO_X are as follows:

New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/hr	15 ppm at 15-percent O_2 or 54 ng/J of useful output (0.43 lb/MWh)
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/hr	42 ppm at 15-percent O_2 or 160 ng/J of useful output (1.3 lb/MWh)

The proposed NO_X emission limits for the Project in combined- and simple-cycle mode will be equivalent to the NSPS when firing natural gas and distillate oil. For turbines located in a continental area such as the Project, the following NSPS emission limits for SO_2 apply:

- Must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh) gross output, or

- Must not burn in the subject stationary combustion turbine any fuel which results in emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMbtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

The above standards translate into the following fuel sulfur content limitations:

- For oil-firing, less than or equal to 0.05 percent sulfur by weight
- For natural gas-firing, less than or equal to 20 grains of sulfur per 100 standard cubic feet

The applicable NO_X emission limit per 40 CFR 60, Subpart KKKK for the duct burner is as follows:

Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15-percent O_2 or 110 ng/J of useful output (0.86 lb/MWh)

The combined CT and duct burner emissions rate with SCR of 18 ppmvd corrected to 15-percent O_2 is three times lower than the applicable NSPS.

4.3 Best Available Control Technology (BACT)

4.3.1 Overview Of Proposed BACT

In recent permitting actions, BACT for heavy-duty industrial gas turbines has been determined to be achieved through good combustion practices for minimizing CO and VOC emissions. The BACT proposed for the Project is consistent with these permits and is summarized below:

CO Emissions

- 4 ppmvd at 15 percent oxygen, when firing natural gas at baseload to 70-percent load;
- 10 ppmvd at 15 percent oxygen, when firing natural gas at 70 percent load to 60-percent load;
- 9 ppmvd at 15 percent oxygen when firing natural gas with duct firing; and
- 30 ppmvd at 15 percent oxygen, when firing distillate oil at baseload to 70 percent load.

VOC Emissions

- 1 ppmvd at 15 percent oxygen, when firing natural gas at baseload to 70-percent load,
- 4 ppmvd at 15 percent oxygen, when firing natural gas at 70 percent load to 60-percent load,
- 2 ppmvd at 15 percent oxygen when firing natural gas with duct firing, and
- 10 ppmvd at 15 percent oxygen firing distillate oil.

4.3.2 Carbon Monoxide

4.3.2.1 Technology Description

Emissions of CO are dependent on the combustor design, which is a result of the manufacturer's operating specifications, including the air-to-fuel ratio, staging of combustion, and the amount of water injected. The CTs proposed for the Project have designs to optimize combustion efficiency and minimize NO_X emissions to the lowest achievable using DLN combustion technology while maintaining low CO emission levels.

For the Project, the following alternatives were evaluated as BACT:

1. Combustion controls, and
2. Oxidation catalyst at 2 ppmvd CO emission rate.

There are two alternatives for installing an oxidation catalyst. One would be the installation of a catalyst prior to the HRSG to reduce CO emissions from the turbine, but the duct burners would be uncontrolled. The second would be the installation of an oxidation catalyst within the HRSG, which would control the CO emissions from both the turbines and the duct burners. The capital cost for an oxidation catalyst and its technical feasibility is no different in considering simple or combined cycle operation.

4.3.2.2 Impact Analysis

Economic-The estimated capital cost for an oxidation catalyst installed in the HRSG is $1.55 million. The annualized cost of a CO oxidation catalyst is $693,000. The resulting cost effectiveness is

approximately $4,772 per ton of CO removed for gas and oil firing. No costs are associated with combustion techniques, since they are inherent in the design.

Environmental-The air quality impacts of both oxidation catalyst control and combustion design control techniques are below the significant impact levels for CO. Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst. Moreover, the air quality impacts, at the proposed CT emission rate, are predicted to be much less than the PSD significant impact levels. The maximum CO impacts are less than 0.1 percent of the applicable AAQS and there are no secondary benefits, such as reductions in ozone precursors and acidic deposition.

In contrast, the installation of an oxidation catalyst would create additional back pressure on the turbine that will result in lost electricity generation that would otherwise be available and thus replaced by older, less efficient technology. The end result is an increase in emissions of CO and other regulated emissions from those other sources.

Energy--An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 1.5 to 2 inches of water gauge would be expected. A catalyst back pressure of 2 inches would result in an energy penalty of about 3.4 million kWh/yr. The energy penalties are sufficient to supply the electrical needs of about 281 residential customers for a year. To replace this lost energy, about 3.4 x 10^{10} Btu/yr or about 35 million cf/yr of natural gas would be required.

4.3.2.3 Proposed BACT and Rationale

Combustion design is proposed as BACT, as there are adverse technical and economic consequences of using catalytic oxidation on CTs. The proposed BACT emission rates for CO will not exceed:

- 4 ppmvd at 15 percent oxygen, when firing natural gas at baseload to 70-percent load,
- 10 ppmvd at 15 percent oxygen, when firing natural gas at 70 percent load to 60-percent load,
- 9 ppmvd at 15 percent oxygen when firing natural gas with duct firing, and
- 30 ppmvd at 15 percent oxygen, when firing distillate oil at baseload to 70-percent load.

Catalytic oxidation is considered unreasonable for the following reasons:

1. Catalytic oxidation will not produce measurable reduction in the air quality impacts,

2. The economic impacts are significant (i.e., the capital cost is $1.55 million, with an annualized cost of about $693,000 per year per unit), and

3. Recent projects in Florida and EPA Region IV have been authorized with BACT emission limits of similar magnitude.

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on CTs. Catalytic oxidation is considered unreasonable, since it will not produce a measurable reduction in the air quality impacts. Indeed, recent BACT decisions for similar advanced CTs have set limits in the 9 to 30 ppmvd range when firing natural gas and distillate oil. The cost of an oxidation catalyst would be significant and not be cost effective given the maximum proposed emission limits.

The cost effectiveness calculations are significantly understated if the actual emission performance is considered. The actual CO emissions performance of the Siemens F-Class turbines is historically much less than the guaranteed rates. This is a direct result of the turbine manufacturers and duct burner vendors including significant margins on CO and VOC emissions to assure that NO_X emission guarantees can be achieved in the combustion systems.

4.3.3 Volatile Organic Compounds

Volatile Organic Compounds (VOCs) will be emitted by the CTs as a result of incomplete combustion. The use of combustion technology and clean fuels will be implemented so that VOC emissions when firing natural gas will not exceed the following:

- 1 ppmvd at 15 percent oxygen, when firing natural gas at baseload to 70-percent load,
- 4 ppmvd at 15 percent oxygen, when firing natural gas at 70 percent load to 60-percent load,
- 2 ppmvd at 15 percent oxygen when firing natural gas with duct firing, and
- 10 ppmvd at 15 percent oxygen firing distillate oil.

These emission levels are similar to the BACT emission levels established for other comparable sources. Combustion controls and the use of clean fuels have been overwhelmingly approved as

BACT for CO and VOC emissions from CTs. The further reduction of emissions would not result in a significant benefit.

A review of the BACT/LAER Information System (BLIS) did not locate any oxidation catalysts on natural gas fired combustion turbines to limit emissions of VOCs. Therefore, an oxidation catalysts' vendor was contacted to determine the typical VOC removal with oxidation catalyst controls(i.e., primarily used for CO LAER in nonattainment areas) and was informed that the VOC removal in a combustion turbine application was in the 30 to 40 percent range. The cost effectiveness calculation is presented below:

VOC Cost Effectiveness Calculations

2.5	lb/hr gas firing at baseload
4.5	lb/hr gas firing at baseload w/duct firing
4.6	lb/hr gas firing power augmentation with duct firing
25.4	lb/hr oil firing
25.4	TPY
40.00%	Removal
10.16	TPY removal
$68,238	per ton VOC removed
90.00%	Removal
22.86	TPY removed
$30,328	per ton VOC removed

At 40 percent removal, the cost effectiveness of an oxidation catalyst is over $68,000 per ton of VOC removed. Assuming that 90 percent reduction were available at the same cost, the cost effectiveness is over $30,000 per ton of VOC removed.

4.3.4 Auxiliary Boiler

The proposed BACT for the auxiliary boiler is good combustion practices to limit emissions of CO and VOC. Although not subject to BACT, natural gas is the cleanest fossil fuel and will minimize the emissions of PM and SO_2 to emission levels recognized as BACT. The auxiliary boiler will also limit NOx emissions using low-NO_X burners. CO emissions will meet the requirements of 40 CFR 60 Subpart DDDDD. The auxiliary boiler will be limited to 1,000 hours per year.

5.0 AMBIENT MONITORING ANALYSIS

The PSD rules require that an air quality analysis be conducted for each criteria and non-criteria pollutant subject to regulation under the Clean Air Act before a major stationary source is constructed. Criteria pollutants are those pollutants for which AAQS have been established. Non-criteria pollutants are those pollutants that may be regulated by emission standards, for which AAQS have not been established. This analysis may be performed by the use of modeling and/or by monitoring the air quality. In addition, if EPA has not established an acceptable ambient monitoring method for the pollutant, monitoring is not required.

Based on the potential emissions from the Project (see Table 2-1), pre-construction ambient monitoring analyses for CO and ozone (based on VOC emissions), may be required as part of an application. However, ambient monitoring analyses are not required if it can be demonstrated that the proposed source's maximum air quality impacts will not exceed the PSD *de minimis* concentration levels and, for ozone (based on VOC emissions), VOC emissions of 100 TPY.

As shown in Section 6.9, the Project's maximum CO impacts are predicted to be below the PSD *de minimis* eight-hour average CO concentration of 575$\mu g/m^3$ and the Project's net VOC emissions are less than 100 TPY. Therefore, an exemption from the preconstruction monitoring requirement is requested.

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 Significant Impact Analysis Approach

As discussed in Section 3, the Project results in increases in CO and VOC emissions above the PSD significant emission levels and, therefore, triggers PSD review for only those two pollutants. For CO, a source impact analysis is also required. Because existing EUSGU Nos. 1, 2 and 3 are to be retired, the net emissions increases for the other criteria pollutants are below the PSD significant emission levels. As such, PSD review for SO_2, NO_X, and PM_{10} is not triggered. However, because the proposed emission sources will have stack and operating parameters that are different from the existing boiler unit stacks, an air modeling analysis was conducted for these non-PSD pollutants to demonstrate that such impacts will be below the respective allowable PSD Class II increments. Because the Bartow Power Plant is relatively isolated from other PSD increment-affecting background emission sources, the proposed emissions from the Project alone, without the offsetting emissions from the existing EUSGUs, were considered sufficient to demonstrate whether compliance would be achieved. The heights above grade of the existing boiler unit stacks are 300 ft, while the proposed CT/HRSG stack and simple cycle stacks are at 120 ft.

For CO, the general modeling approach for this Project followed EPA and FDEP modeling guidelines for determining compliance with AAQS and PSD increments. A significant impact analysis was performed to determine whether the Project's emission and/or stack configuration would result in predicted impacts that are greater than the EPA significant impact levels at any location beyond the plant's restricted boundaries. If these maximum impacts were found to be greater than the significant impact levels, an additional analysis would be performed with the emission reductions from the existing boiler units.

If the Project-only impacts are above the significant impact levels in the vicinity of the facility, then two additional and more detailed air modeling analyses would be performed. The first additional analysis demonstrates compliance with federal and Florida AAQS, and the second analysis demonstrates compliance with allowable PSD Class II increments.

Generally, if a project undergoing the modification is located within 200 km of a PSD Class I area, then a significant impact analysis is also performed to evaluate the impact due to the Project alone at the PSD Class I area. The maximum predicted impacts are compared to EPA's proposed significant

impact levels for PSD Class I areas. These recommended levels have never been promulgated as rules but are the currently accepted criteria to determine whether a proposed Project should perform a more detailed modeling analysis at a PSD Class I area.

If the Project-only impacts at the PSD Class I area are above the proposed EPA PSD Class I significant impact levels, then an analysis is performed to demonstrate compliance with allowable PSD Class I increments at the PSD Class I area.

The nearest PSD Class I area is the Chassahowitzka National Wilderness Area (NWA), located approximately 83 kilometers (km) to the north of the Bartow Power Plant. While pollutant impacts in the vicinity of the Bartow Power Plant site can be largely affected by the height of release and stack operating parameters of the various emission sources, impacts at the Chassahowitzka NWA, are more dependent on pollutant loading. Since the Project involves the shutdown of the existing EUSGUs, substantial emission reductions will be realized for SO_2, NO_X, PM_{10} and sulfuric acid mist (SAM). The magnitude of these emission reductions are as follows:

- SO_2: 24,350 tons per year (TPY);
- NOx: 852 TPY;
- PM_{10}: 146 TPY; and
- SAM: 351 TPY.

As such, predicted impacts of the non-PSD pollutants are expected to decrease at the Chassahowitzka PSD Class I area, and no additional modeling was performed to assess impacts for those pollutants at that area. However, CO impacts were predicted for the project at the Chassahowitzka NWA PSD Class I area because PSD review is required for that pollutant.

Air impacts were not predicted at other PSD Class I areas since they are located more than 200 km from the Bartow Power Plant.

6.2 Pre-construction Monitoring Analysis Approach

The modeling approach followed EPA and FDEP modeling guidelines for evaluating a Project's impacts relative to the *de minimis* monitoring levels to determine the need to submit ambient

monitoring data prior to construction. Current FDEP policies stipulate that the predicted highest annual average and highest short-term concentrations are to be compared to the applicable *de minimis* monitoring levels. This was previously addressed in Section 5.0.

6.3 Air Modeling Analysis Approach

6.3.1 General Procedures

As stated in the previous sections, air modeling analyses are required to determine if the Project's impacts are predicted to be greater than the significant impact levels and *de minimis* monitoring levels for each pollutant that is emitted above the significant emission rate. These analyses consider the Project's impacts alone. Air quality impacts are predicted using five years of meteorological data and selecting the highest predicted ground-level concentrations for comparison to the significant impact levels and *de minimis* monitoring levels.

To predict the maximum annual and short-term concentrations for the Project, the modeling approach was divided into screening and refined phases. Concentrations are predicted for the screening phase using a coarse receptor grid and a five-year meteorological data record. If the highest concentration is predicted at a receptor that lies in an area where the receptor spacing is more than 100 m, then a refined analysis is performed in that area using a receptor grid of greater resolution. Modeling refinements are performed using a receptor spacing of 100 m with a receptor grid centered on the screening receptor at which the maximum concentration was predicted. The air dispersion model is then executed with the refined grid for the entire year of meteorology during which the screening concentration occurred.

If the Project's impacts are greater than the significant impact levels, the air modeling analyses must consider other nearby sources and background concentrations to predict a total concentration for comparison to AAQS and PSD Class II increments.

Generally, when using five years of meteorological data for the analysis, the highest annual and the highest, second-highest (HSH) short-term (i.e., 24 hours or less) concentrations are compared to the applicable AAQS and allowable PSD increments. The HSH concentration is calculated each year for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

The HSH approach is consistent with AAQS and allowable PSD increments, which permit a short-term average concentration to be exceeded once per year at each receptor.

It should be noted that for determining compliance with the 24-hour AAQS for PM_{10}, the highest of the sixth-highest concentration predicted in five years (i.e., H6H), instead of the HSH concentration predicted for each year, is used to compare to the applicable 24-hour AAQS.

The AAQS analysis is a cumulative source analysis that evaluates whether the concentrations from all sources will comply with the AAQS. These concentrations include the modeled impacts from sources at the Project Site and from other nearby facility sources added to a background concentration. The background concentration accounts for sources not included in the modeling analysis.

The PSD Class II analysis is a cumulative source analysis that evaluates whether the concentrations for increment-affecting sources will comply with the allowable PSD Class II increments. These concentrations include the modeled impacts from PSD increment-affecting sources at the Project Site, plus nearby PSD increment-affecting sources at other facilities.

6.3.2 PSD Class I Analysis

For each pollutant for which a significant impact is predicted at the PSD Class I area, a PSD Class I analysis is required. The PSD Class I analysis is a cumulative source analysis that evaluates whether the concentrations for increment-affecting sources located within 200 km of the PSD Class I area will comply with the allowable PSD Class I increments. These concentrations include the impacts from PSD increment-affecting sources at the Project Site, plus the impacts from PSD increment-affecting sources at other facilities.

As previously discussed, since the Project did not trigger review for pollutants for which PSD Class I increments are established (i.e., SO_2, PM_{10}, NO_X), no additional modeling was performed to assess impacts for those pollutants. However, CO impacts were predicted for the Project at the PSD Class I area since CO emissions triggered PSD review.

6.4 Model Selection

The selection of an air quality model to predict air quality impacts for the proposed project was based on the ability of the model to simulate impacts in areas surrounding the projects as well as at the PSD Class I areas. The American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model was selected since the EPA and FDEP recommend its use to predict pollutant concentrations at receptors located within 50 km from a source.

The AERMOD dispersion model (Version 04300) is available on the EPA's Internet web site, Support Center for Regulatory Air Models (SCRAM), within the Technical Transfer Network (TTN).

On November 9, 2005, the EPA implemented AERMOD into its *Guideline of Air Quality Models (Appendix W to 40 CFR Part 51)* as the recommended model for regulatory modeling applications. The FDEP is allowing the use of AERMOD for air permitting projects as a replacement for the Industrial Source Complex Short-Term Model (ISCST3), which will no longer be in effect as of December 2006.

The AERMOD model calculates hourly concentrations based on hourly meteorological data. The AERMOD model is applicable for most applications since it is recognized as containing the latest scientific algorithms for simulating plume behavior in all types of terrain. For evaluating plume behavior within the building wake of structures, the AERMOD model incorporates the Plume Rise Model Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). AERMOD can predict pollutant concentrations for averaging times of annual and 24, 8, 3, and 1 hour.

For this analysis, the EPA regulatory default options were used to predict all maximum impacts. These options include:

- Final plume rise at all receptor locations,
- Stack-tip downwash,
- Buoyancy-induced dispersion,
- Default wind speed profile coefficients,
- Default vertical potential temperature gradients, and

- Calm wind processing.

At distances beyond 50 km from a source, the CALPUFF model is recommended for use by the EPA and the Federal Land Manager (FLM). The CALPUFF model is a long-range transport model applicable for estimating the air quality impacts in areas that are more than 50 km from a source. The CALPUFF model is maintained by the EPA on the SCRAM internet website. The methods and assumptions used in the CALPUFF model are based on the latest recommendations for modeling analysis as presented in the following reports:

- The Interagency Workgroup on Air Quality Models (IWAQM), *Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998); and

- The *Federal Land Manager's Air Quality Relative Values Workgroup (FLAG) Phase I Report* (December, 2000).

The CALPUFF model was used to assess the Project's impact on CO concentration levels at the Class I area. See Appendix C for a more detailed description of the assumptions and methods used for the CALPUFF model.

6.5 Meteorological Data

Meteorological data used in the AERMOD model to determine air quality impacts consisted of a concurrent five-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) office located at the Tampa International Airport. Concentrations were predicted using five years of hourly meteorological data from 2001 through 2005. The NWS office at Tampa is located approximately 13.7 km (8.5 miles) north-northwest of the site. The FDEP considers this station to have surface meteorological data representative of the project site. The data for these stations were processed by FDEP into a format that can be input to the AERMOD model using the meteorological preprocessor program AERMET.

CALMET, the meteorological preprocessor to CALPUFF, was used to develop a three-dimensional wind field necessary to perform the air modeling analysis to evaluate pollutant impacts at each PSD Class I area. The modeling domain consisted of a rectangular three-dimensional grid that extends from approximately 24 to 32 degrees N latitude and from 80 to 90 degrees W longitude. The modeling domain includes the following meteorological and land use parameters:

- Surface weather data,
- Upper air data,
- A 1-degree land use data,
- A 1-degree Digital Elevation Model (DEM) terrain data,
- Mesoscale Model - Generation 5 (MM5) data (for initializing the wind field), and
- Hourly precipitation data.

The CALMET-developed data for the years 2001 to 2003 were obtained from FDEP. These data were developed from the VISTAS program to assess regional haze from sources under the BART regulations.

6.6 Source Data

6.6.1 Project

Summaries of the criteria pollutant emission rates, physical stack, and stack operating parameters for the repowered units used in the air modeling analysis are presented in Section 2. In an effort to obtain the maximum air quality impacts for a range of possible operating conditions, a range of operating loads and ambient temperatures were modeled.

For Phase 1, a total of 6 modeling scenarios were considered for the simple cycle operation of two CT units firing fuel oil for the following conditions:

- 100 percent operating load (35 and 95°F);
- 80 percent operating load (20 and 105°F); and
- 65 percent operating load (20 and 105°F).

Because the pollutant emissions are higher when firing fuel oil, impacts were not predicted when firing natural gas for Phase 1. The air quality impacts due to two natural gas-fired heaters were determined separately, and were added to the maximum impacts due to the two CT units to obtain the total impacts for Phase 1.

For Phase 2, a total of 6 modeling scenarios were considered for the combined cycle operation for four CTs and simple cycle operation for one CT for the following conditions:

- 100 percent operating load (35 and 95°F);
- 80 percent operating load (20 and 105°F); and
- 65 percent operating load (20 and 105°F).

For the Phase 1 modeling, the AERMOD model was used to predict maximum concentrations for the annual and 24-, 8-, 3-, and 1-hour averaging times in the vicinity of the proposed project using a generic emission rate of 10 g/s. For the Phase 2 modeling, the AERMOD model was used to predict maximum concentrations for pollutant-specific averaging times in the vicinity of the proposed project using pollutant-specific worse-case emission rates from fuel oil firing. The load analyses for Phase 2 included five natural gas-fired heaters and an auxiliary boiler. For PM_{10} only, the offsetting emissions due to the existing Boilers 1, 2 and 3 (which are to be retired as a result of the proposed project) were included in the analysis.

6.6.2 AAQS and PSD Class II Sources

The maximum pollutant impacts for the Project are predicted to be less than the significant impact levels for CO. As a result, cumulative source impact analyses are not required to demonstrate compliance with the CO AAQS.

6.7 Building Downwash Effects

All significant building structures in the Project area were identified by the site plot plan. The building structures were processed in the EPA Building Profile Input Program [(BPIP), Version 04274] to determine direction-specific building heights and widths for each 10-degree azimuth direction for each source that was included in the modeling analysis. A listing of dimensions for each structure is presented in Table 6-1. BPIP input and output files and figures showing the buildings and structures at the site are presented in Appendix D.

6.8 Receptor Locations

To determine the maximum impact for all pollutants and averaging times in the vicinity of the repowered unit, concentrations were predicted at and beyond the proposed project site fence line. For predicting pollutant impacts beyond the fence line, a square-shaped array of receptors was used. The array of receptors was centered on the UTM easting and northing coordinates of (342,350, 3,082,550) m in NAD 27. This point is located between the existing boiler stacks and the easternmost proposed CT units.

Along the fence line, receptors were spaced at 50-meter intervals. Beyond the fence line, receptors were located at the following intervals and distances from the fence line:

- Every 100 m from the fence line to 2 km;
- Every 250 m from 2 to 4 km;
- Every 500 m from 4 to 6 km; and
- Every 1,000 m from 6 to10 km.

Overall, 3,095 receptors were used in the analysis to determine the maximum impacts for the Project. Figures showing the receptor locations used in the modeling are presented in Appendix D.

For determining the Project's maximum CO impacts at the PSD Class I area, pollutant concentrations were predicted in an array of 113 discrete receptors located at the PSD Class I area of the Chassahowitzka NWA. The receptors were provided by the National Park Service (NPS).

6.9 Model Results

The maximum pollutant concentrations predicted for the Project are given in Tables 6-2 to 6-4. The maximum concentrations predicted by operating load and range of ambient temperatures for Phase 1 for the simple cycle operation firing fuel oil are presented in Table 6-2 and in Table E-1. The maximum concentrations predicted by operating load and range of ambient temperatures in Phase 2 for the combined cycle operation and simple cycle operation firing fuel oil are presented in Table 6-3. The overall maximum pollutant concentrations, compared to the PSD significant impact levels and allowable PSD Class II increments, are presented in Table 6-4.

As shown in Table 6.4, the maximum concentrations due to the repowered units for Phase 1 are predicted to be less than the PSD significant impact levels for CO and the other non-PSD pollutants. For Phase 2, the maximum concentrations due to the repowered units are predicted to be less than the PSD significant impact levels for CO and, as such, additional modeling is not required for that pollutant.

The maximum and second-highest short-term impacts for pollutants that did not trigger PSD review (i.e., SO_2, PM_{10}, and NO_2) were compared to the allowable PSD Class II increments in Table 6-4. As shown, the maximum impacts due to the repowered units firing fuel oil, with the proposed gas heaters and auxiliary boiler emissions, are predicted to be less than the applicable PSD Class II increments.

As a result, the future Project's impacts are predicted to comply with the allowable PSD Class II increments. Similarly, the Project's impacts are predicted to comply with the AAQS, which are greater in magnitude than the allowable PSD Class II increments.

Summaries of the maximum impacts for the proposed repowering project, including locations and time periods, are presented in Appendix E.

7.0 ADDITIONAL IMPACT ANALYSIS

This section presents the impacts the Project will have on vegetation, soils, visibility, both in the vicinity of the Bartow Plant and at the PSD Class I area of the Chassahowitzka National Wilderness Area, and addresses direct growth resulting from the Project.

7.1 Impacts to Soils, Vegetation, and Visibility in the Vicinity of the Plant

As discussed in Section 3, the Project results in increases in CO and VOC emissions above the PSD significant emission levels and, therefore, triggers PSD review for those pollutants. The maximum CO impacts for the Project for Phase 1 and Phase 2 are predicted to be less than the PSD significant impact levels and, therefore, well below the AAQS. In addition, for pollutants not triggering PSD review (i.e., SO_2, PM_{10}, and NO_X), the maximum air quality impacts for the Project for Phase 1 are also predicted to be less than the PSD significant impact levels and, therefore, well below the AAQS. For Phase 2, the maximum predicted air quality impacts for the Project for Phase 2 for pollutants not triggering PSD review are expected to be below the allowable PSD Class II increments and, therefore, well below the AAQS.

VOC and NO_X emissions are precursors to the formation of ozone. Ozone is formed down-wind from emission sources when VOC and NO_X emissions from a facility react in the presence of sunlight. Because of these reactions, current steady-state regulatory models, such as AERMOD cannot predict what effect the proposed Project's emissions of VOCs will have on ambient ozone concentrations from either a local or regional scale.

Background (without man-made sources) ambient concentrations of ozone are normally in the range of 20 to 39 $\mu g/m^3$ (0.01 to 0.02 ppm) (Heath, 1975). Ozone can cause various damage to broad-leaved plants including: tissue collapse, interveinal necrosis and markings on the upper surface of leaves known as stippling (pigmented yellow, light tan, red brown, dark brown, red, or purple), flecking (silver or bleached straw white), mottling, chlorosis or bronzing, and bleaching. Ozone can also stunt plant growth and bud formation. On certain plants such as citrus, grape, and tobacco, it is common for leaves to wither and drop early. A literature review suggests that exposure for four hours at levels of 0.04 to 11.0 ppm of ozone will result in plant injury for sensitive plants. The extent of the injury depends on the plant species and environmental conditions prior to and during exposure.

Given that the ozone measurements in the region comply with the AAQS and the increase in VOC emissions for the Project represents less than a one percent change in regional VOC emissions, no adverse effects on vegetation due to the Project are expected.

Since the AAQS are designed to protect the public welfare, including effects on soils and vegetation, no detrimental effects on soils should occur in the vicinity of the Bartow Plant due to the Project. In addition, since the emissions of all visibility impairing pollutants (i.e., SO_2, PM_{10} and NO_X) will decrease for this Project, no detrimental effects on near-field visibility are expected.

7.2 Impacts to Soils, Vegetation, and Visibility in the Vicinity of the Plant

Rule 62-212.400(4)(e), F.A.C., states that an application must include information relating to the air quality impacts of, and the nature and extent of all general, residential, commercial, industrial and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect. This growth analysis considers air quality impacts due to emissions resulting from the industrial, commercial, and residential growth associated with the proposed modification at the Bartow Plant. This information is consistent with the EPA Guidance related to this requirement in the *Draft New Source Review Workshop Manual* (EPA, 1990).

In general, there has been minimal growth around the Bartow Power Plant since 1977. Additional growth in the area affected by the plant, as a direct result of the proposed modification, is not expected.

Construction of the Project will occur over a 31-month period (including startup), requiring an average of approximately 300 workers during that time. It is anticipated that many of these construction personnel will commute to the site. Additional operational workers once the Project is completed are not expected.

There are also expected to be no air quality impacts due to associated commercial and industrial growth given the location of the existing Bartow Power Plant. The existing commercial and industrial infrastructure should be adequate to provide any support services that the Project might require and would not increase with the operation of the Project.

7.3 Additional Impact Analysis on the PSD Class I Area of the Chassahowitzka NWA

The analysis presented in this section addresses the potential impacts on vegetation, soils, and wildlife of the Chassahowitzka NWA Class I area due to the proposed modification of the Bartow Power Plant. The Chassahowitzka NWA is located approximately 83 km to the north of the Bartow Power Plant.

7.3.1 Soil, Vegetation, and AQRV Analysis Methodology

An AQRV analysis was conducted to assess the potential risk to AQRVs of the Chassahowitzka NWA due to the proposed emissions from the Project. The U.S. Department of the Interior in 1978 administratively defined AQRVs to be:

> *All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.*
>
> *Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside (Federal Register, 1978).*

Except for visibility, AQRVs were not specifically defined. However, odor, soil, flora, fauna, cultural resources, geological features, water, and climate generally have been identified by land managers as AQRVs. Since specific AQRVs have not been identified for the Chassahowitzka NWA, this AQRV analysis evaluates the effects of air quality on general vegetation types and wildlife found in the Chassahowitzka NWA.

Vegetation type AQRVs and their representative species types have been defined by the USFWS as:

- Marshlands - black needlerush, saw grass, salt grass, and salt marsh cordgrass
- Marsh Islands - cabbage palm and eastern red cedar
- Estuarine Habitat - black needlerush, salt marsh cordgrass, and wax myrtle
- Hardwood Swamp - red maple, red bay, sweet bay, and cabbage palm
- Upland Forests - live oak, scrub oak, longleaf pine, slash pine, wax myrtle, and saw palmetto

- Mangrove Swamp - red, white, and black mangrove

Wildlife AQRVs have been identified as endangered species, waterfowl, marsh and waterbirds, shorebirds, reptiles, and mammals.

The maximum CO pollutant concentrations predicted for the Project in the Chassahowitzka NWA are presented in Table 7-1. These results were compared with effect threshold limits for both vegetation and wildlife as reported in the scientific literature. A literature search was conducted that specifically addressed the effects of air contaminants on plant species reported to occur in the Chassahowitzka NWA. While the literature search focused on such species as cabbage palm, eastern red cedar, lichens, and species of the hardwood swamplands and mangrove forest, no specific citations that addressed these species were found. It is recognized that effect threshold information is not available for all species found in the Chassahowitzka NWA, although studies have been performed on a few of the common species and on other similar species that can be used as indicators of effects.

7.3.2 Impacts to Soils

For soils, the potential and hypothesized effects of atmospheric deposition include:

- Increased soil acidification,
- Alteration in cation exchange,
- Loss of base cations, and
- Mobilization of trace metals.

The potential sensitivity of specific soils to atmospheric inputs is related to two factors. First, the physical ability of a soil to conduct water vertically through the soil profile is important in influencing the interaction with deposition. Second, the ability of the soil to resist chemical changes, as measured in terms of pH and soil cation exchange capacity (CEC), is important in determining how a soil responds to atmospheric inputs.

The soils of the Chassahowitzka NWA are generally classified as histosols. According to the U.S. Department of Agriculture (USDA) Soil Surveys of Citrus and Hernando Counties, nine soil complexes are found in the Chassahowitzka NWA. These include Aripeka fine sand, Aripeka-Okeelanta-Lauderhill, Hallendale-Rock outcrop, Homosassa mucky fine sandy loam, Lacooche, Okeelanta mucks, Okeelanta-Lauderdale-Terra Ceia mucks, Rock outcrop-Homosassa-Lacoochee,

and Weekiwachee-Durbin mucks (Porter, 1996). The majority of the soil complexes found in the Chassahowitzka NWA are inundated by tidal waters, contain a relatively high organic matter content, and have high buffering capacities based on their CEC, base saturation, and bulk density. The regular flooding of these soils by the Gulf of Mexico regulates the pH and any change in acidity in the soil would be buffered by this activity. Therefore, they would be relatively insensitive to atmospheric inputs. However, Terra Ceia, Okeelanta, and Lauderdale freshwater mucks are present along the eastern border of the Chassahowitzka NWA, and may be more sensitive to atmospheric sulfur deposition (Porter, 1996). Although not tidally influenced, these freshwater mucks are highly organic and, therefore, have a relatively high intrinsic buffering capacity.

The relatively low sensitivity of the soils to atmospheric inputs coupled with the extremely low ground-level pollutant concentrations due to the proposed project at the Chassahowitzka NWA precludes any significant impact on soils.

7.3.3 Impacts to Vegetation

In general, the effects of air pollutants on vegetation occur primarily from SO_2, NO_2, O_3, and PM. Effects from minor air contaminants, such as fluoride (F), chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides, have also been reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury," as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage, which is considered to be the major pathway of exposure. For purposes of this analysis, it was assumed that 100 percent of each air contaminant of concern is accessible to the plants.

Injury to vegetation from exposure to various levels or air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and

productivity of the plant. In this assessment, 100 percent of the particular air pollutant in the ambient air was assumed to interact with the vegetation. This is a conservative approach.

The concentrations of the pollutants, duration of exposure and frequency of exposures influence the response of vegetation and wildlife to atmospheric pollutants. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively high ground-level concentrations, which occur during certain meteorological conditions interspersed with long periods of extremely low ground-level concentrations. If there are any effects of stack emissions on plants and animals they will be from the short-term, higher doses. A dose is the product of the concentration of the pollutant and duration of the exposure.

Carbon Monoxide

Information pertaining to the effects of CO on plants is scarce. The main effect of high concentrations of CO is the inhibition of cytochrome c oxidase, the terminal oxidase in the mitochondrial electron transfer chain. Inhibition of cytochrome c oxidase depletes the supply of ATP, the principal donor of free energy required for cell functions. However, this inhibition only occurs at extremely high concentrations of CO. Pollok et al. (1989) reported that exposure to CO:O2 ratio of 25 (equivalent to an ambient CO concentration of 6.85×10^6 $\mu g/m^3$) resulted in stomatal closure in the leaves of the sunflower (Helianthus annuus). Naik et al. (1992) reported cytochrome c oxidase inhibition in corn, sorghum, millet, and Guinea grass at $CO:O_2$ ratios of 2.5 (equivalent to an ambient CO concentration of 6.85×10^5 $\mu g/m^3$). These plants were considered the species most sensitive to CO-induced inhibition of cytochrome c oxidase.

By comparison of published effect values for CO exposure, the possibility of plant damage in the Class I area can be determined. The maximum one hour (most conservative) estimated CO concentration due to the increase in emissions resulting from the proposed project in the Chassahowitzka NWA Class I area is 3.44 $\mu g/m^3$ (see Table 7-1). This concentration is less than 0.0005 percent of the value that caused inhibition in laboratory studies. The amount of damage sustained at this level (if any) for 1 hour would have negligible effects over an entire growing season. The predicted maximum annual CO concentration of 0.054 $\mu g/m^3$ reflects a more realistic (yet conservative) CO level for the Class I area. This concentration is less than 0.00001 percent of the value that caused cytochrome *c* oxidase inhibition.

VOC Emissions and Impacts on Ozone

It is difficult to predict what effect the proposed increase in emissions of VOC will have on ambient ozone (O_3) concentrations on a regional scale. VOC and NO_X emissions are precursors to the formation of O_3. O_3 is not directly emitted from fuel combustion, but is formed down-wind from emission sources when VOC and NO_X emissions react in the presence of sunlight. Natural (without man-made sources) ambient concentrations of O_3 are normally in the range of 20 to 39 $\mu g/m^3$ (0.01 to 0.02 ppm) (Heath, 1975).

O_3 can cause various damage to broad-leaved plants including: tissue collapse, interveinal necrosis and markings on the upper surface leaves know as stippling (pigmented yellow, light tan, red brown, dark brown, red, or purple), flecking (silver or bleached straw white), mottling, chlorosis or bronzing, and bleaching. O_3 can also stunt plant growth and bud formation. On certain plants such as citrus, grape, and tobacco, it is common for leaves to wither and drop early.

As described in Section 7.1, the VOC emissions due to the proposed project represent less than 1-percent increase in regional VOC emissions. Therefore, the effects of O_3, as a result of VOC emissions from the Project, are expected to have an insignificant effect on ozone levels.

7.3.4 Impacts to Wildlife

The major air quality risk to wildlife in the U.S. is from continuous exposure to pollutants above the NAAQS. This occurs in non-attainment areas, *e.g.*, Los Angeles Basin. Risks to wildlife also may occur for wildlife living in the vicinity of an emission source that experiences frequent upsets or episodic conditions resulting from malfunctioning equipment, unique meteorological conditions, or startup operations (Newman and Schreiber, 1988). Under these conditions, chronic effects (*e.g.*, particulate contamination) and acute effects (*e.g.*, injury to health) have been observed (Newman, 1981).

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1981; Newman and Schreiber, 1988). The most severe of these effects have been observed at concentrations above the secondary AAQS. Physiological and behavioral effects have been observed in experimental animals at or below these standards.

Because air quality at the PSD Class I area are less than the AAQS and is expected to remain below the AAQS when the Project becomes operational, the emissions are not expected to have a significant effect on wildlife.

TABLES

Table 2-1. Summary of Maximum Potential Annual Emissions for the Bartow Repowering Project

Pollutant	Annual Emissions (tons/year) 4 - CTs Highest of Simple or Combined Cycle Operation	1 - CT Simple Cycle Operation[b]	Auxiliary Boiler	5 Natural Gas-Fired Heaters	TOTAL	Baseline Emission Rate (tons/yr)[a]	Net Emission Rate (tons/yr)	PSD Significant Emission Rate (tons/year)	PSD Review Required?
SO_2	375	89.7	0.3	0.4	466	24,816	-24,350	40	No
PM	348	64.9	0.09	0.12	413	804	-391	25	No
PM_{10}	348	64.9	0.09	0.12	413	559	-146	15	No
NO_x	2,591	591.3	2.4	6.3	3,191	4,043	-852	40	No
CO	774	154.5	4.1	5.3	938	367	571	100	Yes
VOC (as methane)	121	23.6	0.27	0.3	145	57	88	40	Yes
Sulfuric Acid Mist	58	13.7	Neg.	Neg.	72	423	-351	7	No
Lead	0.049	0.012	Neg.	Neg.	0.06	0.10	-0.04	0.6	No
HAPs	18.5	4.6	Neg.	Neg.	23.1	NE	23.1	NA	No

Note: Neg.= negligible; NA= not applicable; NE= not estimated

[a] Existing Emissions (TPY) Highest 2-year avg.

[b] One simple-cycle CT operating at 7,760 hours per year on natural gas and 1,000 hours per year on oil

Source: Siemens, 2006 - CT Performance Data; Golder, 2006.

Table 2-2. Comparison of Representative Future Actual Emissions for Last Year of Construction and Past Actual Emissions

	Months	Particulate (PM)	Particulate (PM10)	Nitrogen Oxides	Sulfur Dioxides	Carbon Monoxide	Volatile Organic Compounds	SAM
Representative Actual Annual Emissions								
Units 1, 2 and 3	12	804	559	4,043	24,816	367	57	423
Repowered Plant	12	413	413	3,191	466	938	145	72
Representative Future Actual Emissions During Last Year of Construction								
Units 1, 2 and 3	6 [a]	402	280	2,022	12,408	184	29	212
Repowered Plant	6 [a]	207	207	1,596	233	469	73	36
Total:		609	486	3,617	12,641	653	101	248
Past Actual Emissions		804	559	4,043	24,816	367	57	423
Net Emissions Change [b]		-196	-73	-426	-12,175	286	44	-176
Max Hours (gas-firing) [c]		43,444	16,222	7,889	2,233,945	NA [d]	NA [d]	319,091
Max Hours (oil-firing) [c]		6,517	2,433	2,696	256,316	NA [d]	NA [d]	18,474

Notes:

a - Months based on maximum potential operation schedule for new and existing units from commercial operation date of 1st new unit.

b - Represents TPY available for each pollutant without triggering NSR

c - Max hours of operation of new CTs in interim mode without exceeding remaining baseline emissions.

d - NA because these pollutants have already triggered NSR

Table 2-3. Stack, Operating, and Emission Data for Combustion Turbines in Simple Cycle Operation-
Natural Gas Combustion

		Operating and Emission Data [a] for Ambient Temperature			
		Combustion Turbine			
Parameter		35 °F	59 °F	74 °F	w/Evap Clr 95 °F
CT Stack Data (ft)					
Height		120	120	120	120
Diameter		22	22	22	22
100 Percent Load					
Temperature (°F)		1063	1081	1099	1106
Velocity (ft/sec)		120	116	113	112
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	11.5	10.9	10.4	10.3
PM/PM_{10}	lb/hr	9.0	9.0	9.0	9.0
NO_x	lb/hr	118.3	111.7	106.7	105.0
CO	lb/hr	21.3	20.3	19.8	19.7
VOC (as methane)	lb/hr	2.8	2.6	2.5	2.5
Sulfuric Acid Mist	lb/hr	1.15	1.09	1.04	1.03
80 Percent Load		20 °F	59 °F	74 °F	90 °F
Temperature (°F)		1,006	1,032	1,108	1,083
Velocity (ft/sec)		96	92	98	91
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	9.1	8.5	8.7	7.9
PM/PM_{10}	lb/hr	9.0	9.0	9.0	9.0
NO_x	lb/hr	88.3	81.9	90.0	75.9
CO	lb/hr	16.5	15.6	16.7	14.8
VOC (as methane)	lb/hr	2.1	2.0	2.1	1.8
Sulfuric Acid Mist	lb/hr	0.91	0.85	0.87	0.79
60 Percent Load		20 °F	59 °F	74 °F	90 °F
Temperature (°F)		1,088	1,112	1,108	1,083
Velocity (ft/sec)		82	79	83	75
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	7.4	7.1	7.1	6.4
PM/PM_{10}	lb/hr	8.0	8.0	8.0	8.0
NO_x	lb/hr	72.0	68.1	73.3	63.0
CO	lb/hr	33.7	32.3	34.1	30.7
VOC (as methane)	lb/hr	7.1	6.7	6.8	6.1
Sulfuric Acid Mist	lb/hr	0.74	0.71	0.71	0.64

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data. Duct firing is assumed for 100% operating load. No duct firing is assumed for loads less than 100%.

Table 2-4 Stack, Operating, and Emission Data for the Combustion Turbines/HRSGs and Duct Burners for Combined Cycle Operation-Natural Gas Combustion

		Operating and Emission Data * for Ambient Temperature															
		Combustion Turbine/ HRSG								Combustion Turbine/ HRSG/ Duct Burner							
Parameter		35 °F	35 °F w/PA	59 °F	w/EvpClr 59 °F w/PA	74 °F	w/EvpClr 74 °F w/PA	95 °F	w/EvpClr 95 °F w/PA	35 °F	35 °F w/PA	59 °F	w/EvpClr 59 °F w/PA	74 °F	w/EvpClr 74 °F w/PA	95 °F	w/EvpClr 95 °F w/PA
CT/HRSG Stack Data (ft)																	
Height		120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
Diameter		18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
100 Percent Load																	
Temperature (°F)		190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190
Velocity (ft/sec)		76.4	80.5	73.1	78.0	70.3	74.7	69.2	72.8	77.1	71.6	69.9	71.1	71.0	75.4	69.9	73.5
Maximum Hourly Emissions per Unit																	
SO_2	lb/hr	11.5	12.3	10.9	11.8	10.4	11.3	10.3	10.9	14.3	15.0	13.6	14.6	13.2	14.0	13.0	13.7
PM/PM_{10}	lb/hr	11.3	11.5	11.2	11.4	11.1	11.3	11.1	11.2	14.4	14.5	14.3	14.4	14.2	14.3	14.1	14.3
NO_x	lb/hr	118.3	125.5	111.7	120.8	106.7	116.7	105.0	112.0	158.3	165.5	151.7	160.8	146.7	156.7	145.0	152.0
CO	lb/hr	21.3	24.1	20.3	23.4	19.8	22.6	19.7	22.1	41.3	44.1	40.3	43.1	39.8	42.6	39.7	42.1
VOC (as methane)	lb/hr	2.8	2.9	2.6	2.8	2.5	2.7	2.5	2.6	4.8	4.9	4.6	4.8	4.5	4.7	4.5	4.6
Sulfuric Acid Mist	lb/hr	1.15	1.23	1.09	1.18	1.04	1.13	1.03	1.09	1.70	1.78	1.64	1.73	1.60	1.68	1.58	1.65
80 Percent Load		10 °F		59 °F		74 °F	90 °F										
Temperature (°F)		190	NA	190	NA	190	190			NA	NA	NA	NA	NA	NA	NA	NA
Velocity (ft/sec)		63.5	NA	60.2	NA	60.5	57.1			NA	NA	NA	NA	NA	NA	NA	NA
Maximum Hourly Emissions per Unit																	
SO_2	lb/hr	9.1	NA	8.5	NA	8.7	7.9			NA	NA	NA	NA	NA	NA	NA	NA
PM/PM_{10}	lb/hr	10.8	NA	10.7	NA	10.8	10.6			NA	NA	NA	NA	NA	NA	NA	NA
NO_x	lb/hr	88.3	NA	81.9	NA	90.0	75.9			NA	NA	NA	NA	NA	NA	NA	NA
CO	lb/hr	16.5	NA	15.6	NA	16.7	14.8			NA	NA	NA	NA	NA	NA	NA	NA
VOC (as methane)	lb/hr	2.1	NA	2.0	NA	2.1	1.8			NA	NA	NA	NA	NA	NA	NA	NA
Sulfuric Acid Mist	lb/hr	0.91	NA	0.85	NA	0.87	0.79			NA	NA	NA	NA	NA	NA	NA	NA
60 Percent Load		20 °F		59 °F		74 °F	90 °F										
Temperature (°F)		190	NA	190	NA	190	190			NA	NA	NA	NA	NA	NA	NA	NA
Velocity (ft/sec)		51.3	NA	49.0	NA	51.5	47.1			NA	NA	NA	NA	NA	NA	NA	NA
Maximum Hourly Emissions per Unit																	
SO_2	lb/hr	7.4	NA	7.1	NA	7.1	6.4			NA	NA	NA	NA	NA	NA	NA	NA
PM/PM_{10}	lb/hr	9.5	NA	9.4	NA	9.4	9.3			NA	NA	NA	NA	NA	NA	NA	NA
NO_x	lb/hr	72.0	NA	68.1	NA	73.3	63.0			NA	NA	NA	NA	NA	NA	NA	NA
CO	lb/hr	33.7	NA	32.3	NA	34.1	30.7			NA	NA	NA	NA	NA	NA	NA	NA
VOC (as methane)	lb/hr	7.1	NA	6.7	NA	6.8	6.1			NA	NA	NA	NA	NA	NA	NA	NA
Sulfuric Acid Mist	lb/hr	0.74	NA	0.71	NA	0.71	0.64			NA	NA	NA	NA	NA	NA	NA	NA

* Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.
Duct firing is assumed for 100% operating load. No duct firing is assumed for loads less than 100%.

Source: Siemens, 2006 - CT Performance Data; Golder, 2006.

Table 2-5. Stack, Operating, and Emission Data for Combustion Turbines in Simple Cycle Operation-
Distillate Light Oil Combustion

Parameter		Operating and Emission Data [a] for Ambient Temperarure Combustion Turbine 35 °F	59 °F	74 °F	w/Evap Clr 95 °F
CT Stack Data (ft)					
Height		120	120	120	120
Diameter		22.0	22.0	22.0	22.0
100 Percent Load					
Temperature (°F)		1,030	1,044	1,065	1,072
Velocity (ft/sec)		117.4	113.4	110.6	109.3
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	100.4	95.0	91.0	89.6
PM/PM_{10}	lb/hr	60.0	60.0	60.0	60.0
NO_x	lb/hr	334.0	316.0	303.0	298.0
CO	lb/hr	158.3	151.3	147.7	146.8
VOC (as methane)	lb/hr	28.0	27.0	25.0	25.0
Lead	lb/hr	0.03	0.02	0.02	0.02
Sulfuric Acid Mist	lb/hr	20.1	19.0	18.2	17.9
80 Percent Load		**20 °F**	**59 °F**	**72 °F**	**105 °F**
Temperature (°F)		1,120	1,140	1,150	1,170
Velocity (ft/sec)		111.2	106.6	103.8	97.5
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	79.9	74.1	71.9	66.3
PM/PM_{10}	lb/hr	60.0	60.0	60.0	60.0
NO_x	lb/hr	270.3	251.9	243.2	224.0
CO	lb/hr	132.3	125.0	123.0	117.5
VOC (as methane)	lb/hr	22.4	20.9	20.1	18.6
Lead	lb/hr	0.02	0.02	0.02	0.02
Sulfuric Acid Mist	lb/hr	16.0	14.8	14.4	13.3
65 Percent Load		**20 °F**	**59 °F**	**72 °F**	**105 °F**
Temperature (°F)		1,170	228	228	228
Velocity (ft/sec)		105.1	62.8	61.6	58.1
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	67.4	63.0	61.6	57.5
PM/PM_{10}	lb/hr	60.0	60.0	60.0	60.0
NO_x	lb/hr	227.2	212.7	208.0	194.0
CO	lb/hr	110.9	105.5	105.4	102.7
VOC (as methane)	lb/hr	18.8	17.6	17.2	16.1
Lead	lb/hr	0.02	0.02	0.02	0.01
Sulfuric Acid Mist	lb/hr	13.5	12.6	12.3	11.5

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.

Source: Siemens, 2006 - CT Performance Data; Golder, 2006.

Table 2-6. Stack, Operating, and Emission Data for the Combustion Turbines/HRSGs for Combined Cycle Operation-Distillate Light Oil Combustion

Parameter		Operating and Emission Data [a] for Ambient Temperarure Combustion Turbine/ HRSG 35 °F	59 °F	74 °F	w/Evap Clr 95 °F
CT/HRSG Stack Data (ft)					
Height		120	120	120	120
Diameter		18.0	18.0	18.0	18.0
100 Percent Load					
Temperature (°F)		228	228	228	228
Velocity (ft/sec)		81.0	77.5	74.5	73.4
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	100.4	95.0	91.0	89.6
PM/PM_{10}	lb/hr	80.3	79.2	78.4	78.1
NO_x	lb/hr	334.0	316.0	303.0	298.0
CO	lb/hr	158.3	151.3	147.7	146.8
VOC (as methane)	lb/hr	28.0	27.0	25.0	25.0
Lead	lb/hr	0.03	0.02	0.02	0.02
Sulfuric Acid Mist	lb/hr	20.1	19.0	18.2	17.9
80 Percent Load		**20 °F**	**59 °F**	**72 °F**	**105 °F**
Temperature (°F)		228	228	228	228
Velocity (ft/sec)		72.3	68.5	66.3	61.5
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	79.9	74.1	71.9	66.3
PM/PM_{10}	lb/hr	76.2	75.0	74.5	73.4
NO_x	lb/hr	270.3	251.9	243.2	224.0
CO	lb/hr	132.3	125.0	123.0	117.5
VOC (as methane)	lb/hr	22.4	20.9	20.1	18.6
Lead	lb/hr	0.02	0.02	0.02	0.02
Sulfuric Acid Mist	lb/hr	16.0	14.8	14.4	13.3
65 Percent Load		**20 °F**	**59 °F**	**72 °F**	**105 °F**
Temperature (°F)		228	228	228	228
Velocity (ft/sec)		66.3	62.8	61.6	58.1
Maximum Hourly Emissions per Unit					
SO_2	lb/hr	67.4	63.0	61.6	57.5
PM/PM_{10}	lb/hr	73.6	72.7	72.4	71.6
NO_x	lb/hr	227.2	212.7	208.0	194.0
CO	lb/hr	110.9	105.5	105.4	102.7
VOC (as methane)	lb/hr	18.8	17.6	17.2	16.1
Lead	lb/hr	0.02	0.02	0.02	0.01
Sulfuric Acid Mist	lb/hr	13.5	12.6	12.3	11.5

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.

Source: Siemens, 2006 - CT Performance Data; Golder, 2006.

Table 2-7. Proposed Emission Concentrations and Rates For Each CT in Various Operating Modes

Pollutant	Fuel	Method of Operation	Emisssion Rate			
			Maximum		59 °F	
			(ppmvd @15% O_2)	lb/hour	(ppmvd @15% O_2)	lb/hour
Nitrogen Oxides	Gas	Simple Cycle (SC)	15	122.1	15	108.0
	Gas	Combined Cycle (CC)	15	122.1	15	108.0
	Gas	CC - w/Duct Firing	17.8	165.5	16.3	151.7
	Gas	CC - w/Duct Firing, Power Aug.	14.1	152.0	NA	NA
	Oil	SC	42	334.0	42	316.0
	Oil	CC	42	334.0	42	316.0
Carbon Monoxide	Gas	Simple Cycle (SC), > 60% Load	4.0	24.1	4.0	20.3
	Gas	Combined Cycle (CC), > 60% Load	4.0	24.1	4.0	20.3
	Gas	SC and CC at 60% load	10.0	34.1	10.0	32.3
	Gas	CC - w/Duct Firing	9.4	39.8	8.0	40.3
	Gas	CC - w/Duct Firing, Power Aug.	7.8	42.6	NA	NA
	Oil	SC	30.0	158.3	30.0	151.3
	Oil	CC	30.0	158.3	30.0	151.3
Volatile Organic Compounds	Gas	Simple Cycle (SC)	1.00	2.83	1.00	2.50
	Gas	Combined Cycle (CC)	1.00	2.83	1.00	2.50
	Gas	CC - w/Duct Firing	2.17	4.80	1.79	4.60
	Gas	CC - w/Duct Firing, Power Aug.	1.76	4.70	NA	NA
	Oil	SC	10.0	28.0	10.0	27.0
	Oil	CC	10.0	28.0	10.0	27.0
Particulate Matter	Gas	Simple Cycle (SC)	NA	9.0	NA	9.0
	Gas	Combined Cycle (CC)	NA	11.5	NA	11.2
	Gas	CC - w/Duct Firing	NA	14.4	NA	14.3
	Gas	CC - w/Duct Firing, Power Aug.	NA	14.3	NA	NA
	Oil	SC	NA	60.0	NA	60.0
	Oil	CC	NA	80.3	NA	79.2
Sulfur Dioxide	Gas	Simple Cycle (SC)	NA	12.3	NA	10.9
	Gas	Combined Cycle (CC)	NA	12.3	NA	10.9
	Gas	CC - w/Duct Firing	NA	14.4	NA	13.6
	Gas	CC - w/Duct Firing, Power Aug.	NA	14.0	NA	NA
	Oil	SC	NA	100.4	NA	95.0
	Oil	CC	NA	100.4	NA	95.0
Sulfuic Acid Mist (SAM)	Gas	Simple Cycle (SC)	NA	1.23	NA	1.09
	Gas	Combined Cycle (CC)	NA	1.23	NA	1.09
	Gas	CC - w/Duct Firing	NA	1.70	NA	1.64
	Gas	CC - w/Duct Firing, Power Aug.	NA	1.68	NA	NA
	Oil	SC	NA	20	NA	19.0
	Oil	CC	NA	20	NA	19.0

Source: Siemens, 2006 - CT Performance Data; Golder, 2006

Note: Based on maximum emission rates over turbine inlet operating conditions for all operating loads.

Table 2-8. Performance, Stack Parameters and Emissions for Auxiliary Boiler

Performance	
Fuel Usage (scf/hr-gas)	96,945
Heat Input (mmBtu/hr-HHV)	99.00
Hours per Year	1,000
Maximum Fuel Usage (mmscf/yr)	96.94
Stack Parameters	
Diameter (ft)	2.75
Height (ft)	60
Temperature (°F)	296
Velocity (ft/sec)	81
Flow (acfm)	29,000
Emissions	
SO_2 -Basis (grains S/100 scf-gas; %S diesel)	2.00
(lb/hr)	0.55
(tpy)	0.28
NO_x - (lb/mmBtu)	0.05
(lb/hr)	4.85
(tpy)	2.43
CO - (lb/mmBtu)	0.08
(lb/hr)	8.15
(tpy)	4.08
VOC - (lb/mmBtu)	0.01
(lb/hr)	0.53
(tpy)	0.27
PM/PM10 - ($lb/10^6$ ft^3)	1.90
(lb/hr)	0.18
(tpy)	0.09

Table 2-9. Performance, Stack Parameters, and Emissions for Natural Gas Fuel Heaters

	Natural Gas Heaters	
Performance[a]		
Heat Input (MMBtu/hr-HHV)	3.0	
Heat content (Btu/scf)	1040	
Hours per Year	8,760	
Number of Units	1	5
Fuel Usage (scf/hr-gas)	2,885	14,423
Maximum Fuel Usage (MMscf/yr)	25.27	126.35
Stack Parameters (typical)		
Height (ft)	60	60
Diameter (ft)	2	2
Temperature (°F)	500	500
Velocity (ft/sec)	26	26
Flow (acfm)	4,950	4,950
Emissions		
SO_2 -Basis (grains S/100 scf-gas)[b]	2	2
(lb/hr)	0.016	0.082
(TPY)	0.072	0.36
NO_x - (lb/MMscf)[c]	100	100
(lb/hr)	0.29	1.44
(TPY)	1.3	6.3
CO - (lb/MMscf)[c]	84	84
(lb/hr)	0.24	1.21
(TPY)	1.1	5.3
VOC - (lb/MMscf)[c]	5.5	5.5
(lb/hr)	0.02	0.08
(TPY)	0.07	0.35
PM/PM10 - (lb/MMscf)[d]	1.9	1.9
(lb/hr)	0.005	0.027
(TPY)	0.024	0.12

[a] Based on 10 MMBtu/hr (HHV) indirect gas heaters from Hanover Compression Company or equivalent.

[b] Typical maximum for natural gas.

[c] EPA, AP-42 Table 1.4-1 using small boilers < 100 MMBtu.hr and Table 1.4-2.

[d] EPA, AP-42 Table 1.4-2 Filterable PM.

TABLE 3-1
National and State AAQS, Allowable PSD Increments, and Significant Impact Levels

Pollutant	Averaging Time	AAQS ($\mu g/m^3$)[a]			PSD Increments ($\mu g/m^3$)[a]		PSD Class II Significant Impact Levels ($\mu g/m^3$)[b]
		Primary Standard	Secondary Standard	Florida	Class I	Class II	
Particulate Matter[c] (PM_{10})	Annual Arithmetic Mean	50	50	50	4	17	1
	24-Hour Maximum	150	150	150	8	30	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum	365	NA	260	5	91	5
	3-Hour Maximum	NA	1,300	1,300	25	512	25
Carbon Monoxide	8-Hour Maximum	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone[c]	1-Hour Maximum	235	235	235	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

Note: Particulate matter (PM_{10}) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
NA = Not applicable, i.e., no standard exists.

[a] Short-term maximum concentrations are not to be exceeded more than once per year except for the PM_{10} and ozone AAQS. The 24-hour PM_{10} AAQS is attained when the expected number of days per year with a 24-hour concentration above 150 μ/m^3 is equal to or less than 1. For modeling purposes, compliance is based on the sixth highest 24-hour concentration over a 5-year period. For ozone, the daily maximum 1-hour concentration cannot be exceeded an average of more than one per year.

[b] Maximum concentrations are not to be exceeded.

[c] On July 18, 1997, EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, $PM_{2.5}$ standards were introduced with a 24-hour standard of 65 g/m^3 (3-year average of 98th percentile) and an annual standard of 15 g/m^3 (3-year average at community monitors).
The ozone standard was modified to be 0.08 ppm; achieved when 3-year average of 99th percentile is 0.08 ppm 157 μ/m^3 or less. FDEP has not yet adopted these standards.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50; 40 CFR 52.21.
Chapter 62-204, F.A.C.

TABLE 3-2
PSD Significant Emission Rates and *De Minimis* Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration[a] ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter [PM(TSP)]	NSPS	25	10, 24-hour
Particulate Matter (PM_{10})	NAAQS	15	10, 24-hour
Nitrogen Dioxide	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Mercury	NESHAP	0.1	0.25, 24-hour

Note: Ambient monitoring requirements for any pollutant may be exempted if the impact of the increase in emissions is below *de minimis* monitoring concentrations.

NAAQS = National Ambient Air Quality Standards.
NM = No ambient measurement method established; therefore, no *de minimis* concentration has been established.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
g/m^3 = micrograms per cubic meter.

[a] Short-term concentrations are not to be exceeded.
[b] No *de minimis* concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.

Sources: 40 CFR 52.21; Rule 62-212.400.

TABLE 6-1

STRUCTURE DIMENSIONS USED IN THE MODELING ANALYSIS

BPIP Structure ID	Height		Length		Width	
	(ft)	(m)	(ft)	(m)	(ft)	(m)
HRSG 1	80	24.4	25.9	7.9	92.5	28.2
HRSG 2	80	24.4	25.9	7.9	92.5	28.2
HRSG 3	80	24.4	25.9	7.9	92.5	28.2
HRSG 4	80	24.4	25.9	7.9	92.5	28.2
BOILER BLDG LOWER TIER	75	22.9	74.1	22.6	245.1	74.7
BOILER BLDG UPPER TIER	130	39.6	58.1	17.7	245.1	74.7
STEAM TURBINE	70	21.3	123.4	37.6	378.3	115.3
NORTH OF BOILER BLDG	154	46.9	81.0	24.7	103.0	31.4

TABLE 6-2
MAXIMUM POLLUTANT CONCENTRATIONS PREDICTED FOR PHASE I-
SIMPLE CYCLE OPERATION BY OPERATING LOAD AND AIR INLET TEMPERATURE,
FUEL OIL-FIRED COMBUSTION TURBINES AND NATURAL GAS-FIRED GAS HEATERS

Pollutant		Averaging Time	Rank	Maximum Predicted Concentration (ug/m^3) [a] for Phase 1 [b]					
				100% Load		80% Load		65% Load	
				35 °F	95 °F	20 °F	105 °F	20 °F	105 °F
PSD Pollutants Requiring Review									
CO	2 CTs	8-Hour	Highest	15.8	15.7	13.6	14.2	12.1	12.9
		1-Hour	Highest	33.6	34.8	30.0	32.3	27.3	29.5
	2 Gas heaters	8-Hour	Highest	2.16	2.16	2.16	2.16	2.16	2.16
		1-Hour	Highest	4.96	4.96	4.96	4.96	4.96	4.96
	TOTAL	8-Hour	Highest	17.9	17.9	15.8	16.4	14.3	15.1
		1-Hour	Highest	38.6	39.7	35.0	37.3	32.3	34.5
PSD Pollutants Not Requiring Review									
SO_2	2 CTs	Annual	Highest	0.15	0.14	0.12	0.12	0.11	0.10
		24-Hour	Highest	4.59	4.45	3.83	3.71	3.43	3.35
		3-Hour	Highest	13.8	13.1	11.28	10.66	9.98	9.61
	2 Gas heaters	Annual	Highest	0.015	0.015	0.015	0.015	0.015	0.015
		24-Hour	Highest	0.087	0.087	0.087	0.087	0.087	0.087
		3-Hour	Highest	0.235	0.235	0.235	0.235	0.235	0.235
	TOTAL	Annual	Highest	0.16	0.16	0.14	0.13	0.12	0.12
		24-Hour	Highest	4.68	4.54	3.92	3.80	3.52	3.43
		3-Hour	Highest	14.0	13.4	11.5	10.9	10.2	9.8
PM_{10}	2 CTs	Annual	Highest	0.09	0.09	0.09	0.10	0.10	0.11
		24-Hour	Highest	2.74	2.98	2.87	3.35	3.06	3.49
	2 Gas heaters	Annual	Highest	0.005	0.005	0.005	0.005	0.005	0.005
		24-Hour	Highest	0.027	0.027	0.027	0.027	0.027	0.027
	TOTAL	Annual	Highest	0.09	0.10	0.10	0.11	0.10	0.11
		24-Hour	Highest	2.77	3.01	2.90	3.38	3.09	3.52
NO_2	2 CTs	Annual	Highest	0.49	0.47	0.41	0.39	0.36	0.35
	2 Gas heaters	Annual	Highest	0.14	0.14	0.14	0.14	0.14	0.14
	TOTAL	Annual	Highest	0.62	0.60	0.54	0.53	0.50	0.49

[a] Concentrations are based on highest concentrations predicted using five years of meteorological data from 2001 to 2005 of surface and upper air data from the National Weather Service station at Tampa International Airport.

[b] Includes two CTs operating in simple cycle mode with two gas heaters.

TABLE 6-3
MAXIMUM POLLUTANT CONCENTRATIONS PREDICTED FOR PHASE 2-
COMBINED AND SIMPLE CYCLE OPERATIONS BY OPERATING LOAD AND AIR INLET TEMPERATURE,
FUEL OIL-FIRED COMBUSTION TURBINES AND NATURAL GAS-FIRED GAS HEATERS

Pollutant	Averaging Time	Rank	Maximum Predicted Concentration (ug/m^3) [a] for Phase 2 [b] 100% Load 35 °F	100% Load 95 °F	80% Load 20 °F	80% Load 105 °F	60% Load 20 °F	60% Load 105 °F
PSD Pollutants Requiring Review								
CO	8-Hour	Highest	108	108	99.1	100	88.7	92.3
	1-Hour	Highest	153	151	137	138	123	128
PSD Pollutants Not Requiring Review								
SO_2	Annual	Highest	1.94	1.93	1.76	1.73	1.63	1.59
	24-Hour	Highest	33.1	33.2	30.2	29.5	27.8	26.7
		HSH	28.9	28.2	25.6	24.4	23.2	22.1
	3-Hour	Highest	84.2	81.3	73.4	68.7	65.9	61.7
		HSH	79.9	78.1	70.8	66.1	63.7	59.2
PM_{10}	Annual	Highest	0.60	0.60	0.60	0.80	0.70	0.90
	24-Hour	Highest	21.7	24.2	24.0	27.8	25.6	28.5
		HSH	18.0	20.4	20.3	22.6	21.2	24.4
NO_2	Annual	Highest	7.03	7.01	6.55	6.51	6.12	6.09

Note: HSH= highest, second highest

[a] Concentrations are based on highest concentrations predicted using five years of meteorological data from 2001 to 2005 of surface and upper air data from the National Weather Service station at Tampa International Airport.

[b] Includes four CTs operating in combined cycle mode and one CT operating in simple cycle mode with five gas heaters. PM_{10} impacts include emission reductions from Boilers 1, 2 and 3

aux boiler ?

TABLE 6-4
SUMMARY OF MAXIMUM POLLUTANT CONCENTRATIONS PREDICTED FOR THE PROJECT PHASES 1 AND 2 COMPARED TO THE EPA CLASS II SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Time	Rank	Maximum Predicted Concentration (ug/m^3)	EPA Class II Significant Impact Levels (ug/m^3)	PSD Class II Increment (ug/m^3)
Phase 1 - Simple Cycle					
PSD Pollutants Requiring Review					
CO	8-Hour	Highest	17.9	500	NA
	1-Hour	Highest	39.7	2,000	NA
PSD Pollutants Not Requiring Review					
SO_2	Annual	Highest	0.16	1	20
	24-Hour	Highest	4.68	5	91
	3-Hour	Highest	14.0	25	512
PM_{10}	Annual	Highest	0.11	1	17
	24-Hour	Highest	3.52	5	30
NO_2	Annual	Highest [b]	0.47	1	25
Phase 2 - Combined and Simple Cycle					
PSD Pollutants Requiring Review					
CO	8-Hour	Highest	108	500	NA
	1-Hour	Highest	153	2,000	NA
PSD Pollutants Not Requiring Review					
SO_2	Annual	Highest	1.94	1	20
	24-Hour	Highest	33.2	5	NA
		HSH	28.9	NA	91
	3-Hour	Highest	84.2	25	NA
		HSH	79.9	NA	512
PM_{10}	Annual	Highest	0.90	1	17
	24-Hour	Highest	28.5	5	NA
		HSH	24.4	NA	30
NO_2	Annual	Highest [b]	5.27	1	25

Note: NA= not applicable
HSH= highest, second highest

[a] Phase 1 includes two CTs operating in simple cycle mode and firing fuel oil with two gas-fired gas heaters. Phase 2 includes four CTs operating in combined cycle mode and one CT operating in simple cycle mode, with five gas-fired gas heaters and an auxilliary boiler. All CTs are oil-fired.

[b] NO_2 concentration based on NO_x to NO_2 conversion rate of 75%.
PM_{10} impacts include emission reductions from Boilers 1, 2 and 3

TABLE 7-1
MAXIMUM CO CONCENTRATIONS PREDICTED FOR THE PHASE 2 PROJECT,
FUEL OIL-FIRED COMBUSTION TURBINES, NATURAL GAS-FIRED GAS HEATERS,
AND AUXILLIARY BOILER AT THE PSD CLASS I AREA OF THE CHASSAHOWITZKA NWA

Pollutant	Averaging Time	Maximum Predicted Concentration (ug/m^3) [a] for Phase 2 [b] 2001	2002	2003
Phase 2- Combined and Simple Cycle				
CO	Annual	0.054	0.056	0.068
	24-Hour	0.73	0.72	1.03
	8-Hour	1.23	1.87	1.58
	3-Hour	2.09	2.19	2.17
	1-Hour	3.44	2.64	2.94

[a] Concentrations are based on highest concentrations predicted using the CALPUFF model and three years of meteorological data, 2001 to 2003, developd by VISTAS.

[b] Includes four CTs operating in combined cycle mode and one CT operating in simple cycle mode with five gas-fired gas heaters and an auxilliary boiler.

FIGURES

Golder Associates
Tampa, Florida

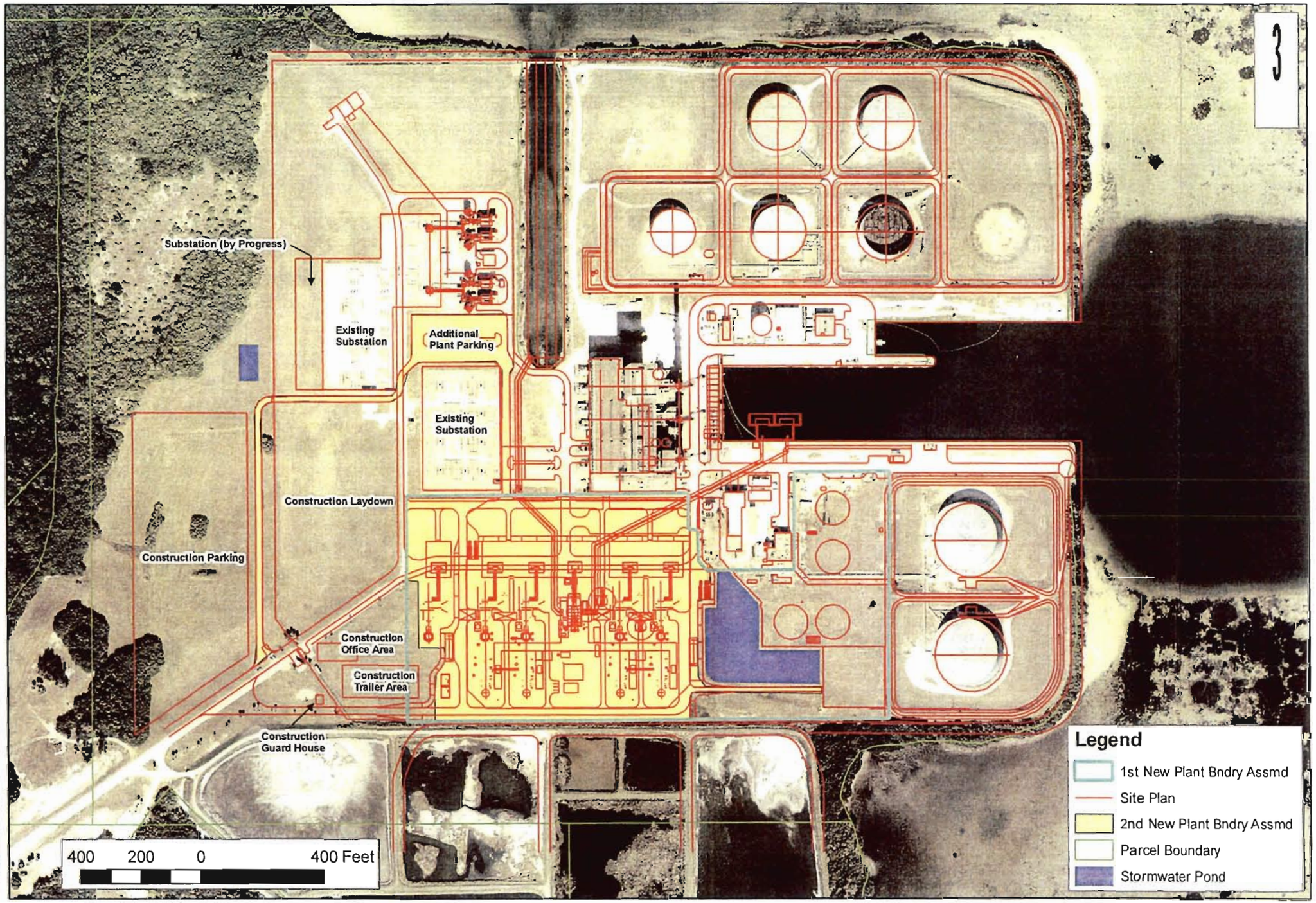
REV	DATE	DES	REVISION DESCRIPTION	DES	CHECK	RVW

PROJECT
PROGRESS ENERGY
BARTOW REPOWERING

TITLE
STUDY AREA

PROJECT No	053-9576	
FILE No	0539576A001.mxd	
REV. 0	SCALE AS SHOWN	
DESIGN	JWT	7/11/2005
DR.	JWT	5/19/2005
CHECK		
REVIEW		

FIGURE 1-1



Golder Associates
Tampa, Florida

PROJECT
Bartow Repowering Project

TITLE
SITE LAYOUT

PROJECT No. 053-9576		
DATE	08 May 2006	
REV. 0	SCALE	
DESIGN	QY	08 May 2006
GIS	QY	08 May 2006
CHECK	MF	08 May 2006
REVIEW	MM	08 May 2006

FIGURE: 2-1

APPLICATION FORMS

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 at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air permit. Also use this form to apply for an air construction permit:

- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- Where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- Where the applicant proposes 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/renewal Title V air operation permit.

Air Construction Permit & Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Florida Power Corporation dba Progress Energy Florida, Inc.**
2. Site Name: **Bartow Plant**
3. Facility Identification Number: **1030011**
4. Facility Location...:
   Street Address or Other Locator: **1601 Weedon Island Drive**
   City: **St. Petersburg** County: **Pinellas** Zip Code: **33702**
5. Relocatable Facility? ☐ Yes ☒ No
6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Ann Quillian, PE**
2. Application Contact Mailing Address...
   Organization/Firm: **Progress Energy Florida, Inc.**
   Street Address: **100 Central Avenue, MAC CX1B**
   City: **St. Petersburg** State: **FL** Zip Code: **33701**
3. Application Contact Telephone Numbers...
   Telephone: **(727) 820-5962** ext. Fax: **(727) 820-5229**
4. Application Contact Email Address: Ann.Quillian@pgnmail.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 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)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.
☐ 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:

☐ 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

The application is submitted for the repowering of the Bartow Steam Units No. 1, No. 2, and No. 3 with four F-Class combined- and simple- cycle operable combustion turbines and one simple-cycle only combustion turbine. The application also includes an auxiliary boiler and 5 fuel gas heaters. See PSD Report.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
	Simple- and Combined Cycle F-Class Combustion Turbine with HRSG Duct Firing	AC1A	
	Simple- and Combined Cycle F-Class Combustion Turbine with HRSG Duct Firing	AC1A	
	Simple- and Combined Cycle F-Class Combustion Turbine with HRSG Duct Firing	AC1A	
	Simple- and Combined Cycle F-Class Combustion Turbine with HRSG Duct Firing	AC1A	
	Simple-Cycle F-Class Combustion Turbine	AC1A	
	Auxiliary Boiler	AC1A	
	Fuel Gas Heaters	AC1A	

Application Processing Fee

Check one: ☒ Attached - Amount: $ 7,500 ☐ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1. Owner/Authorized Representative Name :
   Rufus Jackson
2. Owner/Authorized Representative Mailing Address...
   Organization/Firm: **Progress Energy Florida, Inc.**
   Street Address: **1601 Weedon Island Drive**
   City: **St. Petersburg** State: **FL** Zip Code: **33702**
3. Owner/Authorized Representative Telephone Numbers...
   Telephone: **(727) 827-6111** ext. Fax: **(727) 827-6102**
4. Owner/Authorized Representative Email Address: **Rufus.Jackson@pgnmail.com**
5. Owner/Authorized Representative Statement:

   I, the undersigned, am the owner or authorized representative of the facility 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 requirements identified in this application to which the facility 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.

   Signature Date 7/28/06

Application Responsible Official Certification

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

1. Application Responsible Official Name:

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

3. Application Responsible Official Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) -

5. Application Responsible Official Email Address:

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 Date

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 West Lemon St., Suite 114**
   City: **Tampa** State: **FL** Zip Code: **33609**
3. Professional Engineer Telephone Numbers...
   Telephone: **(813) 287-1717** ext. Fax: **(813) 287-1716**
4. Professional Engineer Email 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 ☐, 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 Date 7/28/06

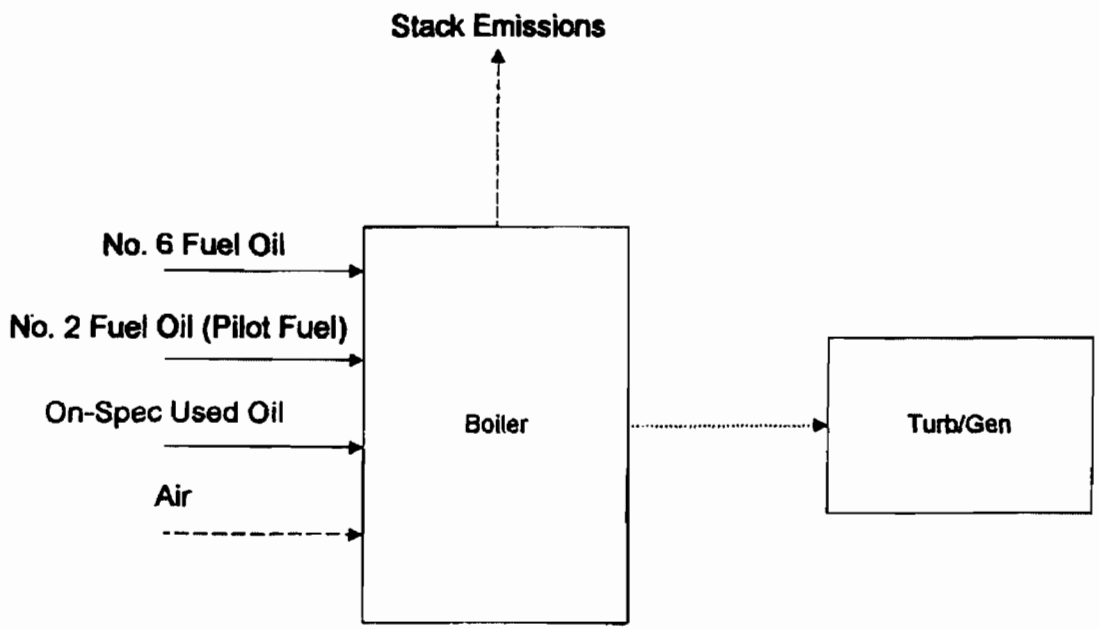
(seal)

SCOTT OSBOURN LICENSE NO. 57557 STATE OF FLORIDA PROFESSIONAL ENGINEER

* Attach any exception to certification statement.
** **Board of Professional Engineers Certificate of Authorization #00001670**

EMISSION UNIT 001
No.1 Unit, FFFSG

ATTACHMENT BA-FI-C8



CLIENT/PROJECT **Progress Energy Florida, Inc**			TAMPA, FLORIDA Golder Associates				TITLE **Process Flow Diagram No. 1 Unit FFFSG P. L. Bartow Plant**			
DRAWN	CHECKED	REVIEWED	DATE 4/16/2009	NOT TO SCALE	FILE NO.	Job No. 083-89614	DWG NO.	SUBTITLE	REV. NO.	**BA-EU1-I1**

ATTACHMENT BA-EU1-I2

FUEL ANALYSIS

No. 6 Fuel Oil

Parameter	Typical Value
API gravity @ 60 F	8[1]
Relative density	8.2 lb/gal [2]
Heat content	18,300 Btu / lb (HHV)
% sulfur	2.5 [3]
% nitrogen	0.25 - 0.50
% ash	0.06 - 0.10

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) FPC's fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the FPC fuel procurement specification

[2] Data from laboratory analysis

[3] Data from current air permit.

No. 2 Fuel Oil

Parameter	Typical Value	Max Value
API gravity @ 60 F	30[1]	-
Relative density	7.1 lb/gal [2]	
Heat content	19,500 Btu / lb (HHV)	
% sulfur	0.04 [2]	0.5 [3]
% nitrogen	0.025 - 0.030	
% ash	negligible	0.1 [1]

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) FPC's fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the FPC fuel procurement specification

[2] Data from laboratory analysis

[3] Data from current air permit.

ATTACHMENT BA-EU1-I2 (Continued)

FUEL ANALYSIS

On-Spec Used Oil

Parameter	Typical Value	Max Value
API gravity @ 60 F	28[1]	-
Relative density	7.4lb/gal [2]	
Heat content	18,700 Btu / lb (HHV)	
% sulfur	0.3 - 0.5 [2]	2.5 [3]
% nitrogen	0.3	
% ash	0.4 - 0.9	

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) FPC's fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the FPC fuel procurement specification

[2] Data from laboratory analysis

[3] Data from current air permit.

ATTACHMENT BA-EU1-I4

PROCEDURES FOR STARTUP AND SHUTDOWN MINIMIZING EXCESS EMISSIONS

Startup of the fossil-fuel boilers begins when fuel (No. 2 or No. 6 fuel oil) is introduced into one or more burners within the boiler and lighted (commencement of combustion). Startup is complete and steady-state operation begins when the combustion process has stabilized and the megawatt load on the unit is stable and above 10 percent load.

Shutdown of the fossil-fuel boilers begins when unit megawatt load is decreased to below 10 percent of maximum and continues until the final burner gun is removed from service.

Emissions may be detected during all modes of boiler operation by various continuous emissions monitors. Continuous monitors are currently in place for NO_x, CO_2, and opacity. Audible and visual alarms are activated whenever the permitted value for opacity is approached.

Countermeasures which may be taken in the event of excess emissions include, but are not limited to:

- burner elevation loading
- proper excess air adjustments
- recognizing and removal of faulty burners
- fuel oil temperature adjustments
- proper and timely operation of boiler cleaning devices
- removal of the unit from system-dispatch mode (load control)
- reduction of unit megawatt load
- stopping and restarting of boiler cleaning devices
- lowering load ramp rate
- pressure rate changes
- placing boiler controls on manual
- adjusting burner dampers to increase windbox/furnace air pressure

Knowledge of the appropriate countermeasures to take when excess emissions occur is a part of the routine operator training for those who operate the boilers. Topics include current permit limits, maximum allowable duration of excess emissions, appropriate countermeasures for excess emissions, duty to notify, and fuels and combustion training.

ATTACHMENT BA-EU1-I6

Particulate Matter and Visible Emissions Test Report

Completed for:

Progress Energy Florida, Inc.
P.L. Bartow Plant
Unit 1 (EU-001)

Test Report Number: 20-3264-01-001

Test Completed: July 21, 22 and 23, 2008

C.E.M. SOLUTIONS

1183 East Overdrive Circle • Hernando, FL 34442 • (352) 489-4337 • Fax: (352) 489-4801

Particulate Matter and Visible Emissions Test Report

Progress Energy Florida, Inc.
P.L. Bartow Plant, Unit 1 (EU-001)
St. Petersburg, Florida

C.E.M. Solutions Project No.: 3264

Testing Completed: July 21, 22 and 23, 2008

C.E.M. Solutions, Inc. Report Number: 20-3264-01-001

C.E.M. Solutions, Inc.
1183 E. Overdrive Circle
Hernando, Florida 34442
Phone: 352-489-4337

Plant's Authorization and Validity Statement

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.

Mr. Tom Lawrey
Plant Manager

Date

Statement of Validity

I hereby certify the information and data provided in this emissions test report for tests performed at Progress Energy Florida Inc.'s P.L. Bartow Plant conducted on July 21, 22 and 23, 2008 are complete and accurate to the best of my knowledge.

Jeremy A. Johnson
President
C.E.M. Solutions, Inc.

Project Background

Name of Source Owner:	Progress Energy Florida, Inc.
Address of Owner:	299 First Avenue North St. Petersburg, Florida 33701
Source Identification:	Facility: 1030011 Emissions Unit: EU-001
Location of Source:	Pinellas County, Florida
Type of Operation:	SIC Code 4911
Tests Performed:	Method 1 – Traverse Points Method 2 – Stack Gas Volumetric Flow and Velocity Method 3A – Determination of Molecular Weight Method 4 – Stack Gas Moisture Content Method 9 – Determination of Opacity of Emissions Method 17 – Particulate Matter Method 19 – Determination of Emissions Rates
Test Supervisor:	Mr. Charles Horton
Date(s) Tests Conducted:	July 21, 2008: Normal (Steady State) July 22 and 23, 2008: Soot-blowing
Site Test Coordinator:	Mr. Charles Dufeny
Regulatory Observers:	Mr. Jeffrey Morris Environmental Specialist II Pinellas County Department of Environmental Management

C.E.M. Solutions, Inc Test Personnel

Project Field Manager:	Mr. Charles Horton
Test Technicians:	Mr. Robert Douglas Mr. Thomas Harris

Table of Contents

List of Tables

List of Figures

Appendices

1.0 Introduction

Progress Energy Florida, Inc. (PEF) retained C.E.M. Solutions, Inc. to conduct emissions testing to determine levels of particulate matter (PM) and visible emissions (VE) from Unit 1 boiler exhausts (emissions unit EU-001) at its P.L. Bartow Plant in St. Petersburg, Florida.

The test program was conducted to determine the compliance status of Unit 1 with respect to its emissions limitations and standards outlined in Title V Air Operating Permit 1030011-009-AV. Target pollutants include the following:

- PM (lb/mmBtu)
- VE (in percent opacity)

Charles Dufeny of Progress Energy coordinated plant operations throughout the test program. All testing was conducted in accordance with test methods promulgated by the Florida Department of Environmental Protection.

Unit 1 was in compliance with the permitted emissions limitations as summarized in Table 1 below.

The test program and results are presented and discussed in this report.

Table 1: Compliance Test Results
Unit 1
P.L. Bartow Plant

Pollutant	Unit Operating Mode	Reported Emissions Rate (3-run average)	Permitted Emissions Rate	Compliance Test Status (Pass/Fail)
PM	Normal	0.04 lb/mmBtu	0.1 lb/mmBtu	Pass
PM	Sootblowing	0.03 lb/mmBtu	0.3 lb/mmBtu	Pass
VE	Normal	19.4 %	≤40 %	Pass
VE	Sootblowing	18.8 %	≤60 %	Pass

2.0 Facility Description

P.L. Bartow Plant Unit 1 is a fossil fuel fired steam generator consisting of a front-fired boiler, rated at 120 MW, with a maximum heat input rate of 1220 mmBtu/hr. Primary fuel is No. 2 through No. 6 fuel oil.

2.1 Process Equipment

Fossil Fuel Steam Generator, Unit 1 is a fuel oil, front-fired boiler. Particulate emissions from Unit 1 are controlled with an Electrostatic Precipitator (ESP). Emissions are exhausted through a brick and mortar 300 ft. stack.

2.2 Regulatory Requirements

Progress Energy Florida, Inc. is required to perform annual compliance testing for particulate matter and opacity in accordance with Title V Permit Number 1030011-009-AV.

Unit 1's emissions limitations and standards are summarized in Table 2.

Table 2: Emissions Limitations and Standards
Unit 1
P.L. Bartow Plant

Pollutant/Standard	Emission Limit	Permit Condition
PM lb/mmBtu	0.1 during normal (steady state), and 0.3 during soot blowing	A.7 and A.8
VE %[a]	40% during normal (steady state), and 60% during soot blowing	A.5 and A.6
Sulfur Content %	Sulfur content shall not exceed 2.5%, by weight	A.10

[a] six-minute average

3.0 Test Program/Operating Conditions

The test program was conducted to determine the compliance status of Unit 1's particulate matter and visible emissions with regard to applicable limitations in the Title V Operating Permit 1030011-009-AV.

Testing was completed during normal operation (steady state) on July 21, 2008. Test runs during soot-blowing conditions were completed on July 22 and 23, 2008

During the test program, Unit 1's heat input averaged 1155.2 mmBtu/hr while operating on 100 percent oil, which correlates to 95 percent of the maximum heat input (1220 mmBtu/hr).

Unit 1 fuel flow and fuel analysis reports are located in Appendix A.

Fuel flow and fuel analysis reports were provided by Progress Energy.

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.

Table 3 summarizes the EPA test methods utilized to complete the test program.

Table 3: Summary of EPA Reference Methods

Unit 1
P.L. Bartow Plant

EPA Method	Description
1	Sample and Velocity Traverses for Stationary Sources
2	Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot)
3A	Gas Analysis for Determining Dry Molecular Weight (Instrument Analyzer Procedure)
4	Moisture Content in Stack Gases
9	Opacity (Visible Emissions)
17	Particulate Emissions from Stationary Sources

4.1 Sample and Velocity Traverse Points

Sample and velocity traverse points were determined utilizing EPA Method 1.

Unit 1's exhaust stack inner diameter, at the sample location, is 120.7". The emissions sampling location is 1440 inches downstream from the nearest flow disturbance, and 1560 inches upstream from the stack exhaust.

A diagram of the sample locations is provided in Appendix C.

4.2 Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tubes)

Method 2 was used to determine the volumetric flow rate of the stack effluent gas.

Stack temperature differential pressure readings were taken with an S type pitot tube and Type K temperature sensor at each sample traverse point.

4.2.1 Method 2 Quality Assurance/Quality Control Procedures

The S type pitot tube was inspected visually and measured to meet the design specifications of EPA Method 2, for a pitot coefficient of 0.84.

The incline manometer and each leg of the pitot tube was leak checked before and immediately after each test run.

Thermocouple sensors were calibrated prior to the test program and a post test check was performed after testing completion.

The incline manometer was leveled and zeroed before each test run.

Appendix D contains the completed QA/QC forms.

4.3 Moisture Content Determination

Moisture content of the stack gas was determined by Method 4.

Stack gas was sampled at each traverse point, passed through pre-weighed impingers and then through a calibrated dry gas meter. Moisture is removed from the sample gas in the pre-weighed impingers, which are submerged in an ice bath, and later analyzed for moisture weight gain. Moisture is determined based upon the amount of moisture weight gain and sample gas collected.

Field moisture data sheets are also located in Appendix E.

4.3.1 Method 4 Quality Assurance/Quality Control Procedures

The moisture sampling train was leak checked prior to each test run at approximately 15 inches hg and immediately after each run at a vacuum higher than the highest vacuum recorded during the respective test run. Results are recorded on the moisture field data sheets.

Weighing to determine moisture content was conducted with a balance having an accuracy of 0.5 grams.

Gas temperature at the exit of the impingers was maintained at less than 68 degrees Fahrenheit.

4.4 Particulate Matter Determination

USEPA Method 17 was used to determine particulate emissions. Stack gas was extracted isokinetically from the gas stream; particulate emissions are measured gravimetrically by determining the amount of particulate matter collected on the stainless steel nozzle and glass or quartz fiber filter. The probe liner temperature was maintained at 248 ± 25 degrees Fahrenheit.

Sample volume was measured by passing the gas through a set of weighed impingers used for moisture content, then passed through a calibrated dry gas meter. An S type pitot tube is attached to the probe to measure stack gas velocity and to maintain sampling conditions between 90% and 110% isokinetic. A type K temperature sensor is also attached to the probe to measure the stack gas temperature.

Isokinetic conditions were maintained throughout each test run of the test program as demonstrated in Table 4.

A minimum of 30 dscf of sample was taken each test run over a sampling period of approximately 60 minutes.

Method 17 field data sheets are located in Appendix E.

Figure 1 contains a diagram of the Method 17 sampling train.

4.4.1 Sample Recovery and Analysis

After each sample run, the nozzle and filter holder ahead of the filter were brushed and rinsed with acetone. Contents were stored in a leak free container for transport to the laboratory. The impingers were weighed for increase, to the nearest 0.5 gram, to determine moisture gain.

Particulate matter was determined by drying each filter at 230 degrees Fahrenheit for three hours, desiccated to a constant weight and recorded to the nearest 0.1 mg. Sample from the probe nozzle and filter holder were evaporated in a tared beaker, desiccated to a constant weight, and recorded to the nearest 0.1 mg.

Appendix E contains the analytical results for each run.

4.4.2 Quality Assurance/Quality Control Procedures

The probe nozzles were inspected and measured across three different diameters to determine the appropriate nozzle diameter.

Before and after each test run, the manometer was leveled and zeroed. Leak checks of the sampling train were conducted before and immediately after each test run.

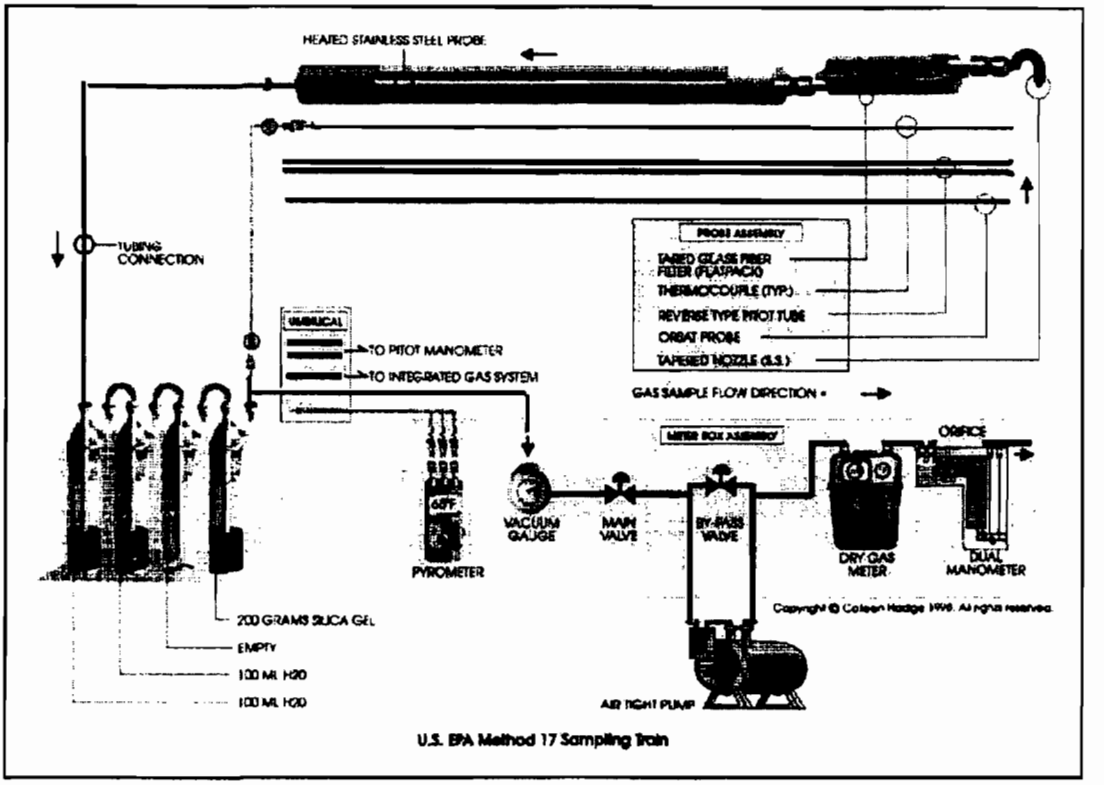
The dry gas meter was fully calibrated within six months prior to the test program using a set of EPA critical orifices. Post test program dry meter checks were completed to verify the accuracy of the meter's Y_i.

Completed QA/QC forms are located in Appendix D.

Table 4: Particulate Matter Isokinetic Summary
Unit 1
P.L. Bartow Plant

Operating Mode	% Isokinetic				
	Run 1	Run 2	Run 3	Average(s)	Tolerance
Normal	103.4	99.1	100.7	101.1	90-110
Sootblowing	101.3	102.3	100.6	101.4	

Figure 1: Method 17 Sampling Train



4.5 Visible Emissions (Percent Opacity) Determination

USEPA Method 9 was utilized to determine visible emissions (VE).

VE 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 minute observation run was performed while the unit was operating at maximum capacity.

Method 9 data summary, field data and VE reader's certification are located in Appendix E.

4.6 CO_2 and O_2 Instrument Analyzer Methods

CO_2 and O_2 reference method data was determined using instrument analyzer procedures. CO_2 and O2 data was used to determine stack gas molecular weight. Mathematical equations used to determine calculated emissions standards can be reviewed in Appendix B. Table 5 summarizes the EPA methods and instrumentation:

Table 5: Summary of EPA Reference Methods and Instrumentation
Unit 1
P.L. Bartow Plant

Pollutant	EPA Method	Instrument	Serial Number
CO_2	3A	Servomex 1440	1415D/3379
O_2	3A	Servomex 1440	1420D/3379

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 heated to approximately 250°F. Samples were then transported to a gas sample conditioner via a heated sample line operating at 250°F or above. The gas sample conditioner lowers the dew point of the sample gas to approximately 5°C 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 6:

Table 6: Reference Method Calibration Span and Calibration Gases
Unit 1
P.L. Bartow Plant

Pollutant	Test Location	Calibration Span	Calibration Gases[a]
CO_2	Unit 1	17.99 %	0.0 % CO_2 9.55 % CO_2 17.99 % CO_2
O_2	Unit 1	23.93 %	0.0 % O_2 9.98 % O_2 23.93 % O_2

[a] Concentrations, CO_2 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 D.

4.6.1 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 and response time 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 6.

Appendix D contains the QA/QC checks.

4.7 Fuel Analysis

ASTM test methods were utilized to determine the heating value and sulfur content of the fuel oil used during the test program as required in permit condition A.22.

Fuel analysis report(s) can be viewed in Appendix A.

5.0 Test Results

The test program results are presented below. Supporting calculations and field data summaries are presented in Appendices B and E, respectively.

5.1 Particulate Matter

The three-run average particulate matter emissions during the normal (steady state) portion of the test program was 0.04 lb/mmBtu, passing the performance specification of 0.1 lb/mmBtu.

The three-run average particulate matter emissions during the sootblowing portion of the test program was 0.03 lb/mmBtu, passing the performance specification of 0.3 lb/mmBtu.

5.2 Visible Emissions

The highest six-minute average opacity observed from the Unit 1 stack during the normal operating mode of the test program was 19.4 percent opacity, passing the 40 percent emission limit.

The highest six-minute average opacity observed from the Unit 1 stack during the sootblowing operating mode portion of the test program was 18.8 percent opacity, passing the 60 percent emission limit.

5.3 Sulfur Content

The sulfur content of the fuel burned during the compliance test was 1.37 % of the fuel by weight, below the 2.5 % limitation.

ATTACHMENT BA-EU1-I7

APPLICABLE REQUIREMENTS LISTING

EMISSION UNIT: Unit 1 – P. L. Bartow Plant

FDEP Rules:

Air Pollution Control-General Provisions:

62-204.800(12) (State Only)	- Acid Rain Program
62-204.800(13) (State Only)	- Allowances
62-204.800(14) (State Only)	- Acid Rain Program Monitoring

Stationary Sources-General:

62-210.700(1)	- Malfunction only for FFGS
62-210.700(2)	- FFSG; startup/shut down
62-210.700(3)	- FFSG; sootblowing/load change
62-210.700(4)	- Maintenance
62-210.700(6)	

Acid Rain:

62-214.300	- Acid Rain Units (Applicability)
62-214.320	- Acid Rain Units (Application Shield)
62-214.330	- Compliance Options (if 62-214.430)
62-214.350(2),(3),(6)	- Acid Rain Units (Certification)
62-214.370	- Revisions; corrections; (potentially applicable)
62-214.430	- Acid Rain Units (Compliance Options)

Stationary Sources-Emission Standards:

62-296.405(1)(a)	- FFSG;VE
62-296.405(1)(b)	- FFSG; PM
62-296.405(1)(c)1.j.	- FFSG; Oil-SO2 (general limit)
62-296.405(1)(e)	- FFSG; Test Methods
62-296.405(1)(f)1.a.(i)	- FFSG; Opacity CEMS exempted for oil/gas units
62-296.405(1)(f)1.b.	- FFSG; SO2 CEMS exempted for non-controlled units (oil/gas)
62-296.700(2)(a)	- RACT; Emission Limitations PM
62-296.700(2)(b)	- RACT; Visible Emissions
62-296.700(3)	- Test Methods
62-296.700(5)	- RACT; Circumvention

Stationary Sources-Emission Monitoring (where stack test is required):

62-297.310(1)	- Test Runs-Mass Emission
62-297.310(2)(b)	- Operating Rate; other than CTs
62-297.310(3)	- Calculation of Emission
62-297.310(4)(a)	- Applicable Test Procedures; Sampling time
62-297.310(4)(b)	- Sample Volume
62-297.310(4)(c)	- Required Flow Rate Range-PM/H2SO4/F
62-297.310(4)(d)	- Calibration
62-297.310(4)(e)	- EPA Method 5-only
62-297.310(5)	- Determination of Process Variables

62-297.310(6)(a)	- Permanent Test Facilities-general
62-297.310(6)(c)	- Sampling Ports
62-297.310(6)(d)	- Work Platforms
62-297.310(6)(e)	- Access
62-297.310(6)(f)	- Electrical Power
62-297.310(6)(g)	- Equipment Support
62-297.310(7)(a)2.	- FFSG excess emissions
62-297.310(7)(a)3.	- Permit Renewal Test Required
62-297.310(7)(a)4.	
62-297.310(7)(a)5.	- PM exemption if <400 hrs/yr
62-297.310(7)(a)6.	- PM exemption if < 200 hrs/6 month
62-297.310(7)(a)9.	- FDEP Notification - 15 days
62-297.310(7)(c)	- Waiver of Compliance Tests (fuel sampling)
62-297.310(8)	- Test Reports

Federal Rules:

Acid Rain-Permits:

40 CFR 72.9(a)	- Permit Requirements
40 CFR 72.9(b)	- Monitoring Requirements
40 CFR 72.9(c)(1)	- SO2 Allowances-hold allowances
40 CFR 72.9(c)(2)	- SO2 Allowances-violation
40 CFR 72.9(c)(1)(iii)	- SO2 Allowances-Phase II Units (listed)
40 CFR 72.9(c)(4)	- SO2 Allowances-allowances held in ATS
40 CFR 72.9(c)(5)	- SO2 Allowances-no deduction for 72.9(c)(1)(i)
40 CFR 72.9(e)	- Excess Emission Requirements
40 CFR 72.9(f)	- Recordkeeping and Reporting
40 CFR 72.9(g)	- Liability
40 CFR 72.20(a)	- Designated Representative; required
40 CFR 72.20(b)	- Designated Representative; legally binding
40 CFR 72.20(c)	- Designated Representative; certification requirements
40 CFR 72.21	- Submissions
40 CFR 72.22	- Alternate Designated Representative
40 CFR 72.23	- Changing representatives; owners
40 CFR 72.30(a)	- Requirements to Apply (operate)
40 CFR 72.30(c)	- Requirements to Apply (reapply before expiration)
40 CFR 72.30(d)	- Requirements to Apply (submittal requirements)
40 CFR 72.32	- Permit Application Shield
40 CFR 72.33(b)	- Dispatch System ID; unit/system ID
40 CFR 72.33(c)	- Dispatch System ID; ID requirements
40 CFR 72.33(d)	- Dispatch System ID; ID change
40 CFR 72.40(a)	- General; compliance plan
40 CFR 72.40(b)	- General; multi-unit compliance options
40 CFR 72.40(c)	- General; conditional approval
40 CFR 72.40(d)	- General; termination of compliance options
40 CFR 72.51	- Permit Shield
40 CFR 72.90	- Annual Compliance Certification

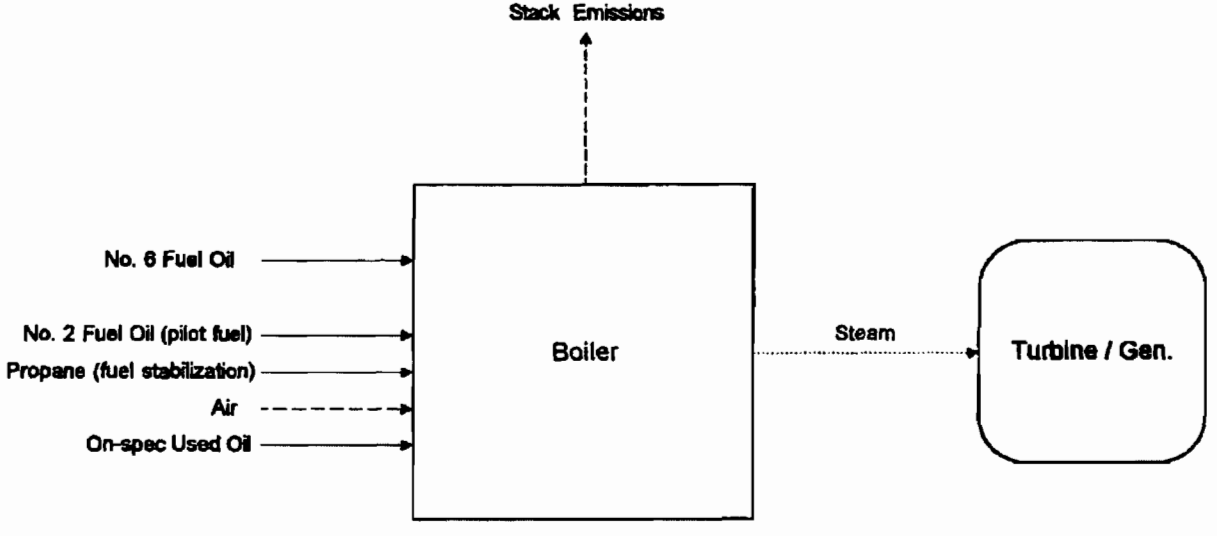
Monitoring Part 75:

40 CFR 75.5	- Prohibitions
40 CFR 75.10(a)(1)	- Primary Measurement; SO2; except 75.11&.16; Subpart D

40 CFR 75.10(a)(2)	- Primary Measurement; NOx; except 75.12&.17; Subpart E
40 CFR 75.10(a)(3)(i)	- Primary Measurement; CO2; monitor
40 CFR 75.10(a)(4)	- Primary Measurement; Opacity; except 75.14&.18
40 CFR 75.10(b)	- Primary Measurement; Performance Requirements
40 CFR 75.10(c)	- Primary Measurement; Heat Input; Appendix F
40 CFR 75.10(d)	- Primary Measurement; Hourly Operating; Opacity; SO2
40 CFR 75.10(f)	- Primary Measurement; Minimum Measurement
40 CFR 75.10(g)	- Primary Measurement; Minimum Recording
40 CFR 75.11(d)	- SO2 Monitoring; Gas- and Oil-fired units
40 CFR 75.11(e)	- SO2 Monitoring; Gaseous fuel firing
40 CFR 75.12(b)	- NOx Monitoring; Determination of NOx emission rate; Appendix F
40 CFR 75.13(a)	- CO2 Monitoring; Continuous monitor
40 CFR 75.14(a)	- Opacity Monitoring; Coal and oil units
40 CFR 75.20(a)(5)	- Initial Certification Approval Process; Loss of Certification
40 CFR 75.20(b)	- Recertification Procedures
40 CFR 75.20(c)	- Certification Procedures
40 CFR 75.20(g)	- Exceptions to CEMS; oil/gas/diesel; Appendix D & E
40 CFR 75.21(a)	- QA/QC; CEMS;
40 CFR 75.21(b)	- QA/QC; Opacity;
40 CFR 75.21(c)	- QA/QC; Calibration Gases
40 CFR 75.21(d)	- QA/QC; Notification of RATA
40 CFR 75.21(e)	- QA/QC; Audits
40 CFR 75.21(f)	- QA/QC; CEMS
40 CFR 75.22	- Reference Methods
40 CFR 75.24	- Out-of-Control Periods; CEMS
40 CFR 75.30(a)(1)	- General Missing Data Procedures; SO2
40 CFR 75.30(a)(2)	- General Missing Data Procedures; flow
40 CFR 75.30(a)(3)	- General Missing Data Procedures; NOx
40 CFR 75.30(a)(4)	- General Missing Data Procedures; CO2
40 CFR 75.30(d)	- General Missing Data Procedures; SO2
40 CFR 75.32	- Monitoring Data Availability for Missing Data
40 CFR 75.33	- Standard Missing Data Procedures
40 CFR 75.35	- Missing Data Procedures for CO2
40 CFR 75.36	- Missing Data Procedures for Heat Input
40 CFR 75.53	- Monitoring Plan (revisions)
40 CFR 75.54(a)	- Recordkeeping-general
40 CFR 75.54(b)	- Recordkeeping-operating parameter
40 CFR 75.54(c)	- Recordkeeping-SO2
40 CFR 75.54(d)	- Recordkeeping-NOx
40 CFR 75.54(e)	- Recordkeeping-CO2
40 CFR 75.54(f)	- Recordkeeping-Opacity
40 CFR 75.55(c);(e)	- Recordkeeping; Special Situations (gas & oil firing)
40 CFR 75.56	- Certification; QA/QC Provisions
40 CFR 75.60	- Reporting Requirements-General
40 CFR 75.61	- Reporting Requirements-Notification cert/recertification
40 CFR 75.63	- Reporting Requirements-Certification/Recertification
40 CFR 75.64(a)	- Reporting Requirements-Quarterly reports; submission
40 CFR 75.64(b)	- Reporting Requirements-Quarterly reports; DR statement
40 CFR 75.64(c)	- Rep. Req.; Quarterly reports; Compliance Certification
40 CFR 75.64(d)	- Rep. Req.; Quarterly reports; Electronic format

40 CFR 75.65	- Opacity Reports
Appendix A-3.	- Performance Specifications
Appendix A-4.	- Data Handling and Acquisition Systems
Appendix A-5.	- Calibration Gases
Appendix A-6.	- Certification Tests and Procedures
Appendix B	- QA/QC Procedures
Appendix C-1.	- Missing Data; SO2/NOx for controlled sources
Appendix C-2.	- Missing Data; Load-Based Procedure; NOx & flow
Appendix F	- Conversion Procedures
Appendix G-2.	- Determination of CO2; from combustion sources
Appendix H	- Traceability Protocol
40 CFR Part 77.3	- Offset Plans (future)
40 CFR Part 77.5(b)	- Deductions of Allowances (future)
40 CFR Part 77.6	- Excess Emissions Penalties SO2 and NOx

EMISSION UNIT 002
No.2 Unit, FFFSG



CLIENT/PROJECT **Progress Energy Florida, Inc**			TAMPA, FLORIDA Golder Associates				TITLE **Process Flow Diagram No. 2 Unit FFFSG P. L. Bartow Plant**			
DRAWN	CHECKED	REVIEWED	DATE 4/16/2009	NOT TO SCALE	FILE NO.	Job No. 083-89614	DWG NO.	SUBTITLE	REV. NO.	**BA-EU2-I1**

ATTACHMENT BA-EU2-I2

FUEL ANALYSIS

No. 6 Fuel Oil

Parameter	Typical Value
API gravity @ 60 F	8[1]
Relative density	8.2 lb/gal [2]
Heat content	18,300 Btu / lb (HHV)
% sulfur	2.5 [3]
% nitrogen	0.25 - 0.50
% ash	0.06 - 0.10

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) FPC's fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the FPC fuel procurement specification

[2] Data from laboratory analysis

[3] Data from current air permit.

No. 2 Fuel Oil

Parameter	Typical Value	Max Value
API gravity @ 60 F	30[1]	-
Relative density	7.1 lb/gal [2]	
Heat content	19,500 Btu / lb (HHV)	
% sulfur	0.04 [2]	0.5 [3]
% nitrogen	0.025 - 0.030	
% ash	negligible	0.1 [1]

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) FPC's fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the FPC fuel procurement specification

[2] Data from laboratory analysis

[3] Data from current air permit.

ATTACHMENT BA-EU2-I2 (Continued)

FUEL ANALYSIS

On-Spec Used Oil

Parameter	Typical Value	Max Value
API gravity @ 60 F	28[1]	-
Relative density	7.4lb/gal [2]	
Heat content	18,700 Btu / lb (HHV)	
% sulfur	0.3 - 0.5 [2]	2.5 [3]
% nitrogen	0.3	
% ash	0.4 - 0.9	

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) FPC's fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the FPC fuel procurement specification

[2] Data from laboratory analysis

[3] Data from current air permit.

ATTACHMENT BA-EU2-I6

Particulate Matter and Visible Emissions Test Report

Completed for:

Progress Energy Florida, Inc.
P.L. Bartow Plant
Unit 2 (EU-002)

Test Report Number: 20-3265-02-001

Testing Completed: July 25, 2008

C.E.M. SOLUTIONS

1183 East Overdrive Circle • Hernando, FL 34442 • (352) 489-4337 • Fax: (352) 489-4801

Particulate Matter and Visible Emissions Test Report

Progress Energy Florida, Inc.
P.L. Bartow Plant, Unit 2 (EU-002)
St. Petersburg, Florida

C.E.M. Solutions Project No.: 3265

Testing Completed: July 25, 2008

C.E.M. Solutions, Inc. Report Number: 20-3265-02-001

C.E.M. Solutions, Inc.
1183 E. Overdrive Circle
Hernando, Florida 34442
Phone: 352-489-4337

Plant's Authorization and Validity Statement

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.

Mr. Tom Lawrey
Plant Manager

Date

Statement of Validity

I hereby certify the information and data provided in this emissions test report for tests performed at the Progress Energy Florida Inc. P.L. Bartow Plant conducted on July 25, 2008 are complete and accurate to the best of my knowledge.

Jeremy A. Johnson
President
C.E.M. Solutions, Inc.

Project Background

Name of Source Owner:	Progress Energy Florida, Inc.
Address of Owner:	299 First Avenue North St. Petersburg, Florida 33701
Source Identification:	Facility: 1030011 Emissions Unit: EU-002
Location of Source:	Pinellas County, Florida
Type of Operation:	SIC Code 4911
Tests Performed:	Method 1 – Traverse Points Method 2 – Stack Gas Volumetric Flow and Velocity Method 3A – Determination of Molecular Weight Method 4 – Stack Gas Moisture Content Method 9 – Determination of Opacity of Emissions Method 17 – Particulate Matter Method 19 – Determination of Emissions Rates
Test Supervisor:	Mr. Charles Horton
Date(s) Tests Conducted:	July 25, 2008
Site Test Coordinator:	Mr. Charles Dufeny
Regulatory Observers:	Mr. Jose Rodriquez Environmental Specialist Pinellas County Department of Environmental Management

C.E.M. Solutions, Inc Test Personnel

Project Field Manager:	Mr. Charles Horton
Test Technicians:	Mr. Robert Douglas Mr. Thomas Harris

Table of Contents

List of Tables

List of Figures

Appendices

1.0 Introduction

Progress Energy Florida, Inc. (PEF) retained C.E.M. Solutions, Inc. to conduct emissions testing to determine levels of particulate matter (PM) and visible emissions (VE) from Unit 2 boiler exhausts (emissions unit EU-002) at its P.L. Bartow Plant in St. Petersburg, Florida.

The test program was conducted to determine the compliance status of Unit 2 with respect to its emissions limitations and standards outlined in Title V Air Operating Permit 1030011-009-AV. Target pollutants include the following:

- PM (lb/mmBtu)
- VE (in percent opacity)

Charles Dufeny of Progress Energy coordinated plant operations throughout the test program. All testing was conducted in accordance with test methods promulgated by the Florida Department of Environmental Protection.

Unit 2 was in compliance with the permitted emissions limitations as summarized in Table 1 below.

The test program and results are presented and discussed in this report.

Table 1: Compliance Test Results
Unit 2
P.L. Bartow Plant

Pollutant	Unit Operating Mode	Reported Emissions Rate (3-run average)	Permitted Emissions Rate	Compliance Test Status (Pass/Fail)
PM	Normal	0.05 lb/mmBtu	0.1 lb/mmBtu	Pass
PM	Sootblowing	0.09 lb/mmBtu	0.3 lb/mmBtu	Pass
VE	Normal	15.0 %	≤40 %	Pass
VE	Sootblowing	26.9 %	≤60 %	Pass

2.0 Facility Description

P.L. Bartow Plant Unit 2 is a fossil fuel fired steam generator consisting of a front-fired boiler, rated at 120 MW, with a maximum heat input rate of 1220 mmBtu/hr. Primary fuel is No. 2 through No. 6 fuel oil.

2.1 Process Equipment

Fossil Fuel Steam Generator, Unit 2 is a fuel oil, front-fired boiler. Emissions are exhausted through a brick and mortar 300 ft. stack.

2.2 Regulatory Requirements

Progress Energy Florida, Inc. is required to perform annual compliance testing for particulate matter and opacity in accordance with Title V Permit Number 1030011-009-AV.

Unit 2's emissions limitations and standards are summarized in Table 2.

Table 2: Emissions Limitations and Standards
Unit 2
P.L. Bartow Plant

Pollutant/Standard	Emission Limit	Permit Condition
PM lb/mmBtu	0.1 during normal (steady state), and 0.3 during soot blowing	A.7 and A.8
VE %[a]	40% during normal (steady state), and 60% during soot blowing	A.5 and A.6
Sulfur Content %	Sulfur content shall not exceed 2.5%, by weight	A.10

[a] six-minute average

3.0 Test Program/Operating Conditions

The test program was conducted to determine the compliance status of Unit 2's particulate matter and visible emissions with regard to applicable limitations in the Title V Operating Permit 1030011-009-AV.

Testing was completed on the July 25, 2008.

During the test program, Unit 2's heat input averaged 1156.2 mmBtu/hr while operating on 100 percent oil, which correlates to 88 percent of the maximum heat input (1317 mmBtu/hr).

Unit 2 fuel flow and fuel analysis reports are located in Appendix A.

Fuel flow and fuel analysis reports were provided by Progress Energy.

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.

Table 3 summarizes the EPA test methods utilized to complete the test program.

Table 3: Summary of EPA Reference Methods

Unit 2
P.L. Bartow Plant

EPA Method	Description
1	Sample and Velocity Traverses for Stationary Sources
2	Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot)
3A	Gas Analysis for Determining Dry Molecular Weight (Instrument Analyzer Procedure)
4	Moisture Content in Stack Gases
9	Opacity (Visible Emissions)
17	Particulate Emissions from Stationary Sources

4.1 Sample and Velocity Traverse Points

Sample and velocity traverse points were determined utilizing EPA Method 1.

Unit 2's exhaust stack inner diameter, at the sample location, is 120.7". The emissions sampling location is 1440 inches downstream from the nearest flow disturbance, and 1560 inches upstream from the stack exhaust.

A diagram of the sample locations is provided in Appendix C.

4.2 Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tubes)

Method 2 was used to determine the volumetric flow rate of the stack effluent gas.

Stack temperature differential pressure readings were taken with an S type pitot tube and Type K temperature sensor at each sample traverse point.

4.2.1 Method 2 Quality Assurance/Quality Control Procedures

The S type pitot tube was inspected visually and measured to meet the design specifications of EPA Method 2, for a pitot coefficient of 0.84.

The incline manometer and each leg of the pitot tube was leak checked before and immediately after each test run.

Thermocouple sensors were calibrated prior to the test program and a post test check was performed after testing completion.

The incline manometer was leveled and zeroed before each test run.

Appendix D contains the completed QA/QC forms.

4.3 Moisture Content Determination

Moisture content of the stack gas was determined by Method 4.

Stack gas was sampled at each traverse point, passed through pre-weighed impingers and then through a calibrated dry gas meter. Moisture is removed from the sample gas in the pre-weighed impingers, which are submerged in an ice bath, and later analyzed for moisture weight gain. Moisture is determined based upon the amount of moisture weight gain and sample gas collected.

Field moisture data sheets are also located in Appendix E.

4.3.1 Method 4 Quality Assurance/Quality Control Procedures

The moisture sampling train was leak checked prior to each test run at approximately 15 inches hg and immediately after each run at a vacuum higher than the highest vacuum recorded during the respective test run. Results are recorded on the moisture field data sheets.

Weighing to determine moisture content was conducted with a balance having an accuracy of 0.5 grams.

Gas temperature at the exit of the impingers was maintained at less than 68 degrees Fahrenheit.

4.4 Particulate Matter Determination

USEPA Method 17 was used to determine particulate emissions. Stack gas was extracted isokinetically from the gas stream; particulate emissions are measured gravimetrically by determining the amount of particulate matter collected on the stainless steel nozzle and glass or quartz fiber filter. The probe liner temperature was maintained at 248 ± 25 degrees Fahrenheit.

Sample volume was measured by passing the gas through a set of weighed impingers used for moisture content, then passed through a calibrated dry gas meter. An S type pitot tube is attached to the probe to measure stack gas velocity and to maintain sampling conditions between 90% and 110% isokinetic. A type K temperature sensor is also attached to the probe to measure the stack gas temperature.

Isokinetic conditions were maintained throughout each test run of the test program as demonstrated in Table 4.

A minimum of 30 dscf of sample was taken each test run over a sampling period of approximately 60 minutes.

Method 17 field data sheets are located in Appendix E.

Figure 1 contains a diagram of the Method 17 sampling train.

4.4.1 Sample Recovery and Analysis

After each sample run, the nozzle and filter holder ahead of the filter were brushed and rinsed with acetone. Contents were stored in a leak free container for transport to the laboratory. The impingers were weighed for increase, to the nearest 0.5 gram, to determine moisture gain.

Particulate matter was determined by drying each filter at 230 degrees Fahrenheit for three hours, desiccated to a constant weight and recorded to the nearest 0.1 mg. Sample from the probe nozzle and filter holder were evaporated in a tared beaker, desiccated to a constant weight, and recorded to the nearest 0.1 mg.

Appendix E contains the analytical results for each run.

4.4.2 Quality Assurance/Quality Control Procedures

The probe nozzles were inspected and measured across three different diameters to determine the appropriate nozzle diameter.

Before and after each test run, the manometer was leveled and zeroed. Leak checks of the sampling train were conducted before and immediately after each test run.

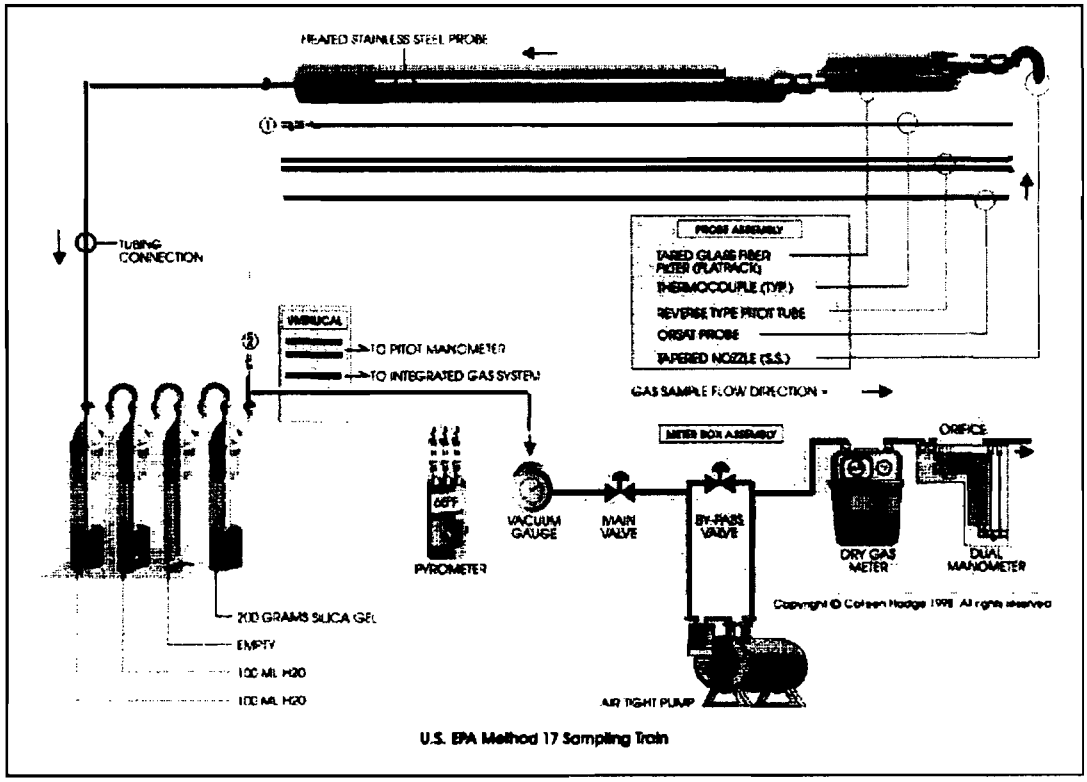
The dry gas meter was fully calibrated within six months prior to the test program using a set of EPA critical orifices. Post test program dry meter checks were completed to verify the accuracy of the meter's Y_i.

Completed QA/QC forms are located in Appendix D.

Table 4: Particulate Matter Isokinetic Summary
Unit 2
P.L. Bartow Plant

Operating Mode	% Isokinetic				
	Run 1	Run 2	Run 3	Average(s)	Tolerance
Normal	98.5	98.8	100.3	99.2	90-110
Sootblowing	101.9	99.7	101.2	101.0	

Figure 1: Method 17 Sampling Train



4.5 Visible Emissions (Percent Opacity) Determination

USEPA Method 9 was utilized to determine visible emissions (VE).

VE 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 minute observation run was performed while the unit was operating at maximum capacity.

Method 9 data summary, field data and VE reader's certification are located in Appendix E.

4.6 CO_2 and O_2 Instrument Analyzer Methods

CO_2 and O_2 reference method data was determined using instrument analyzer procedures. CO_2 and O_2 data was used to determine stack gas molecular weight. Mathematical equations used to determine calculated emissions standards can be reviewed in Appendix B. Table 5 summarizes the EPA methods and instrumentation:

Table 5: Summary of EPA Reference Methods and Instrumentation
Unit 2
P.L. Bartow Plant

Pollutant	EPA Method	Instrument	Serial Number
CO_2	3A	Servomex 1440	1415D/3379
O_2	3A	Servomex 1440	1420D/3379

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 heated to approximately 250°F. Samples were then transported to a gas sample conditioner via a heated sample line operating at 250°F or above. The gas sample conditioner lowers the dew point of the sample gas to approximately 5°C 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 6:

Table 6: Reference Method Calibration Span and Calibration Gases
Unit 2
P.L. Bartow Plant

Pollutant	Test Location	Calibration Span	Calibration Gases[a]
CO_2	Unit 2	17.99 %	0.0 % CO_2 9.55 % CO_2 17.99 % CO_2
O_2	Unit 2	23.93 %	0.0 % O_2 9.98 % O_2 23.93 % O_2

[a] Concentrations, CO_2 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 D.

4.6.1 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 and response time 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 6.

Appendix D contains the QA/QC checks.

4.7 Fuel Analysis

ASTM test methods were utilized to determine the heating value and sulfur content of the fuel oil used during the test program as required in permit condition A.22.

Fuel analysis report(s) can be viewed in Appendix A.

5.0 Test Results

The test program results are presented below. Supporting calculations and field data summaries are presented in Appendices B and E, respectively.

5.1 Particulate Matter

The three-run average particulate matter emissions during the normal (steady state) portion of the test program was 0.0483 lb/mmBtu, passing the performance specification of 0.1 lb/mmBtu.

The three-run average particulate matter emissions during the sootblowing portion of the test program was 0.0879 lb/mmBtu, passing the performance specification of 0.3 lb/mmBtu.

5.2 Visible Emissions

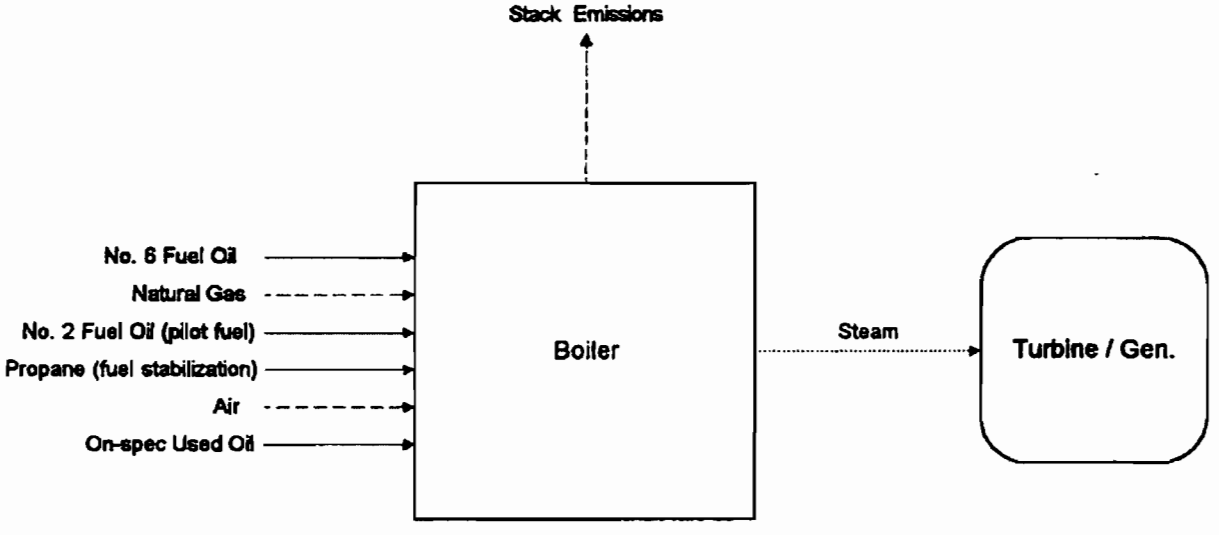
The highest six-minute average opacity observed from the Unit 2 stack during the normal operating mode of the test program was 15.0 percent opacity, passing the 40 percent emission limit.

The highest six-minute average opacity observed from the Unit 2 stack during the sootblowing operating mode portion of the test program was 26.9 percent opacity, passing the 60 percent emission limit.

5.3 Sulfur Content

The sulfur content of the fuel burned during the compliance test was 1.37 % of the fuel by weight, below the 2.5 % limitation.

EMISSION UNIT 003
No.3 Unit, FFFSG



CLIENT/PROJECT **Progress Energy Florida, Inc**			TAMPA, FLORIDA Golder Associates				TITLE **Process Flow Diagram No. 3 Unit FFFSG P. L. Bartow Plant**			
DRAWN	CHECKED	REVIEWED	DATE 4/16/2009	NOT TO SCALE	FILE NO.	Job No. 083-89614	DWG NO.	SUBTITLE	REV. NO.	**BA-EU3-I1**

ATTACHMENT BA-EU3-I2

FUEL ANALYSIS

Natural Gas Analysis

Parameter	Typical Value	Max Value
Relative density	0.58 (compared to air)	
heat content	950 - 1124 Btu/cu ft.	
% sulfur	0.43 grains/CCF [1]	1 grain/100 CF
% nitrogen	0.8% by volume	
% ash	negligible	

Note: The values listed are "typical" values based upon information supplied to FPC by Florida Gas Transmission (FGT). However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data from laboratory analysis

No. 6 Fuel Oil

Parameter	Typical Value
API gravity @ 60 F	8[1]
Relative density	8.2 lb/gal [2]
Heat content	18,300 Btu / lb (LHV)
% sulfur (max.)	2.5 [3]
% nitrogen	0.25 - 0.50
% ash	0.06 - 0.10

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) FPC's fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the FPC fuel procurement specification

[2] Data from laboratory analysis

[3] Data from current air permit.

ATTACHMENT BA-EU3-I2

FUEL ANALYSIS (Continued)

No. 2 Fuel Oil

Parameter	Typical Value	Max Value
API gravity @ 60 F	30[1]	-
Relative density	7.1 lb/gal [2]	
Heat content	19,500 Btu / lb (HHV)	
% sulfur	0.04 [2]	0.5 [3]
% nitrogen	0.025 - 0.030	
% ash	negligible	0.1 [1]

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) FPC's fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the FPC fuel procurement specification

[2] Data from laboratory analysis

[3] Data from current air permit.

On-Spec. Used Oil

Parameter	Typical Value	Max Value
API gravity @ 60 F	28[1]	-
Relative density	7.4 lb/gal [2]	
Heat content	18,700 Btu / lb (HHV)	
% sulfur	0.3 - 0.5 [2]	2.5 [3]
% nitrogen	0.3	
% ash 0.4 - 0.9		

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) FPC's fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the FPC fuel procurement specification

[2] Data from laboratory analysis

[3] Data from current air permit.

Propane Analysis

Parameter	Typical Value
heat content	81 Btu/gal
% sulfur	negligible
% nitrogen	0.8% by volume
% ash	negligible

ATTACHMENT BA-EU3-I6

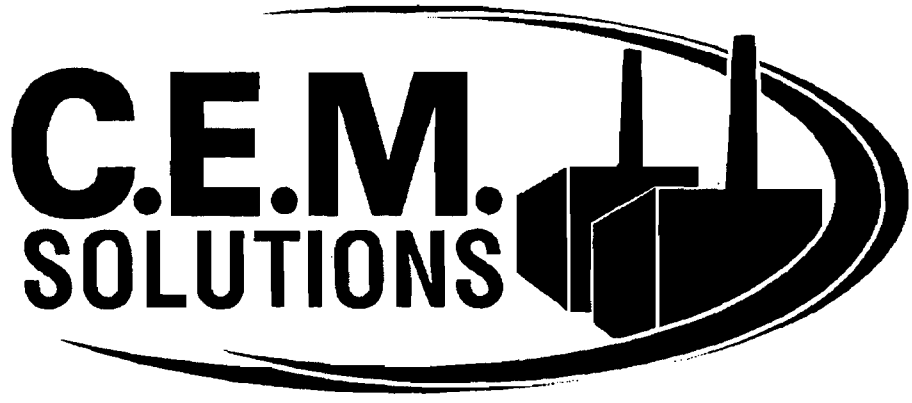
Particulate Matter and Visible Emissions Test Report

Completed for:

Progress Energy Florida, Inc.
P.L. Bartow Station, Unit 3 (EU-003)

Test Report Number: 20-3266-03-001

Testing Completed: May 21, 2008



1183 East Overdrive Circle • Hernando, FL 34442 • (352) 489-4337 • Fax: (352) 489-4801

Particulate Matter and Visible Emissions Test Report

Progress Energy Florida, Inc.
P.L. Bartow Plant, Unit 3 (EU-003)
St. Petersburg, Florida

C.E.M. Solutions Project No.: 3266

Testing Completed: May 21, 2008

C.E.M. Solutions, Inc. Report Number: 20-3266-03-001

C.E.M. Solutions, Inc.
1183 E. Overdrive Circle
Hernando, Florida 34442
Phone: 352-489-4337

Statement of Validity

I hereby certify the information and data provided in this emissions test report for tests performed at Progress Energy Florida Inc.'s P.L. Bartow Plant conducted on May 21, 2008 are complete and accurate to the best of my knowledge.

Jeremy A. Johnson
President
C.E.M. Solutions, Inc.

Project Background

Name of Source Owner:	Progress Energy Florida, Inc.
Address of Owner:	299 First Avenue North St. Petersburg, Florida 33701
Source Identification:	Facility: 1030011 Emissions Unit: EU-003
Location of Source:	Pinellas County, Florida
Type of Operation:	SIC Code 4911
Tests Performed:	Method 1 – Traverse Points Method 2 – Stack Gas Volumetric Flow and Velocity Method 3A – Determination of Molecular Weight Method 4 – Stack Gas Moisture Content Method 9 – Determination of Visible Emissions Method 17 – Particulate Matter Method 19 – Determination of Emissions Rates
Test Supervisor:	Mr. Charles Horton
Date(s) Tests Conducted:	May 21, 2008
Site Test Coordinator:	Mr. Charles Dufeny
Regulatory Observers:	Mr. Jose Rodriquez-Lugo and Ms. Shea Jackson Pinellas County Environmental Management

C.E.M. Solutions, Inc Test Personnel

Project Field Manager:	Mr. Charles Horton
Test Technicians:	Mr. Robert Douglas Mr. Thomas Harris

Table of Contents

List of Tables

List of Figures

Appendices

1.0 Introduction

Progress Energy Florida, Inc. (PEF) retained C.E.M. Solutions, Inc. to conduct emissions testing to determine levels of particulate matter (PM) and visible emissions (VE) from Unit 3 boiler exhausts (emissions unit -003) at its P.L. Bartow Plant in St. Petersburg, Florida.

The test program was conducted to determine the compliance status of Unit 3 in regards to its emissions limitations and standards outlined in Title V Air Operating Permit 1030011-009-AV. Target pollutants include the following:

- PM (lb/mmBtu)
- VE (in percent)

Charles Dufeny of Progress Energy coordinated plant operations throughout the test program. All testing was conducted in accordance with test methods promulgated by the Florida Department of Environmental Protection.

Unit 3 was found to be in compliance with the permitted emissions limitations as summarized in Table 1.

The test program and results are presented and discussed in this report.

Table 1: Compliance Test Results
Unit 3
P.L. Bartow Plant

Pollutant	Unit Operating Mode	Reported Emissions Rate	Permitted Emissions Rate	Compliance Test Status (Pass/Fail)
PM	Normal	0.04 lb/mmBtu*	0.1 lb/mmBtu	Pass
PM	Sootblowing	0.04 lb/mmBtu*	0.3 lb/mmBtu	Pass
VE	Normal	7.5 %	≤40 %	Pass
VE	Sootblowing	11.9 %	≤60 %	Pass
Sulfur Content	N/A	1.19 %	≤2.5 %	PASS

* 3-Run Average

2.0 Facility Description

P.L. Bartow Plant Unit 3 is a fossil fuel fired steam generator consisting of a tangential-fired boiler, rated at 225 MW, with a maximum heat input rate of 2211 mmBtu/hr. Primary fuel is No. 2 through No. 6 fuel oil.

2.1 Process Equipment

Fossil Fuel Steam Generator, Unit 3 is a fuel oil, tangential-fired boiler. Emissions from Unit 3 are uncontrolled. Emissions are exhausted through a brick and mortar 300 ft. stack.

2.2 Regulatory Requirements

The facility is required to conduct annual emissions testing to determine PM and VE emissions in accordance with Title V Permit Number 1030011-009-AV.

Unit 3's emissions limitations and standards are summarized in Table 2.

Table 2: Emissions Limitations and Standards
Unit 3
P.L. Bartow Plant

Pollutant/Standard	Emission Limit	Permit Condition
PM lb/mmBtu	0.1 during normal (steady state), and 0.3 during soot blowing	A.7 and A.8
VE %[a]	40% during normal (steady state), and 60% during soot blowing	A.5 and A.6
Sulfur Content %	Sulfur content shall not exceed 2.5%, by weight	A.10

[a] six-minute average

3.0 Test Program/Operating Conditions

The test program was conducted to determine the compliance status of Unit 3's PM and VE emissions in regards to Title V Operating Permit 1030011-009-AV.

Testing was completed on the May 21, 2008.

During the test program, Unit 3's heat input averaged 1984.5 mmBtu/hr while operating on 100 percent oil, which correlates to 90.0 percent of the maximum heat input (2211 mmBtu/hr).

Unit 3 fuel flow and fuel analysis reports are located in Appendix A.

Fuel flow and fuel analysis reports were provided by Progress Energy.

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.

Table 3 summarizes the EPA test methods utilized to complete the test program.

Table 3: Summary of EPA Reference Methods

Unit 3
P.L. Bartow Plant

EPA Method	Description
1	Sample and Velocity Traverses for Stationary Sources
2	Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot)
3A	Gas Analysis for Determining Dry Molecular Weight (Instrument Analyzer Procedure)
4	Moisture Content in Stack Gases
9	Visible Emissions
17	Particulate Emissions from Stationary Sources

4.1 Sample and Velocity Traverse Points

Sample and velocity traverse points were determined utilizing EPA Method 1.

Unit 3's exhaust stack inner diameter, at the sample location, is 143.88". The emissions sampling location is 1440 inches downstream from the nearest flow disturbance, and 1560 inches upstream from the stack exhaust.

A diagram of the sample location can be viewed in Appendix C.

4.2 Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tubes)

Method 2 was used to determine the volumetric flow rate of the stack effluent gas.

Stack temperature differential pressure readings were taken with an S type pitot tube and Type K temperature sensor at each sample traverse point.

4.2.1 Method 2 Quality Assurance/Quality Control Procedures

The S type pitot tube was inspected visually and measured to meet the design specifications of EPA Method 2, for a pitot coefficient of 0.84.

The incline manometer and each leg of the pitot tube was leak checked before and immediately after each test run.

Thermocouple sensors were calibrated prior to the test program and a post test check was performed after testing completion.

The incline manometer was leveled and zeroed before each test run.

Appendix D contains the completed QA/QC forms.

4.3 Moisture Content Determination

Moisture content of the stack gas was determined by Method 4.

Stack gas was sampled at each traverse point, passed through pre-weighed impingers and then through a calibrated dry gas meter. Moisture is removed from the sample gas in the pre-weighed impingers, which are submerged in an ice bath, and later analyzed for moisture weight gain. Moisture is determined based upon the amount of moisture weight gain and sample gas collected.

Field moisture data sheets are also located in Appendix E.

4.3.1 Method 4 Quality Assurance/Quality Control Procedures

The moisture sampling train was leak checked prior to each test run at approximately 15 inches hg and immediately after each run at a vacuum higher than the highest vacuum recorded during the respective test run. Results are recorded on the moisture field data sheets.

Weighing to determine moisture content was conducted with a balance having an accuracy of 0.5 grams.

Gas temperature at the exit of the impingers was maintained at less than 68 degrees Fahrenheit.

4.4 Particulate Matter Determination

USEPA Method 17 was used to determine particulate emissions. Stack gas was extracted isokinetically from the gas stream; particulate emissions are measured gravimetrically by determining the amount of particulate matter collected on the stainless steel nozzle and glass or quartz fiber filter. The probe liner temperature was maintained at 248 ± 25 degrees Fahrenheit.

Sample volume was measured by passing the gas through a set of weighed impingers used for moisture content, then passed through a calibrated dry gas meter. An S type pitot tube is attached to the probe to measure stack gas velocity and to maintain sampling conditions between 90% and 110% isokinetic. A type K temperature sensor is also attached to the probe to measure the stack gas temperature.

Isokinetic conditions were maintained throughout each test run of the test program as demonstrated in Table 4.

A minimum of 30 dscf of sample was taken each test run over a sampling period of approximately 60 minutes.

Method 17 field data sheets are located in Appendix E.

Figure 1 contains a diagram of the Method 17 sampling train.

4.4.1 Sample Recovery and Analysis

After each sample run, the nozzle and filter holder ahead of the filter were brushed and rinsed with acetone. Contents were stored in a leak free container for transport to the laboratory. The impingers were weighed for increase, to the nearest 0.5 gram, to determine moisture gain.

Particulate matter was determined by drying each filter at 230 degrees Fahrenheit for three hours, desiccated to a constant weight and recorded to the nearest 0.1 mg. Sample from the probe nozzle and filter holder were evaporated in a tared beaker, desiccated to a constant weight, and recorded to the nearest 0.1 mg.

Appendix E contains the analytical results for each run.

4.4.2 Quality Assurance/Quality Control Procedures

The probe nozzles were inspected and measured across three different diameters to determine the appropriate nozzle diameter.

Before and after each test run, the manometer was leveled and zeroed. Leak checks of the sampling train were conducted before and immediately after each test run.

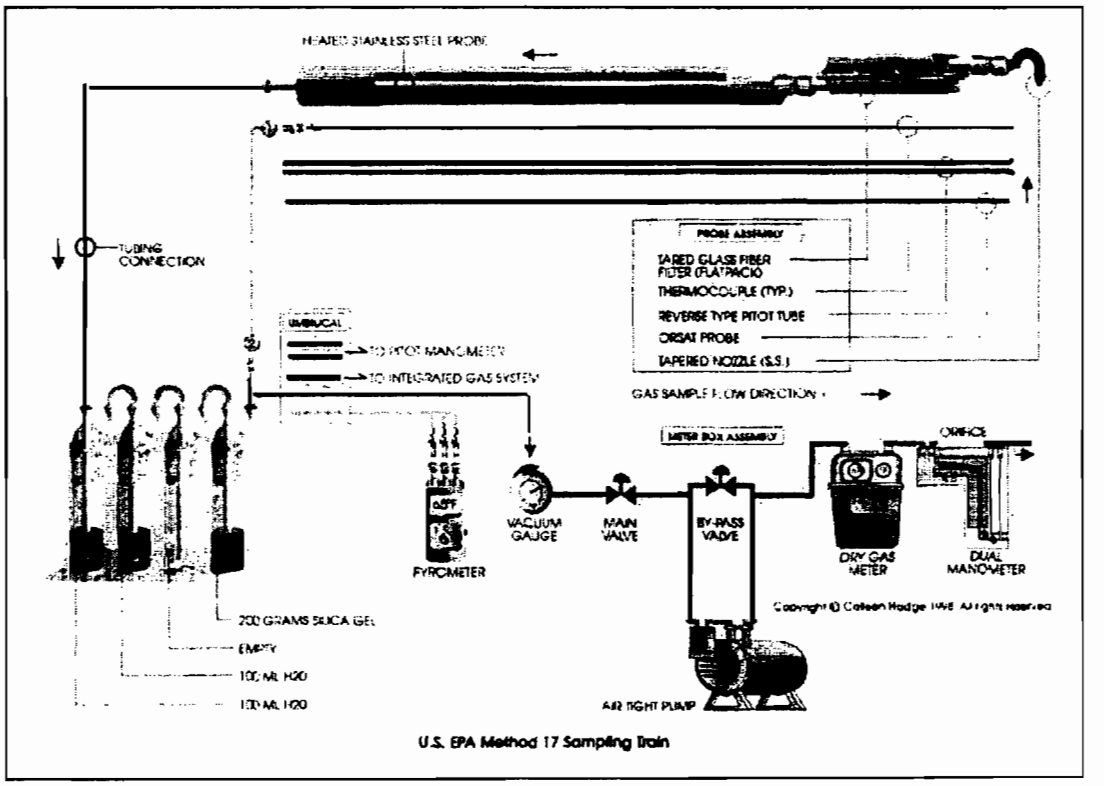
The dry gas meter was fully calibrated within six months prior to the test program using a set of EPA critical orifices. Post test program dry meter checks were completed to verify the accuracy of the meter's Y_i.

Completed QA/QC forms are located in Appendix D.

Table 4: Particulate Matter Isokinetic Summary
Unit 3
P.L. Bartow Plant

Operating Mode	% Isokinetic				
	Run 1	Run 2	Run 3	Average(s)	Tolerance
Normal	105.8	107.1	102.4	105.1	90-110
Soot-blowing	106.0	106.6	96.1	102.9	

Figure 1: Method 17 Sampling Train



4.5 Visible Emissions Determination

USEPA Method 9 was utilized to determine visible emissions.

Visible emissions observations were performed by a FDEP certified visual emissions reader. Readings were taken at 15 second intervals and reduced into six minute averages as required by the applicable EPA standard. One-sixty minute visible emissions test run was performed while the unit was operating at maximum capacity.

Method 9 data summary, field data and VE reader's certification are located in Appendix E.

4.6 CO_2 and O_2 Instrument Analyzer Methods

CO_2 reference method data was determined using instrument analyzer procedures. O_2 was back calculated using the fuel F_o factor and stack moisture content. CO_2 and O2 data was used to determine stack gas molecular weight. Table 6 summarizes the EPA methods and instrumentation:

Table 5: Summary of EPA Reference Methods and Instrumentation
Unit 3
P.L. Bartow Plant

Pollutant	EPA Method	Instrument	Serial Number
CO_2	3A	CAI ZRH	N4J0831T

All reference method analyzers used meet or exceed applicable performance specifications detailed in the appropriate method.

Gaseous emissions were tested using an in-stack dilution extraction probe. Gas samples were continuously extracted from the stack by a gas sample probe and diluted at a ratio of approximately 100:1 with clean, dry instrument air (dilution air). Samples were then transported to 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 6:

Table 6: Reference Method Instrument Ranges and Calibration Spans
Unit 3
P.L. Bartow Plant

Pollutant	Test Location	Calibration Span	Calibration Gases[a]
CO_2	Unit 3	18.98 %	0.0 % CO_2 9.10 % CO_2 18.98 % CO_2

[a] Concentrations, CO_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 D.

4.6.1 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 and response time 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 6.

Appendix D contains the QA/QC checks.

4.7 Fuel Analysis

ASTM test methods were utilized to determine the heating value and sulfur content of the fuel oil used during the test program as required in permit condition A.22.

Fuel analysis report(s) can be viewed in Appendix A.

5.0 Test Results

The following presents the results of the test program. Supporting calculations and field data summaries are presented in Appendices B and E, respectively.

Table 7 summarizes the results of the test program.

5.1 Particulate Matter

The three-run average particulate matter emissions during the normal (steady state) portion of the test program was 0.04 lb/mmBtu, passing the performance specification of 0.1 lb/mmBtu.

The three-run average particulate matter emissions during the sootblowing portion of the test program was 0.04 lb/mmBtu, passing the performance specification of 0.3 lb/mmBtu.

5.2 Visual Emissions

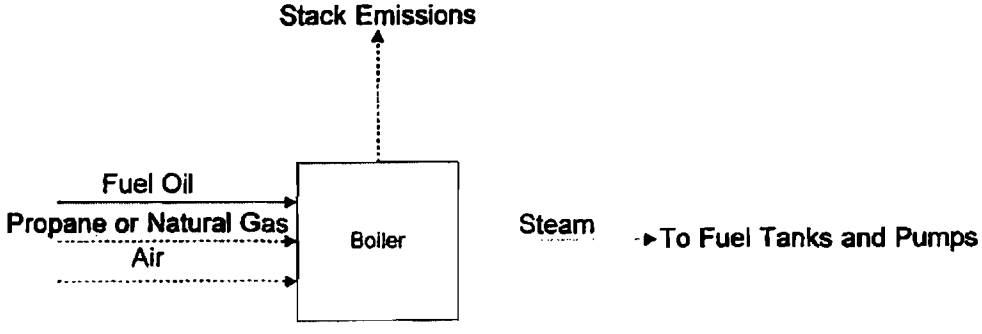
The highest six-minute average visible emissions observed from the Unit 3 stack during the normal portion of the test program was 7.5 percent, passing the 40 percent emission limit.

The highest six-minute average visible emissions observed from the Unit 3 stack during the sootblowing portion of the test program was 11.9 percent, passing the 60 percent emission limit.

5.3 Sulfur Content

The sulfur content of the fuel burned during the compliance test was 1.19 % of the fuel by weight, below the 2.5 % limitation.

EMISSION UNIT 004
Bartow-Anclote Pipeline Heating Boiler



CLIENT/PROJECT **Progress Energy Florida, Inc**			TAMPA, FLORIDA Golder Associates				TITLE **Process Flow Diagram Bartow-Anclote pipeline Heating Boiler P. L. Bartow Plant**			
DRAWN	CHECKED	REVIEWED	DATE 4/16/2009	NOT TO SCALE	FILE NO.	Job No. 083-89614	DWG NO.	SUBTITLE	REV. NO.	**BA-EU4-I1**

ATTACHMENT BA-EU4-I2

FUEL ANALYSIS

Natural Gas Analysis

Parameter	Typical Value	Max Value
Relative density	0.58 (compared to air)	
heat content	950 - 1124 Btu/cu ft.	
% sulfur	0.43 grains/CCF [1]	1 grain/100 CF
% nitrogen	0.8% by volume	
% ash	negligible	

Note: The values listed are "typical" values based upon information supplied to FPC by Florida Gas Transmission (FGT). However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data from laboratory analysis

No. 2 Fuel Oil

Parameter	Typical Value	Max Value
API gravity @ 60 F	30 [1]	-
Relative density	6.92 lb/gal [2]	
Heat content	18,400 Btu / lb (LHV)	
% sulfur	0.04 [2]	0.5 [3]
% nitrogen	0.025 - 0.030	
% ash	negligible	0.01 [1]

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) FPC's fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the FPC fuel procurement specification

[2] Data from laboratory analysis

[3] Data from current air permit

Propane Analysis

Parameter	Typical Value
heat content	81 Btu/gal
% sulfur	negligible
% nitrogen	0.8% by volume
% ash	negligible

Pinellas County
ENVIRONMENTAL MANAGEMENT
Air Quality

April 1, 2009

Mr. Rufus Jackson, Plant Manager
Progress Energy Florida, Inc.
Florida Power, Bartow Plant
1601 Weedon Island Drive
St. Petersburg, FL 33733-4042

RE: Compliance Test Results, Permit No.: 1030011-009-AV, Emission Unit ID: 0011 004

Mr. Jackson:

This letter is to inform you the Air Quality Division has received and reviewed the compliance test conducted on February, 5, 2009, for Pipeline Heater Boiler. The boiler's maximum heat input rate is 15.5 million Btu per hour firing natural gas, No. 2 fuel oil, or propane. The test results indicate the source appears to be operating in compliance with permitted emission limits.

However, the annual compliance test was conducted at a process rate of 4.7 MMBTU/hr, which is not within 90 - 100% of the maximum permitted process rate of 15.5.MMBTU/hr. Therefore, operation of this emission unit is limited to 5.2 MMBTU/hr, which is 110 percent of the process rate during the test. (Permit condition B.16. and [Rules 62-297.310(2) & (2)(b), F.A.C.]) This facility should not operate this emission unit in excess of 5.2 MMBTU/hr unless it is for the express purpose of compliance testing, to re-establish compliance at a higher process rate, up to the maximum permitted process rate of 15.5.MMBTU/hr.

If you have any questions, contact Jose A. Rodriguez Lugo or Wayne R Martin at this office at 464-4422.

Sincerely,

Jose A. Rodriguez Lugo, Environmental Specialist II
Air Quality Division

cc: Permit File (0011 004), Read File

H:\users\wpdocs\airqual\Air_Compliance\AQC\0011004VETstRevLttr2009.doc

PLEASE ADDRESS REPLY TO:
300 S. Garden Avenue
Clearwater, Florida 33756
Phone: (727) 464-4422
FAX: (727) 464-4420
TDD: (727) 464-4106
Website: www.pinellascounty.org

Progress Energy

Via Certified Mail
March 3, 2009

Mr. Wayne Martin
Pinellas County Department of Environmental Management
Air Quality Division
300 South Garden Ave.
Clearwater, FL 34616

Re: Visible Emissions Compliance Tests
Progress Energy Florida, Inc.
P.L. Bartow Power Plant
Permit No.1030011-009-AV
E.U. ID -004

Dear Mr. Martin:

Please find attached copies of the Visible Emissions Test for Progress Energy's P.L. Bartow Power Plant. The VE test was performed on February 5, 2009. The results show compliance with the applicable rules. The following tables summarize the emissions and operating conditions during the test.

Bartow Plant - Opacity Compliance Data 2009

Unit	Date / Time	Highest Value Observed	Permit Limit
Pipeline Heater	2/5/09 8:56	0%	20%

Bartow Plant - Ops Data 2009

Unit	Date / Time	Calculated Heat Input *mmBTU/hr*	Permitted Heat Input *mmBTU/hr*	Capacity *%*
Pipeline Heater	2/5/09 8:56	4.7	15.5	31%

Please contact Charles Dufeny at (727) 820-5854 if you have any questions.

Progress Energy Florida, Inc.
P.O. Box 14042
St. Petersburg, FL 33733

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,

Rufus Jackson
Plant Manager

Attachments

cc: Danielle D. Henry, FDEP-SWD

bc: L. Gonzalez, BP43A
T. Sanchez, BR44
C. Bradley, PEF903
K. McDaniel, PEF903

Danielle D. Henry, FDEP
Florida Department of Environmental Protection
Southwest District
13051 North Telecom Parkway
Temple Terrace, Florida 33637-0926

EPA
VISIBLE EMISSION OBSERVATION FORM 1

Form Number							Page	1	Of	1
Continued on VEO Form Number										

Method Used (Circle One): Method 9 | 203A | 203B | Other: _____

Observation Date	Time Zone	Start Time	End Time
2-5-09	EST	0755	0855

Company Name	Progress Energy
Facility Name	Bartow Plant
Street Address	1601 Weedon Island Dr
City	St. Pete
State	FL
Zip	33702

Process	Package Boiler	Unit # 004	Operating Mode
Control Equipment	N/A		Operating Mode N/A

Describe Emission Point: Vent off roof on Ctl. room

Height of Emiss. Pt. Start ~25' End ~95'	Height of Emiss. Pt. Rel. to Observer Start ~25' End ~25'
Distance to Emiss. Pt. Start ~75' End ~75'	Direction to Emiss. Pt. (Degrees) Start W End W
Vertical Angle to Obs. Pt. Start — End —	Direction to Obs. Pt. (Degrees) Start — End —
Distance and Direction to Observation Point from Emission Point Start ~75' W End ~75' W	

Describe Emissions: Start none End none

Emission Color: Start none End none

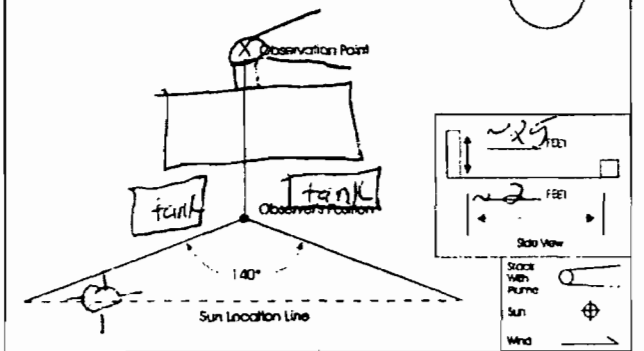
Water Droplet Plume: Attached ☐ Detached ☐ None ☑ *

Describe Plume Background: Start sky End sky

Background Color Start blue End blue	Sky Conditions Start clear End clear
Wind Speed Start 9 mph End 9 mph	Wind Direction Start N End N
Ambient Temp Start 32°F End 32°F	Wet Bulb Temp N/A / RH Percent N/A

Source Layout Sketch

Draw North Arrow ☐ TRUE ☐ MAG



Longitude	Latitude	Declination
—	—	—

Additional Information:

Seconds					Seconds				Comments
Min.	00	15	30	45	Min.	00	15	30	45	
1	0	0	0	0	31	0	0	0	0	0% Opacity Avg.
2	0	0	0	0	32	0	0	0	0	
3	0	0	0	0	33	0	0	0	0	
4	0	0	0	0	34	0	0	0	0	
5	0	0	0	0	35	0	0	0	0	
6	0	0	0	0	36	0	0	0	0	
7	0	0	0	0	37	0	0	0	0	
8	0	0	0	0	38	0	0	0	0	
9	0	0	0	0	39	0	0	0	0	
10	0	0	0	0	40	0	0	0	0	
11	0	0	0	0	41	0	0	0	0	
12	0	0	0	0	42	0	0	0	0	
13	0	0	0	0	43	0	0	0	0	
14	0	0	0	0	44	0	0	0	0	
15	0	0	0	0	45	0	0	0	0	
16	0	0	0	0	46	0	0	0	0	
17	0	0	0	0	47	0	0	0	0	
18	0	0	0	0	48	0	0	0	0	
19	0	0	0	0	49	0	0	0	0	
20	0	0	0	0	50	0	0	0	0	
21	0	0	0	0	51	0	0	0	0	
22	0	0	0	0	52	0	0	0	0	
23	0	0	0	0	53	0	0	0	0	
24	0	0	0	0	54	0	0	0	0	
25	0	0	0	0	55	0	0	0	0	
26	0	0	0	0	56	0	0	0	0	
27	0	0	0	0	57	0	0	0	0	
28	0	0	0	0	58	0	0	0	0	
29	0	0	0	0	59	0	0	0	0	
30	0	0	0	0	60	0	0	0	0	

Observer's Name (Print)	Teresa Sanchez
Observer's Signature	Teresa Sanchez / Date 2/5/09
Organization	PEF
Certified By	ETA / Date 8/08

VEOF1.1

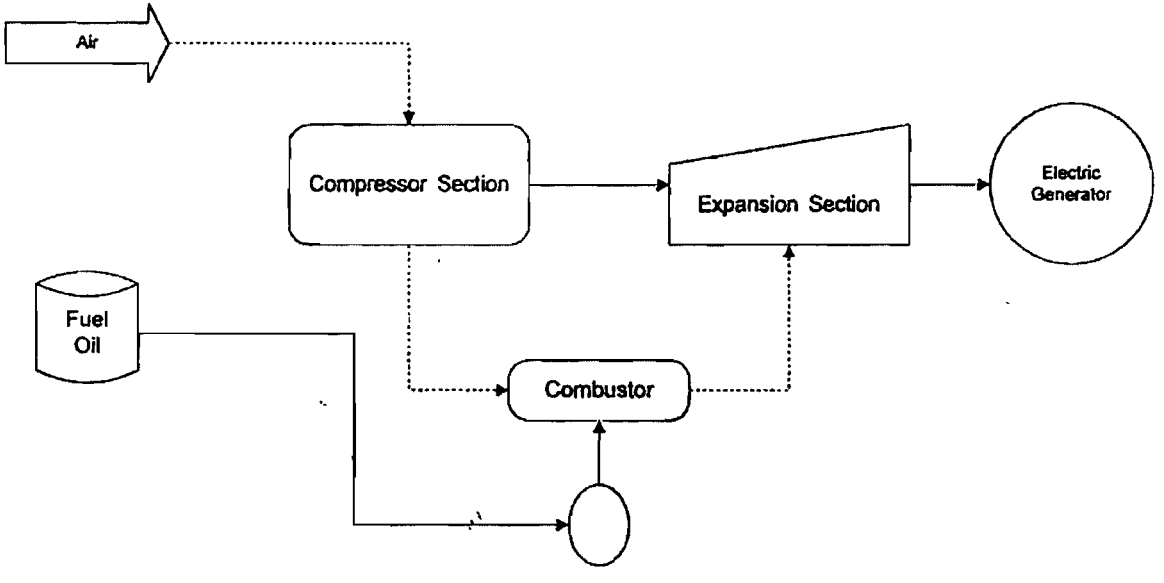
Bartow Anclote Pipeline Heater

	FUEL GAS
2/5/2009 8:56	FLW SCFH
	BPL00_FT
2/5/2009 9:56	105
1 m	*SCFH*
2/5/09 8:56	4596.1
2/5/09 8:57	4664.1
2/5/09 8:58	4549.1
2/5/09 8:59	4600.9
2/5/09 9:00	4807.5
2/5/09 9:01	4512.3
2/5/09 9:02	4612.2
2/5/09 9:03	4488.0
2/5/09 9:04	4708.1
2/5/09 9:05	4551.6
2/5/09 9:06	4779.4
2/5/09 9:07	4468.9
2/5/09 9:08	4579.9
2/5/09 9:09	4533.5
2/5/09 9:10	4603.1
2/5/09 9:11	4644.9
2/5/09 9:12	4570.0
2/5/09 9:13	4675.5
2/5/09 9:14	4644.4
2/5/09 9:15	4645.2
2/5/09 9:16	4541.3
2/5/09 9:17	4649.3
2/5/09 9:18	4579.8
2/5/09 9:19	4497.9
2/5/09 9:20	4488.1
2/5/09 9:21	4569.9
2/5/09 9:22	4614.6
2/5/09 9:23	4522.2
2/5/09 9:24	4671.7
2/5/09 9:25	4511.0
2/5/09 9:26	4682.1
2/5/09 9:27	4749.4
2/5/09 9:28	4697.0
2/5/09 9:29	4622.2
2/5/09 9:30	4675.7
2/5/09 9:31	4575.9
2/5/09 9:32	4698.2
2/5/09 9:33	4552.4
2/5/09 9:34	4699.1
2/5/09 9:35	4654.1
2/5/09 9:36	4443.5
2/5/09 9:37	4636.2
2/5/09 9:38	4622.9
2/5/09 9:39	4581.7
2/5/09 9:40	4650.5
2/5/09 9:41	4601.1
2/5/09 9:42	4550.7
2/5/09 9:43	4548.0
2/5/09 9:44	4617.1
2/5/09 9:45	4671.1
2/5/09 9:46	4581.5
2/5/09 9:47	4627.2
2/5/09 9:48	4757.9
2/5/09 9:49	4536.2
2/5/09 9:50	4572.6
2/5/09 9:51	4425.9
2/5/09 9:52	4852.5
2/5/09 9:53	4661.8
2/5/09 9:54	4686.2
2/5/09 9:55	4642.8
2/5/09 9:56	4653.4
Average	4613.2
HTIP	**4.7** **mmBTU/hr**
Permit Limit	15.5 mmBTU/hr
Capacity	**31%**

Florida Gas Transmission-8030

Date	2/5/2009
BTU	1028
CO2	1.175
N2	0.521
Grav	0.588
Methan	95.446
Ethane	2.217
Propan	0.359
Ibutan	0.079
Nbutan	0.08
Ipenta	0.035
Npenta	0.023
C6	0.065
C7	0
C8	0
C9	0
Wobbe	1340.432
CHDP	NA

EMISSION UNIT 005 - 008
Gas Turbine Peaking Units # P-1, # P-2, # P-3, and # P-4



CLIENT/PROJECT **Progress Energy Florida, Inc**			TAMPA, FLORIDA Golder Associates				TITLE **Process Flow Diagram Gas Turbine Peaking Units # P-1, P-2, P-3, and P-4 P. L. Bartow Plant**			
DRAWN	CHECKED	REVIEWED	DATE 4/16/2009	NOT TO SCALE	FILE NO.	Job No. 083-89614	DWG NO.	SUBTITLE	REV. NO.	**BA-EU5-I1**

ATTACHMENT BA-EU5-I2

FUEL ANALYSIS

No. 2 Fuel Oil

Parameter	Typical Value	Max Value
API gravity @ 60 F	30[1] -	
Relative density	7.1 lb/gal [2]	
Heat content	18,400 Btu / lb (LHV)	
% sulfur	0.12[2] 0.5 [3]	
% nitrogen	0.025 - 0.030	
% ash	negligible	0.01 [1]

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) FPC's fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the FPC fuel procurement specification

[2] Data from laboratory analysis

[3] Data from current air permit.

Natural Gas Analysis

Parameter	Typical Value	Max Value
Relative density	0.58 (compared to air)	
heat content	950 - 1124 Btu/cu ft.	
% sulfur	0.43 grains/CCF [1]	1 grain/100 CF
% nitrogen	0.8% by volume	
% ash	negligible	

Note: The values listed are "typical" values based upon information supplied to FPC by Florida Gas Transmission (FGT). However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data from laboratory analysis

ATTACHMENT BA-EU5-I6

Progress Energy

Via Certified Mail
March 3, 2009

Mr. Wayne Martin
Pinellas County Department of Environmental Management
Air Quality Division
300 South Garden Ave.
Clearwater, FL 34616

Re: Visible Emissions Compliance Tests
Progress Energy Florida, Inc.
P.L. Bartow Power Plant
Permit No.1030011-009-AV
E.U. ID's -005, -006, 007, and -008

Dear Mr. Martin:

Please find attached copies of the Visible Emissions Tests for Progress Energy's P.L. Bartow Power Plant. The VE tests were performed on February 4, 2009. The results show compliance with the applicable rules. The following tables summarize the emissions and operating conditions during the test.

Bartow Plant - Opacity Compliance Data 2009

Unit	Date / Time	Highest Value Observed	Permit Limit
1	2/4/09 8:38	15%	20%
2	2/4/09 10:23	5%	20%
3	2/4/09 8:38	5%	20%
4	2/4/09 10:23	5%	20%

Bartow Plant - Ops Data 2009

Unit	Date / Time	Inlet Temp	Calculated Heat Input	Permitted Heat Input	Permitted Heat Input at Inlet Temp	Capacity
		deg F	*mmBTU/hr*	*mmBTU/hr @ 59 deg F*	*mmBTU/hr*	*%*
1	2/4/09 8:38	64.0	645.0	714	710.3	91%
2	2/4/09 10:23	59.0	646.0	714	718.2	90%
3	2/4/09 8:38	64.0	646.6	714	710.3	91%
4	2/4/09 10:23	59.0	691.5	714	718.2	96%

Please contact Charles Dufeny at (727) 820-5854 if you have any questions.

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,

David Karp
Mgr-Plant Production-CT

Attachments

cc: Danielle D. Henry, FDEP-SWD

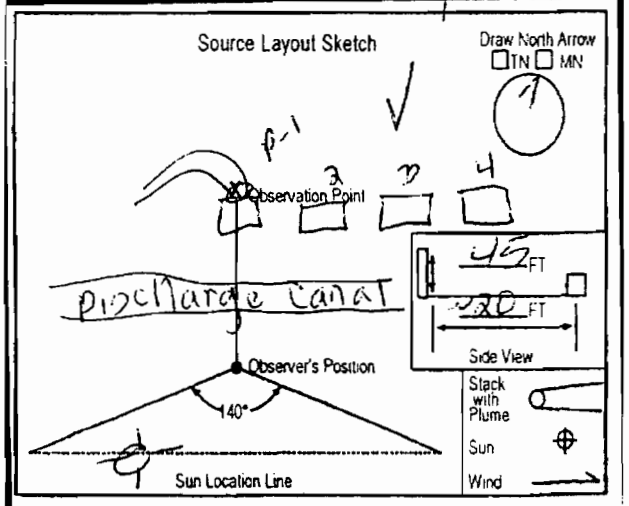
bc: R. Scallions, BP44
G. Schaefer, PEF 903
T. Sanchez, BR44
C. Bradley, PEF903
K. McDaniel, PEF903

Danielle D. Henry, FDEP
Florida Department of Environmental Protection
Southwest District
13051 North Telecom Parkway
Temple Terrace, Florida 33637-0926

EPA METHOD 9 (40 CFR 60 - Appendix A)
VISIBLE EMISSION OBSERVATION FORM

COMPANY NAME: Progress Energy Florida
PLANT: Bartow Plant
LOCATION: Peaking - CT's - P-1
CITY: St. Pete | STATE: FL | ZIP: 33702
PROCESS EQUIPMENT: C.T. - Diesel fired | OPERATING MODE:
CONTROL EQUIPMENT: N/A | OPERATING MODE:
DESCRIBE EMISSION POINT: Square stack - South most
HEIGHT OF EMISSION POINT: 45 ft. | HEIGHT OF EMISSION POINT RELATIVE TO OBSERVER: START 45' END 45'
DISTANCE TO EMISSION POINT: START ~100' END ~100' | DIRECTION TO EMISSION PT. (DEGREES (0-360)): START W END W
VERTICAL ANGLE TO OBSERVATION POINT: START N/A END | DIRECTION TO OBSERVATION POINT (DEGREES (0-360)): START W END N/A W
DISTANCE & DIRECTION TO OBSERVATION POINT FROM EMISSION POINT: START ~100' W END ~100' W
DESCRIBE EMISSIONS: START black plume END black plume
EMISSION COLOR: START black END black | WATER DROPLET PLUME: ATTACHED ☐ DETACHED ☐ NONE ☑
DESCRIBE PLUME BACKGROUND: START sky END sky
BACKGROUND COLOR: START blue END blue | SKY CONDITIONS: START clear END clear
WIND SPEED: START 15 mph END 15 mph | WIND DIRECTION: START ØN END N
AMBIENT TEMP: START 56°F END 56°F | WET BULB TEMP: N/A | RH percent

Source Layout Sketch



ADDITIONAL INFORMATION:

OBSERVATION DATE: 2-4-09 | START TIME: 0938 | END TIME: 0938

MIN \ SEC	0	15	30	45	COMMENTS
1	15	15	15	15	15 %
2	15	15	15	15	
3	15	15	15	15	
4	15	15	15	15	
5	15	15	15	15	
6	15	15	15	15	
7	15	15	15	15	
8	15	15	15	15	
9	15	15	15	15	
10	15	15	15	15	
11	15	15	15	15	
12	15	15	15	15	
13	15	15	15	15	
14	15	15	15	15	
15	15	15	15	15	
16	15	15	15	15	
17	15	15	15	15	
18	15	15	15	15	
19	15	15	15	15	
20	15	15	15	15	
21	15	15	15	15	
22	15	15	15	15	
23	15	15	15	15	
24	15	15	15	15	
25	15	15	15	15	
26	15	15	15	15	
27	15	15	15	15	
28	15	15	15	15	
29	15	15	15	15	
30	15	15	15	15	

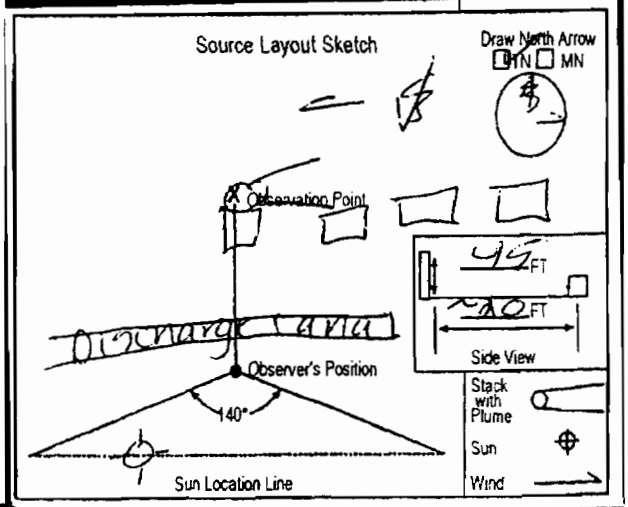
OBSERVER'S NAME (PRINT): Teresa Sanchez
OBSERVER'S SIGNATURE: Teresa Sanchez | DATE: 2/4/09
ORGANIZATION: P.E.F.
CERTIFIED BY: ETA | DATE: 3/8/08

EPA METHOD 9 (40 CFR 60 - Appendix A)
VISIBLE EMISSION OBSERVATION FORM

COMPANY NAME: Progress Energy Florida		
LOCATION: Bartow Plant		
LOCATION: P-1 CT's		
CITY: St. Pete	STATE: FL	ZIP: 33702
PROCESS EQUIPMENT: Pratt C.T.	OPERATING MODE:	
CONTROL EQUIPMENT: N/A	OPERATING MODE: N/A	
DESCRIBE EMISSION POINT: square - 3rd from south		
HEIGHT OF EMISSION POINT: 45 ft.	HEIGHT OF EMISSION POINT RELATIVE TO OBSERVER: START 45' END 45'	
DISTANCE TO EMISSION POINT: START ~100' END ~100'	DIRECTION TO EMISSION PT. (DEGREES (0-360)): START W END W	
VERTICAL ANGLE TO OBSERVATION POINT: START N/A END	DIRECTION TO OBSERVATION POINT (DEGREES (0-360)): START W END W	
DISTANCE & DIRECTION TO OBSERVATION POINT FROM EMISSION POINT: START ~100' W	END ~100' W	
DESCRIBE EMISSIONS: START lofting	END lofting	
EMISSION COLOR: START black	END black	WATER DROPLET PLUME: ATTACHED ☐ DETACHED ☐ NONE ☑
DESCRIBE PLUME BACKGROUND: START sky	END sky	
BACKGROUND COLOR: START blue	END blue	SKY CONDITIONS: START clear END clear
WIND SPEED: START 15mph	END 15mph	WIND DIRECTION: START N END N
AMBIENT TEMP: START 56°F	END 56°F	WET BULB TEMP: N/A RH percent

Source Layout Sketch

Draw North Arrow ☐ TN ☐ MN



ADDITIONAL INFORMATION

OBSERVATION DATE	START TIME	END TIME
2-4-09	0938	0938

SEC / MIN	0	15	30	45	COMMENTS
1	15	15	15	15	
2	15	15	15	15	
3	15	15	15	15	
4	15	15	15	15	
5	10	10	10	10	
6	10	10	10	10	
7	10	10	10	10	
8	10	10	10	10	
9	10	10	10	10	
10	10	10	10	10	
11	10	10	10	10	
12	10	10	10	10	
13	10	10	10	10	
14	10	10	10	10	
15	10	10	10	10	
16	10	10	10	10	
17	10	10	10	10	
18	10	10	10	10	
19	10	10	10	10	
20	10	10	10	10	
21	10	10	10	10	
22	10	10	10	10	
23	10	10	10	10	
24	10	10	10	10	
25	10	10	10	10	
26	10	10	10	10	
27	10	10	10	10	
28	10	10	10	10	
29	10	10	10	10	
30	10	10	10	10	

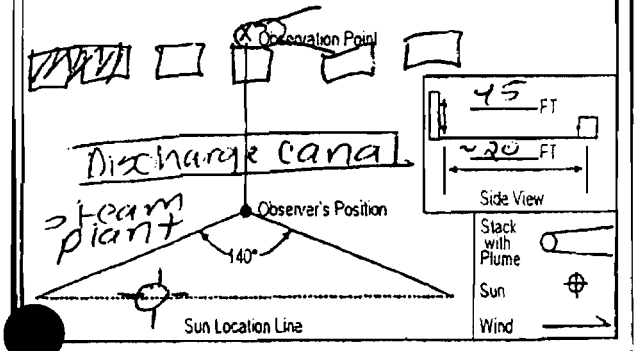
OBSERVER'S NAME (PRINT): Terese Sanchez		
OBSERVER'S SIGNATURE: Terese Sanchez	DATE: 2/4/09	
ORGANIZATION: PEF		
CERTIFIED BY: ETA	DATE: 8/08	

EPA METHOD 9 (40 CFR 60 - Appendix A)
VISIBLE EMISSION OBSERVATION FORM

COMPANY NAME	Progress Energy Florida
LOCATION	Bartow Plant
LOCATION	CT Peakers - P-2
CITY	St. Pete
STATE	FL
ZIP	33702
PROCESS EQUIPMENT	Peaking gen ~~square duct~~
OPERATING MODE	
CONTROL EQUIPMENT	N/A
OPERATING MODE	N/A
DESCRIBE EMISSION POINT	2nd from south square stack, ~~north most~~
HEIGHT OF EMISSION POINT	45 ft.
HEIGHT OF EMISSION POINT RELATIVE TO OBSERVER	START 45' END 45'
DISTANCE TO EMISSION POINT	START ~100' END ~100'
DIRECTION TO EMISSION PT. ~~(DEGREES (0-360))~~	START W END W
VERTICAL ANGLE TO OBSERVATION POINT	START N/A END
DIRECTION TO OBSERVATION POINT ~~(DEGREES (0-360))~~	START W END W
DISTANCE & DIRECTION TO OBSERVATION POINT FROM EMISSION POINT	START ~100 ft W END ~100 ft W
DESCRIBE EMISSIONS	START lofting END lofting
EMISSION COLOR	START black END black
WATER DROPLET PLUME	ATTACHED ☐ DETACHED ☐ NONE ☑
DESCRIBE PLUME BACKGROUND	START sky END sky
BACKGROUND COLOR	START blue END blue
SKY CONDITIONS	START clear END clear
WIND SPEED	START 15mph END 15mph
WIND DIRECTION	START N END N
AMBIENT TEMP	START 56°F END 56°F
WET BULB TEMP / RH percent	N/A

Source Layout Sketch

Draw North Arrow ☑ TRUE ☐ MAG



ADDITIONAL INFORMATION

OBSERVATION DATE	START TIME	END TIME
2-4-09	1023	1123

SEC / MIN	0	15	30	45	COMMENTS
1	5	5	5	5	
2	5	5	5	5	
3	5	5	5	5	
4	5	5	5	5	
5	5	5	5	5	
6	5	5	5	5	
7	5	5	5	5	
8	5	5	5	5	
9	5	5	5	5	
10	5	5	5	5	
11	5	5	5	5	
12	5	5	5	5	
13	5	5	5	5	
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23	5	5	5	5	
24	5	5	5	5	
25	5	5	5	5	
26	5	5	5	5	
27	5	5	5	5	
28	5	5	5	5	
29	5	5	5	5	
30	5	5	5	5	

OBSERVER'S NAME (PRINT)	Teresa Sanchez
OBSERVER'S SIGNATURE	Teresa Sanchez
DATE	2-4-09
ORGANIZATION	PEF
CERTIFIED BY	ETA
DATE	8/08

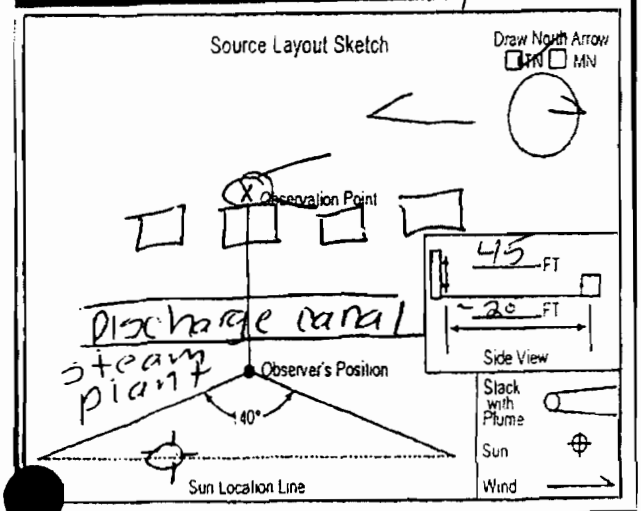
EPA METHOD 9 (40 CFR 60 - Appendix A)
VISIBLE EMISSION OBSERVATION FORM

2 of 2

COMPANY NAME: Progress Energy Florida
LOCATION: Bartow Plant
LOCATION: CT Peakers - P-2
CITY: St. Pete | STATE: FL | ZIP: 33702
PROCESS EQUIPMENT: Rating Generator | OPERATING MODE:
CONTROL EQUIPMENT: N/A | OPERATING MODE: N/A
DESCRIBE EMISSION POINT: Square Stack - 2nd from South
HEIGHT OF EMISSION POINT: 45'
HEIGHT OF EMISSION POINT RELATIVE TO OBSERVER: START ~100' 45' 45' END ~100'
DISTANCE TO EMISSION POINT: START ~100' END ~100'
DIRECTION TO EMISSION PT. (~~DEGREES (0-360)~~): START W END W
VERTICAL ANGLE TO OBSERVATION POINT: START N/A END
DIRECTION TO OBSERVATION POINT (~~DEGREES (0-360)~~): START W END W
DISTANCE & DIRECTION TO OBSERVATION POINT FROM EMISSION POINT: START ~100' W END ~100' W
DESCRIBE EMISSIONS: START lofting END lofting
EMISSION COLOR: START black END black
WATER DROPLET PLUME: ATTACHED ☐ DETACHED ☐ NONE ☑
DESCRIBE PLUME BACKGROUND: START sky END sky
BACKGROUND COLOR: START blue END blue
SKY CONDITIONS: START clear END clear
WIND SPEED: START 15 mph END 15 mph
WIND DIRECTION: START N END N
AMBIENT TEMP: START 56°F END 56°F
WET BULB TEMP: N/A | RH percent

Source Layout Sketch

Draw North Arrow: ☑ TN ☐ MN



ADDITIONAL INFORMATION:

OBSERVATION DATE: 2-4-09 | START TIME: 1023 | END TIME: 1123

SEC / MIN	0	15	30	45	COMMENTS
1	5	5	5	5	50%
2	5	5	5	5	
3	5	5	5	5	
4	5	5	5	5	
5	5	5	5	5	
6	5	5	5	5	
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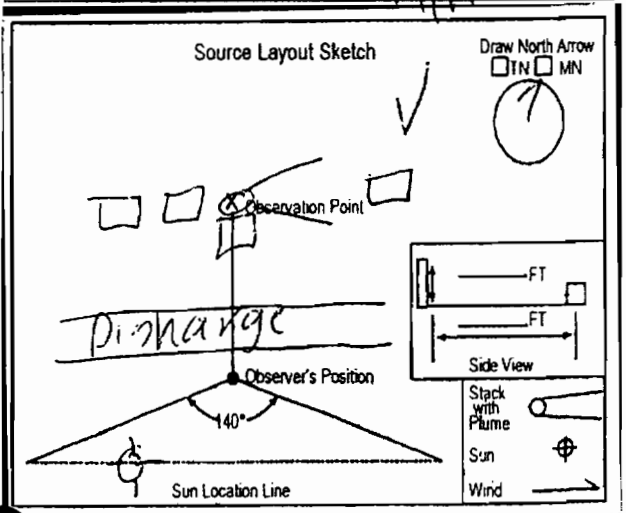
25	5	5	5	5	
26	5	5	5	5	
27	5	5	5	5	
28	5	5	5	5	
29	5	5	5	5	
30	5	5	5	5	

OBSERVER'S NAME (PRINT): Teresa Sanchez
OBSERVER'S SIGNATURE: Teresa Sanchez | DATE: 2/4/09
ORGANIZATION: PEF
CERTIFIED BY: ETI | DATE: 8/08

EPA METHOD 9 (40 CFR 60 - Appendix A)
VISIBLE EMISSION OBSERVATION FORM

COMPANY NAME: Progress Energy Florida		
LOCATION: Bartow Plant		
LOCATION: P-3		
CITY: St. Pete	STATE: FL	ZIP: 33702
PROCESS EQUIPMENT: CT - Diesel Fired		OPERATING MODE
CONTROL EQUIPMENT: N/A		OPERATING MODE
DESCRIBE EMISSION POINT: Square stack - 3rd from South		
HEIGHT OF EMISSION POINT: 45ft	HEIGHT OF EMISSION POINT RELATIVE TO OBSERVER: START 45' END 45	
DISTANCE TO EMISSION POINT: START ~100' END ~100'	DIRECTION TO EMISSION PT. (DEGREES (0-360)): START W END W	
VERTICAL ANGLE TO OBSERVATION POINT: START N/A END	DIRECTION TO OBSERVATION POINT: DEGREES (0-360): START W END N/A W	
DISTANCE & DIRECTION TO OBSERVATION POINT FROM EMISSION POINT: START ~100' W	END ~100' W	
DESCRIBE EMISSIONS: START lofting plume	END lofting plume	
EMISSION COLOR: START black END black	WATER DROPLET PLUME: ATTACHED ☐ DETACHED ☐ NONE ☑	
DESCRIBE PLUME BACKGROUND: START sky	END sky	
BACKGROUND COLOR: START blue END blue	SKY CONDITIONS: START clear END clear	
WIND SPEED: START 15 mph END 5 mph	WIND DIRECTION: START SW END N	
AMBIENT TEMP: START END	WET BULB TEMP: RH percent N/A	



ADDITIONAL INFORMATION

OBSERVATION DATE	START TIME	END TIME
2-4-09	0938	0938

SEC / MIN	0	15	30	45	COMMENTS
1	5	5	5	5	
2	5	5	5	5	
3	5	5	5	5	
4	5	5	5	5	
5	5	5	5	5	
6	5	5	5	5	
7	5	5	5	5	
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11	5	5	5	5	
12	5	5	5	5	
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26	5	5	5	5	
27	5	5	5	5	
28	5	5	5	5	
29	5	5	5	5	
30	5	5	5	5	

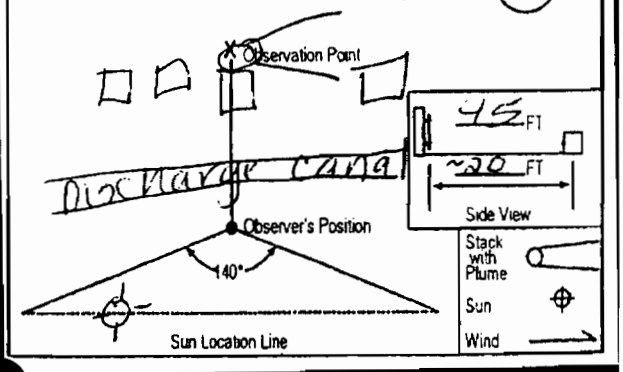
OBSERVER'S NAME (PRINT): Teresa Sanchez	
OBSERVER'S SIGNATURE: Teresa Sanchez	DATE: 2/4/09
ORGANIZATION: PEF	
CERTIFIED BY: ETA	DATE: 8/08

EPA METHOD 9 (40 CFR 60 - Appendix A)
VISIBLE EMISSION OBSERVATION FORM

COMPANY NAME	Progress Energy Florida
LOCATION	Bartow Plant
LOCATION	P-3 CT's
CITY	St. Pete
STATE	FL
ZIP	33702
PROCESS EQUIPMENT	Peaker generator
OPERATING MODE	
CONTROL EQUIPMENT	N/A
OPERATING MODE	N/A
DESCRIBE EMISSION POINT	S. Most square plume
HEIGHT OF EMISSION POINT	45 ft.
HEIGHT OF EMISSION POINT RELATIVE TO OBSERVER	START 45' END 45'
DISTANCE TO EMISSION POINT	START ~100' END ~100'
DIRECTION TO EMISSION PT. ~~(DEGREES (0-360))~~	START W END W
VERTICAL ANGLE TO OBSERVATION POINT	START N/A END
DIRECTION TO OBSERVATION POINT ~~(DEGREES (0-360))~~	START W END W N/A
DISTANCE & DIRECTION TO OBSERVATION POINT FROM EMISSION POINT	START ~100ft W END ~100ft W
DESCRIBE EMISSIONS	START lofting END lofting
EMISSION COLOR	START black END black
WATER DROPLET PLUME	ATTACHED ☐ DETACHED ☐ NONE ☑
DESCRIBE PLUME BACKGROUND	START sky END sky
BACKGROUND COLOR	START blue END blue
SKY CONDITIONS	START clear END clear
WIND SPEED	START 15mph END 15mph
WIND DIRECTION	START N END N
AMBIENT TEMP	START 56°F END 56°F
WET BULB TEMP	N/A
RH percent	

Source Layout Sketch

Draw North Arrow ☑ TN ☐ MN



ADDITIONAL INFORMATION

OBSERVATION DATE	START TIME	END TIME
2-4-09	0838	0938

SEC / MIN	0	15	30	45	COMMENTS
1	5	5	5	5	
2	5	5	5	5	5%
3	5	5	5	5	
4	5	5	5	5	
5	5	5	5	5	
6	5	5	5	5	
7	5	5	5	5	
8	5	5	5	5	
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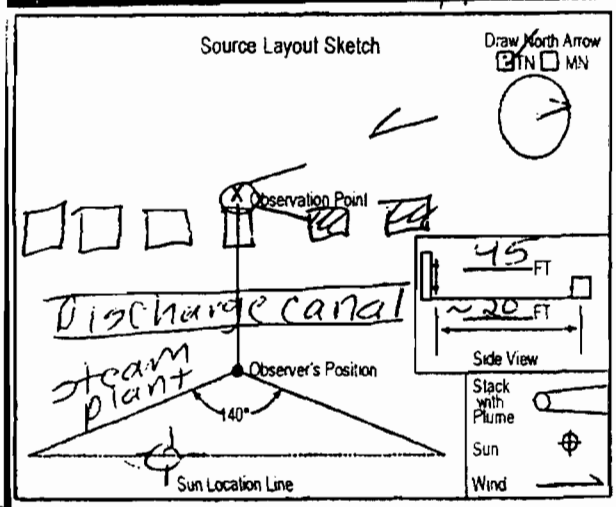
25	5	5	5	5	
26	5	5	5	5	
27	5	5	5	5	
28	5	5	5	5	
29	5	5	5	5	
30	5	5	5	5	

OBSERVER'S NAME (PRINT)	Terese Sanchez
OBSERVER'S SIGNATURE	Terese Sanchez
DATE	2/4/09
ORGANIZATION	PEF
CERTIFIED BY	ETA
DATE	8/08

EPA METHOD 9 (40 CFR 60 - Appendix A)
VISIBLE EMISSION OBSERVATION FORM

COMPANY NAME: Progress Energy Florida	OBSERVATION DATE: 2-4-09	START TIME: 1023
LOCATION: Bartow Plant		END TIME: 1123
LOCATION: CT Peakers P-4		
CITY: St. Pete / STATE: FL / ZIP: 33702		
PROCESS EQUIPMENT: Peaker generator / OPERATING MODE:		
CONTROL EQUIPMENT: N/A / OPERATING MODE: N/A		
DESCRIBE EMISSION POINT: square stack - north most		
HEIGHT OF EMISSION POINT: 45 ft.	HEIGHT OF EMISSION POINT RELATIVE TO OBSERVER: START 45' END 45'	
DISTANCE TO EMISSION POINT: START ~100' END ~100'	DIRECTION TO EMISSION PT. (DEGREES 0-360): START W END W	
VERTICAL ANGLE TO OBSERVATION POINT: START N/A END	DIRECTION TO OBSERVATION POINT (DEGREES (0-360)): START W END W	
DISTANCE & DIRECTION TO OBSERVATION POINT FROM EMISSION POINT: START ~100 ft W END ~100 ft W		
DESCRIBE EMISSIONS: START lofting END lofting		
EMISSION COLOR: START Black END black	WATER DROPLET PLUME: ATTACHED ☐ DETACHED ☐ NONE ☑	
DESCRIBE PLUME BACKGROUND: START sky END sky		
BACKGROUND COLOR: START blue END blue	SKY CONDITIONS: START clear END clear	
WIND SPEED: START 15 mph END 15 mph	WIND DIRECTION: START N END N	
AMBIENT TEMP: START 56°F END 56°F	WET BULB TEMP: N/A	RH, percent

Source Layout Sketch



ADDITIONAL INFORMATION

SEC / MIN	0	15	30	45	COMMENTS
1	5	5	5	5	
2	5	5	5	5	
3	5	5	5	5	
4	5	5	5	5	
5	5	5	5	5	
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26	5	5	5	5	
27	5	5	5	5	
28	5	5	5	5	
29	5	5	5	5	
30	5	5	5	5	

OBSERVER'S NAME (PRINT): Teresa Sanchez	
OBSERVER'S SIGNATURE: Teresa Sanchez	DATE: 2/4/09
ORGANIZATION: PEF	
CERTIFIED BY: ETA	DATE: 8/08

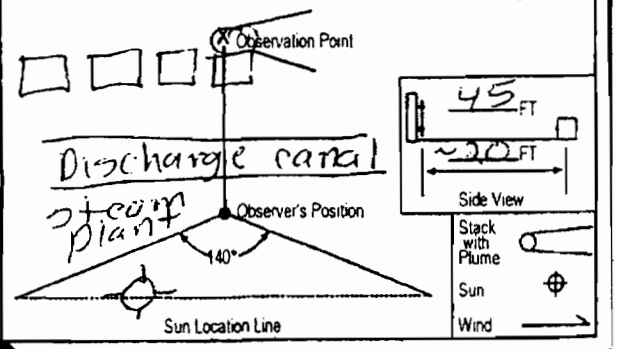
2 of 2

EPA METHOD 9 (40 CFR 60 - Appendix A)
VISIBLE EMISSION OBSERVATION FORM

COMPANY NAME: Progress Energy Florida
LOCATION: Bartow Plant
LOCATION: CT Peakers, P-4
CITY: St. Pete | STATE: FL | ZIP: 33703
PROCESS EQUIPMENT: Peaker generator | OPERATING MODE:
CONTROL EQUIPMENT: N/A | OPERATING MODE: N/A
DESCRIBE EMISSION POINT: square stack - north most
HEIGHT OF EMISSION POINT: 45'
HEIGHT OF EMISSION POINT RELATIVE TO OBSERVER: START 45' END 45'
DISTANCE TO EMISSION POINT: START ~100' END ~100'
DIRECTION TO EMISSION PT ~~(DEGREES (0-360))~~: START W END W
VERTICAL ANGLE TO OBSERVATION POINT: START N/A END
DIRECTION TO OBSERVATION POINT ~~(DEGREES (0-360))~~: START W END W
DISTANCE & DIRECTION TO OBSERVATION POINT FROM EMISSION POINT: START ~100' W END ~100' W
DESCRIBE EMISSIONS: START lofting END lofting
EMISSION COLOR: START black END black
WATER DROPLET PLUME: ATTACHED ☐ DETACHED ☐ NONE ☑
DESCRIBE PLUME BACKGROUND: START sky END sky
BACKGROUND COLOR: START blue END blue
SKY CONDITIONS: START clear END clear
WIND SPEED: START 5 mph END 15mph
WIND DIRECTION: START N END N
AMBIENT TEMP: START 56°F END 56°F
WET BULB TEMP: N/A percent

Source Layout Sketch

Draw North Arrow ☐ TRUE ☐ MN



ADDITIONAL INFORMATION

OBSERVATION DATE: 2-4-09 | START TIME: 1023 | END TIME: 1123

SEC / MIN	0	15	30	45	COMMENTS
1	5	5	5	5	
2	5	5	5	5	5%
3	5	5	5	5	
4	5	5	5	5	
5	5	5	5	5	
6	5	5	5	5	
7	5	5	5	5	
8	5	5	5	5	
9	5	5	5	5	
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25	5	5	5	5	
26	5	5	5	5	
27	5	5	5	5	
28	5	5	5	5	
29	5	5	5	5	
30	5	5	5	5	

OBSERVER'S NAME (PRINT): Teresa Sanchez
OBSERVER'S SIGNATURE: Teresa Sanchez | DATE: 2/4/09
ORGANIZATION: PEF
CERTIFIED BY: ETA | DATE: 8/08

Laboratory Services

5012 Causeway Blvd • Tampa Fl. 33619 • Ph (813)630-7378 • Fax (813)630-7360 • DOH #E54272

Report For: Terese Sanchez,Progress Energy Florida
1601 Weedon Island Dr. - MAC BT11
St. Petersburg, FL 33702

terese.sanchez@pgnmail.com

Route To: *Progress Energy - Bartow GT, Progress Energy - Admin*

Report Date: 2/5/2009
Laboratory ID: AA99242
Location Code: PEI-#2-BARTOW

Sample Information

Description: #2 Oil, Bartow CT, Progress Energy Inc.
Project Account Code: 01
Sample Collection Method: Sampled by Customer

Sampled By: R. BEALE
Date and Time Collected: 1/8/2009 9:30:00 AM
Date of Sample Receipt: 1/22/2009
SAMPLE TYPE: COMBUSTION TURBINE

Laboratory Results

PARAMETER	Result	Units	MDL	Qual Code	Test Method	Analyst	Analysis Date & Time	Lower Limit	Upper Limit	Violation Check
API Gravity @ 60 Deg. F	32.3	Degrees API	0.1		ASTM D5002	KAPXJ	02/03/09 10:59			
Carbon, Hydrogen, and Nitrogen in Oil										
Carbon	87.2	%			ASTM 5291	KAPXJ	01/22/09 10:04			
Hydrogen	12.5	%			ASTM 5291	KAPXJ	01/22/09 10:04			
Nitrogen	< 0.2	%	0.2	U	ASTM 5291	KAPXJ	01/22/09 10:04			
Density @ 15 C (59 F)	0.8634	kg/L	0.0001		ASTM Table3	KAEMD	02/03/09 15:17			
Gross Heat of Combustion, Oils, (HHV)	5796000	BTU/Barrel	1		Calculation	KACLH	02/05/09 08:42			
Gross Heat of Combustion, Oils, (HHV)	138000	BTU/Gal.	1		Calculation	KACLH	02/05/09 08:42	137000		
Gross Heat of Combustion, Oils, (HHV)	19204	BTU/Lb.	1		ASTM D-240	KAPXJ	02/04/09 15:58			
Net Heat of Combustion, Oils, (LHV)	5457228	BTU/Barrel	1		Calculation	KACLH	02/05/09 08:42			
Net Heat of Combustion, Oils, (LHV)	129934	BTU/Gal.	1		Calculation	KACLH	02/05/09 08:42			
Net Heat of Combustion, Oils, (LHV)	18064	BTU/Lb.	1		ASTM D-240	KACLH	02/05/09 08:41			
Pounds / Gallon @ 60 Deg. F	7.193	Lbs./Gal.	0.001		ASTM D 1250-80	KAEMD	02/03/09 15:16		9.5	
Relative Density 60/60 Deg. F	0.8639		0.0001		ASTM D-1298	KAEMD	02/03/09 15:17			
Sulfur in Petroleum Products	0.22	%	0.01		ASTM D-1552	KAEMD	02/02/09 10:26		0.5	

Comments

Data Qualifier Codes Explanation:
U - Indicates that the compound was analyzed for but not detected.

Should there be any questions regarding this report, please contact:

Cheryl Howard,
Designee for Peggy Penner
Manager, Laboratory Services
(813) 630-7490

HST_PEF

Plant	Progress Energy	P1		P3		
2/4/09 8:38	UC OUTSIDE TEMPERATURE	PEMS - CORRECTED FUEL OIL FLOW	PEMS - GENERATOR LOAD	UC OUTSIDE TEMPERATURE	PEMS - CORRECTED FUEL OIL FLOW	PEMS - GENERATOR LOAD
2/4/09 9:38	BAR00_TT-0001	BRP01_G1:FQL_MASS_FLO.OUT	BRP01_G1:DWATT.OUT	BAR00_TT-0001	BRP03_G3:FQL_MASS_FLO.OUT	BRP03_G3:DWATT.OUT
1m	*DEG F*	*#SEC*	*MW*	*DEG F*	*#SEC*	*MW*
2/4/09 8:38	63.5	9.563	51.4	63.5	9.399	51.9
2/4/09 8:39	63.2	9.388	51.5	63.2	9.329	52.0
2/4/09 8:40	62.7	9.324	51.5	62.7	9.325	52.0
2/4/09 8:41	62.4	9.365	51.7	62.4	9.366	52.0
2/4/09 8:42	62.9	9.315	51.4	62.9	9.410	52.0
2/4/09 8:43	63.6	9.297	51.8	63.6	9.318	52.0
2/4/09 8:44	63.4	9.309	51.8	63.4	9.336	52.0
2/4/09 8:45	63.3	9.290	51.7	63.3	9.363	52.0
2/4/09 8:46	63.2	9.305	51.6	63.2	9.332	52.0
2/4/09 8:47	63.1	9.298	51.4	63.1	9.325	52.0
2/4/09 8:48	62.3	9.275	51.4	62.3	9.313	51.9
2/4/09 8:49	61.4	9.275	51.2	61.4	9.193	51.8
2/4/09 8:50	62.4	9.275	51.7	62.4	9.299	51.7
2/4/09 8:51	63.3	9.220	51.4	63.3	9.311	51.6
2/4/09 8:52	63.8	9.285	51.2	63.8	9.327	51.6
2/4/09 8:53	62.7	9.282	51.4	62.7	9.312	51.6
2/4/09 8:54	63.1	9.260	51.6	63.1	9.301	51.5
2/4/09 8:55	63.5	9.277	51.4	63.5	9.266	51.5
2/4/09 8:56	63.5	9.275	51.6	63.5	9.256	51.4
2/4/09 8:57	63.6	9.241	51.2	63.6	9.289	51.4
2/4/09 8:58	63.8	9.254	51.1	63.8	9.240	51.4
2/4/09 8:59	63.6	9.266	51.7	63.6	9.259	51.8
2/4/09 9:00	63.4	9.279	52.1	63.4	9.271	51.8
2/4/09 9:01	63.7	9.248	51.5	63.7	9.315	51.8
2/4/09 9:02	63.7	9.272	51.6	63.7	9.309	51.7
2/4/09 9:03	64.2	9.258	51.8	64.2	9.291	51.7
2/4/09 9:04	64.5	9.253	51.3	64.5	9.294	51.7
2/4/09 9:05	64.4	9.256	51.0	64.4	9.318	51.6
2/4/09 9:06	65.1	9.260	50.8	65.1	9.327	51.6
2/4/09 9:07	64.7	9.281	51.5	64.7	9.339	51.6
2/4/09 9:08	63.7	9.267	51.6	63.7	9.276	51.5
2/4/09 9:09	63.4	9.287	51.4	63.4	9.275	51.6
2/4/09 9:10	63.8	9.274	51.4	63.8	9.277	51.6
2/4/09 9:11	64.3	9.261	51.4	64.3	9.268	51.6
2/4/09 9:12	64.1	9.248	51.3	64.1	9.261	51.6
2/4/09 9:13	64.3	9.277	51.7	64.3	9.308	51.7
2/4/09 9:14	64.3	9.315	51.5	64.3	9.264	51.7
2/4/09 9:15	64.3	9.246	51.2	64.3	9.279	51.7
2/4/09 9:16	64.8	9.280	51.6	64.8	9.359	51.7
2/4/09 9:17	64.7	9.276	51.6	64.7	9.347	51.8
2/4/09 9:18	64.7	9.262	51.7	64.7	9.333	51.8
2/4/09 9:19	65.2	9.238	51.4	65.2	9.254	51.8
2/4/09 9:20	65.2	9.264	51.1	65.2	9.145	51.8
2/4/09 9:21	64.8	9.290	51.6	64.8	9.279	51.8
2/4/09 9:22	64.6	9.264	51.2	64.6	9.347	51.8
2/4/09 9:23	65.0	9.260	51.3	65.0	9.334	51.7
2/4/09 9:24	66.3	9.273	51.2	66.3	9.321	51.7
2/4/09 9:25	66.4	9.246	51.6	66.4	9.266	51.7
2/4/09 9:26	66.6	9.240	51.6	66.6	9.311	51.7
2/4/09 9:27	66.7	9.347	51.3	66.7	9.317	51.7
2/4/09 9:28	66.9	9.273	51.6	66.9	9.332	51.7
2/4/09 9:29	66.9	9.285	51.4	66.9	9.270	51.7
2/4/09 9:30	65.9	9.278	51.6	65.9	9.387	51.9
2/4/09 9:31	66.2	9.233	51.3	66.2	9.343	51.9
2/4/09 9:32	66.7	9.286	51.4	66.7	9.305	52.0
2/4/09 9:33	66.4	9.475	52.3	66.4	9.314	52.0
2/4/09 9:34	65.7	9.393	51.8	65.7	9.374	52.0
2/4/09 9:35	65.0	9.266	51.5	65.0	9.316	52.0
2/4/09 9:36	65.9	9.274	51.5	65.9	9.304	52.1
2/4/09 9:37	66.2	9.282	51.7	66.2	9.324	52.1
2/4/09 9:38	66.4	9.238	51.7	66.4	9.373	52.1
	AVG Fuel	33431 Lbs/hour		AVG Fuel	33509 Lbs/hour	
	Avg TEMP	64.4 DEG F		Avg TEMP	64.4 DEG F	
	HI	645.0 MMBtu/hr		HI	646.6 MMBtu/hr	

HST_PEF

Bartow Plant	Progress Energy	P2		P4		
2/4/09 10:23	UC OUTSIDE TEMPERATURE	PEMS - CORRECTED FUEL OIL FLOW	PEMS - GENERATOR LOAD	UC OUTSIDE TEMPERATURE	PEMS - CORRECTED FUEL OIL FLOW	PEMS - GENERATOR LOAD
2/4/09 11:23	BAR00_TT-0001	BRP02_G2:FQL_MASS_FLO.OUT	BRP02_G2:DWATT.OUT	BAR00_TT-0001	BRP04_G4:FQL_MASS_FLO.OUT	BRP04_G4:DWATT.OUT
Time	DEG F	#/SEC	MW	DEG F	#/SEC	MW
2/4/09 10:23	61.2	9.281	51.7	61.2	10.197	56.9
2/4/09 10:24	61.2	9.293	51.6	61.2	10.039	56.8
2/4/09 10:25	61.3	9.259	51.6	61.3	10.118	56.8
2/4/09 10:26	61.3	9.322	51.6	61.3	10.072	56.7
2/4/09 10:27	61.4	9.263	51.6	61.4	10.075	56.7
2/4/09 10:28	60.5	9.259	51.5	60.5	9.964	56.6
2/4/09 10:29	59.3	9.226	51.6	59.3	9.976	56.6
2/4/09 10:30	59.1	9.281	51.6	59.1	9.854	56.6
2/4/09 10:31	58.9	9.268	51.6	58.9	9.721	56.5
2/4/09 10:32	58.9	9.523	51.7	58.9	9.753	56.6
2/4/09 10:33	59.1	9.310	51.7	59.1	9.977	56.6
2/4/09 10:34	59.3	9.399	51.7	59.3	10.067	56.6
2/4/09 10:35	59.5	9.247	51.8	59.5	10.172	56.6
2/4/09 10:36	59.6	9.332	51.8	59.6	9.732	56.6
2/4/09 10:37	59.4	9.300	51.8	59.4	9.911	56.7
2/4/09 10:38	59.2	9.272	51.8	59.2	10.105	56.7
2/4/09 10:39	59.0	9.280	51.9	59.0	9.769	56.7
2/4/09 10:40	58.9	9.355	51.9	58.9	9.783	56.7
2/4/09 10:41	58.6	9.334	51.9	58.6	9.941	56.7
2/4/09 10:42	58.3	9.315	51.8	58.3	9.900	56.7
2/4/09 10:43	58.3	9.317	51.8	58.3	10.062	56.6
2/4/09 10:44	58.4	9.261	51.8	58.4	9.961	56.2
2/4/09 10:45	58.5	9.265	51.8	58.5	10.034	56.2
2/4/09 10:46	58.4	9.270	51.8	58.4	10.334	56.2
2/4/09 10:47	57.9	9.293	51.8	57.9	10.078	56.2
2/4/09 10:48	58.1	9.274	51.8	58.1	9.637	56.2
2/4/09 10:49	58.1	9.356	51.8	58.1	9.927	56.2
2/4/09 10:50	58.0	9.378	51.8	58.0	9.773	56.1
2/4/09 10:51	57.9	9.272	51.8	57.9	9.978	56.2
2/4/09 10:52	57.9	9.347	51.8	57.9	10.064	56.2
2/4/09 10:53	58.0	9.330	51.9	58.0	9.924	56.2
2/4/09 10:54	58.0	9.320	52.0	58.0	10.035	56.2
2/4/09 10:55	58.1	9.292	52.0	58.1	9.934	56.2
2/4/09 10:56	58.2	9.289	52.0	58.2	9.893	56.2
2/4/09 10:57	58.2	9.323	52.0	58.2	9.991	56.3
2/4/09 10:58	58.2	9.302	51.9	58.2	9.930	56.7
2/4/09 10:59	58.2	9.312	51.9	58.2	10.071	56.4
2/4/09 11:00	58.2	9.279	51.9	58.2	10.139	56.4
2/4/09 11:01	57.9	9.305	51.9	57.9	9.958	56.4
2/4/09 11:02	57.7	9.239	51.9	57.7	9.819	56.4
2/4/09 11:03	57.4	9.254	51.9	57.4	10.034	56.4
2/4/09 11:04	57.1	9.268	51.8	57.1	10.099	56.4
2/4/09 11:05	57.2	9.341	51.8	57.2	9.684	56.4
2/4/09 11:06	57.2	9.303	51.8	57.2	9.830	56.4
2/4/09 11:07	57.3	9.247	51.8	57.3	10.066	56.4
2/4/09 11:08	57.3	9.254	51.8	57.3	10.029	56.4
2/4/09 11:09	57.6	9.294	51.8	57.6	9.705	56.2
2/4/09 11:10	58.3	9.471	51.8	58.3	9.880	56.2
2/4/09 11:11	58.4	9.243	51.8	58.2	9.907	56.5
2/4/09 11:12	58.4	9.304	51.8	58.4	9.876	56.5
2/4/09 11:13	58.1	9.351	51.8	58.1	9.943	56.5
2/4/09 11:14	58.0	9.324	51.8	58.0	10.020	56.5
2/4/09 11:15	58.1	9.262	51.9	58.1	9.957	56.5
2/4/09 11:16	58.2	9.270	51.9	58.2	9.795	56.6
2/4/09 11:17	57.8	9.238	52.0	57.8	10.010	56.4
2/4/09 11:18	57.4	9.192	52.0	57.4	9.884	56.4
2/4/09 11:19	57.5	9.254	52.1	57.5	9.501	56.4
2/4/09 11:20	57.6	9.311	52.1	57.6	9.958	56.5
2/4/09 11:21	57.7	9.296	52.1	57.7	9.981	56.6
2/4/09 11:22	57.7	9.325	52.2	57.7	10.123	56.6
2/4/09 11:23	57.8	9.344	52.2	57.8	10.044	56.7
	AVG Fuel	33479 Lbs/hour		AVG Fuel	35840 Lbs/hour	
	Avg TEMP	58.5 DEG F		Avg TEMP	58.5 DEG F	
	HI	646.0 MMBtu/hr		HI	691.5 MMBtu/hr	

Progress Energy

299 First Avenue North

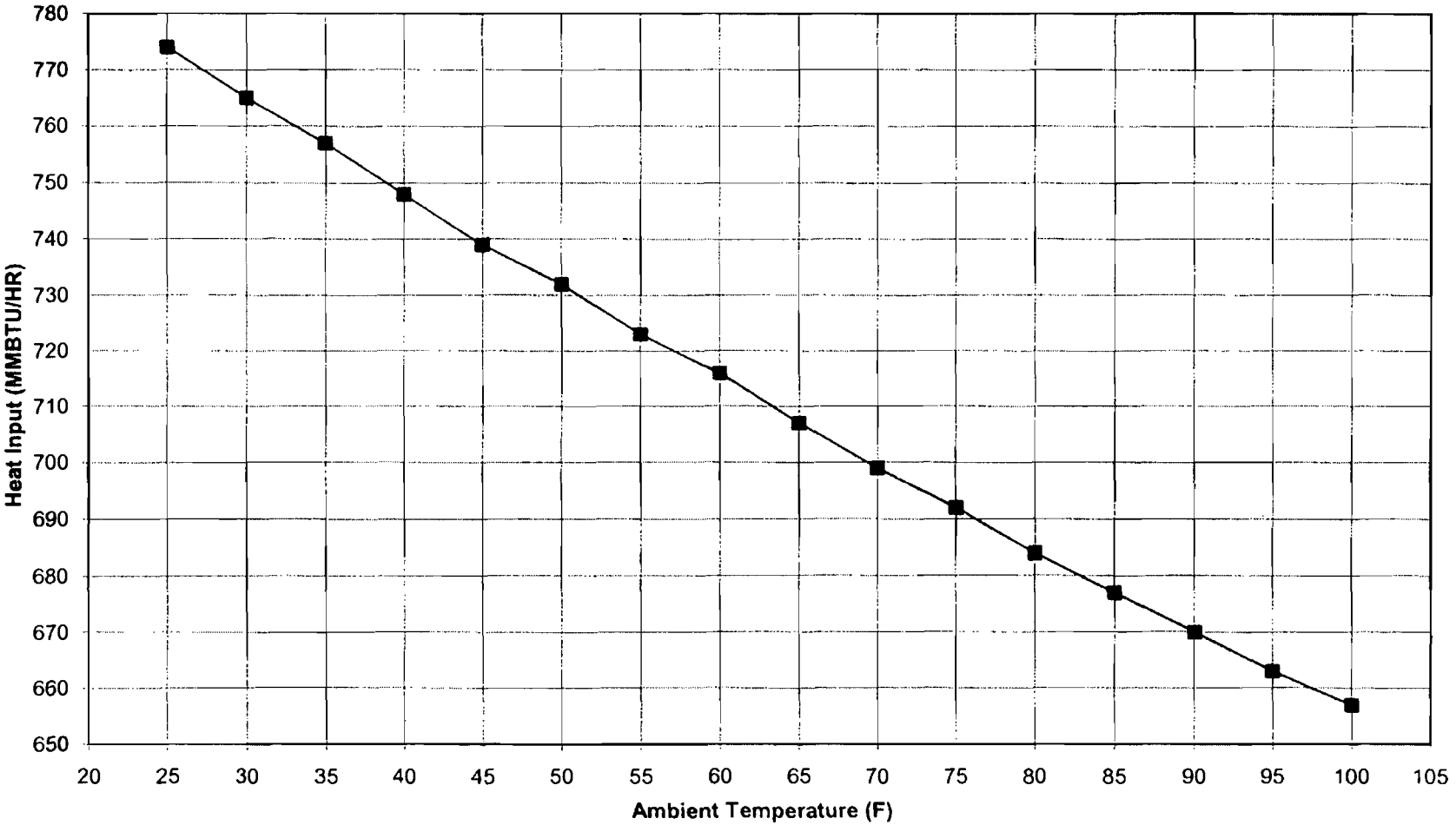
fax

To:	Jose Rodriguez	From:	Charles Dufeny
Company:	Pinellas County DEM	Phone No.:	727-820-5854
Fax No.:	(727) 464-4420 (fax)	Date:	April 2, 2009
Subject:	Bartow VE Test Report completed 2/4/09.	Pages:	3

Comments:
Attachments: Visible Emissions Certification for Terese Sanchez and Heat Input Curve for Units P1-P3.

BARTOW COMBUSTION TURBINE

Fuel Heat Input vs. Ambient Temperature



BartowP1_P3HICurve11012005

VISIBLE EMISSIONS EVALUATOR

This is to certify that

M TERESE SANCHEZ

met the specifications of Federal Reference Method 9 and qualifies as a visible emissions evaluator. Maximum deviation on white and black smoke did not exceed 7.5% opacity and no single error exceeding 15% opacity was incurred during the certification test conducted by Eastern Technical Associates of Raleigh, NC. This certificate is valid for six months from date of issue

370157
CERT NUMBER

2/11/2009
DATE OF SCHOOL

TAMPA, FL
SCHOOL LOCATION

8/13/2009
CERTIFICATION EXP DATE

SAN607347
STUDENT ID NUMBER

MANAGER OF TRAINING SERVICES

EASTERN TECHNICAL ASSOCIATES

M TERESE SANCHEZ

SAN607347 STUDENT ID NUMBER

met the specifications of Federal Reference Method 9 and qualifies as a visible emissions evaluator. Maximum deviation on white and black smoke did not exceed 7.5% opacity and no single error exceeding 15% opacity was incurred during the certification test conducted by Eastern Technical Associates of Raleigh, NC. This certificate is valid for six months from date of issue and expires on the date below

TAMPA, FL	2/11/2009	370157
SCHOOL LOCATION	DATE OF SCHOOL	CERT NUMBER
TMPS07	8/13/2009	
LAST LECTURE	CERTIFICATION EXP DATE	BEARER

Customer Support
Debbie or Sheila
919-878-3188
www.eta-is-opacity.com

ATTACHMENT BA-EU10-I6
Compliance Test Reports

Progress Energy

INITIAL COMPLIANCE TEST REPORT

for

Progress Energy
P. L. Bartow Power Plant
Units 4A, 4B, 4C, and 4D Bypass Stacks – Gas
St. Petersburg, Pinellas County, Florida

February 2009

Prepared By:

RMB Consulting and Research, Inc.
5104 Bur Oak Circle
Raleigh, North Carolina 27612
(919) 510-5102

CONTENTS

List of Tables

List of Appendices

CERTIFICATION STATEMENT

Air Permits issued by the Florida Department of Environmental Protection (FL DEP) require "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."

I certify that, to the best of my knowledge and belief, that all data required and provided are true and correct, with respect to the test procedures used.

_____

Robert J. Bivens
Senior Engineer I
Responsible for Test Protocol and Report Authorship, Project Oversight, and Quality Assurance
RMB Consulting & Research, Inc.

EXECUTIVE SUMMARY

Progress Energy's P. L. Bartow Plant (Bartow Plant) is currently completing construction on four (4) combustion turbine (CT) units (Units 4A, 4B, 4C, and 4D) at its St. Petersburg, Florida facility. As a result, the four units are subject to air emissions testing and reporting requirements as set forth by the United States Environmental Protection Agency in Title 40 of the Code of Federal Regulations Part 60 (40 CFR Part 60) for New Source Performance Standard (NSPS) Subpart KKKK and Best Available Control Technology (BACT).

The purpose of this test program was to determine the compliance status with specific air emission permit limits as contained in Air Permit No. PSD-FL-381, issued by FL DEP. Emissions testing was performed for NO_x, CO, VOC, and visible emissions on the bypass stack of each unit while firing natural gas only.

The following report shows that compliance was demonstrated on each unit, for each of the required pollutants, at each load condition while combusting natural gas as required by the current air permit.

1.0 INTRODUCTION

Progress Energy's P. L. Bartow Plant (Bartow Plant) is currently completing construction on four (4) combustion turbine (CT) units (Units 4A, 4B, 4C, and 4D) at its St. Petersburg, Florida facility. As a result, the four units are subject to air emissions testing and reporting requirements as set forth by the United States Environmental Protection Agency in Title 40 of the Code of Federal Regulations Part 60 (40 CFR Part 60) for New Source Performance Standard (NSPS) Subpart KKKK and Best Available Control Technology (BACT). These requirements are administered by the Florida Department of Environmental Protection (FL DEP), and on a local basis by the Pinellas County Department of Environmental Management (PC DEM).

The purpose of the test program was to determine compliance with specific air emission permit limits as contained in FL DEP Air Permit No. PSD-FL-381. This report outlines the procedures that were followed, the test methods that were used, and any approved deviations from either the specific conditions and limitations as listed in the above referenced air permit, or from the test methods themselves.

For this test program, all emissions testing was performed by TRC Environmental Corporation. Overall project oversight, testing supervision, test protocol development, and final report generation was or is being provided by RMB Consulting & Research, Inc. (RMB). RMB personnel were also present for the entire duration of the test program. Contact information for this test program can be found in Appendix 9 of this report.

2.0 BACKGROUND

Testing was performed on the respective bypass stack outlet of Units 4A, 4B, 4C, and 4D. Air Permit No. PSD-FL-381, Emissions Unit Specific Condition Nos. 17, 18, 27, and 28 outline the specific compliance testing requirements for Units 4A-4D.

Compliance testing for oxides of nitrogen (NO_x), oxygen (O_2), carbon monoxide (CO), volatile organic compounds (VOCs), and visible emissions (VE) was required for each unit. Per the above referenced air permit, the testing of emissions was to be conducted with each respective unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. For Units 4A-4D, this was specifically defined in the test protocol as at least 90 percent of 215 MW, or at least 194 MW[1]. Testing was performed while firing natural gas only, while the appropriate fuel-specific control technologies were in normal operational mode[2].

Note also the Progress Energy recently amended Air Permit No. PSD-FL-381, Emissions Unit Specific Condition Nos. 15.e and 18.c to the following:

"Other than startup, shutdown, fuel switching or documented malfunction simple-cycle CT operations shall be at a load not less than 45% or that load at which compliance was demonstrated at initial [compliance testing], whichever is higher."

In light of this change to the permit language, compliance testing was also performed between 45-70% load while firing natural gas. It was determined that compliance can be demonstrated for each of the above referenced pollutants at a **minimum operating load of 55%** (based upon the ambient characteristics at the time of testing) for Units 4A, 4B, and 4C[3].

---

[1] This MW rating is based upon a compressor inlet air temperature of 59 ^{0}F, the higher heating value (HHV) of each fuel, and 100% load. **This rating changes based upon the ambient conditions and fuel characteristics in evidence at the time of testing.** For this particular test program, all high-load testing was performed at 100% load, based upon the ambient characteristics at the time of testing.

[2] Compliance testing while firing No. 2 fuel oil will be performed as a separate test program.

[3] Due to a process upset, the low load testing on Unit 4D could not be completed during this particular testing mobilization. The Unit 4D low load test (while firing gas) will be performed at the time the units are tested while firing oil.

Note also that a NO_x CEMS relative accuracy test audit (RATA) was performed concurrently on each unit along with the compliance test program. The results of the NO_x CEMS RATA (and other certification tests) will be submitted as a separate report, under separate cover. Due to the concurrent nature of testing, as with previous test programs the data assimilated during the NO_x RATAs "doubled" as the NO_x and CO compliance testing data. That is, RATA Runs 1-3 = Compliance Run 1, etc. since three 21-minute RATA runs provide at least 60 minutes worth of compliance data[4]. All test runs while operating at low load were 60 minutes in length.

These pollutants, the prescribed load/fuel conditions, and their respective emission limitations are described in Table 2-1. This table also describes the applicable test methods that were used to test for each pollutant as well as the run times of each reference method (RM).

Table 2-1. Initial Compliance Test Matrix – Units 4A-4D

Pollutant	Method	Fuel	Load Level	# of Runs	Run Duration	Emission Limits[1]	
						Permit Limit #1	Permit Limit #2
NO_x	7E	Gas	100%	9 (RATA)	21 minutes	15 ppm @ Stack O_2	15 ppm @ 15% O_2
		Gas	45-70%	3	60 minutes	15 ppm @ Stack O_2	15 ppm @ 15% O_2
O_2	3A	Gas	100%	9 (RATA)	21 minutes	N/A	N/A
		Gas	45-70%	3	60 minutes	N/A	N/A
CO	10	Gas	100%	9	21 minutes	4.1ppm @ 15% O_2	20.8 lb/hr
		Gas	45-70%	3	60 minutes	4.1ppm @ 15% O_2	20.8 lb/hr
VOC[2]	25A	Gas	100%	9	21 minutes	1.2 ppm @ 15% O_2	3.0 lb/hr
		Gas	45-70%	3	60 minutes	1.2 ppm @ 15% O_2	3.0 lb/hr
VE	9	Gas	100%	1	30 minutes	10% per 6-min block	N/A
		Gas	45-70%	1	30 minutes	10% per 6-min block	N/A
H_2O	4	Gas	100%	3	60 minutes	N/A	N/A
		Gas	45-70%	3	60 minutes	N/A	N/A

[1] Permitted ppm limits expressed as ppm dry.
[2] Moisture determinations were made simultaneously (using RM 4 procedures) in order to convert VOC ppmw to ppmd.

[4] Due to TRC's sampling and data acquisition limitations, the CO and VOC test runs at high load were also 21 minutes in length during the RATA (where three 21-minute runs comprised a single compliance test run).

For this test program, all pollutants were concurrently sampled. For clarity, Table 2-2 summarizes the run layout at high load for each unit, since a RATA was performed concurrently at this condition.

Table 2-2. Run Layout for Units 4A-4D Bypass Stacks – Gas

Unit	Run No.	
	Compliance	RATA
4A	1	1-3
	2	4-6
	3	7-9
4B	1	1-3
	2	4-6
	3	7-9
4C	1	1-3
	2	4-6
	3	7-9
4D[1]	1	Stratification, 1-2
	2	3-5
	3	6-8

[1] For the Unit 4D testing, the unit tripped during RATA Run #9. As a result, the stratification data was substituted for RATA Run #1, and the eight (8) valid runs were used as RATA Run #s 2-9. As a result, the stratification run and RATA Runs #s 1 and 2 correspond to Compliance Run #1. (The moisture data obtained during RATA Runs #s 1 and 2 was also applied to the stratification run.)

3.0 SUMMARY OF COMPLIANCE TESTING RESULTS

Compliance was demonstrated for each of the required pollutants while firing natural gas at each load condition as required by the current air permit. Tables 3-1 through 3-4 summarize the results (based upon the 3-run averages) of this testing program. Appendix 1 of this report contains the more detailed and comprehensive run-by-run results. All high load testing corresponded to 100% of the maximum achievable load of the unit, based upon the ambient characteristics in evidence at the time of testing. All low load testing corresponded to 55% of the maximum achievable load of the unit, based upon the ambient characteristics in evidence at the time of testing.

Table 3-1. Summary of Initial Compliance Testing Results – Unit 4A High Load (100%)

Load Level (MW)	Heat Input (mmBtu/hr)[1]	Ambient (°F)	Pollutant	Test Result	Permit Limit	Compliance Indicated?
190.0	1851.9	75.1	NO_x ppm	10.6	15	Yes
			NO_x ppm @15% O_2	8.63	15	Yes
			CO ppm @15% O_2	0.30	4.1	Yes
			CO lb/hr	1.24	20.8	Yes
			VOC ppm @15% O_2	0.40	1.2	Yes
			VOC lb/hr	0.94	3.0	Yes
			VE %[2]	0.0	10	Yes

[1] Heat input based upon a gross calorific (GCV) value of 1,033 Btu/scf during testing.
[2] VE % permit limits and test results are based upon 6-minute block averages.

Table 3-2. Summary of Initial Compliance Testing Results – Unit 4A Low Load (55%)

Load Level (MW)	Heat Input (mmBtu/hr)[1]	Ambient (°F)	Pollutant	Test Result	Permit Limit	Compliance Indicated?
102.0	1211.1	76.7	NO_x ppm	6.94	15	Yes
			NO_x ppm @15% O_2	6.19	15	Yes
			CO ppm @15% O_2	2.61	4.1	Yes
			CO lb/hr	7.10	20.8	Yes
			VOC ppm @15% O_2	0.54	1.2	Yes
			VOC lb/hr	0.84	3.0	Yes
			VE %[2]	0.0	10	Yes

[1] Heat input based upon a gross calorific (GCV) value of 1,033 Btu/scf during testing.
[2] VE % permit limits and test results are based upon 6-minute block averages.

Table 3-3. Summary of Initial Compliance Testing Results – Unit 4B High Load (100%)

Load Level (MW)	Heat Input (mmBtu/hr)[1]	Ambient (°F)	Pollutant	Test Result	Permit Limit	Compliance Indicated?
191.6	1850.1	73.2	NO_x ppm	7.36	**15**	**Yes**
			NO_x ppm @15% O_2	6.04	**15**	**Yes**
			CO ppm @15% O_2	0.35	**4.1**	**Yes**
			CO lb/hr	1.44	**20.8**	**Yes**
			VOC ppm @15% O_2	0.52	**1.2**	**Yes**
			VOC lb/hr	1.24	**3.0**	**Yes**
			VE %[2]	0.0	**10**	**Yes**

[1] Heat input based upon a gross calorific (GCV) value of 1,034 Btu/scf during testing.
[2] VE % permit limits and test results are based upon 6-minute block averages.

Table 3-4. Summary of Initial Compliance Testing Results – Unit 4B Low Load (55%)

Load Level (MW)	Heat Input (mmBtu/hr)[1]	Ambient (°F)	Pollutant	Test Result	Permit Limit	Compliance Indicated?
102.9	1211.6	74.2	NO_x ppm	8.34	**15**	**Yes**
			NO_x ppm @15% O_2	7.42	**15**	**Yes**
			CO ppm @15% O_2	3.72	**4.1**	**Yes**
			CO lb/hr	10.12	**20.8**	**Yes**
			VOC ppm @15% O_2	0.62	**1.2**	**Yes**
			VOC lb/hr	0.95	**3.0**	**Yes**
			VE %[2]	0.0	**10**	**Yes**

[1] Heat input based upon a gross calorific (GCV) value of 1,034 Btu/scf during testing.
[2] VE % permit limits and test results are based upon 6-minute block averages.

Table 3-5. Summary of Initial Compliance Testing Results – Unit 4C High Load (100%)

Load Level (MW)	Heat Input (mmBtu/hr)[1]	Ambient (°F)	Pollutant	Test Result	Permit Limit	Compliance Indicated?
193.6	1888.0	69.5	NO_x ppm	8.75	**15**	**Yes**
			NO_x ppm @15% O_2	7.12	**15**	**Yes**
			CO ppm @15% O_2	0.39	**4.1**	**Yes**
			CO lb/hr	1.65	**20.8**	**Yes**
			VOC ppm @15% O_2	0.64	**1.2**	**Yes**
			VOC lb/hr	1.54	**3.0**	**Yes**
			VE %[2]	0.0	**10**	**Yes**

[1] Heat input based upon a gross calorific (GCV) value of 1,032 Btu/scf during testing.
[2] VE % permit limits and test results are based upon 6-minute block averages.

Table 3-6. Summary of Initial Compliance Testing Results – Unit 4C Low Load (55%)

Load Level (MW)	Heat Input (mmBtu/hr)[1]	Ambient (°F)	Pollutant	Test Result	Permit Limit	Compliance Indicated?
107.0	1260.2	68.0	NO_x ppm	8.56	15	Yes
			NO_x ppm @15% O_2	7.61	15	Yes
			CO ppm @15% O_2	2.45	4.1	Yes
			CO lb/hr	6.91	20.8	Yes
			VOC ppm @15% O_2	0.62	1.2	Yes
			VOC lb/hr	1.01	3.0	Yes
			VE %[2]	0.0	10	Yes

[1] Heat input based upon a gross calorific (GCV) value of 1,032 Btu/scf during testing.
[2] VE % permit limits and test results are based upon 6-minute block averages.

Table 3-7. Summary of Initial Compliance Testing Results – Unit 4D High Load (100%)

Load Level (MW)	Heat Input (mmBtu/hr)[1]	Ambient (°F)	Pollutant	Test Result	Permit Limit	Compliance Indicated?
199.6	1918.5	65.1	NO_x ppm	11.1	15	Yes
			NO_x ppm @15% O_2	9.14	15	Yes
			CO ppm @15% O_2	0.42	4.1	Yes
			CO lb/hr	1.83	20.8	Yes
			VOC ppm @15% O_2	0.47	1.2	Yes
			VOC lb/hr	1.16	3.0	Yes
			VE %[2]	0.0	10	Yes

[1] Heat input based upon a gross calorific (GCV) value of 1,031 Btu/scf during testing.
[2] VE % permit limits and test results are based upon 6-minute block averages.

Table 3-8. Summary of Initial Compliance Testing Results – Unit 4D Low Load (55%)

Load Level (MW)	Heat Input (mmBtu/hr)[1]	Ambient (°F)	Pollutant	Test Result	Permit Limit	Compliance Indicated?
TBD	TBD	TBD	NO_x ppm	TBD	15	TBD
			NO_x ppm @15% O_2	TBD	15	TBD
			CO ppm @15% O_2	TBD	4.1	TBD
			CO lb/hr	TBD	20.8	TBD
			VOC ppm @15% O_2	TBD	1.2	TBD
			VOC lb/hr	TBD	3.0	TBD
			VE %[2]	TBD	10	TBD

4.0 FACILITY DESCRIPTION

4.1 Facility Location

Progress Energy's Bartow Plant is located at 1601 Weedon Island Drive, St. Petersburg, Pinellas County, Florida. The Bartow Plant is currently in the process of performing a "re-powering" project. For this project, three (3) existing fossil-fuel fired steam boilers designated as Units 1, 2, and 3 with a total nominal capacity of 465 MW will be shut down. In its place a "4-x-1" combined-cycle turbine unit, rated at 1,280 MW will be constructed. Construction is anticipated to be completed in the Spring of 2009. The combined-cycle unit will be used for electricity generation and sale.

4.2 Unit Descriptions

The "4-x-1" combined-cycle unit consists of Units 4A, 4B, 4C, and 4D, which will all share a single steam turbine generator. Units 4A-4D are Siemens Model SGT6-5000F combustion turbines (CTs) with a maximum rated electrical output of 215 MW per unit. The steam turbine will be rated at 420 MW, for a total combined-cycle unit system output of approximately 1,280 MW.

Units 4A-4D are each dual-fuel fired units that will combust natural gas (gas) as a primary fuel and No. 2 distillate fuel oil (oil) as an "off-season" back-up fuel. The maximum heat input rating (based upon the higher heating value of the fuel, and an ambient temperature of 59 °F) of each unit while firing natural gas will be 1,972 mmBtu/hr. The maximum heat input rating rating (based upon the higher heating value of the fuel, and an ambient temperature of 59 °F) of each unit while firing No. 2 fuel oil will be 1,876 mmBtu/hr.

Units 4A-4D will each have its own dedicated main[5] and bypass stacks, for a total of 2 stacks per unit, which equates to 8 stacks for the entire combined-cycle "system". Units 4A-4D will each have its own dedicated heat recovery steam generator (HRSG), as well as a 500 mmBtu/hr duct burner to be used for supplementary heat input[6]. Each of the four (4) units is permitted to

[5] The main stacks are also referred to as the heat recovery steam generator (HRSG) stacks.
[6] The duct burner will only be used for combined-cycle operation while firing gas.

operate in either simple-cycle mode by directing the exhaust to the bypass stack, or in combined-cycle mode by directing the exhaust through the HRSG to the main stack.

While in either simple-cycle or combined-cycle mode, for the control of NO_x emissions, dry low NO_x burners (DLNBs) are used while firing gas and water injection is used while firing oil. For any additional NO_x control, while in combined-cycle mode each unit's HRSG will be equipped with a selective catalytic reduction (SCR) system, which can utilize ammonia injection while firing either gas or oil[7]. For the control of CO emissions, each unit will use clean fuels and good combustion practices. No direct CO control technology (e.g., oxidation catalysts) is currently planned for installation on these units. Appendix 2 of this protocol contains the combined process flow diagram for Units 4A-4D.

4.3 Reference Methods Sampling Locations

The stack testing locations (as well as other pertinent, descriptive information) for each unit's outlet bypass stack is described in Table 4-1. Appendix 2 contains the engineering and stack diagrams for Units 4A-4D. All stack dimensions were verified for completeness and accuracy at the time of testing.

Table 4-1. Stack Testing Locations – Units 4A, 4B, 4C, and 4D Bypass Stacks

Unit	Stack	Stack Exit Height (feet)	Test Port Height (feet)	Stack ID (feet)	Accessed By
4A	Bypass	132.5	121.5	22.0	Ladder
4B	Bypass	132.5	121.5	22.0	Ladder
4C	Bypass	132.5	121.5	22.0	Ladder
4D	Bypass	132.5	121.5	22.0	Ladder

[7] Note that the HRSG/SCR systems will only be installed on the main, and not the bypass, stacks.

5.0 REFERENCE METHOD COMPLIANCE TESTING PROCEDURES

This section includes a brief discussion of the test methods that were used for sampling and analysis at the Bartow Repower facility. Unless stated otherwise, all stack sampling was performed in accordance with the applicable test methods as prescribed in the referenced air permit. Any deviations from the standard procedures were previously noted in the test protocol that was previously submitted and approved.

During the compliance test program, all process data was electronically logged and printed out by the plant control room's data acquisition and handling system (DAHS). All process data taken during this test program is provided in Appendix 4 of this report.

5.1 Sample and Velocity Traverse (RM 1)

RM 1, which is used for the determination of the number and location of sample points used for a "full" velocity or isokinetic traverse, was not applicable or relevant to this test program. Additionally, the verification of the absence of cyclonic flow was not necessitated.

For the pollutant and diluent measurements[8], the number of traverse points to be sampled during each test run was determined by a pre-test stratification check on each unit prior to sampling, in accordance with 40 CFR Part 75. Note that on August 14, 2006, EPA made effective certain revisions to Methods 3A, 6C, 7E, and 10. Among these rule revisions was an updated stratification test procedure as outlined by Method 7E, §8.1.2. However, per EPA's "Frequently Asked Questions[9]" regarding the August 2006 revisions made to these methods, the existing stratification test requirements prescribed by 40 CFR Part 75, Appendix A for RATAs take precedence over the stratification requirements of the revised Method 7E.

As such, for the stratification tests, a twelve (12) point traverse was performed using the sampling points determined via 40 CFR Part 60, Appendix A, Method 1. Each point was sampled for NO_x and O_2 for two times (2X) the system response time, with a minimum sampling time of 2 minutes at each traverse point as required by Method 7E, §8.1.2 and 40 CFR Part 75,

[8] Also known as Instrumental Reference Method, or IRM, measurements.
[9] See EPA's Technology Transfer Network website at http://www.epa.gov/ttn/emc/methods/method7e.html.

Appendix A, §6.5.6.1(c). Methods 7E and 3A were used to measure NO_x and O_2, respectively, during the stratification tests. The load remained constant (± 3.0 percent) during the stratification traverses. From the stratification results, the number and location of the test points were determined according to the criteria summarized in Table 5-1.

Table 5-1. Stratification Determination Criteria – Gas

Pollutant	12-pt. Stratification Result	Required Test Run Traverse
NO_x	Each pt ≤ 5.0% of average or within ±3 ppm of average	1-pt.
	Each pt ≤ 10.0% of average or within ±5 ppm of average	3-pt. @ 0.4, 1.2, and 2.0 meters
	Any pt > 10.0% of average or not within ±1.0 ppm of average	3-pt. @ 16.7, 50.0, and 83.3% of stack diameter
O_2	Each pt within ±0.3% of average	1-pt.
	Each pt within ±0.5% of average	3-pt. @ 0.4, 1.2, and 2.0 meters
	Any pt not within ±0.5% of average	3-pt. @ 16.7, 50.0, and 83.3% of stack diameter

Note
The 0.4, 1.2, and 2.0 meter 3-point traverse corresponds to 15.7, 47.2, and 78.7 inches. If this 3-point traverse option is selected, the traverse should be performed along the measurement line (i.e., test port) exhibiting the highest average concentration during the stratification test. In addition, any single point traverse shall be located at least 1.0 meter (i.e., 39.4 inches) from the stack wall if selected.

Note that the required test run traverse was determined upon the results which least satisfied the stratification determination criteria. For example, say the single point criteria is satisfied for O_2, but only the 3-point criteria is satisfied for NO_x. In this case, a 3-point traverse would have been used for all of the sampling.

The results of the Part 75 stratification test for NO_x and O_2 served as the traverse point basis for the NO_x, CO, O_2, and VOC sampling for the high and low load testing on each unit[10]. Note also that, if needed, the stratification test data can also be used as (or part of) the first test run. For this test program, each bypass stack qualified for a single-point traverse. The results of each

[10] Stratification testing is not required for VOC sampling. However, due to the configuration of the test team's equipment, the VOC sample was acquired via the same sampling system (and traverse) used for the NO_x, CO, and O_2 testing. Also note that stratification testing for CO is technically not required. However, CO stratification data was nevertheless obtained for plant informational purposes.

stratification test are included in Appendix 3 of this test report. Appendix 2 of this report includes a summary of the calculated traverse points used during the test program.

5.2 Instrumental Reference Methods – NO_x (RM 7E), CO (RM 10), and O_2 (RM 3A)

Source emission testing was performed on each of the four bypass stacks to demonstrate compliance with the NO_x limits specified in the referenced air permit. RM 7E was used for the NO_x testing. For the NO_x sampling, a set of nine (9) 21-minute test runs was performed at high (i.e., normal) load on each unit while combusting natural gas. A set of three 1-hour test runs was performed at low load on Units 4A, 4B, and 4C while combusting natural gas.

Testing was also performed to verify compliance with the CO limits as specified in the air permit. RM 10 was used to determine CO emissions. CO sampling was performed concurrently with the NO_x sampling.

O_2 concentrations were concurrently determined using the procedures described in RM 3A. The O_2 values were obtained in order to calculate values of NO_x and CO ppm corrected to 15% O_2, as well as VOC corrected to 15% O_2. Since molecular weight values were not required for any part of this test program, CO_2 measurements were not necessitated (though they were taken). All O_2 sampling was performed concurrently with the NO_x, CO, and VOC sampling.

For the NO_x, CO, and O_2 measurements, the sample was extracted from the stack effluent through a heated sample probe and heated sample line to a sample conditioner where moisture was removed. The dried gas sample was then pumped to a distribution manifold where a portion of the sample gas was distributed to each analyzer.

In accordance with RM 3A, 7E, and 10, a three-point (i.e., low-, mid- and high-level) analyzer calibration error test (i.e., direct analyzer calibration) was conducted on the O_2 (and CO_2), NO_x, and CO analyzers at the beginning of each test day, or when deemed necessary at the tester's discretion (e.g., switching units or gases, lengthy downtime, suspected drift, etc.). Per the August 14, 2006 test method revisions, **the high-level calibration gas established (i.e., equaled) the calibration span** of the analyzer and was selected so that the measured emissions

were between 20-100% of the calibration span, to the extent practicable. The low-level calibration gas is required to be less than 20% of the calibration span (and is typically a zero gas), and the mid-level calibration gas is required to be 40-60% of the calibration span.

The calibration error test was conducted by sequentially injecting the low and span calibration gases directly into the analyzer, recording the responses, and comparing these responses to the actual tag values of the calibration gas cylinders. For the calibration error test, it is permissible to set the analyzer for the zero adjustment using the zero calibration gas (either nitrogen or cross-zero gas) and the span adjustment using only one of the two span gases. The reference calibration gases used during this test program were certified following EPA Protocol analysis procedures as defined in 40 CFR Part 75, Appendix A, §5.1.4. Copies of the calibration gas "certificates of analysis" are provided in Appendix 8 of this test report. For the calibration error test(s), acceptable system performance checks dictate that the difference between the analyzer responses and the respective cylinder tag values must be ≤ 2.0 % of the calibration span value or within $\pm$ 0.5 ppm.

"Hands off" zero and upscale system calibration checks (i.e., system bias calibration) were also performed both before and after each test run in order to quantify reference measurement sampling system bias and calibration drift. In instances when the test runs immediately followed one another, the post-cal for the run immediately preceding a subsequent run was also considered the pre-cal for that forthcoming run. Upscale was considered either the mid- or high-level gas, or whichever gas most closely approximated the flue gas level. During these checks, the calibration gases were introduced into the sampling system at the in-stack probe outlet so that they were conveyed throughout the entire sampling system in the same manner as the flue gas samples. System bias and drift were then assessed. Sampling system bias is defined as the difference between the test run calibration check responses (system bias calibration) and the initial calibration error responses (direct analyzer calibration) as a percentage of span. Drift is defined as the difference between the pre- and post-test run system bias calibration responses.

If an acceptable post-test bias check result was obtained but the zero or upscale drift result exceeded the drift limit, the test run was considered valid; however, the direct analyzer

calibration and system bias check procedures must be repeated before conducting the next test run. A run was considered invalid and must be repeated if the post-test zero or upscale calibration check result exceeded the bias specification. Again, the direct analyzer calibration and system bias check procedures must be repeated before conducting the next test run. Acceptable system performance checks dictate that system bias calibration checks must be ≤ 5.0 % of the calibration span value or within $\pm$ 0.5 ppm. For drift checks, the low-level and upscale drift must be ≤ 3.0 % of the calibration span value or within $\pm$ 0.5 ppm.

Note also that, as an additional QA check, a NO to NO_2 converter efficiency test was performed on the RM NO_x analyzer used during the test program according to the procedures described in §8.2.4 of RM 7E. The converter check was performed while the test trailer was set up between Units 4A and 4B and also when the test trailer was set up between Units 4C and 4D. The results of these converter efficiency tests are provided in Appendix 8 of this report.

5.3 Instrumental Reference Methods – VOCs (RM 25A)

Testing for VOC concentrations was performed using RM 25A. A set of nine (9) 21-minute test runs was performed at high (i.e., normal) load on each unit while combusting natural gas. A set of three 1-hour test runs was performed at low load on each unit while combusting natural gas. The VOC sampling was performed concurrently with the NO_x and CO sampling.

The VOC measurements were extracted through the same heated probe and sample line as that of the NO_x, CO, and O_2 samples. However, once in the test trailer the VOC sample was directed through a different sample line in order to bypass the moisture knockout system used for the other pollutants, since VOC is measured on a hot/wet basis. All raw VOC data was calibrated and quantified as methane (CH_4). When calibrating with methane, it is not necessary to use any carbon correction factors. In addition, all total hydrocarbons (THC) measured were conservatively assumed to be VOC.

Prior to the test series, the heated sample line was heated to ~250 °F and the hydrocarbon analyzer was heated above 300 °F to prevent condensation. After the temperatures had stabilized, the

hydrocarbon analyzer was ignited using a blended hydrogen/helium fuel and hydrocarbon free air. The analyzer(s) was then calibrated.

In accordance with RM 25A, a four-point (i.e., zero-, low-, mid- and high-level) calibration error check (i.e., a system tuning check) was conducted on the VOC analyzer at the beginning of each test day, or when deemed necessary at the tester's discretion. For RM 25A, the low-level calibration gas is required to be 25-35% of span, the mid-level calibration gas is required to be 45-55% of span, and the high-level calibration gas is required to be 80-90% of span. Unlike the direct calibration error check employed by RM 3A, 7E, and 10, RM 25A uses a system tuning check by shooting calibration gas throughout the entire sampling system, rather than immediately from the calibration gas cylinder(s) to the analyzer. This check was conducted by sequentially injecting the zero and span calibration gases throughout the sampling system, recording the responses, and comparing these responses to the actual tag values of the calibration gas cylinders. During the system tuning check, it is permissible to set the analyzer for the zero adjustment using the zero calibration gas (hydrocarbon free air) and the span adjustment using the high-level calibration gas. Based upon the zero- and high-level responses, the predicted response for the low- and mid-level gases were then calculated. Acceptable performance specifications for the system tuning checks dictate that the difference between the analyzer responses (either tuned [high] or predicted [low/mid]) and the respective cylinder tag values will not exceed $\geq$ 5% of the respective calibration gas tag value. For the zero gas, a performance specification of $<$ 3% of span was used, since any % of the tag value for zero gas is 0.00 ppm.

Zero and upscale system calibration checks (i.e., system bias calibrations) were performed both before and after each test run in order to quantify reference measurement calibration drift. In instances when the test runs immediately followed one another, the post-cal for the run immediately preceding a subsequent run was also be the pre-cal for that forthcoming run. Upscale was considered either the low-, mid-, or high-level gas, or whichever gas most closely approximated the flue gas level. During these checks, the calibration gases were introduced into the sampling system at the stack probe outlet so that they were conveyed throughout the entire sampling system in the same manner as the flue gas samples. System drift was then assessed. (Note that RM 25A does not assess system bias, nor does it correct any raw values for system

bias.) Drift is defined as the difference between the pre- and post-test run calibration responses. A run was considered invalid and must be repeated if the post-test zero or upscale calibration check result exceeded a "pre-test versus post-test" drift specification of ≥ 3% of span.

During this test program, in no instance did a system tuning check, system bias calibration, or drift comparison exceed the specifications as prescribed by RM 25A or the submitted test protocol. The actual calibrations can be found in Appendix 3 of this report.

Note that, for this test program, it was not necessary to "subtract out" any non-VOC constituents via Tedlar bag sampling, since the raw THC values measured were well below the permitted limits for all fuel and load conditions.

5.4 Instrumental Reference Method Calibration Gases and Equipment

Since RM 3A, 7E, 10, and 25A are instantaneous, "real time" test methods, NO_x, CO, and VOC compliance was determined at the time of the initial compliance test.

The reference calibration gases used during this test program were certified following EPA Protocol analysis procedures. No calibration gas cylinders were used that contained less than 200 psi of gas, nor were any cylinders expired. Copies of the calibration gas "certificates of analysis" are provided in Appendix 8 of this report. RMB personnel have cross-checked and verified that the certification sheets provided in this test report match those cylinders/respective calibration gas concentrations used in the field during this test program.

Table 5-2 summarizes the analyzer spans and calibration gas values used for the RM measurements during the compliance testing for Units 4A-4D. The spans used were based upon either the permitted emission limits, a suitably accurate operating range for a particular monitor, or on concentrations exhibited by identical sources in prior test programs.

Table 5-2. RM Analyzer Spans and Calibration Gas Values – Gas

Analyzer	Span	Calibration Gas Values (% of span)			
		Zero-Level	Low (<20%)	Mid (40–60%)	High (100%)
NO_x	15.3 ppm	See Low-Level	0.00 ppm (N_2)	8.44 ppm	15.27 ppm
O_2	22.0%	See Low-Level	0.00 % (N_2)	11.97 %	22.0 %
CO	9.30 ppm	See Low-Level	0.00 ppm (N_2)	5.15 ppm	9.30 ppm
		Zero-Level	Low (25–35%)	Mid (45–55%)	High (80–90%)
VOC (CH_4)[1]	10 ppm	0.00 ppm (N_2)	2.99 ppm	4.99 ppm	8.95 ppm

Table 5-3 summarizes the RM analyzer manufacturer, model, and principle of operation for each analyzer used during the test program. All of the RM analyzers used were those that are typical of the RMs used.

Table 5-3. RM Analyzer Descriptions

Method	Analyzer	Manufacturer	Model	Principle of Operation
7E	NO_x	Thermo Environmental	42C	Chemiluminescence
3A	O_2	Servomex	1440	Paramagnetic Cell Detector
10	CO	Thermo Environmental	48C	Gas Filter Correlation
25A	VOC	California Analytical	300-HFID	Flame Ionization

5.5 Instrumental Reference Method Calculations

The RM analyzer measurements were recorded as 1-, 21-, and 60-minute averages on the test team's DAHS, where applicable. All test run concentration results were determined from the average gas concentrations measured during the run. For NO_x, CO, and O_2, the raw data values were adjusted for bias based upon the zero and upscale sampling system bias calibration results (per Equation 6C-1 presented in RM 6C, §8). For VOC, the raw, uncorrected run average values were used to determine compliance.

The NO_x, CO, and VOC ppm values corrected to 15% O_2 were calculated as follows:

$$C_{15} = C * \frac{5.9}{20.9 - \%O_2}$$

Where: C_{15} = Average pollutant concentration corrected to 15% O_2, expressed as ppm dry
C = Average pollutant concentration during respective compliance test run, expressed as ppm dry
O_2 = Average oxygen content during respective compliance test run, expressed as % dry

Note that, based upon the concurrently performed moisture sampling, all VOC ppmw values were converted to ppmd, for the purposes of calculating VOC ppmd corrected to 15% O_2. One moisture run was performed for every three (3) RATA runs at high load and one moisture run was performed for each compliance test run at low load. The ppmw to ppmd conversion was performed as follows:

$$ppmd = \frac{ppmw}{1 - B_{ws}}$$

Where: ppmd = Average VOC concentration converted to ppm dry
ppmw = Average VOC concentration during respective compliance test run, measured as ppm wet
B_{ws} = Moisture content of stack gas, expressed as a decimal (e.g., 12% H_2O = 0.12 B_{ws})

5.6 Visible Emissions Testing (RM 9)

As part of this test program, VE readings were taken by a certified VE reader using RM 9. One thirty (30) minute test run was performed on each unit at both high and low load. VE readings were taken at 15-second intervals, or 120 readings per run. Six-minute block averages were calculated in order to determine compliance with the permit limit, which requires that the stack "opacity" be no more than 10 % per six-minute block. The VE field data and VE reader certification are contained in Appendix 6 of this report.

6.0 OTHER COMPLIANCE REQUIREMENTS

6.1 Compliance Testing for SO_2

In lieu of emissions testing for sulfur dioxide (SO_2), the referenced air permit, in conjunction with the fuel sampling and analysis procedures prescribed by NSPS Subpart KKKK and 40 CFR Part 75, Appendix D, provides alternate means and/or methods for determining compliance with the SO_2 standard.

The fuels to be combusted by the units have sulfur limitations that effectively limit the potential emissions of SO_2 (and sulfuric acid mist, or SAM) from the turbines and represent the BACT determination for these pollutants. Compliance with the fuel specifications (and subsequently and SO_2 limits) will be demonstrated by keeping records of the sulfur contents of the fuels.

As required by Air Permit No. PSD-FL-381, Section III, Specific Condition No. 36.a, compliance with the sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor (Gulfstream) indicating the sulfur content of the natural gas being supplied from the pipeline, for each month of operation. Note that the facility intends to qualify as a PNG user under 40 CFR Part 75, Appendix D, in which the natural gas combusted shall contain no more than 0.5 grains of sulfur per 100 standard cubic feet (hscf) of natural gas, which is less than the permitted limit of 2 grains per hscf. Note also that combusting natural gas fuel with a sulfur content of $\leq$ 20 grains per hscf also serves to demonstrate compliance with the NSPS Subpart KKKK emission limit of 0.060 lb SO_2/mmBtu.

Appendix 4 of this report contains the sulfur analysis results for the natural gas combusted during the compliance test period.

6.2 Turbine Performance Curves

Specific Condition No. 12 of Air Permit No. PSD-FL-381 also requires that "manufacturer performance curves" be submitted within the same time frame after testing as the compliance test report. These performance (i.e., "correction") curves typically depict the relationship between

electrical output, heat input, and ambient temperature, for the purpose of making site-specific corrections for heat input and power output (on an ambient conditions basis). The curves are provided in Appendix 7 of this report.

Note that initially these curves are theoretical in nature only, and can differ based upon any actual, real-world plant data that is accumulated during the forthcoming operating histories of the units.

7.0 HEAT INPUT AND MASS EMISSIONS CALCULATIONS

Natural gas fuel flow is measured using a dedicated orifice-plate type fuel flow meter for each unit. The Bartow facility quantifies fuel flow for natural gas in units of thousand pounds per hour (KPPH). The following equation is used in order to convert KPPH to heat input (mmBtu/hr):

$$HI_g = (Q_g * 21.3) * \frac{GCV}{1{,}000}$$

where: HI_g = heat input while combusting gas (mmBtu/hr)
Q_g = volumetric flow rate of gas combusted (KPPH)
21.3 = factor to convert lb to scf
GCV = Gross Calorific Value (or heating value) of gas combusted (Btu/scf)
1,000 = factor to convert from kscf to mmBtu

For this particular test program, the Btu content of the natural gas combusted varied between 1,031-1,034 Btu/scf. Copies of these fuel analyses are contained in Appendix 4 of this report.

The permitted limits for CO and VOC are not only expressed in a concentration based standard of ppm @ 15% O_2, but also as a mass emission based standard of lb/hr. In the initial protocol submittal, Progress Energy requested that, in lieu of performing Method 2 measurements for velocity and volumetric flow rate, the appropriate fuel flow measurements (and corresponding F-factors) monitored and recorded by the plant be used in conjunction with the measured RM CO and VOC concentrations to determine compliance with the mass emission based standards for CO and VOC. The mass emission rates for CO and VOC would be calculated according to Method 19 as follows:

$$M = HI_g * E$$

Where: M = CO or VOC mass emission based standard (lb/hr)
HI = Gas-fired heat input (mmBtu/hr) [as described above]
E = CO or VOC emissions during respective compliance test run (lb/mmBtu)

$$E = KC_h F_d \frac{20.9}{20.9 - \%O_2}$$

Where: E = CO or VOC emissions during respective compliance test run (lb/mmBtu)
K = Pollutant conversion factor (CO = 7.26 e-08; VOC [as methane] = 4.154 e-08)
C_h = Average dry pollutant concentration during respective compliance test run (ppmd)
F_d = Fuel-factor (8,710 dscf/mmBtu)
O_2 = Oxygen content volume during respective compliance test run ($\%O_{2d}$)

8.0 MISCELLANEOUS COMMENTS

For clarification, this section serves to summarize the aspects of the test program which deviated from what was indicated in the original protocol submittal. These aspects were beyond the control of the test firm or plant operations staff, and are not uncommon for typical stack test programs. Under no circumstances was the accuracy or integrity of the final test results compromised. These deviations are as follows:

1. As of the week in which the compliance testing was performed on the bypass stacks while firing natural gas, fuel oil had yet to be combusted in the units. Fuel oil testing on the bypass stacks will be performed under a separate stack test program mobilization.

2. The plant data acquisition and handling system (DAHS) "locked up" during the high load testing on Unit 4B. As a result, the process data for this portion of the sampling was pulled from the plant's backup DCS system. The backup DCS data is in a different "visual" format; however, the data itself is the same.

3A. For the Unit 4D testing, the turbine tripped during RATA Run #9. As a result, the stratification data was substituted for RATA Run #1, and the eight (8) valid runs were used as RATA Run #s 2-9. As a result, the stratification run and RATA Runs #s 1 and 2 correspond to Compliance Run #1. (The moisture data obtained during RATA Runs #s 1 and 2 was also applied to the stratification run.)

3B. Due to this unit trip, the low load testing on Unit 4D could not be completed during this particular testing mobilization. The Unit 4D low load test (while firing gas) will be performed at the time the units are tested while firing oil.