Permit Application

APPLICATION FOR TITLE V AIR OPERATION PERMIT REVISION

Florida Power & Light Company
Cape Canaveral Energy Center

Prepared For: Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408

Submitted By: Golder Associates Inc.
6026 NW 1st Place
Gainesville, FL 32607 USA

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APPLICATION FOR AIR PERMIT

LONG FORM

Department of Environmental Protection

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OCT 28 2013
DIVISION OF AIR RESOURCE MANAGEMENT

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: **Florida Power & Light Company**	
2. Site Name: **Cape Canaveral Energy Center (CCEC)**	
3. Facility Identification Number: **0090006**	
4. Facility Location... Street Address or Other Locator: **6000 US Highway 1 North** City: **COCOA** County: **BREVARD** Zip Code: **32927**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Mary J. Archer, QEP, Project Manager**
2. Application Contact Mailing Address... Organization/Firm: **Florida Power & Light Company** Street Address: **700 Universe Blvd.** City: **Juno Beach** State: **FL** Zip Code: **33408**
3. Application Contact Telephone Numbers... Telephone: **(561) 691-7057** ext. Fax: **(561) 758-3760**
4. Application Contact E-mail Address: **Mary.Archer@fpl.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 10-28-13	3. PSD Number (if applicable):
2. Project Number(s): 0090006-009-AC 0090006-010-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

Application is for the revision of Title V Permit No. 0090006-006-AV for FPL Cape Canaveral Energy Center to incorporate Air Construction (AC) Permit Nos. 0090006-005-AC and 0090006-007-AC.

AC Permit 0090006-005-AC authorized construction of 1,250-MW Combined Cycle (CC) Unit 3 comprising three nominal 265 MW combustion turbine-electrical generators (EU IDs 009, 010, 011) with natural gas-fired duct burners located in HRSGs and other ancillary equipment.

The auxiliary boiler (012), gas-fired process heaters (013), natural gas compressors (014) and temporary natural gas-fired boiler (017) authorized in AC Permit No. 0090006-005-AC were not installed. Therefore, they may be removed from the revised air operation permit.

AC Permit 0090006-007-AC revised excess emissions provisions for CC Unit 3 and authorized excess emissions of NO_x and CO resulting from startup, shutdown, or malfunction to be excluded from the CEMS data in any 24-hour period.

Note that the fossil fuel steam generator units 1 and 2 (EUs 001 and 002) have been dismantled and can be removed from the revised air operation permit. EU 006 has been removed from the facility and should also be removed from the revised air operation permit.

A compliance plan is attached for the two diesel-fired emergency generators (EU015) and the fire water pump diesel engine (EU016), which are larger in size than originally permitted. The emergency generators are expected to be installed by December 2014.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
009	Unit 3A – one nominal 265-MW Siemens H CTG with supplementary-fired HRSG	AF2A	N/A
010	Unit 3B – one nominal 265-MW Siemens H CTG with supplementary-fired HRSG	AF2A	N/A
011	Unit 3C – one nominal 265-MW Siemens H CTG with supplementary-fired HRSG	AF2A	N/A
015	Two nominal 3,000 kW liquid fueled emergency generators	AF2C	N/A
016	One nominal 315-hp emergency diesel fire pump engine	AF2C	N/A

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:
   Mark Lemasney, Plant General Manager

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 or CAIR source.

3. Application Responsible Official Mailing Address...
   Organization/Firm: Florida Power & Light Company
   Street Address: 6000 US 1 North
   City: Cocoa State: FL Zip Code: 32927

4. Application Responsible Official Telephone Numbers...
   Telephone: (321) 639-5510 ext. Fax: ( )

5. Application Responsible Official E-mail Address: Mark.Lemasney@fpl.com

6. Application Responsible Official Certification:

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

Mark Lemasney 10/22/13

Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **Kennard F. Kosky** Registration Number: **14996**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **6026 NW 1st Place** City: **Gainesville** State: **FL** Zip Code: **32607**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 336-5600** ext. Fax: **(352) 336-6603**
4.	Professional Engineer E-mail Address: **kkosky@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.

KENNARD F. KOSKY No. 14996 PROFESSIONAL ENGINEER

Signature (seal) October 22, 2013
Date

* Attach any exception to certification statement.
**Board of Professional Engineers Certificate of Authorization #00001670.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **522.97** North (km) **3149.11**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **28/28/6.1** Longitude (DD/MM/SS) **80/45/55.3**	
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 : **FPL Cape Canaveral Energy Center consists of one nominal 1,250-MW 3-on-1 combined cycle unit with three combustion turbine (CT)/heat recovery steam generator (HRSG) trains (Units 3A, 3B, and 3C). Ancillary equipment includes two diesel-fired emergency generators (EU015) and one emergency diesel fire pump engine (EU016).**			

Facility Contact

1. Facility Contact Name: **Mark Lemasney**
2. Facility Contact Mailing Address... Organization/Firm: **Florida Power & Light Company** Street Address: **6000 us Highway 1 North** City: **Cocoa** State: **FL** Zip Code: **32927**
3. Facility Contact Telephone Numbers: Telephone: **(321) 639-5510** ext. Fax: ( )
4. Facility Contact E-mail Address: **mark.lemasney@fpl.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. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☐ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☒ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: **Gas Turbines and Duct Burners are subject to NSPS 40 CFR 60 Subpart KKKK.** **Emergency fire pump engine and fire pump engine are subjected to NSPS 40 CFR 60 IIII.**	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
PM	**A**	**N**
PM10	**A**	**N**
VOC	**A**	**N**
SO2	**A**	**N**
NOx	**A**	**N**
CO	**A**	**N**
SAM	**A**	**N**

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

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

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

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID:**CCEC-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) ☒ Attached, Document ID: **See EU sections** ☐ 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) ☒ Attached, Document ID:**CCEC-FI-C3** ☐ Previously Submitted, Date:__________

Additional Requirements for Air Construction Permit Applications

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

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications

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

Additional Requirements for Title V Air Operation Permit Applications

1.	List of Insignificant Activities: (Required for initial/renewal applications only) ☒ Attached, Document ID: CCEC-FI-CV1 ☐ Not Applicable (revision application)
2.	Identification of Applicable Requirements: (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought) ☒ Attached, Document ID: CCEC-FI-CV2 ☐ Not Applicable (revision application with no change in applicable requirements)
3.	Compliance Report and Plan: (Required for all initial/revision/renewal applications) ☒ Attached, Document ID: CCEC-FI-CV3 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: CCEC-FI-CV4 ☐ Equipment/Activities Onsite but Not Required to be Individually Listed ☐ Not Applicable
5.	Verification of Risk Management Plan Submission to EPA: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☒ Not Applicable
6.	Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:__________ ☒ 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)):
   ☒ Attached, Document ID: **CCEC-FI-CA1** ☐ Previously Submitted, Date:__________
   ☐ Not Applicable (not an Acid Rain source)

   Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.):
   ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☒ Not Applicable

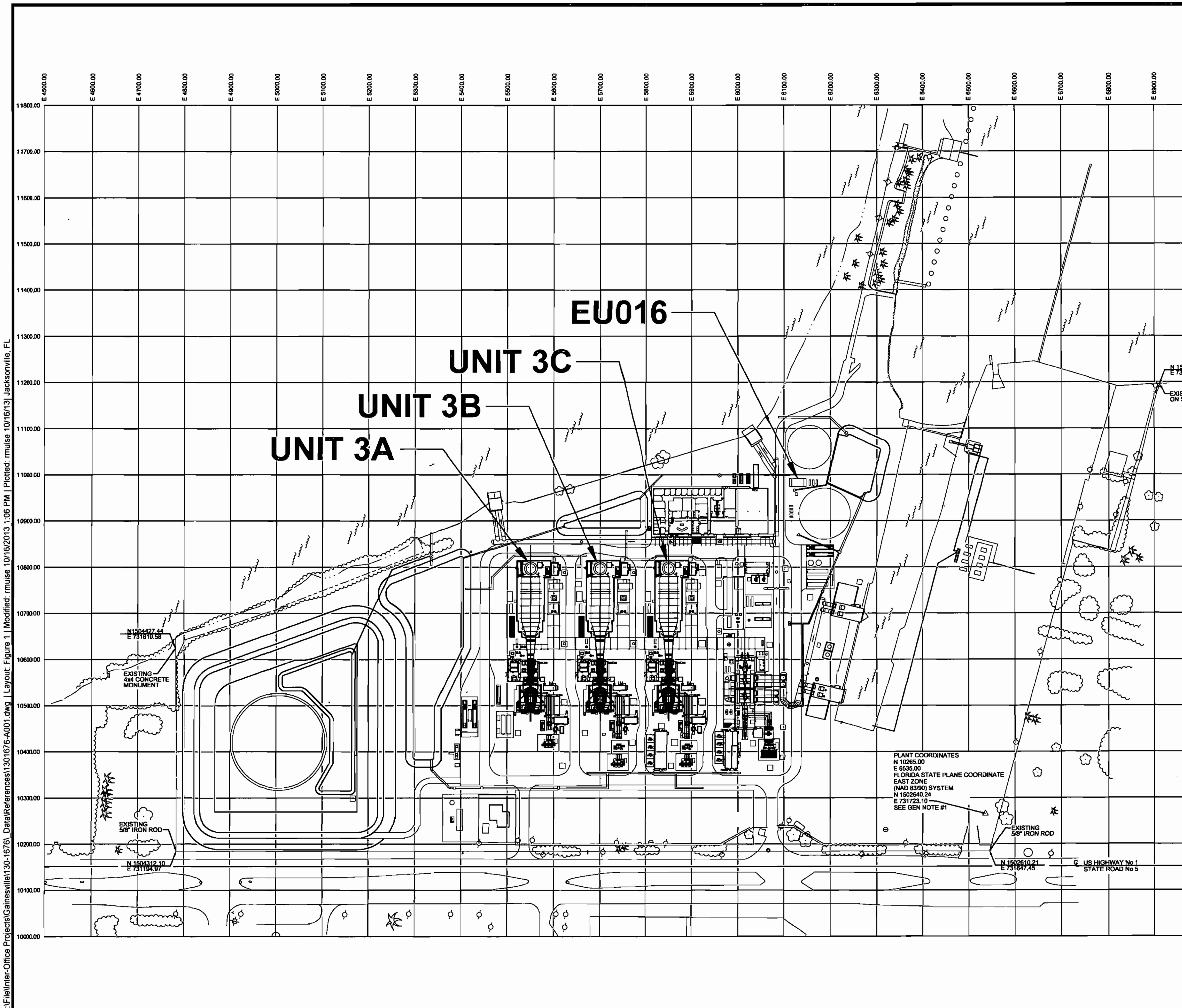
   New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.):
   ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☒ Not Applicable

2. CAIR Part (DEP Form No. 62-210.900(1)(b)):
   ☒ Attached, Document ID: **CCEC-FI-CA2** ☐ Previously Submitted, Date:--__________
   ☐ Not Applicable (not a CAIR source)

Additional Requirements Comment

ATTACHMENT CCEC-FI-C1

FACILITY PLOT PLAN



N:\File\Inter-Office Projects\Gainesville\130-1676_Data\References\1301676-A001.dwg | Layout: Figure 1 | Modified: rmuise 10/16/2013 1:06 PM | Plotted: rmuise 10/16/13 | Jacksonville, FL

REFERENCES

1) BASE MAP TAKEN FROM CADD FILE ORIGINALLY PREPARED BY ZACHRY ENGINEERING CORPORATION TITLED "CAPE CANAVERAL ENERGY CENTER UNIT 3", FILE No. D008710-STWL00002", DATED 11/12/2010.

2,500 0 2,500
SCALE FEET

REV	DATE	DES	REVISION DESCRIPTION	CADD	CHK	RVW

PROJECT
FLORIDA POWER & LIGHT
TITLE V REVISION PERMIT
CAPE CANAVERAL ENERGY CENTER UNIT 3

TITLE
FACILITY PLOT PLAN

Golder Associates

PROJECT No.		130-1676	FILE No.	1301676-A001
DESIGN	RL	10/16/13	SCALE	AS SHOWN
CADD	MRM	10/16/13	FIGURE 1	
CHECK				
REVIEW				

ATTACHMENT CCEC-FI-C3

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

ATTACHMENT CCEC-FI-C3

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include:

- Paving of roads, parking areas, and equipment yards
- Landscaping and planting vegetation
- Use of thick poly flaps over the doorways to prevent any sandblasting material from leaving the sandblast facility. Temporary sandblasting enclosures are constructed and operated when necessary, in order to perform sandblasting on fixed plant equipment
- Maintenance of paved roads as needed
- Regular mowing of grass and care of vegetation
- Limiting access to plant property by unnecessary vehicles
- Bagged chemical products are stored in weather tight buildings until they are used. Spills of any powdered chemical products are cleaned up as soon as practicable
- Vehicles are restricted to slow speeds on the plant site

ATTACHMENT CCEC-FI-CV1A

LIST OF INSIGNIFICANT ACTIVITIES

ATTACHMENT CCEC-FI-CV1A
LIST OF INSIGNIFICANT ACTIVITIES

A list of existing units and/or activities that are considered to be insignificant and are exempted from Title V permitting under Rule 62-213.430(6) is presented below. The exempt activities listed are also those activities that are included in Rule 62-210.300(3)(a) that would not exceed the thresholds in Rule 62-213.430(6)(b)3.

Brief Description of Emissions Units and/or Activities:

- 6,278,925-gallon No. 2 fuel oil storage tank
- 500-gallon No. 2 diesel storage tank for fire pump
- Miscellaneous new and used oil drums in storage building
- Portable diesel generators (wheel mounted)
- Internal combustion engines of vehicles used for transportation of passengers or freight
- Vacuum pumps in laboratory operations
- Equipment used for steam cleaning
- Belt or drum sanders having a total sanding surface of 5 square feet or less
- Laboratory equipment used exclusively for chemical or physical analyses
- Brazing, soldering, or welding equipment
- Fire and safety equipment
- Petroleum lubrication systems
- Degreasing units
- Non-halogenated solvent storage and cleaning operations
- Surface coating operations
- Combustion turbine lube oil vents
- Steam turbine lube oil vents
- Miscellaneous steam and condensate vents
- Two 40,000-gallon aqueous ammonia (19-percent) storage tanks
- Sealed drums and containers
- Natural gas metering station
- Compressed nitrogen bottles
- Compressed air systems
- Storage & use of water treatment chemicals
- Water treatment systems
- Parts washer (aliphatic hydrocarbon solvent)
- Miscellaneous painting activities
- Two 12,000-gallon each oil/water separators
- Water treatment chemicals
- Water treatment sulfuric acid tank
- Water treatment sodium hydroxide tank
- Miscellaneous electrical equipment

- Miscellaneous enclosed oil filled equipment
- Enclosed transformers
- No. 2 fuel oil tank truck unloading area
- Fire pump diesel storage
- Tank truck unloading area
- Storage of bottled gases
- Lube oil storage area (55-gallon lube oil drums)
- Lube oil storage tanks:
  - 9,247-gallon steam turbine lube oil storage tank
  - Three 6,200-gallon each lube oil storage tanks for the CTs
  - Three 93-gallon each boiler feed pump lube oil storage tanks
- Mineral oil storage tanks:
  - Three 793-gallon each CTG static excitation equipment transformers
  - Two 5,298-gallon each Unit Auxiliary Transformers (#1 and #2)
  - Three 11,468-gallon CT generator step-up transformers
  - 16,500-gallon steam turbine generator step-up transformer
  - 1,240-gallon steam turbine excitation transformer
  - Two 339-gallon each common area PDC 480V SUS transformers
  - Four 334-gallon each ST electrical enclosure 480V SUS transformers
  - 232-gallon electrical fire pump 480V SUS transformer
  - Two 334-gallon each MV electrical enclosure 480V SUS transformers
  - Two 339-gallon each MV electrical enclosure 480V SUS transformers
- Four 456-gallon each manatee heating system transformers storing FR3
- Three 100-gallon each hydraulic oil skids for the CTs
- Three 2,693-gallon each No. 2 fuel oil and fuel gas hydrocarbon condensate tanks
- 264-gallon hydraulic oil tank for steam turbine electro-hydraulic control unit skid
- New and used oil drum storage
- Condensate storage tanks:
  - 150-gallon gas inlet metering station pipeline scrubber tank
  - 500-gallon gas inlet metering station pipeline condensate drain tank
  - 250-gallon gas outlet metering station pipeline scrubber tank
  - 317-gallon gas outlet metering station pipeline condensate drain tank
- Various oily wastewater tanks
- Two propane-fired Ford Model 0049884 hurricane emergency generators

ATTACHMENT CCEC-FI-CV1B

TANKS 4.0.9d
EMISSIONS REPORT

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification	
User Identification:	FOA-TK-0004
City:	Cocoa
State:	Florida
Company:	FPL
Type of Tank:	Vertical Fixed Roof Tank
Description:	No.2 fuel oil storage tank
Tank Dimensions	
Shell Height (ft):	44.00
Diameter (ft):	155.80
Liquid Height (ft) :	44.00
Avg. Liquid Height (ft):	44.00
Volume (gallons):	6,274,955.65
Turnovers:	27.00
Net Throughput(gal/yr):	169,423,802.60
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	Gray/Medium
Shell Condition	Good
Roof Color/Shade:	Gray/Medium
Roof Condition:	Good
Roof Characteristics	
Type:	Dome
Height (ft)	0.00
Radius (ft) (Dome Roof)	0.00
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Orlando, Florida (Avg Atmospheric Pressure = 14.75 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

FOA-TK-0004 - Vertical Fixed Roof Tank
Cocoa, Florida

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	82.03	71.24	92.82	75.40	0.0128	0.0094	0.0177	130.0000			188.00	Option 1: VP70 = .009 VP80 = .012

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

FOA-TK-0004 - Vertical Fixed Roof Tank
Cocoa, Florida

Annual Emission Calcaulations	
Standing Losses (lb):	1,610.6794
Vapor Space Volume (cu ft):	203,730.4416
Vapor Density (lb/cu ft):	0.0003
Vapor Space Expansion Factor:	0.0761
Vented Vapor Saturation Factor:	0.9928
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	203,730.4416
Tank Diameter (ft):	155.8000
Vapor Space Outage (ft):	10.6864
Tank Shell Height (ft):	44.0000
Average Liquid Height (ft):	44.0000
Roof Outage (ft):	10.6864
Roof Outage (Dome Roof)	
Roof Outage (ft):	10.6864
Dome Radius (ft):	155.8000
Shell Radius (ft):	77.9000
Vapor Density	
Vapor Density (lb/cu ft):	0.0003
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0128
Daily Avg. Liquid Surface Temp. (deg. R):	541.6978
Daily Average Ambient Temp. (deg. F):	72.3167
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	535.0667
Tank Paint Solar Absorptance (Shell):	0.6800
Tank Paint Solar Absorptance (Roof):	0.6800
Daily Total Solar Insulation Factor (Btu/sqft day):	1,486.6667
Vapor Space Expansion Factor	
Vapor Space Expension Factor:	0.0761
Daily Vapor Temperature Range (deg. R):	43.1501
Daily Vapor Pressure Range (psia):	0.0083
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0128
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0094
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0177
Daily Avg. Liquid Surface Temp. (deg R):	541.6978
Daily Min. Liquid Surface Temp. (deg R):	530.9103
Daily Max. Liquid Surface Temp. (deg R):	552.4854
Daily Ambient Temp. Range (deg. R):	20.6167
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9928
Vapor Pressure at Daily Average Liquid:	

Surface Temperature (psia): 0.0128
Vapor Space Outage (ft): 10.6864

Working Losses (lb): 6,718.2495
Vapor Molecular Weight (lb/lb-mole): 130.0000
Vapor Pressure at Daily Average Liquid
Surface Temperature (psia): 0.0128
Annual Net Throughput (gal/yr.): 169,423,802.6048
Annual Turnovers: 27.0000
Turnover Factor: 1.0000
Maximum Liquid Volume (gal): 6,274,955.6520
Maximum Liquid Height (ft): 44.0000
Tank Diameter (ft): 155.8000
Working Loss Product Factor: 1.0000

Total Losses (lb): 8,328.9289

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

FOA-TK-0004 - Vertical Fixed Roof Tank
Cocoa, Florida

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	6,718.25	1,610.68	8,328.93

ATTACHMENT CCEC-FI-CV2

IDENTIFICATION OF APPLICABLE REQUIREMENTS

ATTACHMENT CCEC-FI-CV2
IDENTIFICATION OF APPLICABLE REQUIREMENTS
TITLE V CORE LIST

Effective: 03/01/02

(Updated based on current version of FDEP Air Rules)

[Note: The Title V Core List is meant to simplify the completion of the "List of Applicable Regulations" for DEP Form No. 62-210.900(1), Application for Air Permit - Long Form. The Title V Core List is a list of rules to which all Title V Sources are presumptively subject. The Title V Core List may be referenced in its entirety, or with specific exceptions. The Department may periodically update the Title V Core List.]

Federal: ***(description)***

Acid Rain, Phase I and II
Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR)
40 CFR 60, Subpart KKKK: NSPS for Stationary Combustion Turbines that Commence Construction after February 18, 2005.
40 CFR 60, Subpart IIII: NSPS for Stationary Compression Ignition Internal Combustion Engines.
40 CFR 63, Subpart ZZZZ: National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)
40 CFR 98, Subpart C: General Stationary Fuel Combustion Sources

State: ***(description)***

CHAPTER 62-4, F.A.C.: PERMITS, effective 02-16-12

62-4.030, F.A.C.: General Prohibition.
62-4.040, F.A.C.: Exemptions.
62-4.050, F.A.C.: Procedure to Obtain Permits; Application.
62-4.060, F.A.C.: Consultation.
62-4.070, F.A.C.: Standards for Issuing or Denying Permits; Issuance; Denial.
62-4.080, F.A.C.: Modification of Permit Conditions.
62-4.090, F.A.C.: Renewals.
62-4.100, F.A.C.: Suspension and Revocation.
62-4.110, F.A.C.: Financial Responsibility.
62-4.120, F.A.C.: Transfer of Permits.
62-4.130, F.A.C.: Transferability of Definitions.
62-4.150, F.A.C.: Review.
62-4.160, F.A.C.: Permit Conditions.
62-4.210, F.A.C.: Construction Permits.
62-4.220, F.A.C.: Operation Permit for New Sources.

CHAPTER 62-210, F.A.C.: STATIONARY SOURCES - GENERAL REQUIREMENTS, effective 03-28-12

62-210.300, F.A.C.: Permits Required.
62-210.300(1), F.A.C.: Air Construction Permits.
62-210.300(2), F.A.C.: Air Operation Permits.
62-210.300(3), F.A.C.: Exemptions.
62-210.300(5), F.A.C.: Notification of Startup.
62-210.300(6), F.A.C.: Emissions Unit Reclassification.
62-210.300(7), F.A.C.: Transfer of Air Permits.
62-210.350, F.A.C.: Public Notice and Comment.
62-210.350(1), F.A.C.: Public Notice of Proposed Agency Action.

62-210.350(2), F.A.C.: Additional Public Notice Requirements for Emissions Units Subject to Prevention of Significant Deterioration or Nonattainment-Area Preconstruction Review.
62-210.350(3), F.A.C.: Additional Public Notice Requirements for Sources Subject to Operation Permits for Title V Sources.

62-210.360, F.A.C.: Administrative Permit Corrections.
62-210.370, F.A.C.: Emissions Computation and Reporting.
62-210.400, F.A.C.: Emission Estimates.
62-210.650, F.A.C.: Circumvention.
62-210.700, F.A.C.: Excess Emissions.

62-210.900, F.A.C.: Forms and Instructions.
62-210.900(1), F.A.C.: Application for Air Permit – Title V Source, Form and Instructions.
62-210.900(5), F.A.C.: Annual Operating Report for Air Pollutant Emitting Facility, Form and Instructions.
62-210.900(7), F.A.C.: Application for Transfer of Air Permit – Title V and Non-Title V Source.

CHAPTER 62-212, F.A.C.: STATIONARY SOURCES - PRECONSTRUCTION REVIEW, effective 03-28-12

CHAPTER 62-213, F.A.C.: OPERATION PERMITS FOR MAJOR SOURCES OF AIR POLLUTION, effective 02-16-12

62-213.205, F.A.C.: Annual Emissions Fee.
62-213.400, F.A.C.: Permits and Permit Revisions Required.
62-213.410, F.A.C.: Changes Without Permit Revision.
62-213.412, F.A.C.: Immediate Implementation Pending Revision Process.
62-213.415, F.A.C.: Trading of Emissions Within a Source.
62-213.420, F.A.C.: Permit Applications.
62-213.430, F.A.C.: Permit Issuance, Renewal, and Revision.
62-213.440, F.A.C.: Permit Content.
62-213.450, F.A.C.: Permit Review by EPA and Affected States
62-213.460, F.A.C.: Permit Shield.

62-213.900, F.A.C.: Forms and Instructions.
62-213.900(1), F.A.C.: Major Air Pollution Source Annual Emissions Fee Form.
62-213.900(7), F.A.C.: Statement of Compliance Form.

CHAPTER 62-296, F.A.C.: STATIONARY SOURCES - EMISSION STANDARDS, effective 02-16-12

62-296.320(4)(c), F.A.C.: Unconfined Emissions of Particulate Matter.

62-296.320(2), F.A.C.: Objectionable Odor Prohibited.

CHAPTER 62-297, F.A.C.: STATIONARY SOURCES - EMISSIONS MONITORING, effective 02-16-12

62-297.310, F.A.C.: General Test Requirements.
62-297.310(4), F.A.C.: Applicable Test Procedures.
62-297.310(7), F.A.C.: Frequency of Compliance Tests.
62-297.310(6), F.A.C.: Repaired Stack Sampling Facilities.
62-297.310(5), F.A.C.: Determination of Process Variables.
62-297.510(8), F.A.C.: Test Report.
62-297.620, F.A.C.: Exceptions and Approval of Alternate Procedures and Requirements.

Miscellaneous:

CHAPTER 28-106, F.A.C.: Decisions Determining Substantial Interests effective 02-05-13
CHAPTER 62-110, F.A.C.: Exception to the Uniform Rules of Procedure, effective 07-01-98
CHAPTER 62-256, F.A.C.: Open Burning and Frost Protection Fires, effective 10-06-08
CHAPTER 62-257, F.A.C.: Asbestos Notification and Fee, effective 02-16-12
CHAPTER 62-281, F.A.C.: Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling, effective 02-16-12

ATTACHMENT CCEC-FI-CV3A

COMPLIANCE REPORT

ATTACHMENT CCEC-FI-CV3A
COMPLIANCE REPORT

Florida Power and Light Company certifies that the Cape Canaveral Energy Center in Cocoa, Florida, as of the date of this application, is in compliance with each applicable requirement addressed in this Title V air operation permit application.

I, the undersigned, am the responsible official as designed in Chapter 62-213, F.A.C., of the Title V source for which this report is being submitted. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made and data contained in this report are true, accurate, and complete.

Compliance statements for this facility will be submitted on an annual basis to FDEP, within 60 days after the end of each calendar year.

Mark Lemasney 10/22/13

Signature, Responsible Official Date

ATTACHMENT CCEC-FI-CV3B

COMPLIANCE PLAN FOR
CAPE CANAVERAL ENERGY CENTER

ATTACHMENT CCEC-FI-CV3B
COMPLIANCE PLAN FOR CAPE CANAVERAL ENERGY CENTER

A. EU015 Emergency Generators

Deviation

Air Construction Permit No. 0090006-005-AC authorized construction for two nominal 2,250 kilowatts (kW) diesel-fired emergency generators, which are subject to 40 CFR 60 Subpart IIII, NSPS for Stationary Compression Ignition Internal Combustion Engines (Stationary ICE). While the purchasing agreement for these generators has been completed, they have not been acquired yet and installation is not expected to occur until the second half of 2014. The purchased Caterpillar C175 rated at 3,000 kW are also slightly larger than the permitted units.

Compliance Plan

FPL expects the emergency generators to be delivered in the second half on 2014. With installation and readiness testing, the units are expected to be ready for service by December 31st, 2014. FPL will notify FDEP as soon as the installation and readiness testing is complete. Please note that based on Permit No. 0090006-005-AC, the units are subject to NSPS 40 CFR 60, Subpart IIII and manufacturer certification can be provided to the Department in lieu of actual stack testing for the applicable emissions limits. The units are also subject to 40 CFR 60 Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (RICE) and will comply with the Subpart ZZZZ requirements by complying with the Subpart IIII requirements.

An initial visible emission (VE) testing using EPA Method 9 will be conducted within 60 days after achieving the maximum operating rate of the unit, but not later than 180 days after the initial startup. A report indicating the results of the results of the initial VE testing will be submitted to the Compliance Authority no later than 45 days after completion of the test.

Detailed emissions calculation for the units is presented in Attachment CCEC-EU2-F1.10.

B. EU016 Fire Pump Engine

Deviation

Air Construction Permit No. 0090006-005-AC authorized construction one nominal less than or equal to 300 horsepower (hp) emergency diesel fire pump engine, which is subject to 40 CFR 60 Subpart IIII, NSPS for Stationary Compression Ignition Internal Combustion Engines (Stationary ICE). The installed John Deere JU6H-UFAD98 fire pump engine rated at 315 hp is also slightly larger than the permitted unit.

Compliance Plan

FPL submitted manufacturer information and emissions certification to FDEP Central District Office in letter to Ms. Caroline Shine dated July 10, 2012 (please see attached letter). As shown, the certified emissions rates comply with the emissions limits applicable to the engine in Permit No. 0090006-005-AC. Detailed emissions calculation for the unit is presented in Attachment CCEC-EU3-F1.10.

C. EU009, -010 and -011 Units 3A, 3B and 3C

Deviation

Commissioning for ultra-low sulfur distillate (ULSD) oil was initiated in August 2013 but not been completed. An initial compliance demonstration for ULSD oil firing on each CT unit will be required pursuant to Condition A.19 of Permit No. 0090006-005-AC.

Compliance Plan

The compliance demonstration for ULSD oil firing will be completed within 60 days of any unit achieving maximum production rate and no later than 180 days after initial startup on ULSD oil. Compliance demonstration is expected to be completed prior to mid-2014 for all three units.

ATTACHMENT CCEC-FI-CV4

EQUIPMENT/ACTIVITIES REGULATED UNDER TITLE VI

ATTACHMENT CCEC-FI-CV4
EQUIPMENT/ACTIVITIES REGULATED UNDER TITLE VI

The facility currently has no equipment with CFCs greater than 50 pounds.

ATTACHMENT CCEC-FI-CA1

ACID RAIN PART APPLICATION

FPL

April 11, 2011

Ms. Trina Vielhauer, Bureau Chief
Division of Air Resource Management
2600 Blair Stone Road, MS 5500
Tallahassee, Florida 32399-2400

RE: Florida Power & Light
Cape Canaveral Energy Center
Acid Rain Part Application
EPA ORIS Code #000609

Dear Ms. Vielhauer:

Per the requirements of 40 CFR 72.30, 72.31 and 74; and Rule 62-214.320, F.A.C., please find the attached Acid Rain Part Application for Florida Power & Light' s Cape Canaveral Energy Center (CCEC) Unit 3 in Brevard County, Florida. The FPL CCEC is currently expected to commence commercial operation mid-2013.

If you have any questions or need additional information, please contact Jacquelyn Kingston at 561-691-7063 or Elisa Ostertag at 561-691-2341.

Sincerely,
Florida Power & Light Company

Jacquelyn Kingston for

Barbara P Linkiewicz
Director of Environmental Licensing

cc: Caroline Shine, DEP Central District
Michael Halpin, DEP Siting Office
Laurel Desantis, EPA CAMD

Acid Rain Part Application

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

This submission is: ■ New ☐ Revised ☐ Renewal

STEP 1

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

Plant name Cape Canaveral Energy Center	State Florida	0609 ORIS/Plant Code

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

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

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

a	b	c	d	e
Unit ID#	SO_2 Opt-in Unit? (Yes or No)	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	New or SO_2 Opt-in Units Commence Operation Date	New or SO_2 Opt-in Units Monitor Certification Deadline
CCCT3A	NO	Yes	6/1/2013	8/30/2013
CCCT3B	NO	Yes	6/1/2013	8/30/2013
CCCT3C	NO	Yes	6/1/2013	8/30/2013

Plant Name (from STEP 1) Cape Canaveral Energy Center

STEP 3

Read the standard requirements.

Acid Rain Part Requirements.

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

Monitoring Requirements.

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

Sulfur Dioxide Requirements.

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

Nitrogen Oxides Requirements.

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

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

Plant Name (from STEP 1) Cape Canaveral Energy Center

STEP 3, Continued.

Recordkeeping and Reporting Requirements (cont)

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

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

Liability.

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

Effect on Other Authorities.

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

STEP 4
For SO_2 Opt-in units only.

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

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

In column "h" enter the hours.

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

Plant Name (from STEP 1) Cape Canaveral Energy Center

STEP 5

For SO_2 Opt-in units only.

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

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

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

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

STEP 6

For SO_2 Opt-in units only.

Attach additional requirements, certify and sign.

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

Signature	Date

STEP 7

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

Certification (for designated representative or alternate designated representative only)

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

Name Sheila M Wilkinson	Title PGD Technical Services General Manager
Owner Company Name Florida Power & Light	
Phone 561-691-2287	E-mail address Sheila.M.Wilkinson@fpl.com
Signature SmWilkinson	Date 4/11/11

ATTACHMENT CCEC-FI-CA2

CAIR PART

Clean Air Interstate Rule (CAIR) Part

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

This submission is: **New** Revised Renewal

STEP 1

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

Plant Name: Cape Canaveral Energy Center	State: Florida	ORIS or EIA Plant Code: 000609

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
CCCT3A	X	X	X	6/1/2013	8/30/2013
CCCT3B	X	X	X	6/1/2013	8/30/2013
CCCT3C	X	X	X	6/1/2013	8/30/2013

Plant Name (from STEP 1)	Cape Canaveral Energy Center

STEP 3

Read the standard requirements.

CAIR NO_X ANNUAL TRADING PROGRAM

CAIR Part Requirements.

(1) The CAIR designated representative of each CAIR NO_X source and each CAIR NO_X unit at the source shall:
 (i) Submit to the DEP a complete and certified CAIR Part form under 40 CFR 96.122 and Rule 62-296.470, F.A.C., in accordance with the deadlines specified in Rule 62-213.420, F.A.C.; and
 (ii) [Reserved];

(2) The owners and operators of each CAIR NO_X source and each CAIR NO_X unit at the source shall have a CAIR Part included in the Title V operating permit issued by the DEP under 40 CFR Part 96, Subpart CC, and operate the source and the unit in compliance with such CAIR Part.

Monitoring, Reporting, and Recordkeeping Requirements.

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

NO_X Emission Requirements.

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

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

Plant Name (from STEP 1) Cape Canaveral Energy Center

STEP 3, Continued

Liability.

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

Effect on Other Authorities.

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

CAIR SO_2 TRADING PROGRAM

CAIR Part Requirements.

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

Monitoring. Reporting, and Recordkeeping Requirements.

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

SO_2 Emission Requirements.

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

Excess Emissions Requirements.

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

Plant Name (from STEP 1) Cape Canaveral Energy Center

STEP 3, Continued

Recordkeeping and Reporting Requirements.

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

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

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

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

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

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

Liability.

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

Effect on Other Authorities.

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

CAIR NO_x OZONE SEASON TRADING PROGRAM

CAIR Part Requirements.

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

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

(ii) [Reserved];

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

Monitoring, Reporting, and Recordkeeping Requirements.

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

NO_x Ozone Season Emission Requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, CAIR NO_X Ozone Season allowances available for compliance deductions for the control period under 40 CFR 96.354(a) in an amount not less than the tons of total NO_X emissions for the control period from all CAIR NO_X Ozone Season units at the source, as determined in accordance with 40 CFR Part 96, Subpart HHHH.
(2) A CAIR NO_X Ozone Season unit shall be subject to the requirements under paragraph (1) of the NO, Ozone Season Emission Requirements starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 96.370(b)(1),(2), or (3) and for each control period thereafter.
(3) A CAIR NO_X Ozone Season allowance shall not be deducted, for compliance with the requirements under paragraph (1) of the NO_X Ozone Season Emission Requirements, for a control period in a calendar year before the year for which the CAIR NO_X Ozone Season allowance was allocated.
(4) CAIR NO_X Ozone Season allowances shall be held in, deducted from, or transferred into or among CAIR NO_X Ozone Season Allowance Tracking System accounts in accordance with 40 CFR Part 96, Subparts FFFF and GGGG.
(5) A CAIR NO_X Ozone Season allowance is a limited authorization to emit one ton of NO_X in accordance with the CAIR NO_X Ozone Season Trading Program. No provision of the CAIR NO_X Ozone Season Trading Program, the CAIR Part, or an exemption under 40 CFR 96.305 and no provision of law shall be construed to limit the authority of the state or the United States to terminate or limit such authorization.
(6) A CAIR NO_X Ozone Season allowance does not constitute a property right.
(7) Upon recordation by the Administrator under 40 CFR Part 96, Subpart EEEE, FFFF or GGGG, every allocation, transfer, or deduction of a

CAIR NO_X Ozone Season allowance to or from a CAIR NO_X Ozone Season unit's compliance account is incorporated automatically in any CAIR Part of the source that includes the CAIR NO_X Ozone Season unit..

Plant Name (from STEP 1) Cape Canaveral Energy Center

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: Christian Kiernan	Title PGD Technical Services General Manager (DR)
Company Owner Name: Florida Power & Light	
Phone 561-691-2781	E-mail Address: Christian.Kiernan@fpl.com
Signature Chr Kr	Date 10/2/2012

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.)

   ☒ 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).

   ☒ 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:
   Three nominal 265 MW Siemens H combustion turbine-electrical generators (CTG) with supplementary fired heat recovery steam generators (HRSGs). Units designated as 3A, 3B, and 3C.

3. Emissions Unit Identification Number: **009, 010, and 011**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A	**2011**	**2013**	**49**

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

   ☒ Acid Rain Unit

   ☒ CAIR Unit

9. Package Unit:
   Manufacturer: **Mitsubishi Power Systems (MPS) or Siemens** Model Number: **MPS Frame G, Siemens H**

10. Generator Nameplate Rating: **795** MW (for three)

11. Emissions Unit Comment:
    Nominal 1,250-MW 3-on-1 Combined Cycle Unit 3 consists of three nominal 265-MW CTGs and one nominal 500-MW steam turbine generator (STG). Each CTG consists of automated control, inlet air filtration and evaporative cooling system with a nominal 460 MMBtu/hr (LHV) duct burner. within each of the three HSRGs.

Emissions Unit Control Equipment/Method: Control 1 of 3

1. Control Equipment/Method Description: **SCR for NOx control**	
2. Control Device or Method Code: **139**	

Emissions Unit Control Equipment/Method: Control 2 of 3

1. Control Equipment/Method Description: **Water Injection for NOx control**	
2. Control Device or Method Code: **028**	

Emissions Unit Control Equipment/Method: Control 3 of 3

1. Control Equipment/Method Description: **Low NOx burners for NOx control**	
2. Control Device or Method Code: **205**	

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: **7,758** million Btu/hr (MMBtu/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 rate for each CTG (at 100% load, 59°F ambient temperature)** **Natural gas-firing --- 2,586 MMBtu/hr (LHV)** **Distillate oil-firing --- 2,440 MMBtu/hr (LHV)** **Maximum heat input rate for 3 CTGs = 2,586 x 3 = 7,758 MMBtu/hr** **Maximum heat input rate for each DB=460 MMBtu/hr (LHV)** **Maximum annual heat input for all three DBs limited to 3,697,920 MMBtu/yr, combined.** **Fuel oil-firing limited to 3,000 hr/yr for all 3 CTGs combined.**	

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: **Units 3A, 3B, and 3C**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Each CTG exhaust is emitted through a separate HRSG stack**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **149** feet	7. Exit Diameter: **22** feet
8. Exit Temperature: **185**°F	9. Actual Volumetric Flow Rate: **1,346,000** 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:
Exit temperature and flow rate are for each CT/HRSG and based on natural gas firing at 100-percent load at 59°F ambient temperature (Permit application dated December 2008). Stack flow rate of 955,283 scfm was recorded during stack testing of Unit 3A dated April 16, 2013.

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Internal Combustion Engines: Electric Generation; Natural Gas; Turbine Generator**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million cubic feet**	
4. Maximum Hourly Rate: **8.32**	5. Maximum Annual Rate: **72,883.2**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **933**
10. Segment Comment: **Maximum hourly rate=2,586 MMBtu/hr ÷ 933 MMBtu/ft^3 x 3 CTGs= 8.32 MMft^3/hr** **Maximum annual fuel rate= 8.32 MMft^3/hr x 8,760 hr/yr= 72,883.2 MMBtu/yr** **Fuel heat content based on LHV.** **Maximum hourly and annual rates do not consider maximum annual heat input of 3,697,920 MMBtu/yr for three DBs combined.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Internal Combustion Engines: Electric Generation; Distillate Oil (No. 2); Turbine Generator**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **1,000 Gallons**	
4. Maximum Hourly Rate: **55.9**	5. Maximum Annual Rate: **55,900**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.0015**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **131**
10. Segment Comment: **Maximum hourly rate=2,440 MMBtu/hr ÷ 131 kGal/ft^3 x 3 CTGs = 55.9 kGal/hr** **Maximum annual fuel rate= 55.9 kGal/hr x 1,000 hr/yr= 55,900 kGal/yr** **Fuel heat content based on LHV.**		

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	205, 028, 139		EL
CO			EL
VOC			EL
SAM			EL
Ammonia			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: **90.0** lb/hour **185.5** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2 gr S/100 SCF of gas** **0.0015-percent sulfur fuel oil** Reference: **Permit No. 009006-005-AC**	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: **Potential hourly emissions based on distillate oil firing at 59°F inlet condition.** **Potential hourly emissions for one CT/HRSG at base load = 30 lb/hr.** **Potential hourly emissions of three CT/HRSGs = 30 lb/hr x 3 = 90 lb/hr.** **Potential annual emissions for 3 CTGs = 185.5 TPY based on Table 2-3B of PSD permit application dated December, 2008.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Potential emissions vary with turbine inlet conditions.**	

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 gr S/100 SCF of gas**	4. Equivalent Allowable Emissions: **49.2** lb/hour tons/year
5. Method of Compliance: **Fuel Analysis Records**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT for natural gas firing: Fuel sulfur content limited to 2 grains per 100 scf. Equivalent hourly emissions based on 59°F inlet condition. Hourly emissions of one CT/HRSG with DB = 16.4 lb/hr. Hourly emissions of three CT/HRSGs with DB = 16.4 x 3 = 49.2 lb/hr.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.0015-percent sulfur fuel oil**	4. Equivalent Allowable Emissions: **90** lb/hour tons/year
5. Method of Compliance: **Fuel Analysis Records**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT for fuel oil firing: Fuel sulfur content limited to 0.0015 percent, by weight. Equivalent hourly emissions based on 59°F inlet condition. Hourly emissions of one CT/HRSG = 30 lb/hr Hourly emissions of three CT/HRSG = 30 x 3 = 90 lb/hr**	

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: **51.3** lb/hour **201.9** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2 gr S/100 SCF of gas** **0.0015-percent sulfur fuel oil** Reference: **Permit No. 009006-005-AC**	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:

Potential hourly emissions based on natural gas firing with DB at 59°F inlet conditions:
Potential hourly emissions of one CT/HRSG with DB = 17.1 lb/hr.
Potential hourly emissions of three CT/HRSGs = 17.1 lb/hr x 3 = 51.3 lb/hr.
Potential annual Emissions of one CT/HRSG = 67.1 TPY (Table 2-3 of PSD permit application dated December 2008).
Annual Emissions for three CT/HRSGs = 67.1 x 3 = 201.9 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential mass emissions vary with turbine inlet conditions.
Duct-firing limited to 3,697,920 MMBtu for three CT/HRSGs (equivalent to 2,679 hr/yr per CT/HRSG).
Distillate oil firing limited to 3,000 hr/yr aggregated over 3 CTGs (equivalent to 1,000 hr/yr/CTG.

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 gr S/100 SCF of gas**	4. Equivalent Allowable Emissions: **51.3** lb/hour tons/year
5. Method of Compliance: **Fuel Analysis Records**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT for natural gas firing: Fuel sulfur content limited to 2 grains per 100 scf. Equivalent hourly emissions based on 59°F inlet condition. Hourly emissions of one CT/HRSG = 17.1 lb/hr. Hourly emissions of three CT/HRSGs = 17.1 lb/hr x 3 = 51.3 lb/hr.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.0015-percent sulfur fuel oil**	4. Equivalent Allowable Emissions: **11.1** lb/hour tons/year
5. Method of Compliance: **Fuel Analysis Records**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT for fuel oil firing: Fuel sulfur content limited to 0.0015 percent. Equivalent hourly emissions based on 59°F inlet condition. Hourly emissions of one CT/HRSG = 3.7 lb/hr. Hourly emissions of three CT/HRSGs = 3.7 lb/hr x 3 = 11.1 lb/hr.**	

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: **240.0** lb/hour **357.6** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2.0 ppmvd at 15% O_2 firing natural gas** **8.0 ppmvd at 15% O_2 firing fuel oil** Reference: **Permit No. 009006-005-AC**	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:
Potential hourly emissions based on Fuel Oil firing at 59°F inlet conditions:
Potential hourly emissions of one CT/HRSG = 80.0 lb/hr.
Potential hourly emissions of three CT/HRSG = 80.0 x 3 = 240.0 lb/hr.
Potential annual Emissions for one CTG= 119.2 TPY (Table 2-3B of PSD permit application dated December 2008).
Potential annual emissions of 3 CTGs = 119.2 TPY x 3 = 357.6 TPY

11. Potential, Fugitive, and Actual Emissions Comment:
Potential mass emissions vary with turbine inlet conditions.
Distillate oil firing limited to 3,000 hr/yr aggregated over three CTG (equivalent to 1,000 hr/yr per CT/HRSG).
Duct-firing limited to 3,697,920 MMBtu for three CT/HRSGs (equivalent to 2,679 hr/yr per CT/HRSG, Maximum heat input 460 MMBtu/hr).

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 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2.0 ppmvd@15% O_2 and 19.3 lb/hr**	4. Equivalent Allowable Emissions: **57.9** lb/hour **253.6** tons/year
5. Method of Compliance: **CEMS 30-day rolling average, initial stack test using EPA Methods 7E or 20.**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT for natural gas firing CT only. Equivalent hourly emissions based on 59°F inlet condition. Equivalent hourly emissions of one CT = 19.3 lb/hr Equivalent hourly emissions of three CTs = 19.3 x 3 = 57.9 lb/hr Equivalent Annual Emissions= 57.9 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 253.6 TPY**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2.0 ppmvd@15% O_2 and 22.8 lb/hr**	4. Equivalent Allowable Emissions: **68.4** lb/hour **91.6** tons/year
5. Method of Compliance: **CEMS 30-day rolling average, initial stack test using EPA Methods 7E or 20.**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT for natural gas firing with duct burners. Equivalent hourly emissions based on 59°F inlet condition. Equivalent hourly emissions of one CT = 22.8 lb/hr Equivalent hourly emissions of three CTs = 22.8 x 3 = 68.4 lb/hr Equivalent Annual Emissions= 68.4 lb/hr x 2,679 hr/yr x 1 ton/2,000 lb = 91.6 TPY**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **8.0 ppmvd@15% O_2**	4. Equivalent Allowable Emissions: **240** lb/hour **120** tons/year
5. Method of Compliance: **CEMS 30-day rolling average, initial stack test using EPA Methods 7E or 20.**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT for fuel oil firing. Equivalent hourly emissions based on 59°F inlet condition. Equivalent hourly emissions of one CT = 80.0 lb/hr Equivalent hourly emissions of three CTs = 80.0 x 3 = 240.0 lb/hr Equivalent Annual Emissions= 240.0 lb/hr x 1,000 hr/yr x 1 ton/2,000 lb = 120 TPY**	

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: **183.0** lb/hour **511.2** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **7.6 ppmvd @ 15% O_2 (NG-firing with DB)** **5.0 ppmvd @ 15% O_2 (NG-firing without DB)** **10.0 ppmvd @ 15% O_2 (Fuel Oil)** Reference: **Permit No. 009006-005-AC**	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:

Potential hourly emissions based on Fuel Oil firing with DB at 59°F inlet conditions.
Potential hourly emissions of one CT/HRSG = 61.0 lb/hr.
Potential hourly emissions of three CT/HRSG = 61.0 x 3 = 183.0 lb/hr.

Potential annual emissions for one CT/HRSG = 170.4 TPY (Table 2-3B of PSD permit application dated December 2008)
Potential annual emissions for three CT/HRSGs = 170.4 x 3 = 511.2 TPY.

11. Potential, Fugitive, and Actual Emissions Comment:

Potential mass emissions vary with turbine inlet conditions.
Distillate oil firing limited to 3,000 hr/yr aggregated over three CTG (equivalent to 1,000 hr/yr per CT/HRSG).
Duct-firing limited to 3,697,920 MMBtu for three CT/HRSGs (equivalent to 2,679 hr/yr per CT/HRSG, Maximum heat input 460 MMBtu/hr).

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 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **5.0 ppmvd @15% O_2 and 29.0 lb/hr**	4. Equivalent Allowable Emissions: **87.0** lb/hour **381.1** tons/year
5. Method of Compliance: **Initial stack test (EPA Method 10)**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT for natural gas firing CT only. Annual stack test limit applies only at 90-100 percent load.** **Equivalent hourly emissions based on 59°F inlet condition.** **Equivalent hourly emissions of one CT = 29.0 lb/hr** **Equivalent hourly emissions of three CTs = 29.0 x 3 = 87.0 lb/hr** **Equivalent Annual Emissions= 87.0 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 381.1 TPY**	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **7.6 ppmvd @15% O_2 and 52.7 lb/hr**	4. Equivalent Allowable Emissions: **158.1** lb/hour **211.8** tons/year
5. Method of Compliance: **Initial stack test (EPA Method 10)**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT for natural gas firing with duct burners. Duct firing limited to 2,679 hr/yr per CT/HRSG.** **Equivalent hourly emissions based on 59°F inlet condition.** **Equivalent hourly emissions of one CT = 52.7 lb/hr** **Equivalent hourly emissions of three CTs = 52.7 x 3 = 158.1 lb/hr** **Equivalent Annual Emissions= 158.1 lb/hr x 2,679 hr/yr x 1 ton/2,000 lb = 211.8 TPY**	

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10.0 ppmvd @15% O_2 and 61.0 lb/hr**	4. Equivalent Allowable Emissions: **183** lb/hour **91.5** tons/year
5. Method of Compliance: **CEMs 30-day rolling average; Initial stack test using EPA Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT for Fuel oil firing. Oil firing limited to 1,000 hr/yr per CT/HRSG.** **Equivalent hourly emissions based on 59°F inlet condition.** **Hourly emissions for one CT/HRSG = 61 lb/hr.** **Equivalent hourly emissions for three CT/HRSG = 61 lb/hr x 3 = 183 lb/hr.** **Equivalent Annual Emissions= 183 lb/hr x 1,000 hr/yr x 1 ton/2,000 lb = 91.5 TPY**	

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 4 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **8 ppmvd @ 15-percent O_2**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: **CEMS 30-day rolling average**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT for natural gas firing**	

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: **56.7** lb/hour **77.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **1.9 ppmvd @ 15% O_2 (NG-firing with DB)** **1.5 ppmvd @ 15% O_2 (NG-firing without DB)** **6.0 ppmvd @ 15% O_2 (Fuel Oil)** Reference: **Permit No. 009006-005-AC**	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:

Potential hourly emissions based on fuel oil firing at 59°F inlet condition.
Potential hourly emissions of one CT/HRSG = 18.9 lb/hr.
Potential hourly emissions of three CT/HRSG = 18.9 lb/hr x 3 = 56.7 lb/hr.

Potential annual emissions for one CT/HRSG = 25.7 TPY (Table 2-3B of PSD permit application dated December 2008)
Potential annual emissions for three CT/HRSGs = 25.7 x 3 = 77.1 TPY.

11. Potential, Fugitive, and Actual Emissions Comment:

Potential mass emissions vary with turbine inlet conditions.
Distillate oil firing limited to 3,000 hr/yr aggregated over three CTG (equivalent to 1,000 hr/yr per CT/HRSG).
Duct-firing limited to 3,697,920 MMBtu for three CT/HRSGs (equivalent to 2,679 hr/yr per CT/HRSG, Maximum heat input 460 MMBtu/hr).

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 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.5 ppmvd @15% O_2 and4.8 lb/hr**	4. Equivalent Allowable Emissions: **14.4** lb/hour **63.1** tons/year
5. Method of Compliance: **Initial stack test using EPA Methods 25A or 18**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT for natural gas firing CT only. Equivalent hourly emissions for one CT/HRSG = 4.8 lb/hr. Equivalent hourly emissions for three CT/HRSGs = 4.8 lb/hr x 3 = 14.4 lb/hr. Equivalent Annual Emissions= 14.4 lb/hr x 8,760 hr/yr x (1 ton/2,000 lb) = 63.1 TPY**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.9 ppmvd @15% O_2 and 7.2 lb/hr**	4. Equivalent Allowable Emissions: **21.6** lb/hour **28.9** tons/year
5. Method of Compliance: **Initial stack test using EPA Methods 25A or 18**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT for natural gas firing with duct burners. Equivalent hourly emissions for one CT/HRSG = 7.2 lb/hr. Equivalent hourly emissions for three CT/HRSG = 7.2 lb/hr x 3 = 21.6 lb/hr. Equivalent Annual Emissions= 21.6 lb/hr x 2,679 hr/yr x (1 ton/2,000 lb) = 28.9 TPY**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **6.0 ppmvd @15% O2 and 18.9 lb/hr**	4. Equivalent Allowable Emissions: **56.7** lb/hour **28.4** tons/year
5. Method of Compliance: **Initial stack test using EPA Methods 25A or 18**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT for fuel oil firing. Fuel oil firing limited to 1,000 hr/yr per CT/HRSG. Equivalent hourly emissions based on 59°F inlet condition and 100% load. Equivalent hourly emissions of one CT/HRSG = 18.9 lb/hr Equivalent hourly emissions of three CT/HRSGs = 18.9 x 3 = 56.7 lb/hr Equivalent Annual Emissions= 56.7 lb/hr x 1,000 hr/yr x 1 ton/2,000 lb = 28.4 TPY**	

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: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.1** lb/hour **40.8** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2 gr S/100 SCF of gas** **0.0015-percent of sulfur fuel oil** Reference: **Permit No. 009006-005-AC**	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:

Potential hourly emissions based on natural gas firing with DB at 59°F inlet conditions:
Potential hourly emissions of one CT/HRSG = 3.7 lb/hr.
Potential hourly emissions of three CT/HRSGs = 3.7 lb/hr x 3 = 11.1 lb/hr.
Potential annual emissions of one CT/HRSG = 13.6 TPY (Table 2-3B of PSD permit application dated December 2008)
Potential annual emissions for three CT/HRSGs = 13.6 x 3 = 40.8 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential hourly emissions vary with turbine inlet conditions.
Duct-firing limited to 3,697,920 MMBtu for three CT/HRSGs (equivalent to 2,880 hr/yr per CT/HRSG).
Distillate oil firing limited to 3,000 hr/yr aggregated over 3 CT/HRSGs (equivalent to 1,000 hr/yr per CT/HRSG.

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 gr S/100 SCF of gas**	4. Equivalent Allowable Emissions: **11.1** lb/hour tons/year
5. Method of Compliance: **Fuel Analysis Records**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT for natural gas firing: Fuel sulfur content limited to 2 grains per 100 standard cubic feet of natural gas. Equivalent hourly emissions based on 59°F inlet condition. Hourly emissions of one CT/HRSG = 3.7 lb/hr. Hourly emissions of three CT/HRSGs = 3.7 lb/hr x 3 = 11.1 lb/hr.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.0015-percent of sulfur fuel oil**	4. Equivalent Allowable Emissions: **2.1** lb/hour tons/year
5. Method of Compliance: **Fuel Analysis Records**	
6. Allowable Emissions Comment (Description of Operating Method): **BACT for fuel oil firing: Fuel sulfur content limited to 0.0015 percent. Equivalent hourly emissions based on 59°F inlet condition. Hourly emissions of one CT/HRSG = 0.7 lb/hr. Hourly emissions of three CT/HRSGs = 0.7 lb/hr x 3 = 2.1 lb/hr.**	

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: **NH3**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **See Comment** lb/hour tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **5 ppmvd @15% O_2** Reference: **Permit No. 009006-005-AC**	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: **Ammonia slip limited to 5 ppmvd @ 15-percent O_2. State requirement only. Ammonia is not a regulated air pollutant under Title V or NSPS.**	

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 ppmvd @ 15-percent O_2**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: **Annual stack test using EPA Method CTM-027 or EPA Method 320.**	
6. Allowable Emissions Comment (Description of Operating Method): **For natural gas and fuel oil firing including duct burner operation.**	

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: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **BACT requirement. Visible emissions limited to 10% opacity for each 6-minute block average.**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: **20** % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Visible emissions due to startup, shutdown, and malfunction limited to ten 6-minute periods per calendar day.** **Alternative visible emission standard.**	

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 9

1. Parameter Code: **EM**	2. Pollutant(s): **NOx**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **42I**	Serial Number: **1205851855**
5. Installation Date:	6. Performance Specification Test Date: **12/15/2012**
7. Continuous Monitor Comment: **Continuous monitoring of NOx emissions. Unit 3A** **40 CFR 75**	

Continuous Monitoring System: Continuous Monitor 2 of 9

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **48i**	Serial Number: **JC1134200175**
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Continuous monitoring of CO emissions. Unit 3A** **40 CFR 75**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

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

Continuous Monitoring System: Continuous Monitor 3 of 9

1. Parameter Code: **O2**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Servomex** Model Number: **1440D**	Serial Number: **01440D1VO2/4246**
5. Installation Date:	6. Performance Specification Test Date: **12/15/2012**
7. Continuous Monitor Comment: **Monitoring of O_2 for dilution with NOx and CO monitors. Unit 3A** **40 CFR 75**	

Continuous Monitoring System: Continuous Monitor 4 of 9

1. Parameter Code: **EM**	2. Pollutant(s): **NOx**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **42i**	Serial Number: **101452373**
5. Installation Date:	6. Performance Specification Test Date: **12/05/2012**
7. Continuous Monitor Comment: **Continuous monitoring of NOx emissions. Unit 3B** **40 CFR 75**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

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

Continuous Monitoring System: Continuous Monitor 5 of 9

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **48i**	Serial Number: **JC113410074**
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Continuous monitoring of CO emissions. Unit 3B 40 CFR 75**	

Continuous Monitoring System: Continuous Monitor 6 of 9

1. Parameter Code: **O2**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Servomex** Model Number: **1440D**	Serial Number: **01440D1V02/4680**
5. Installation Date:	6. Performance Specification Test Date: **12/05/2012**
7. Continuous Monitor Comment: **Monitoring of O_2 for dilution with NOx and CO monitors. Unit 3B 40 CFR 75**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

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

Continuous Monitoring System: Continuous Monitor 7 of 9

1. Parameter Code: **EM**	2. Pollutant(s): **NOx**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **42i**	Serial Number: **1205851860**
5. Installation Date:	6. Performance Specification Test Date: **11/19/2012**
7. Continuous Monitor Comment: **Continuous monitoring of NOx emissions. Unit 3C 40 CFR 75**	

Continuous Monitoring System: Continuous Monitor 8 of 9

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **48i**	Serial Number: **JC1201300190**
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Continuous monitoring of CO emissions. Unit 3C 40 CFR 75**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

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

Continuous Monitoring System: Continuous Monitor 9 of 9

1. Parameter Code: **O2**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Servomex** Model Number: **1440D**	Serial Number: **01440D1V02/4606**
5. Installation Date:	6. Performance Specification Test Date: **11/19/2012**
7. Continuous Monitor Comment: **Monitoring of O_2 for dilution with NOx and CO monitors. Unit 3C. 40 CFR 75**	

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: **CCEC-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)
   ☒ Attached, Document ID: **CCEC-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: **CCEC-EU1-I3** ☐ 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: **CCEC-EU1-I4** ☐ Previously Submitted, Date ______
   ☐ Not Applicable (construction application)

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

6. Compliance Demonstration Reports/Records:
   ☒ Attached, Document ID: **CCEC-EU1-I6**
   Test Date(s)/Pollutant(s) Tested: **NOx, CO, VOC, NH_3, VE; April 16-17, 2013**

   ☐ 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: CCEC-EU1-IV1
2.	Compliance Assurance Monitoring: ☐ Attached, Document ID: ____________ ☒ Not Applicable
3.	Alternative Methods of Operation: ☒ Attached, Document ID: CCEC-EU1-IV3 ☐ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: ____________ ☒ Not Applicable

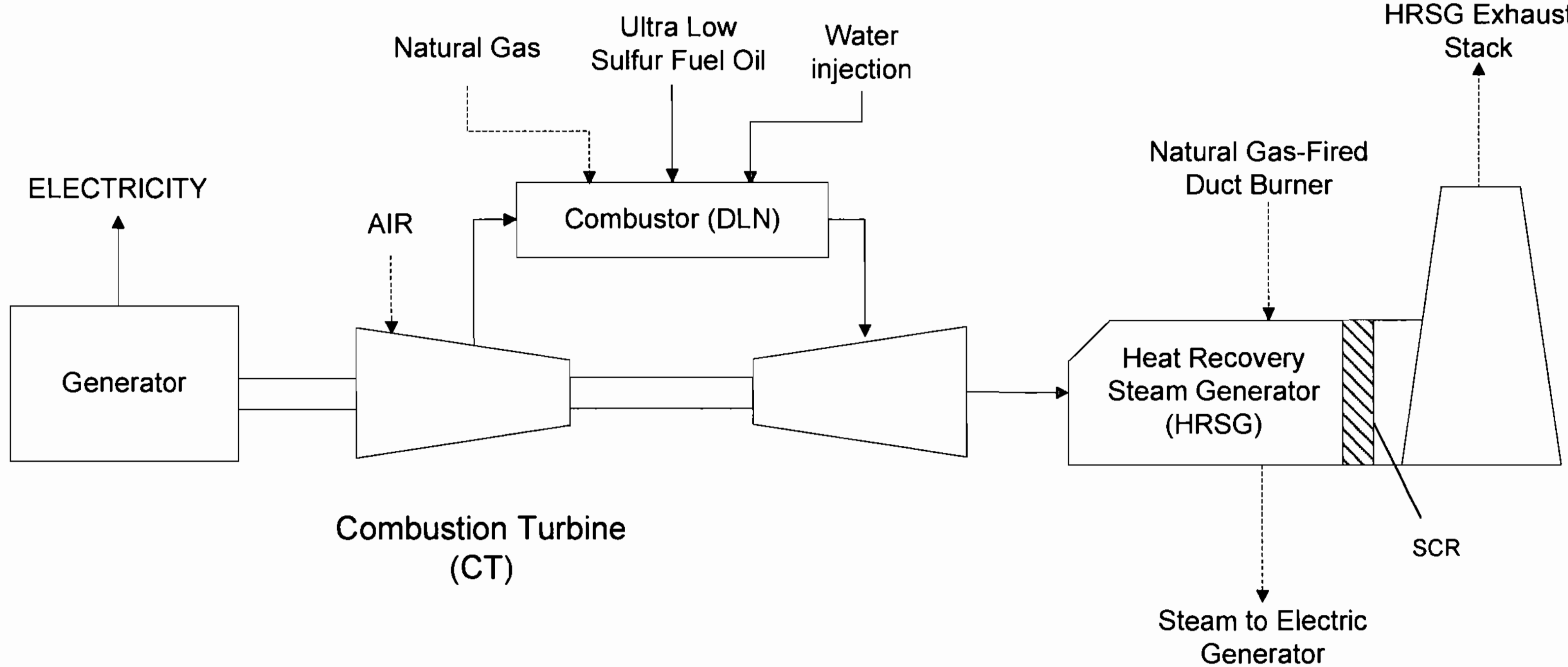
Additional Requirements Comment

Combined cycle units 3A, 3B, and 3C are exempt from the CAM requirements for NO_x control using SCR since continuous compliance is required to be demonstrated by a CEMS.
Rule:40 CFR 64.29(b)(vi).

Please see Attachment CCEC-EUI-I4 for requested changes in excess emissions.

ATTACHMENT CCEC-EU1-I1

PROCESS FLOW DIAGRAM



CCEC-EU1-I1 . Process Flow Diagram for CTG/HRSG
FPL Cape Canaveral Energy Center, Brevard, Florida

Source: Golder, 2013.

Process Flow Legend
Solid/Liquid
Gas
Steam

Golder Associates

ATTACHMENT CCEC-EU1-I2

FUEL ANALYSIS OR SPECIFICATION

SGS

DATE: 10/10/2012

SGS Oil, Gas and Chemicals
SGS Port Canaveral
8985 Columbia Road
Cape Canaveral, FL, 32920
U.S.A.
Tel: (321)-784-1941
Fax: (321)-784-1943

FLORIDA POWER & LIGHT CO
FUELS MANAGEMENT DEPT
PO BOX 14000
JUNO BEACH
UNITED STATES
33408

Certificate of Analysis: PC12-00365.001

CLIENT ORDER NO :	Job# 289803	SGS ORDER NO.:	--
CLIENT ID :	Vitol# 701679 / FP&L# 121001	PRODUCT DESCRIPTION :	Diesel - ULSD
LOCATION :	Seaport Canaveral	VESSEL :	OSG-242
SAMPLE SOURCE :	Shore Tank	SOURCE ID :	150-2
SAMPLE TYPE :	After Discharge	SAMPLE BY :	SGS
SAMPLED :	10/08/2012	RECEIVED :	10/08/2012
ANALYSED :	10/08/2012 - 10/10/2012	COMPLETED :	10/10/2012

SGS OG&C makes no representation and assumes no responsibility for the reliability of analysis by a Sub-Contract Laboratory. The laboratory analysis for the Sub-Contract Laboratory tests are provided by:
S15 - Subcontracted to another SGS Laboratory - New Orleans

PROPERTY	METHOD	RESULT	UNITS	MIN	MAX
Sulfur Content	ASTM D5453	3.2	mg/kg	--	15
Pour Point	ASTM D97	<-11	°F	--	15
Flash Point by PMCC - Proc. A / Automatic Tester	ASTM D93	140	°F	140	--
Water Content	ASTM D95	0.00	% (v/v)	--	--
Sediment By Extraction Content	ASTM D473	0	% (v/v)	--	--
Ash Content	ASTM D482	<0.001	% (m/m)	--	0.01
Kinematic Viscosity at 100°F	ASTM D445	2.547	cSt	--	--
Saybolt Universal Viscosity at 100°F	ASTM D2161	34.4	SUS	32.6	40
API at 60°F - Running	ASTM D4052	37.2	°API	30	40
Trace Metals in Gas Turbine Fuels by AAS - Flame Emission Spectroscopy	ASTM D3605				
Sodium content		<0.1	ppm	--	--
Potassium content §		<0.1	ppm	--	--
Summation of Sodium and Potasium §		<0.2	ppm	--	0.5
Calcium content		<0.1	ppm	--	0.5
Lead content		<0.1	ppm	--	0.5
Vanadium content		<0.1	ppm	--	0.5
Ramsbottom Carbon Residue 10% Bottoms	ASTM D524	0.10	% (m/m)	--	0.35/0.15
Distillation of Petroleum Products at Atmospheric Pressure	ASTM D86				
Initial boiling point (IBP)		339.1	°F	--	--
10% Recovered at		390.0	°F	--	--
50% Recovered at		482.9	°F	--	--
90% Recovered at		608.2	°F	540	640
Final boiling point (FBP)		661.6	°F	--	690
% Recovery		97.9	% (v/v)	--	--

§ - Analyte not in published method scope

AUTHORISED SIGNATORY

Jason Hobbs

Jason Hobbs-Laboratory Supervisor

SGS

DATE: 10/10/2012

SGS Oil, Gas and Chemicals
SGS Port Canaveral
8985 Columbia Road
Cape Canaveral, FL, 32920
U.S.A.
Tel: (321)-784-1941
Fax: (321)-784-1943

FLORIDA POWER & LIGHT CO
FUELS MANAGEMENT DEPT
PO BOX 14000
JUNO BEACH
UNITED STATES
33408

Certificate of Analysis: PC12-00365.001

CLIENT ORDER NO :	Job# 289803	SGS ORDER NO.:	--
CLIENT ID :	Vitol# 701679 / FP&L# 121001	PRODUCT DESCRIPTION :	Diesel - ULSD
LOCATION :	Seaport Canaveral	VESSEL :	OSG-242
SAMPLE SOURCE :	Shore Tank	SOURCE ID :	150-2
SAMPLE TYPE :	After Discharge	SAMPLE BY :	SGS
SAMPLED :	10/08/2012	RECEIVED :	10/08/2012
ANALYSED :	10/08/2012 - 10/10/2012	COMPLETED :	10/10/2012

SGS OG&C makes no representation and assumes no responsibility for the reliability of analysis by a Sub-Contract Laboratory. The laboratory analysis for the Sub-Contract Laboratory tests are provided by:
S15 - Subcontracted to another SGS Laboratory - New Orleans

PROPERTY	METHOD	RESULT	UNITS	MIN	MAX	
% Residue		1.2	% (v/v)	--	--	
% Loss		0.9	% (v/v)	--	--	
Visual Colour	Visual Colour	Undyed	---	--	Dyed Red	
Copper Strip corrosion (3h / 50°C)	ASTM D130	1a	Rating	--	1	
Acid Number (Inflection end-point)	ASTM D664 (Method A)	<0.05	mg KOH/g	--	--	#
S15 - Cetane Number	ASTM D613	44.6	Rating	--	--	
Gross Calorific Value	ASTM D240	5759	MBtu/bbl	--	--	
Particulate Contamination in Aviation Fuels	ASTM D5452					
Volume of Sample Filtered		1.000	L	--	--	
Particulate Contamination		0.20	mg/L	--	--	
Particulate Contamination		0.20	mg/kg	--	10	
150 °C Accelerated Fuel Oil Stability Test	Octel Method F21-61					
Product Colour ASTM D1500 - before Ageing		L. 0.5	---	--	--	
Product Colour ASTM D1500 - after Ageing		0.5	---	--	--	
Aging Time		90	min	--	--	
Pad Reflectance after ageing		90	%	--	--	
Reference Blotter Number		1	---	--	7.0	
S15 - Carbon, Hydrogen and Nitrogen in Petroleum Products and Lubricants	ASTM D5291					
Carbon		86.9	% (m/m)	--	--	
Hydrogen		13.5	% (m/m)	--	--	
Nitrogen		<0.75	% (m/m)	--	--	

**** End of Analytical Results ****

§ - Analyte not in published method scope
# - Result is outside of test method limits and/or analytical range used in method precision study

AUTHORISED SIGNATORY

Jason Hobbs

Jason Hobbs-Laboratory Supervisor

SGS

DATE: 09/28/2012

SGS Oil, Gas and Chemicals
SGS Port Canaveral
8985 Columbia Road
Cape Canaveral, FL, 32920
U.S.A.
Tel: (321)-784-1941
Fax: (321)-784-1943

FLORIDA POWER & LIGHT CO
FUELS MANAGEMENT DEPT
PO BOX 14000
JUNO BEACH
UNITED STATES
33408

Certificate of Analysis: PC12-00350.001

CLIENT ORDER NO :	Job# 289073	SGS ORDER NO.:	--
CLIENT ID :	CCVITOL150-1	PRODUCT DESCRIPTION :	Diesel - ULSD
LOCATION :	Seaport Canaveral		
SAMPLE SOURCE :	Shore Tank	SOURCE ID :	150-1
SAMPLE TYPE :	Inventory	SAMPLE BY :	SGS
SAMPLED :	09/26/2012	RECEIVED :	09/26/2012
ANALYSED :	09/28/2012	COMPLETED :	09/28/2012
SAMPLE COMMENT :	FP&L Ref# CCVITOL150-1/150-2SAMPLE/TEST09/26/12		

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S15 - Subcontracted to another SGS Laboratory - New Orleans

PROPERTY	METHOD	RESULT	UNITS	MIN	MAX
Sulfur Content	ASTM D5453	4.1	mg/kg	--	15
Pour Point	ASTM D97	<-6	°F	--	15
Flash Point by PMCC - Proc. A / Automatic Tester	ASTM D93	149	°F	140	--
Water Content	ASTM D95	0.0	% (v/v)	--	--
Sediment By Extraction Content	ASTM D473	0	% (v/v)	--	--
Ash Content	ASTM D482	<0.001	% (m/m)	--	0.01
Kinematic Viscosity at 100°F	ASTM D445	2.943	cSt	--	--
Saybolt Universal Viscosity at 100°F	ASTM D2161	35.8	SUS	32.6	40
API at 60°F	ASTM D4052	34.5	°API	30	40
Trace Metals in Gas Turbine Fuels by AAS - Flame Emission Spectroscopy	ASTM D3605				
Sodium content		<0.1	ppm	--	--
Potassium content §		<0.1	ppm	--	--
Summation of Sodium and Potasium §		<0.2	ppm	--	0.5
Calcium content		<0.1	ppm	--	0.5
Lead content		<0.1	ppm	--	0.5
Vanadium content		<0.1	ppm	--	0.5
Ramsbottom Carbon Residue 10% Bottoms	ASTM D524	0.10	% (m/m)	--	0.35/0.15
Distillation of Petroleum Products at Atmospheric Pressure	ASTM D86				
Initial boiling point (IBP)		340.7	°F	--	--
10% Recovered at		410.2	°F	--	--
50% Recovered at		507.2	°F	--	--
90% Recovered at		618.6	°F	540	640
Final boiling point (FBP)		670.6	°F	--	690

§ - Analyte not in published method scope

AUTHORISED SIGNATORY

Jason Hobbs

Jason Hobbs-Laboratory Supervisor

DATE: 09/28/2012

SGS Oil, Gas and Chemicals
SGS Port Canaveral
8985 Columbia Road
Cape Canaveral, FL, 32920
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Tel: (321)-784-1941
Fax: (321)-784-1943

FLORIDA POWER & LIGHT CO
FUELS MANAGEMENT DEPT
PO BOX 14000
JUNO BEACH
UNITED STATES
33408

Certificate of Analysis: PC12-00350.001

CLIENT ORDER NO :	Job# 289073	SGS ORDER NO.:	--
CLIENT ID :	CCVITOL150-1	PRODUCT DESCRIPTION :	Diesel - ULSD
LOCATION :	Seaport Canaveral		
SAMPLE SOURCE :	Shore Tank	SOURCE ID :	150-1
SAMPLE TYPE :	Inventory	SAMPLE BY :	SGS
SAMPLED :	09/26/2012	RECEIVED :	09/26/2012
ANALYSED :	09/28/2012	COMPLETED :	09/28/2012
SAMPLE COMMENT :	FP&L Ref# CCVITOL150-1/150-2SAMPLE/TEST09/26/12		

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S15 - Subcontracted to another SGS Laboratory - New Orleans

PROPERTY	METHOD	RESULT	UNITS	MIN	MAX	
% Recovery		97.9	% (v/v)	--	--	
% Residue		1.3	% (v/v)	--	--	
% Loss		0.8	% (v/v)	--	--	
Visual Colour	Visual Colour	Undyed	---	--	Dyed Red	
Copper Strip corrosion (3h / 50°C)	ASTM D130	1a	Rating	--	1	
Acid Number (Buffer end-point)	ASTM D664 (Method A)	<0.05	mg KOH/g	--	--	#
S15 - Cetane Number	ASTM D613	44.3	Rating	--	--	
Gross Calorific Value	ASTM D240	5832	MBtu/bbl	--	--	
Particulate Contamination In Aviation Fuels	ASTM D5452					
Volume of Sample Filtered		1.000	L	--	--	
Particulate Contamination		0.30	mg/L	--	--	
Particulate Contamination		0.35	mg/kg	--	10	
150 °C Accelerated Fuel Oil Stability Test	Octel Method F21-61					
Product Colour ASTM D1500 - before Ageing		L. 1.0	---	--	--	
Product Colour ASTM D1500 - after Ageing		L. 1.0	---	--	--	
Aging Time		90	min	--	--	
Pad Reflectance after ageing		91	%	--	--	
Reference Blotter Number		1	---	--	7.0	
S15 - Carbon, Hydrogen and Nitrogen in Petroleum Products and Lubricants	ASTM D5291					
Carbon		87.2	% (m/m)	--	--	#
Hydrogen		13.3	% (m/m)	--	--	
Nitrogen		<0.8	% (m/m)	--	--	

**** End of Analytical Results ****

§ - Analyte not in published method scope
# - Result is outside of test method limits and/or analytical range used in method precision study

AUTHORISED SIGNATORY

Jason Hobbs

Jason Hobbs-Laboratory Supervisor

NATURAL GAS INFORMATION

Florida Gas makes no warranty or representation whatsoever as to the accuracy of the information provided.
This information is provided on a best efforts basis and is an estimate.
The information is not used for billing purposes.
Florida Gas is not responsible for any reliance on this information by any party.

Stream History

	Perry 36" Stream #1		Perry 30" Stream #2		Perry 24" Stream #3		Brooker 24" Stream	
Gas Day	Avg ppm	Avg Grains/hcf	Avg ppm	Avg Grains/hcf	Avg ppm	Avg Grains/hcf	Avg ppm	Avg Grains/hcf
09/30/2013	1.463	0.091	1.270	0.079	1.278	0.080	0.765	0.048
09/29/2013	1.430	0.089	1.290	0.081	1.333	0.083	0.880	0.055
09/28/2013	1.408	0.088	1.318	0.082	1.325	0.083	0.611	0.038
09/27/2013	1.337	0.084	1.279	0.080	1.282	0.080	0.689	0.043
09/26/2013	1.272	0.079	1.184	0.074	1.172	0.073	0.745	0.047
09/25/2013	1.225	0.077	1.151	0.072	1.154	0.072	0.852	0.053
09/24/2013	2.043	0.128	1.857	0.116	1.842	0.115	0.892	0.056
09/23/2013	1.388	0.087	1.381	0.086	1.338	0.084	0.769	0.048
09/22/2013	1.409	0.088	1.404	0.088	1.358	0.085	0.767	0.048
09/21/2013	1.396	0.087	1.383	0.086	1.352	0.085	1.185	0.074
09/20/2013	1.338	0.084	1.306	0.082	1.291	0.081	1.096	0.069
09/19/2013	1.286	0.080	1.307	0.082	1.287	0.080	1.017	0.064
09/18/2013	1.404	0.088	1.400	0.088	1.373	0.086	0.804	0.050
09/17/2013	1.456	0.091	1.455	0.091	1.431	0.089	1.139	0.071
09/16/2013	1.447	0.090	1.438	0.090	1.409	0.088	1.413	0.088
09/15/2013	1.446	0.090	1.388	0.087	1.369	0.086	1.758	0.110
09/14/2013	1.429	0.089	1.386	0.087	1.375	0.086	2.198	0.137
09/13/2013	1.440	0.090	1.405	0.088	1.407	0.088	2.158	0.135
09/12/2013	1.421	0.089	1.432	0.089	1.413	0.088	0.636	0.040
09/11/2013	1.389	0.087	1.418	0.089	1.405	0.088	0.689	0.043
09/10/2013	1.381	0.086	1.386	0.087	1.371	0.086	0.632	0.039
09/09/2013	1.381	0.086	1.351	0.084	1.343	0.084	0.767	0.048
09/08/2013	1.408	0.088	1.422	0.089	1.410	0.088	0.870	0.054
09/07/2013	1.333	0.083	1.419	0.089	1.412	0.088	0.891	0.056
09/06/2013	1.373	0.086	1.443	0.090	1.417	0.089	1.036	0.065
09/05/2013	1.427	0.089	1.475	0.092	1.474	0.092	1.515	0.095
09/04/2013	1.640	0.103	1.569	0.098	1.605	0.100	1.597	0.100
09/03/2013	3.546	0.222	3.635	0.227	3.634	0.227	1.096	0.069
09/02/2013	1.452	0.091	1.479	0.092	1.466	0.092	1.048	0.066
09/01/2013	1.407	0.088	1.455	0.091	1.439	0.090	0.885	0.055
08/31/2013	1.419	0.089	1.426	0.089	1.398	0.087	1.020	0.064
08/30/2013	1.382	0.086	1.323	0.083	1.302	0.081	1.511	0.094
08/29/2013	1.445	0.090	1.390	0.087	1.386	0.087	1.212	0.076
08/28/2013	1.431	0.089	1.426	0.089	1.412	0.088	0.989	0.062
08/27/2013	1.795	0.112	1.786	0.112	1.770	0.111	0.681	0.043
08/26/2013	1.279	0.080	1.245	0.078	1.242	0.078	0.698	0.044
08/25/2013	1.166	0.073	1.207	0.075	1.193	0.075	0.499	0.031
08/24/2013	1.217	0.076	1.244	0.078	1.236	0.077	0.750	0.047
08/23/2013	1.153	0.072	1.165	0.073	1.146	0.072	0.678	0.042
08/22/2013	1.002	0.063	1.023	0.064	0.998	0.062	0.620	0.039
08/21/2013	1.193	0.075	1.222	0.076	1.198	0.075	0.848	0.053
08/20/2013	1.196	0.075	1.244	0.078	1.227	0.077	0.924	0.058
08/19/2013	1.246	0.078	1.288	0.080	1.259	0.079	1.157	0.072
08/18/2013	1.258	0.079	1.319	0.082	1.286	0.080	0.894	0.056
08/17/2013	1.211	0.076	1.205	0.075	1.221	0.076	0.857	0.054
08/16/2013	1.243	0.078	1.254	0.078	1.237	0.077	0.790	0.049
08/15/2013	1.234	0.077	1.256	0.078	1.275	0.080	1.540	0.096
08/14/2013	761.353	47.585	855.564	53.473	814.625	50.914	2.027	0.127
08/13/2013	1423.523	88.970	1473.664	92.104	1503.260	93.954	2.382	0.149
08/12/2013	1.247	0.078	1.273	0.080	1.286	0.080	2.170	0.136
08/11/2013	1.334	0.083	1.349	0.084	1.343	0.084	2.245	0.140
08/10/2013	1.185	0.074	1.212	0.076	1.223	0.076	1.924	0.120
08/09/2013	1.251	0.078	1.261	0.079	1.293	0.081	1.899	0.119
08/08/2013	1.293	0.081	1.316	0.082	1.334	0.083	1.578	0.099
08/07/2013	1.336	0.084	1.362	0.085	1.263	0.079	1.478	0.092
08/06/2013	1.263	0.079	1.359	0.085	1.250	0.078	1.676	0.105

08/05/2013	1.307	0.082	1.392	0.087	1.299	0.081	2.166	0.135
08/04/2013	1.309	0.082	1.393	0.087	1.290	0.081	0.031	0.002
08/03/2013	1.444	0.090	1.563	0.098	1.445	0.090	0.037	0.002
08/02/2013	1.420	0.089	1.520	0.095	1.412	0.088	0.031	0.002
08/01/2013	1.416	0.089	1.540	0.096	1.379	0.086	0.076	0.005
07/31/2013	1.504	0.094	1.544	0.097	1.485	0.093	0.059	0.004
07/30/2013	42.351	2.647	42.945	2.684	62.459	3.904	0.055	0.003
07/29/2013	1.417	0.089	1.471	0.092	1.433	0.090	0.044	0.003
07/28/2013	1.444	0.090	1.453	0.091	1.390	0.087	0.061	0.004
07/27/2013	1.391	0.087	1.411	0.088	1.362	0.085	0.066	0.004
07/26/2013	0.998	0.062	1.033	0.065	1.001	0.063	1.215	0.076
07/25/2013	1.437	0.090	1.443	0.090	1.385	0.087	4.141	0.259
07/24/2013	1.364	0.085	1.300	0.081	1.262	0.079	4.006	0.250
07/23/2013	1.398	0.087	1.333	0.083	1.289	0.081	4.030	0.252
07/22/2013	1.363	0.085	1.384	0.087	1.293	0.081	4.249	0.266
07/21/2013	1.371	0.086	1.388	0.087	1.318	0.082	3.115	0.195
07/20/2013	1.382	0.086	1.387	0.087	1.321	0.083	3.331	0.208
07/19/2013	1.435	0.090	1.423	0.089	1.340	0.084	4.670	0.292
07/18/2013	1.470	0.092	1.477	0.092	1.403	0.088	4.332	0.271
07/17/2013	1.475	0.092	1.489	0.093	1.401	0.088	4.368	0.273
07/16/2013	1.483	0.093	1.467	0.092	1.425	0.089	4.526	0.283
07/15/2013	1.679	0.105	1.646	0.103	1.483	0.093	2.435	0.152
07/14/2013	1.568	0.098	1.607	0.100	1.472	0.092	2.555	0.160
07/13/2013	1.488	0.093	1.506	0.094	1.424	0.089	2.782	0.174
07/12/2013	1.498	0.094	1.488	0.093	1.408	0.088	3.087	0.193
07/11/2013	1.163	0.073	1.149	0.072	1.081	0.068	3.473	0.217
07/10/2013	1.445	0.090	1.457	0.091	1.379	0.086	4.270	0.267
07/09/2013	1.455	0.091	1.457	0.091	1.390	0.087	4.215	0.263
07/08/2013	1.523	0.095	1.525	0.095	1.468	0.092	4.247	0.265
07/07/2013	1.047	0.065	0.999	0.062	1.007	0.063	1.986	0.124
07/06/2013	0.955	0.060	0.966	0.060	0.969	0.061	2.026	0.127
07/05/2013	0.891	0.056	0.931	0.058	0.912	0.057	1.981	0.124
07/04/2013	1.491	0.093	1.500	0.094	1.436	0.090	2.737	0.171
07/03/2013	618.203	38.638	610.484	38.155	565.454	35.341	2.957	0.185
07/02/2013	4199.973	262.498	4010.718	250.670	3981.018	248.814	2.815	0.176
07/01/2013	3551.171	221.948	3462.233	216.390	3415.582	213.474	2.977	0.186
06/30/2013	2671.701	166.981	2636.064	164.754	2666.531	166.658	1.844	0.115
06/29/2013	1.152	0.072	1.162	0.073	1.107	0.069	1.117	0.070
06/28/2013	1.489	0.093	1.600	0.100	1.514	0.095	1.145	0.072
	Perry 36" Stream #1		Perry 30" Stream #2		Perry 24" Stream #3		Brooker 24" Stream	

ATTACHMENT CCEC-EU1-I3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

PEERLESS Mfg. Co.

NOOTER ERIKSEN
FP&L
Cape Canaveral, FL

OPERATION & MAINTENANCE MANUAL

Nooter Eriksen PO#	102000-005
Nooter Eriksen Job#	102024
Peerless Sales Order#	206382
Peerless Document #	206382-A250-00090-56

APPROVED: Christy Saludares DATE: ______________

Project Engineer

REVISION HISTORY		
Rev. No.	Date	Description of Change
0	11/8/10	Issued for approval
1	1/24/11	Updated tagging
2	2/17/11	Updated per comments

NOOTER/ERIKSEN INC. SUPPLIER SUBMITTAL REVIEW							
REVIEW OF SUPPLIER DRAWINGS DOES NOT RELIEVE THE SUPPLIER OF RESPONSIBILITIES FOR ACCURACY OF DIMENSIONS AND COMPLIANCE TO CODES, NOOTER ERIKSEN SPECIFICATIONS AND P. O. REQUIREMENTS							
	A	REVIEWED AND ACCEPTED					
x	B	REVIEWED WITH COMMENTS (WORK MAY PROCEED)					
	C	REVISE AND RESUBMIT (WORK MAY NOT PROCEED)					
	D	REVIEWED FOR INFORMATION ONLY					
RELEASE DATE:		REVIEWERS INITIALS					
PROJECT NAME: FP& L–Cape Canaveral			JOB NO	CODE	SHT	REV	FE
NE		DRAWING NO.	102024	-QD-	001	C	X

SECTION 1 - INTRODUCTION

The Selective Catalytic Reduction (SCR) System described in this manual is designed to reduce oxides of Nitrogen (NO_x) from combustion turbine exhaust gases. As the exhaust gas mixes with ammonia and flows over a catalyst bed, the NO_x is reduced to Nitrogen (N_2) gas and water (H_20) vapor.

The NO_x reduction system is commonly termed selective catalytic reduction (SCR), and requires ammonia as a reducing agent. Aqueous ammonia is supplied to the SCR system, and vaporized by a high temperature exhaust gas in a packed tower. The mixture of ammonia and exhaust, or process gas, is injected upstream of the SCR catalyst bed. As the gas flows through the catalyst bed, a chemical reaction occurs and reduces the NO_x emissions.

NOTES:

1. Six (6) units are required:
   Three (3) for Cape Canaveral E.C. (PMC SO# 206382)
   Three (3) for Riviera Beach E.C. (PMC SO# 206383)

DESIGN BASIS

A. Performance:	
Combustion Turbine Type	Siemens SGT6-8000H
Outlet NOx (Natural Gas)	25 ppmvd @ 15% O_2
(Distillate)	42 ppmvd @ 15% O_2
Max. Exhaust Flow (Natural Gas)	5,436,226 lb/hr
(Distillate)	5,519,879 lb/hr
Stack NOx (Natural Gas)	2.0 ppmvd @ 15% O_2
(Distillate)	8.0 ppmvd @ 15% O_2
Stack NH3	5.0 ppmvd @ 15% O_2
Ammonia Consumption (19% by weight)	
Skid capacity	975 lb/hr
Dilution Air	6,585 ACFM @ 32" w.c. SP
B. Site Conditions:	
Location	Cape Canaveral & Riviera Beach,FL
Elevation	12 ft
Ambient Temperature Range	19 – 103°F
Design Criteria	
Building Code	IBC 2006
Electrical Classification	Class 1, Group D, Div. 2, NEMA 4
Utilities Available	
Control	120 VAC
Motor Power	460 Volt, 3 Phase, 60 Hz
Aqueous Ammonia	40 psig (minimum)
Instrument Air	60-125 psig (@ 20-100°F)

SYSTEM DESCRIPTION

I. AMMONIA SUPPLY

Technical grade ammonia (99.5% or higher in purity with a impurity content of 0.2%) mixed with de-ionized water to a concentration of approximately 19% by weight is required for this system. Ammonia storage equipment is furnished by others.

II. EQUIPMENT

The SCR system is composed of the following items:

A. Each turbine has a dedicated ammonia flow control unit (AFCU). Aqueous ammonia is supplied to the AFCU skid at 40 PSIG and ambient temperature. Two fans, a primary and secondary, are used to direct the gas through the skid and distribution piping. They are designed to provide 6585 ACFM each with a static pressure gain of 32" w.c. SP.

B. The process gas, a combination of exhaust gas and vaporized ammonia, is distributed from the AFCU skid through the interconnecting piping to the manifold and AIG assemblies. The gas is then injected with ammonia upstream of the internal structure frame containing the catalyst modules (provided by others).

III. CONTROL

Wiring for instrumentation is terminated in a junction box (YCCF-JB-X001) located on the AFCU skid. Control of the SCR system is achieved through a DCS system (supplied by others).

ATTACHMENT CCEC-EU1-I4

PROCEDURES FOR STARTRUP AND SHUTDOWN

ATTACHMENT CCEC-EU1-I4
PROCEDURES FOR STARTUP/SHUTDOWN

Startup for the combustion turbine (CT)/heat recovery steam generator (HRSG) system begins with an electric control system using a switch to initiate the unit startup cycle. A period of several hours is required to allow metal temperatures in the HRSG and in the steam turbine to equilibrate without undue metal stress, before putting the unit "on the line" and sending electric power to the grid.

The CTs can be started on either natural gas or distillate fuel oil. The CTs utilize Dry Low-NO_x (DLN) combustion technology during natural gas firing and water injection during oil firing to reduce emissions of nitrogen oxides (NO_x). A selective catalytic reduction (SCR) system is also used to further reduce NO_x emissions.

Excess emissions resulting from startup, shutdown, fuel switches, and documented malfunctions are allowed provided that operators employ best operational practices to minimize the amount and duration of emissions during such incidents.

For each gas turbine/HRSG system, excess emissions of NO_X and CO resulting from startup, shutdown, or malfunction shall be excluded from CEMS data in any 24-hour period ("any 24-hour period" means a calendar day, midnight to midnight) for the following conditions (these conditions are considered separate events and each event may occur independently within any 24-hour period):

- *Steam Turbine Cold Startup:* For cold startup of the steam turbine, excluded emissions from any gas turbine/HRSG system shall not exceed 12 hours for the first CD and shall not exceed no more than 8 hours for subsequent CTs in any 24-hour period. A cold "startup of the steam turbine system" is defined as startup of the 3-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

  [Note: During a cold startup of the steam turbine, 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 metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.]
- *Gas Turbine/HRSG System Cold Startup:* For cold startup of a gas turbine/HRSG system, excluded 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 one-hour period.
- *Gas Turbine/HRSG system Warm Startup:* For warm startup of a gas turbine/HRSG system, excluded emissions shall not exceed two hours in any 24-hour period."Warm startup of a gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum is above 450 psig.
- *Shutdown Combined Cycle Operation:* For shutdown of the combined cycle operation, excluded emissions from any gas turbine/HRSG system will not exceed 3 hours in any 24-hour period.

- *Gas Turbine/HRSG System Shutdown:* For shutdown of the gas turbine/HRSG operation, excluded emissions from any gas turbine/HRSG system shall not exceed two hours in any 24-hour period.
- *Fuel Switching:* For each fuel switch, excluded emissions shall not exceed 2 hours in any 24-hour period and no more than four hours in any 24-hour period for any gas turbine/ HRSG system.
- Documented Malfunction: For the gas turbine/HRSG system, excess emissions of NOx and CO resulting from documented malfunctions shall not exceed two hours in any 24-hour period. A "documented malfunction" means malfunction that is documented within one working day of detection by contacting the Company Authority by Telephone, facsimile, transmittal or electronic mail.

Shutdown is performed by reducing the unit load (electrical production) to a minimum level, opening the breaker (which disconnects the unit generator from the system electrical grid), shutting off the fuel, and coasting to a stop.

ATTACHMENT CCEC-EU1-I6

COMPLIANCE DEMONSTRATION REPORTS

Emissions Compliance Test
Siemens, 8000H, Unit 3A
Zachary Engineering Corporation
Cape Canaveral Energy Center
Brevard County, Florida
April 16-17, 2013

1.0 INTRODUCTION

Air Hygiene International, Inc. (Air Hygiene) has completed the emissions testing study for nitrogen oxides (NOx), carbon monoxide (CO), total hydrocarbons/volatile organic compounds (THC/VOC), ammonia (NH_3), opacity, moisture (H_2O), and oxygen (O_2) from the exhaust of the Siemens, 8000H, Unit 3A for Zachary Engineering Corporation at the Cape Canaveral Energy Center near Brevard County, Florida. This report details the background, results, process description, and the sampling/analysis methodology of the stack sampling survey conducted on April 16-17, 2013.

1.1 TEST PURPOSE AND OBJECTIVES

The purpose of the test was to conduct an initial compliance emission test to document levels of selected pollutants at two test loads (Base Load and Base Load with Duct Burners). The information will be used to confirm compliance with the operating permit issued by the Florida Department of Environmental Protection (FDEP). The specific objective was to determine the emission concentration of NOx, CO, THC/VOC, NH_3, opacity, H_2O, and O_2 from the exhaust of Zachary Engineering Corporation's Siemens, 8000H, Unit 3A at Base Load with and without Duct Burners.

1.2 SUMMARY OF TEST PROGRAM

The following list details pertinent information related to this specific project:

1.2.1 Participating Organizations
- Florida Department of Environmental Protection (FDEP)
- Zachary Engineering Corporation
- Florida Power and Light (FPL)
- Air Hygiene

1.2.2 Industry
- Electric Utility / Electric Services

1.2.3 Air Permit Number
- Permit Number: 0090006-005-AC

1.2.4 Plant Location
- Cape Canaveral Energy Center near Brevard County, Florida
- Universal Transverse Mercator (UTM) coordinates: Zone 17, 523.1km E and 3,149 km N
- GPS Coordinates [Latitude N 28 degrees 28.166' Longitude W 80 degrees 45.831']

1.2.5 Equipment Tested
- Siemens, 8000H, Unit 3A

1.2.6 Emission Points
- Exhaust from the Siemens, 8000H, Unit 3A

1.2.7 Pollutants Measured

- NOx
- CO
- THC/VOC
- NH_3
- Opacity
- H_2O
- O_2

1.2.8 Dates of Emission Test

- April 16-17, 2013

1.3 KEY PERSONNEL

Zachary Engineering Corporation:	Mike McCullough, PE	806-359-2650
Air Hygiene:	Nathan Arthur	918-307-8865
Air Hygiene:	Jake Fahlenkamp	918-307-8865

2.0 SUMMARY OF TEST RESULTS

Results from the sampling conducted on Zachary Engineering Corporation's Siemens, 8000H, Unit 3A located at the Cape Canaveral Energy Center on April 16-17, 2013 are summarized in the following table and relate only to the items tested.

TABLE 2.1
SUMMARY OF SIEMENS, 8000H, UNIT #3A RESULTS

Parameter	Base Load	Base Permit Limits	Base W/Db Load	Base w/DB Permit Limits
Date (mm/dd/yy)	04/16/13	--	04/17/13	--
Start Time (hh:mm:ss)	12:32:04	--	10:25:12	--
End Time (hh:mm:ss)	18:41:34	--	13:46:42	--
Run Duration (min / run)	60	--	60	--
Bar. Pressure (in. Hg)	30.15	--	29.88	--
Amb. Temp. (°F)	81	--	83	--
Rel. Humidity (%)	68	--	61	--
Spec. Humidity (lb water / lb air)	0.015502	--	0.014883	--
Unit Number	3A	--	3A	--
Load Designator	Base	--	Base w/DB	--
Turbine Fuel Flow (lb/min)	1,792	--	1,799	--
Duct Burner Fuel Flow (lb/min)	0	--	205	--
Total Fuel Flow (SCFH)	2,467,104	--	2,759,699	--
Stack Flow (RM19) (SCFH)	57,317,001	--	57,313,144	--
Stack Moisture (% Method 4 or 320)	6.8	--	7.3	--
Heat Input (MMBtu/hr)	2,470.0	--	2,763.0	--
Power Output (megawatts)	254.9	--	256.6	--
NH3 Flow (lb/hr)	329.67	--	358.43	--
NOx (ppmvd)	2.41	--	2.63	--
NOx (ppm@15%O_2)	1.84	2	1.79	2
NOx (lb/hr)	16.51	19.3	18.02	22.8
CO (ppmvd)	0.56	--	0.52	--
CO (ppm@15%O_2)	0.43	5	0.35	7.6
CO (lb/hr)	2.35		2.16	
VOC (ppmvd)	0.04	--	0.03	--
VOC (ppm@15%O_2)	0.03	1.5	0.00	1.9
VOC (lb/hr)	0.09	4.8	0.05	7.2
NH_3 (ppmvd)	0.61	--	0.23	--
NH_3 (ppm@15%O_2)	0.47	5	0.16	5
Opacity (%)	0.00	10	0.00	10
O_2 (%)	13.15	--	12.23	--

The results of all measured pollutant emissions were below the required limits. All testing was performed without any real or apparent errors. All testing was conducted according to the approved testing protocol.

Emissions Compliance Test
Siemens, 8000H, Unit 3B
Zachary Engineering Corporation
Cape Canaveral Energy Center
Brevard County, Florida
April 16-17, 2013

1.0 INTRODUCTION

Air Hygiene International, Inc. (Air Hygiene) has completed the emissions testing study for nitrogen oxides (NOx), carbon monoxide (CO), total hydrocarbons/volatile organic compounds (THC/VOC), ammonia (NH_3), opacity, moisture (H_2O), and oxygen (O_2) from the exhaust of the Siemens, 8000H, Unit 3B for Zachary Engineering Corporation at the Cape Canaveral Energy Center near Brevard County, Florida. This report details the background, results, process description, and the sampling/analysis methodology of the stack sampling survey conducted on April 16-17, 2013.

1.1 TEST PURPOSE AND OBJECTIVES

The purpose of the test was to conduct an initial compliance emission test to document levels of selected pollutants at two test loads (Base Load and Base Load with Duct Burners). The information will be used to confirm compliance with the operating permit issued by the Florida Department of Environmental Protection (FDEP). The specific objective was to determine the emission concentration of NOx, CO, THC/VOC, NH_3, opacity, H_2O, and O_2 from the exhaust of Zachary Engineering Corporation's Siemens, 8000H, Unit 3B at Base Load with and without Duct Burners.

1.2 SUMMARY OF TEST PROGRAM

The following list details pertinent information related to this specific project:

1.2.1 Participating Organizations
- Florida Department of Environmental Protection (FDEP)
- Zachary Engineering Corporation
- Florida Power and Light (FPL)
- Air Hygiene

1.2.2 Industry
- Electric Utility / Electric Services

1.2.3 Air Permit Number
- Permit Number: 0090006-005-AC

1.2.4 Plant Location
- Cape Canaveral Energy Center near Brevard County, Florida
- Universal Transverse Mercator (UTM) coordinates: Zone 17, 523.1km E and 3,149 km N
- GPS Coordinates [Latitude N 28 degrees 28.166' Longitude W 80 degrees 45.831']

1.2.5 Equipment Tested
- Siemens, 8000H, Unit 3B

1.2.6 Emission Points
- Exhaust from the Siemens, 8000H, Unit 3B

1.2.7 Pollutants Measured

- NOx
- CO
- THC/VOC
- NH_3
- Opacity
- H_2O
- O_2

1.2.8 Dates of Emission Test

- April 16-17, 2013

1.3 KEY PERSONNEL

Zachary Engineering Corporation:	Mike McCullough, PE	806-359-2650
Air Hygiene:	Nathan Arthur	918-307-8865
Air Hygiene:	Jake Fahlenkamp	918-307-8865

2.0 SUMMARY OF TEST RESULTS

Results from the sampling conducted on Zachary Engineering Corporation's Siemens, 8000H, Unit 3B located at the Cape Canaveral Energy Center on April 16-17, 2013 are summarized in the following table and relate only to the items tested.

TABLE 2.1
SUMMARY OF SIEMENS, 8000H, UNIT #3B RESULTS

Parameter	Base Load Load	Permit Limits	Base W/Db Load	Permit Limits
Date (mm/dd/yy)	04/16/13	--	04/17/13	--
Start Time (hh:mm:ss)	12:32:03	--	10:25:09	--
End Time (hh:mm:ss)	15:53:33	--	13:46:39	--
Run Duration (min / run)	60	--	60	--
Bar. Pressure (in. Hg)	30.15	--	29.88	--
Amb. Temp. (°F)	81	--	83	--
Rel. Humidity (%)	68	--	61	--
Spec. Humidity (lb water / lb air)	0.015502	--	0.014883	--
Load Designator	Base Load	--	Base w/DB	--
Turbine Fuel Flow (lb/min)	1,778	--	1,792	--
Duct Burner Fuel Flow (lb/min)	0	--	206	--
Total Fuel Flow (SCFH)	2,447,985	--	2,749,605	--
Stack Flow (RM19) (SCFH)	57,326,932	--	57,449,127	--
Stack Moisture (% Method 4 or 320)	9.4	--	10.3	--
Heat Input (MMBtu/hr)	2,450.3	--	2,752.9	--
Power Output (megawatts)	254.6	--	257.4	--
NH3 Flow (lb/hr)	367.80	--	367.80	--
NOx (ppmvd)	2.27	--	2.47	--
NOx (ppm@15%O_2)	1.75	2.00	1.69	2.00
NOx (lb/hr)	15.57	19.30	16.95	22.80
CO (ppmvd)	0.59	--	0.74	--
CO (ppm@15%O_2)	0.46	5.00	0.51	7.60
CO (lb/hr)	2.48	29.00	3.11	52.70
VOC (ppmvd)	0.17	--	0.04	--
VOC (ppm@15%O_2)	0.13	1.50	0.03	1.90
VOC (lb/hr)	0.40	4.80	0.10	7.20
NH_3 (ppmvd)	0.60	--	0.50	--
NH_3 (ppm@15%O_2)	0.46	5.00	0.34	5.00
Opacity (%)	0.00	--	0.00	--
O_2 (%)	13.21	--	12.28	--

The results of all measured pollutant emissions were below the required limits. All testing was performed without any real or apparent errors. All testing was conducted according to the approved testing protocol.

Emissions Compliance Test
Siemens, 8000H, Unit 3C
Zachary Engineering Corporation
Cape Canaveral Energy Center
Brevard County, Florida
April 16-17, 2013

1.0 INTRODUCTION

Air Hygiene International, Inc. (Air Hygiene) has completed the emissions testing study for nitrogen oxides (NOx), carbon monoxide (CO), total hydrocarbons/volatile organic compounds (THC/VOC), methane, ethane, ammonia (NH_3), opacity, moisture (H_2O), and oxygen (O_2) from the exhaust of the Siemens, 8000H, Unit 3C for Zachary Engineering Corporation at the Cape Canaveral Energy Center near Brevard County, Florida. This report details the background, results, process description, and the sampling/analysis methodology of the stack sampling survey conducted on April 16-17, 2013.

1.1 TEST PURPOSE AND OBJECTIVES

The purpose of the test was to conduct an initial compliance emission test to document levels of selected pollutants at two test loads (Base Load and Base Load with Duct Burners). The information will be used to confirm compliance with the operating permit issued by the Florida Department of Environmental Protection (FDEP). The specific objective was to determine the emission concentration of NOx, CO, THC/VOC, methane, ethane, NH_3, opacity, H_2O, and O_2 from the exhaust of Zachary Engineering Corporation's Siemens, 8000H, Unit 3C at Base Load with and without Duct Burners.

1.2 SUMMARY OF TEST PROGRAM

The following list details pertinent information related to this specific project:

1.2.1 Participating Organizations
- Florida Department of Environmental Protection (FDEP)
- Zachary Engineering Corporation
- Florida Power and Light (FPL)
- Air Hygiene

1.2.2 Industry
- Electric Utility / Electric Services

1.2.3 Air Permit Number
- Permit Number: 0090006-005-AC

1.2.4 Plant Location
- Cape Canaveral Energy Center near Brevard County, Florida
- Universal Transverse Mercator (UTM) coordinates: Zone 17, 523.1km E and 3,149 km N
- GPS Coordinates [Latitude N 28 degrees 28.166' Longitude W 80 degrees 45.831']

1.2.5 Equipment Tested
- Siemens, 8000H, Unit 3C

1.2.6 Emission Points
- Exhaust from the Siemens, 8000H, Unit 3C

1.2.7 Pollutants Measured
- NOx
- CO
- THC/VOC
- Methane
- Ethane
- NH_3
- Opacity
- H_2O
- O_2

1.2.8 Dates of Emission Test
- April 16-17, 2013

1.3 KEY PERSONNEL

Zachary Engineering Corporation:	Mike McCullough, PE	806-359-2650
Air Hygiene:	Nathan Arthur	918-307-8865
Air Hygiene:	Jake Fahlenkamp	918-307-8865

2.0 SUMMARY OF TEST RESULTS

Results from the sampling conducted on Zachary Engineering Corporation's Siemens, 8000H, Unit 3C located at the Cape Canaveral Energy Center on April 16-17, 2013 are summarized in the following table and relate only to the items tested.

TABLE 2.1
SUMMARY OF SIEMENS, 8000H, UNIT #3C RESULTS

Parameter	Base Load	Base Permit Limits	Base W/Db Load	Base w/DB Permit Limits
Date (mm/dd/yy)	04/16/13	--	04/17/13	--
Start Time (hh:mm:ss)	12:32:16	--	10:25:07	--
End Time (hh:mm:ss)	15:53:46	--	13:46:37	--
Run Duration (min / run)	60	--	60	--
Bar. Pressure (in. Hg)	30.15	--	29.88	--
Amb. Temp. (°F)	81	--	83	--
Rel. Humidity (%)	68	--	61	--
Spec. Humidity (lb water / lb air)	0.015458	--	0.014883	--
Unit Number	3C	--	3C	--
Load Designator	Base	--	Base w/DB	--
Turbine Fuel Flow (lb/min)	1,806	--	1,818	--
Duct Burner Fuel Flow (lb/min)	0	--	206	--
Total Fuel Flow (SCFH)	2,486,223	--	2,786,160	--
Stack Flow (RM19) (SCFH)	58,334,921	--	58,778,355	--
Stack Moisture (% Method 4 or 320)	4.4	--	4.3	--
Heat Input (MMBtu/hr)	2,488.8	--	2,790.2	--
Power Output (megawatts)	251.6	--	254.2	--
NH3 Flow (lb/hr)	366.30	--	413.70	--
NOx (ppmvd)	2.22	--	2.45	--
NOx (ppm@15%O_2)	1.71	2.0	1.69	2.0
NOx (lb/hr)	15.47	19.3	17.17	22.8
CO (ppmvd)	0.99	--	0.86	--
CO (ppm@15%O_2)	0.76	5.0	0.60	7.6
CO (lb/hr)	4.21	29.0	3.68	52.7
VOC (ppmvd)	0.99	--	0.91	--
VOC (ppm@15%O_2)	0.76	1.5	0.63	1.9
VOC (lb/hr)	2.41	4.8	2.21	7.2
NH_3 (ppmvd)	0.05	--	0.60	--
NH_3 (ppm@15%O_2)	0.04	5.0	0.42	5.0
Opacity (%)	0.00	10	0.00	10
O_2 (%)	13.23	--	12.36	--

The results of all measured pollutant emissions were below the required limits. All testing was performed without any real or apparent errors. All testing was conducted according to the approved testing protocol.

ATTACHMENT CCEC-EU1-IV1

IDENTIFICATION OF APPLICABLE REQUIREMENTS

Memorandum

Florida Department of Environmental Protection

TO:	Joseph Kahn, Director, Division of Air Resource Management
THROUGH	Trina Vielhauer, Chief, Bureau of Air Regulation TV
FROM:	Teresa Heron and Alvaro Linero, P.E., Special Projects Section T.H. aal
DATE:	July 1, 2009
SUBJECT:	DEP File No. 0090006-005-AC Florida Power and Light (FPL) Cape Canaveral Energy Center Plant Conversion Project

The final permit for this project is attached for your approval and signature, which authorizes construction of a nominal 1,250 megawatts (MW) combined cycle unit and ancillary equipment at the Cape Canaveral Plant that will be renamed the Cape Canaveral Energy Center. Two existing steam generators with a total nominal capacity of 800 MW will be shut down and dismantled as part of this project. The project results in a minor source air construction permit and is not subject to PSD preconstruction review.

The attached Final Determination summarizes the publication and comment process. There are no longer any pending petitions for administrative hearings or extensions of time in which to file a petition for an administrative hearing. We recommend your approval of the attached final permit for this project.

Attachments

TLV/aal/th

FINAL DETERMINATION

Air Construction Permit
Florida Power and Light Cape Canaveral Energy Center

DEP File No. 0090006-005-AC

PERMITTEE

Florida Power and Light Company (FPL)
700 Universe Boulevard
Juno Beach, Florida 33408

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

DEP File No. 0090006-005-AC
FPL Cape Canaveral Energy Center (CCEC)
Plant Conversion Project
Brevard County

The project is a plant conversion that includes the construction of a nominal 1,250 megawatts (MW) natural gas-fueled combined cycle unit (Unit 3) and requires the permanent shutdown and dismantlement of residual oil and natural gas-fueled Units 1 and 2 at the FPL Cape Canaveral Plant. The project did not require a review under the rules for the prevention of significant deterioration of air quality (PSD) or a determination of best available control technology (BACT). The converted plant will be called the Cape Canaveral Energy Center (CCEC). The address is 6000 North U.S. Highway 1 between Cocoa and Titusville in Brevard County.

Unit 3 will consist of:

- Three G-class or H-class combustion turbine-electrical generators (CTG) with evaporative inlet cooling systems;
- Three heat recovery steam generators (HRSG) with duct burners (DB) for supplementary gas firing and with selective catalytic reduction (SCR) reactors;
- Three 149-feet exhaust stacks; and
- One 500 MW steam-electrical generator (STG).

Unit 3 will use ultralow sulfur distillate (ULSD) fuel oil as backup fuel. Unit 3 will rely on some of the existing infrastructure including the water intake structures for once-through cooling and one of the fuel oil storage tanks.

Additional ancillary equipment to be installed includes: a permanent auxiliary boiler; a temporary boiler used during the construction phase; two emergency generators; two process (fuel) heaters; a diesel fire pump; and a gas compression station.

Air pollution control will be accomplished by SCR for the control of nitrogen oxides (NO_X) and efficient combustion of inherently low polluting fuels to control emissions of particulate matter (PM/PM_{10}), sulfur oxides (SO_2 and sulfuric acid mist), carbon monoxide (CO) and volatile organic compounds (VOC).

NOTICE AND PUBLICATION

The Department distributed a draft minor air construction permit package on March 13, 2009. The applicant published the Public Notice in Florida Today on March 20, 2009. The Department received the proof of publication on April 7, 2009. The Department granted extensions of time to file a petition for an administrative hearing on April 14 and June 10, 2009. The second extension expired on June 30, 2009 after which the Department is taking this final action.

COMMENTS

No written comments on the draft permit were received from the public or any agencies. Written comments were received from the applicant.

Applicant

On April 6, 2009, the Department received the main body of comments from the applicant. The Department received additional comments on May 11, May 29, June 5 and June 18, 2009. The following summarizes the comments and the Department's response.

1. FPL comment: Section I, page 2, Facility Description, 3rd bullet: Revise as follows - "Three nominal ~~428~~ 460 million Btu per hour ..."

   Department response: The Department agrees and notes that Section III.A., Specific Conditions 3 and 6 give a value of 460 million Btu per hour (mmBtu/hr). The Department will also clarify that the value is based on "maximum" rather than "nominal" heat input consistent with FPL comment No. 8 below.

2. FPL comment: Section I, page 2, Facility Description, 3rd paragraph: Revise as follows - "Unit 3 will use ultra low-sulfur ~~diesel~~ distillate (ULSD) fuel oil as backup fuel. Unit 3 will rely on some of the existing infrastructure including ~~the cooling water system and~~ one of the fuel oil storage tanks."

   Department response: The Department will change ultralow sulfur "diesel" to the slightly more general term of ultralow sulfur "distillate". The ULSD specification of 0.0015 percent sulfur will be maintained. The Department will remove the second reference to the cooling water system because it is mentioned earlier in the same section.

3. FPL comment: Section I, page 2, New Emission Units, ID No. 010: Revise as follows - "Two nominal 10-mmBtu/hr natural gas-fired process heaters (one is a spare)."

   Department response: The Department will make this change.

4. FPL comment: Section II, page 5, Condition No. 8: Revise as follows - "... and dismantled before ~~December 31, 2010~~ December 31, 2011."

   Department response: The Department will make this change. It is clear that the shut down and dismantlement of the two existing units must occur before installation of the replacement unit can begin on the same plot of land. Operation of the new unit cannot feasibly occur for at least one year after the shut down and dismantlement of the existing units.

5. FPL comment: Section III.A, page 8, Condition 2: Please delete the permitting note, as it is included in the Technical Evaluation document and has no bearing on this permit condition.

   Department response: The Department will delete the permitting note that sought to explain the difference between a "G" Class unit and an "H" Class unit.

6. FPL comment: Section III.A, page 8, Condition 3: Revised as follows - "...having a ~~nominal~~ maximum heat input rate of 460 mmBtu/hr (LHV)."

Department response: See Comment 1 above.

7. FPL comment: Section III.A, page 9, Condition 5: Revise the heat input rating while firing natural gas to reflect the agreed-upon 7.5 percent increase, as follows - "The maximum heat input rate to each CTG is ~~2,490~~ 2,586 mmBtu/hr when firing natural gas and..."

   Department response: The Department originally added 7.5 percent (%) to the nominal heat input rate assuming installation of a Siemens "H" Class unit firing natural gas. The basis should have been a Mitsubishi "G" Class unit firing natural gas. The correction will be made as requested.

8. FPL comment: Section III.A, page 9, Condition 6: Revise the permitted capacity as follows—"The total ~~nominal~~ maximum heat input rate to the DB for each HRSG..."

   Department response: See Comment 1 above.

9. FPL comment: Section III.A, page 10, Condition 10, footnote d: Please clarify what is meant by "basic DB mode".

   Department response: The Department will remove the term "basic" as there is only one DB mode.

10. FPL comment: Section III.A, page 12, Condition 17: Revise as follows - "... the permittee shall provide the Compliance Authority with an advance notice of at least ~~7~~ 3 days..." If this revision is not acceptable to the Department, then FPL requests clarification on the phrase "maintenance to a combustor" as used in the condition.

    Department response: A 7-day notice is a proper time frame to advise the Department regarding "major tuning sessions". The requirement for the West County Energy Center (WCEC) is even greater (14 days). The same terms used in Condition 17 were included in the FPL Turkey Point Unit 5 permit and in the WCEC permit.

    During subsequent discussions with FPL, the company advised that they don't necessarily wish to exclude data for some of the work described in the condition. The condition will allow rather than require data exclusion and will be further clarified as follows:

    17. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions ~~shall~~ may be excluded by the permittee from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" ~~would~~ may 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, where the intent is to exclude data from the CEMS compliance demonstration, 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.]

11. FPL issue: Section III.A, Condition 20: In its original application, FPL requested initial compliance testing schedule relief from 40 CFR 60, Subparts A and KKKK for the first (and only for the first) installed CTG in the event that the Siemens H technology is selected for the project. The comment relates to the same issue but is now moot and is withdrawn because the request for relief from the Subpart A and Subpart KKKK has been withdrawn.

    Department response: The Department will clarify the condition consistent with the mentioned withdrawal but will retain the conditions in the draft permit that provided relief from the initial compliance testing schedule from the more stringent state implementation plan (SIP) permit emission limits. Section III.A, Condition 20 is revised as follows:

20. Initial Compliance Determinations if "H" Technology CTG are Utilized: In the event CTG incorporating "H" level technology ~~(described in Specific Condition 2 above)~~ are selected for use at the CCEC, the initial compliance tests for the first, and only for the first, installed CTG to demonstrate achievement of the emission limits listed in Specific Condition 10 above shall be conducted within 180 days after achieving the maximum production rate at which the unit will be operated, but not later than 300 days after the initial startup of the unit. ~~[Subject to final approval by EPA]~~

{The additional 120 day test period ~~will~~ may be required to allow comprehensive commissioning, testing, and tuning of the "H" technology CTG. This condition does not exempt the CTG from the applicable requirements in 40 CFR 60, Subpart A or in 40 CFR 60, Subpart KKKK.}

Furthermore, the Department will modify Section III.A, Condition 24.a. regarding installation of CO CEMS to comport with the additional time provided for compliance with the permit limits for the first CTG installed at the facility. The condition is modified as follows:

a. *CO Monitors:* For each CTG, ~~T~~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. If "H" technology CTG are utilized, the described certification shall be performed on the CEMS associated with the first, and only with the first, installed CTG within 180 calendar days of achieving permitted capacity, but no later than 300 calendar days after initial startup. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report in 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.

12. FPL comment: Section III.D, page 21, Condition 6: As the applicable NSPS Subpart JJJJ does not regulate opacity, a standard of 20% was proposed by FPL. It is requested that the limit of 10% in the current draft permit be revised to the 20% value originally requested.

Department response: In fact a value of 10% was originally requested by the applicant per Section 5, page 28 of the application form. In Section 5, page 31 of the application form both a 20% emission limit (basis Section 62-296.320(4)(b)1, Florida Administrative Code) and a 10% requested limit (to limit particulate matter) were included. According to the application, the air emission controls are representative of best available control technology (BACT) emission limits that have been determined under PSD regulations for other similar combined cycle units [e.g., PSD-FL-396, July 30, 2008, for West County Energy Center (WCEC) Unit 3]. A 20% limit would be inconsistent with the particulate matter (PM) limits established for the subject natural gas-fueled compressors. The Department will leave the 10% limit.

13. FPL comment: Section III.D, page 21, Condition 8: NSPS Subpart JJJJ (40 CFR 60.4243) allows for compliance with applicable emission limits to be demonstrated by manufacturer certification. FPL requests that this permit condition allow for the use of a manufacturer certification in lieu of compliance testing for the natural gas-fired compressor units. Alternatively, if the Department requires testing, FPL requests that one of the seven units be selected for testing as representative of all of the units.

Department response: The governing Subpart JJJJ provides for compliance by manufacturer certification. If the owner demonstrates compliance by tests, then all seven compressors must be tested as described in the draft permit. Each compressor is a source for purposes of 40 CFR 60, Subpart A and Subpart JJJJ. The condition will be changed as follows:

8. Compressor Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO, VOC, NO_X 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. With the exception of visible emissions testing, manufacturer certification can be provided to the Department in lieu of actual testing. [Rule 62-297.310(7)(a)1, F.A.C.; 40 CFR 60.8 and 40 CFR 60.4244]

14. FPL comment: Section III.E, page 23, Condition 5: FPL requests that this condition be revised to clarify that a manufacturer's certification may be used in lieu of stack testing to demonstrate compliance with the applicable permits, per NSPS Subpart IIII, 40 CFR 60.4211, which are as stringent as BACT values.

    Department response: The Department agrees with FPL that a manufacturer's certification of the two liquid fueled emergency generators may be used in lieu of stack testing to demonstrate compliance with the applicable permits. Specific Condition 5 will be revised accordingly.

15. FPL comment: Section III.E, page 23, Condition 6: Revise as follows - "Each ~~natural gas compressor~~ liquid-fueled emergency generator..."

    Department response: The Department will correct the condition as the section pertains to emergency generators.

16. FPL comment: Section III.E, page 23, Condition 7: Revise as follows—"The permittee shall maintain records of the amount of natural gas used in the ~~process heaters~~ emergency generators..."

    Department response: The Department will correct the condition as the section pertains to emergency generators and also correct the reference to natural gas that should indicate fuel oil.

17. FPL comment: Section IV, Appendix SC, page SC-3, Condition 20: Revise as follows—"... by ~~March 1st~~ April 1st..."

    Department response: The condition will be corrected as requested.

18. FPL comments regarding the technical evaluation: FPL submitted a number of comments on and recommended changes to the Department technical evaluation and preliminary determination document distributed with the draft permit.

    Department response: Most comments and changes relate to matters discussed in comments and changes to the draft permit discussed above. The document is actually a final document that reflects the technical evaluation conducted to make the preliminary decision to issue the permit. The comments by FPL are noted. The present final determination document reflects the evaluation to support the decision to issue a final permit.

19. Additional FPL comment (May 11, 2009): Section III.B, Condition 2: FPL requests the following- "The hours of operation of the auxiliary boiler shall not exceed ~~500~~ 1,000 hours per year." This request for an increase in hours of operation does not change any of the standards that CCEC would be required to meet.

    Department response: See responses to comments 21 and 22 below.

20. Additional FPL comment (May 29, 2009): Section III.B, Condition 9. FPL requests the following: "The hours of operation of the temporary boiler shall not exceed ~~500~~ 1,000 hours per year and the temporary boiler shall not operate beyond the expiration date of this permit." This request for an

increase in hours of operation does not change any of the standards that CCEC would be required to meet.

Department response: See response to comment 23 below.

21. Additional FPL comment (June 5, 2009): Section III.B, Condition 1. FPL requests the following:

    1. Equipment: The permittee is authorized to install, operate, and maintain one auxiliary boiler with a maximum design heat input of 99.8 mmBtu/hr (85,000 lb/hr) to produce steam during start up of the CTG. The permittee is authorized to operate the auxiliary boiler during the construction period of Unit 3, as well as during permanent operation after the completion of construction. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

    Department response: The Department agrees that the auxiliary boiler may be used during the construction phase as well as during the permanent operation of Unit 3 within the allocation of 1000 hours per year described in comment 19 above. The permit will be modified as requested by FPL.

22. Additional FPL comment (June 5, 2009): Section III.B, Condition 2. FPL requests the following:

    2. Hours of Operation: The hours of operation of the auxiliary boiler shall not exceed ~~500~~ 1000 hours per year. Prior to expiration of this permit and commencement of commercial operation of the combined cycle system which it supports, the auxiliary boiler shall not exceed 4000 hours per year. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

    Department response: The Department agrees that the auxiliary boiler may be used for 1,000 hours per year as requested in comment 19 above but not 4,000 hours per year as subsequently requested.

23. Additional FPL comment (June 5, 2009): Section III.B, Condition 9. FPL requests the following:

    9. Hours of Operation: The hours of operation of the temporary boiler shall not exceed ~~500~~ 4,000 hours per year and the temporary boiler shall not operate beyond the expiration date of this permit. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

    Department response: The Department agrees that the temporary boiler may be used for 1,000 hours per year as requested in comment 20 above but not 4,000 hours per year as subsequently requested.

24. Additional FPL comment (June 18, 2009): Section III.A, Condition 25.e. FPL requests insertion of the same language in the CCEC permit that was acceptable for Condition 24.e of the Riviera Beach Energy Center (RBEC) permit, allowing for the exclusion of CO data in the event an oxidation catalyst is required. The CCEC permit could be revised with a similar Condition 25.e for consistency between the 2 facilities.

    Department response: The Department will identify a new case for data exclusion within Section III.A, Condition 25, CEMS Data Requirements as follows:

    e. *Data Exclusion during Installation of Oxidation Catalyst:* The permittee may exclude CO CEMS data in excess of the 8.0 ppmvd @15% O_2 from the 30 operating day rolling average calculation during the installation of the oxidation catalyst (which shall not exceed 12 months) provided all reasonable efforts are used to minimize such emissions. However, all CEMS data must be included when determining whether there is a net emission increase (as defined in Section 62-210.200 (definitions), F.A.C.) of CO greater than or equal to the significant emissions rate of 100 tons per year.

CONCLUSION

The final action of the Department is to issue the permit with the changes, corrections and clarifications as described above.

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

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Mr. Randall R. LaBauve, Vice President
Florida Power and Light Company (FPL)
700 Universe Boulevard
Juno Beach, Florida 33408

DEP File No. 0090006-005-AC
FPL Cape Canaveral Energy Center
Conversion Project
Brevard County

Enclosed is the final air construction permit, which authorizes construction/installation of a nominal 1,250 megawatts (MW) natural gas-fueled combined cycle unit and requires the shut down and dismantlement of the two 400 MW residual oil and gas-fueled units at the FPL Cape Canaveral Plant located in Brevard County at 6000 North U.S. Highway 1, between Cocoa and Titusville. This permit is issued pursuant to Chapter 403, Florida Statutes (F.S.).

Any party to this order has the right to seek judicial review of it under Section 120.68, F.S. 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 (Department) in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina 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 Final Determination), or a link to these documents available electronically on a publicly accessible server was sent by electronic mail with received receipt requested before the close of business on July 23, 2009 to the persons listed below.

Randall R. LaBauve, FPL: randall_labauve@fpl.com
Chair, Brevard Board of County Commissioners: chuck.nelson@brevardcounty.us
Manager, City of Cocoa: rholt@cocoafl.org
Manager, City of Titusville through his Executive Assistant: kathy.daniels@titusville.com
Dick Dubose, EPA Region 4: dubose.dick@epa.gov
Heather Abrams, EPA: abrams.heather@epa.gov
Katy Forney, EPA: forney.kathleen@epa.gov
Dee Morse, U.S. National Park Service: dee_morse@nps.gov
Meredith Bond, U.S. Fish and Wildlife Service: meredith_bond@fws.gov
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Barbara Linkiewicz, FPL: barbara_p_linkiewicz@fpl.com
Scott Osbourn, P.E., Golder: sosbourn@golder.com
Victoria Gibson (read file), DEP BAR: victoria.gibson@dep.state.fl.us

Clerk Stamp

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

(Clerk) 7/23/09 (Date)

Florida Department of
Environmental Protection
Bob Martinez Center
2600 Blairstone Road
Tallahassee, Florida 32399-2400

PERMITTEE:

Florida Power and Light Company (FPL)
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:
Randall R. LaBauve, Vice President

DEP File No. 0090006-005-AC
FPL Cape Canaveral Energy Center
Plant Conversion Project
Brevard County
SIC No. 4911
Expires: December 31, 2014

PROJECT AND LOCATION

This permit authorizes the construction of one nominal 1,250 megawatts (MW) combined cycle unit and ancillary equipment at the FPL Cape Canaveral Energy Center previously known as the Cape Canaveral Plant.

Two existing steam generators designated with a total nominal capacity of 800 MW will be shut down and dismantled as part of this project.

The proposed project will be located at 6000 North U.S. Highway 1 between Cocoa and Titusville in Brevard County. The UTM coordinates are Zone 17, 523.1 kilometers (km) East and 3,149 km North.

STATEMENT OF BASIS

This air construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.). 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.

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7/23/09

Joseph Kahn, Director (Date)
Division of Air Resource Management

FACILITY DESCRIPTION

FPL operates the Cape Canaveral Plant (CCP), which is an existing power plant (SIC No. 4911). The plant currently consists of two steam generating units designated as Units 1 and 2 that produce 400 MW each of electrical power. Units 1 and 2 use residual fuel oil and natural gas. There are two 397-foot stacks, two fuel oil storage tanks, water intake structures for once-through cooling and other ancillary equipment.

The project is a plant conversion that includes the construction of a nominal 1,250 MW natural gas-fueled combined cycle unit (Unit 3) and requires the permanent shutdown and dismantling of Units 1 and 2. The converted plant will be called the Cape Canaveral Energy Center (CCEC). Unit 3 will consist of:

- Three nominal 265 MW combustion turbine-electrical generators (CTG) with evaporative inlet cooling systems;
- Three supplementary-fired heat recovery steam generators (HRSG) with selective catalytic reduction (SCR) reactors;
- Three maximum 460 million Btu per hour, lower heating value (mmBtu/hr, LHV), natural gas-fueled duct burners (DB) located in the three HRSG (one DB/HRSG);
- Three 149-feet exhaust stacks; and
- One common nominal 500 MW steam-electrical generator (STG).

Unit 3 will use ultralow sulfur distillate (ULSD) fuel oil as backup fuel. Unit 3 will rely on some of the existing infrastructure including one of the fuel oil storage tanks.

Additional ancillary equipment to be installed includes: a permanent auxiliary boiler; a temporary boiler used during the construction phase; two emergency generators; two process (fuel) heaters; a diesel fire pump; and a gas compression station. The details of the equipment to be installed are listed in the table below.

The project includes and requires the permanent shutdown and dismantlement of Units 1 and 2 and the respective stacks as well as one of the fuel oil storage tanks. When emissions from Unit 3 are considered and offset by reductions from the shut down and dismantlement of Units 1 and 2, there will not be a significant net emission increase in any PSD pollutant.

{Note: Throughout this permit, the electrical generating capacities represent nominal values for the given operating conditions.}

NEW EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units.

ID	Emission Unit Description
006	Unit 3A – one nominal 265 MW CTG with supplementary-fired HRSG
007	Unit 3B – one nominal 265 MW CTG with supplementary-fired HRSG
008	Unit 3C – one nominal 265 MW CTG with supplementary-fired HRSG
009	One nominal 85,000 pounds per hour (lb/hr) auxiliary boiler (99.8 mmBtu/hr)
010	Two nominal 10 mmBtu/hr natural gas-fired process heaters (one is a spare)
011	Seven nominal 1,340 horsepower (hp) natural gas compressors
012	Two nominal 2,250 kilowatts (kW) liquid fueled emergency generators
013	One nominal 300-hp emergency diesel fire pump engine and 500 gallon fuel oil storage tank
014	One temporary 110 mmBtu/hr natural gas-fueled boiler to be used only during construction

REGULATORY CLASSIFICATION

The CCP is a "Major Stationary Source" as defined in Rule 62-210.200, Florida Administrative Code (F.A.C.). The CCEC project does not trigger the rules for the Prevention of Significant Deterioration (PSD) pursuant to Rule 62-212.400, F.A.C. and does not require a best available control technology (BACT) determination.

The CCEC will be a Title V or "Major Source" of air pollution in accordance with Chapter 213, F.A.C. because the potential emissions of at least one regulated pollutant exceed 100 tons per year (TPY). Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfur dioxide (SO_2), volatile organic compounds (VOC) and sulfuric acid mist (SAM).

The CCEC will be subject to several subparts under 40 Code of Federal Regulations (CFR), Part 60 – Standards of Performance for New Stationary Sources (NSPS). Unit 3 is subject to 40 CFR 60, Subpart KKKK – NSPS for Stationary Combustion Turbines that Commence Construction after February 18, 2005. This rule also applies to duct burners (DB) that are incorporated into combined cycle projects.

Two emergency generators will be subject to 40 CFR 60, Subpart IIII – NSPS for Stationary Compression Ignition Internal Combustion Engines.

Natural gas compressors will be subject to 40 CFR 60, Subpart JJJJ – NSPS for Stationary Spark Ignition Internal Combustion Engines.

The temporary natural gas-fueled boiler will be subject to 40 CFR 60, Subpart Db – NSPS for Industrial-Commercial-Institutional Steam Generating Units.

The auxiliary boiler and two process (fuel) heaters will be subject to 40 CFR 60, Subpart Dc – NSPS Requirements for Small Industrial-Commercial-Institutional Steam Generating Units.

The CCEC will be a minor (area source) of hazardous air pollutants (HAP). The CCEC will include emission units that will be subject to certain area source provisions of 40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants (NESHAP). The specific subpart is 40 CFR 63, Subpart ZZZZ – NESHAP for Stationary Reciprocating Internal Combustion Engines (RICE).

The CCEC will operate units subject to the Title IV Acid Rain provisions of the Clean Air Act (CAA).

The CCEC is subject to the Clean Air Interstate Rule (CAIR) in accordance with the Final Department Rules issued pursuant to CAIR as implemented by the Department in Rule 62-296.470, F.A.C.

The project is subject to certification under the Florida Power Plant Siting Act, 403.501-518, Florida Statutes (F.S.) and Chapter 62-17, F.A.C.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A: Identification of General Provisions Subpart A from NSPS 40 CFR 60 and Subpart A from NESHAP 40 CFR 63.

Appendix GC: General Conditions.

Appendix Db: NSPS Subpart Db Requirements for Industrial-Commercial-Institutional Steam Generating Units.

Appendix Dc: NSPS Subpart Dc Requirements for Small Industrial Commercial-Institutional Steam Generating Units.

Appendix IIII: NSPS Requirements for Compression Ignition Internal Combustion Engines.

Appendix JJJJ: NSPS Requirements for Stationary Spark Ignition Internal Combustion Engines.

Appendix KKKK: NSPS Requirements for Gas Turbines, 40 CFR 60, Subpart KKKK.

Appendix SC: Standard Conditions.

Appendix XS: Semiannual NSPS Excess Emissions Report.

Appendix ZZZZ: NESHAP Requirements for Stationary Reciprocating Internal Combustion Engines, 40 CFR 63, Subpart ZZZZ.

RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Permit application received on December 30, 2008;
- Supplemental information received on February 11, 2009;
- Draft permit package issued on March 13, 2009; and
- Final Determination accompanying final permit issued on July 1, 2009.

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Permitting Authority, which is the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP or the Department) at 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority. Telephone: (850)488-0114. Fax: (850)921-9533.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Central District Office. The mailing address and phone number of the Central District Office are: Department of Environmental Protection, Central District Office, 3319 Maguire Boulevard, Suite 232, Orlando Florida 32803-3767. Telephone: (407)894-7555. Fax: (407)897-5963.

3. Appendices: The following Appendices are attached as part of this permit: Appendices A, Db, Dc, GC (General Conditions), IIII, JJJJ, KKKK, SC, XS and ZZZZ.

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S.; and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.

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: No emissions unit 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. For good cause, the permittee may request that this air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, and 62-210.300(1), F.A.C.]

8. Permanent Shutdown and Dismantlement of Units 1 and 2: Units 1 and 2 shall be permanently shut down and dismantled before December 31, 2011.
[Application and Avoidance of Rule 62-212.400(4) through (12), F.A.C.]

9. 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.]

10. 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 (EPA) 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]

11. Title V Permit: This permit authorizes specific modifications and/or new construction on the affected emissions units as well as initial operation to determine compliance with conditions of this permit. 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 completing the required work and 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 Bureau of Air Regulation with copies to the Compliance Authority.
[Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. UNIT 3 – COMBUSTION TURBINE GENERATORS (EU 006, 007, and 008)

This section of the permit addresses the following emissions units.

Unit 3 and associated equipment
Description: Unit 3 will be comprised of emissions units (EU) 006, 007, and 008. Each EU will consist of: a CTG with automated control, inlet air filtration system and evaporative cooling, a gas-fired HRSG with DB, a HRSG stack, and associated support equipment. The project also includes one STG that will serve the combined cycle unit. **Fuels**: Each CTG fires natural gas as the primary fuel and ULSD fuel oil as a restricted alternate fuel. **Generating Capacity**: Each of the three CTG has a nominal generating capacity of 265 MW. The STG has a nominal generating capacity of 500 MW. The total nominal generating capacity of the "3 on 1" combined cycle unit is approximately 1,250 MW. **Controls**: The efficient combustion of natural gas and restricted firing of ULSD fuel oil minimizes the emissions of CO, PM/PM_{10}, SAM, SO_2 and VOC. Dry Low-NO_X (DLN) combustion technology for gas firing and water injection for oil firing reduce NO_X emissions. A SCR system further reduces NO_X emissions. **Stack Parameters**: Each HRSG has a stack at least 149 feet tall with a nominal diameter of 22 feet. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. **Continuous Monitors**: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NO_X emissions as well as flue gas oxygen or carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

1. NSPS Requirements: The CTG 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. The Department determines that compliance with the emissions standards in Condition 10 below also assures compliance with the New Source Performance Standards given in 40 CFR 60, Subpart KKKK. Some separate reporting and monitoring may be required by the individual subparts.

   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 Gas Turbines*: These provisions include standards for CTG and DB.

EQUIPMENT AND CONTROL TECHNOLOGY

2. Combustion Turbines-Electrical Generators (CTG): The permittee is authorized to install, tune, operate, and maintain three "G" or "H" technology CTG each with a nominal generating capacity of 265 MW. Each CTG shall include an automated control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system and an evaporative inlet air-cooling system. The CTG will utilize DLN combustors. [Application and Design]

3. Heat Recovery Steam Generators (HRSG): The permittee is authorized to install, operate, and maintain three new HRSG with separate exhaust stacks. Each HRSG shall be designed to recover exhaust heat energy from one of the three CTG (3A to 3C) and deliver steam to the steam turbine-electrical generator (STG). Each HRSG may be equipped with a gas-fired duct burner (DB) having a maximum heat input rate of 460 mmBtu per hour (LHV).

4. CTG/Supplementary-fired HRSG Emission Controls

   a. *Dry Low NO_X (DLN) Combustion*: The permittee shall operate and maintain the DLN system to control NO_X emissions from each CTG when firing natural gas. Prior to the initial emissions performance tests required for each CTG, the DLN combustors and automated control system shall be tuned to achieve sufficiently low CO and NO_X values to meet the CO and NO_X limits with the additional SCR control technology described below. Thereafter, each turbine shall be maintained and tuned in accordance with the manufacturer's recommendations.

   b. *Wet Injection (WI)*: The permittee shall install, operate, and maintain a WI system (water or steam) to reduce NO_X emissions from each CTG when firing ULSD fuel oil. Prior to the initial emissions performance tests required for each CTG, the WI system shall be tuned to achieve sufficiently low CO and NO_X values to meet the CO and NO_X limits with the additional SCR control technology described below. Thereafter, each turbine shall be maintained and tuned in accordance with the manufacturer's recommendations.

   c. *Selective Catalytic Reduction (SCR) System*: The permittee shall install, tune, operate, and maintain an SCR system to control NO_X emissions from each CTG when firing either natural gas or distillate fuel oil. 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.

   d. *Oxidation Catalyst*: The permittee shall design and build the project to facilitate possible future installation of an oxidation catalyst system to control CO emissions from each CTG/supplementary-fired HRSG.

   e. *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.

   [Application and Design; Rule 62-4.070, F.A.C.]

PERFORMANCE RESTRICTIONS

5. Permitted Capacity – Combustion Turbine-Electric Generators (CTG): The maximum heat input rate to each CTG is 2,586 mmBtu per hour when firing natural gas and 2,440 mmBtu per hour when firing distillate fuel oil (based on a compressor inlet air temperature of 59° F, LHV of each fuel, and 100% load). Heat input rates will vary depending upon CTG characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

6. Permitted Capacity - HRSG Duct Burners (DB): The total maximum heat input rate to the DB for each HRSG is 460 mmBtu per hour based on the LHV of natural gas. Only natural gas shall be fired in the DB. [Rule 62-210.200(PTE), F.A.C.]

7. Authorized Fuels: The CTG shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet (gr S/100 SCF) of natural gas. As a restricted alternate fuel, the CTG may fire ULSD fuel oil containing no more than 0.0015% sulfur by weight. Fuel oil may be fired up to the fuel equivalent of 3,000 hours aggregated over the three CTG during any calendar year. [Rules 62-210.200(PTE), F.A.C.]

8. Hours of Operation: Subject to the operational restrictions of this permit, the CTG may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below. [Rules 62-210.200(Definitions - PTE), F.A.C.]

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

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

   b. *Inlet Conditioning*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power.

   c. *Duct Burner (DB) Firing*: When firing natural gas in a CTG, the respective HRSG may fire natural gas in the DB to raise additional steam for use in the STG or in the operation of CTG components. The total combined heat input rate to the DB (all three HRSG) shall not exceed 3,697,920 mmBtu (LHV) during any consecutive 12 months.

   [Application; Rule 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

10. Emissions Standards: Emissions from each CTG/DB shall not exceed the following standards developed under state implementation plan (SIP) permitting procedures. Compliance with these limits also assures compliance with the emission limitations in 40 CFR 60, Subpart KKKK.

Pollutant	Fuel	Method of Operation	Initial Stacks Tests		CEMS Rolling Average Limit
			ppmvd [a]	lb/hr [b]	ppmvd [a]
CO [d]	Oil	CTG	10.0	61.0	10.0, 30 unit operating days [c,d]
	Gas	CTG & DB	7.6	52.7	8.0, 30 unit operating days [c,d]
		CTG Normal Mode	5.0	29.0	
NO_X [e]	Oil	CTG	8.0	80.0	8.0, 30 unit operating days [c,e]
	Gas	CTG & DB	2.0	22.8	2.0, 30 unit operating days [c,e]
		CTG Normal Mode	2.0	19.3	
VOC [f]	Oil	CTG	6.0	18.9	NA
	Gas	CTG & DB	1.9	7.2	
		CTG Normal Mode	1.5	4.8	
NH_3 [g]	Oil/Gas	CTG, All Modes	5	NA	NA
SAM/SO_2 [h]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
PM/PM_{10} [i]			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		

a. Concentration standards are given in terms of parts per million, by volume, dry at 15 percent oxygen and abbreviated as ppmvd.

b. The mass emission rate standards in pounds per hour (lb/hr) 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 filed with the Department.

c. "Unit operating day" means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period. [40 CFR 60.4420]

d. Compliance with the continuous 30-unit operating days rolling CO standard shall be demonstrated based on data collected by the required CEMS. The initial EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate initial performance guarantees for natural gas, oil, and DB mode.

e. Continuous compliance with the 30-unit operating days rolling NO_X standards shall be demonstrated based on data collected by the required CEMS and will also insure compliance with the less stringent Subpart KKKK limits of 15 and 42 ppmvd for gas and fuel oil respectively on a 30-unit operating day rolling average basis. The initial EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart KKKK or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as nitrogen dioxide (NO_2).

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

g. Compliance with the NH_3 slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.

h. The clean fuel sulfur specifications and visible emissions standard effectively limit the potential emissions of SAM and SO_2 from the CTG. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.

i. The clean fuel sulfur specifications, low CO and NO_X limits, and the visible emissions standard will effectively limit $PM/PM_{10}/PM_{2.5}$ emissions. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

[Application and Avoidance of Rule 62-212.400(4) through (12), F.A.C.; 40 CFR 60, Subpart KKKK]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 10 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.}

11. Operating Procedures: The emission standards 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 CTG, DB, HRSG, 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), F.A.C.]

12. 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. [Applicant Request and Rule 62-4.070(3), F.A.C.]

13. 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.]

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

15. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, fuel switching and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For each CTG/HRSG system, excess emissions of NO_X and CO resulting from startup, shutdown, or 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. *STG/HRSG System Cold Startup*: For cold startup of the steam turbine system, excess NO_X and CO emissions from any CTG/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 3-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 STG system, each CTG/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the STG and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}

    b. *Shutdown Steam Turbine System*: For shutdown of steam turbine system, excess NO_X and CO emissions from any CTG/HRSG system shall not exceed three (3) hours in any 24-hour period.

c. *CTG/HRSG System Cold Startup*: For cold startup of a CTG/HRSG system, excess NO_X and CO emissions shall not exceed four (4) hours in any 24-hour period. "Cold startup of a CTG/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

d. *Fuel Switching*: For fuel switching, excess NO_X and CO emissions shall not exceed two (2) hours in any 24-hour period.

16. Ammonia Injection: Ammonia injection shall begin as soon as operation of the CTG/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the CTG.
[Design; Rules 62-4.070(3) and 62-210.700, F.A.C.]

17. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions may be excluded by the permittee from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" may occur after completion of initial construction, a major repair, or other similar circumstances. Prior to performing any major tuning session, where the intent is to exclude data from the CEMS compliance demonstration, 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

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

Method	Description of Method and Comments
CTM-027 or 320	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.} 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. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C.
[Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

19. Initial Compliance Determinations: Initial compliance 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 the unit, unless the alternate initial compliance test timeline in Condition 20 applies. Each CTG shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X, VOC, visible emissions, and ammonia slip. Each unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. Referenced method data collected during the required Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the initial CO and NO_X standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NO_X 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]

20. Initial Compliance Determinations if "H" Technology CTG are Utilized: In the event CTG incorporating "H" level technology are selected for use at the CCEC, the initial compliance tests for the first, and only for the first, installed CTG to demonstrate achievement of the emission limits listed in Specific Condition 10 above shall be conducted within 180 days after achieving the maximum production rate at which the unit will be operated, but not later than 300 days after the initial startup of the unit.

{The additional 120 day test period may be required to allow comprehensive commissioning, testing, and tuning of the "H" technology CTG. This condition does not exempt the CTG from the applicable requirements in 40 CFR 60, Subpart A or in 40 CFR 60, Subpart KKKK.}

21. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 30-unit operating days rolling average CO and 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 62-4.070(3), F.A.C.; 40 CFR 60, Subpart KKKK]

22. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each CTG shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia slip. 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. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period.

{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions. The Department retains the right to require VOC testing if CO limits are exceeded or for the reasons given in Appendix SC, Condition 17, Special Compliance Tests.}

[Rules 62-4.070(3) and 62-297.310(7)(a)4, F.A.C.]

23. Compliance for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$: In stack compliance testing is not required for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$. Compliance with the limits and control requirements for SAM, SO_2 and $PM/PM_{10}/PM_{2.5}$ is based on the recordkeeping required in Specific Condition 29, the visible emissions standard and the CO/NO_X continuous monitoring. [Rule 62-4.070(3), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

24. Continuous Emissions Monitoring System(s) (CEMS): The permittee shall install, calibrate, maintain, and operate CEMS to measure and record the emissions of CO and NO_X from the combined cycle CTG 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:* For each CTG, 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. If "H" technology CTG are utilized, the described certification shall be performed on the CEMS associated with the first, and only with the first, installed CTG within 180 calendar days of achieving permitted capacity, but no later than 300 calendar days after initial startup. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report in 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 and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

25. CEMS Data Requirements:

    a. *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 corrected to 15% oxygen. 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 International Organization of Standardization (ISO) conditions.

    b. *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.

c. *30-Unit Operating Day Rolling Averages*: Compliance shall be determined after each operating day by calculating the arithmetic average of all the valid hourly averages from that operating day and the prior 29 operating days. For purposes of determining compliance with the 30-unit operating day rolling CEMS standards, the missing data substitution methodology of 40 CFR Part 75, subpart D, shall not be utilized. Instead, the 30-unit operating day rolling average shall be determined using the remaining hourly data in the 30-day rolling period.

  {Permitting Note: There may be more than one 30-unit operating day compliance demonstration required for CO and NO_X emissions depending on the use of alternate fuels.}

d. *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 CEMS compliance demonstration subject to the provisions of Condition Nos. 15 and 17 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.

e. *Data Exclusion during Installation of Oxidation Catalyst:* The permittee may exclude CO CEMS data in excess of the 8.0 ppmvd @15% O_2 from the 30 operating day rolling average calculation during the installation of the oxidation catalyst (which shall not exceed 12 months) provided all reasonable efforts are used to minimize such emissions. However, all CEMS data must be included when determining whether there is a net emission increase [as defined in Section 62-210.200 (definitions), F.A.C.] of CO greater or equal to the significant emissions rate of 100 tons per year.

f. *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, except as otherwise authorized by the Department's Compliance Authority.

[Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; 40 CFR 60, Appendix F - Quality Assurance Procedures; and Rules 62-4.070(3), F.A.C.]

26. 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 combustion turbine load condition. [Rules 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

27. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each CTG and HRSG DB system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown, malfunction and fuel switching). Such monitoring shall be made using a monitoring component of the CEMS 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. [Rule 62-4.070(3), F.A.C.]

28. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each CTG 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), F.A.C.]

29. 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:* 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 or more recent versions.

    b. *ULSD Fuel Oil:* 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 may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

    The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75, Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

30. 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.].

31. 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 and NO_X emissions in excess of the permit emission 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.

   c. *NSPS Semi-Annual Excess Emissions Reports*: For purposes of reporting emissions in excess of NSPS Subpart KKKK, excess emissions from the CTG are defined as: a specified averaging period over which either the NO_X emissions are higher than the applicable emission limit in 40 CFR 60.4320; or the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in 60.4330. Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions that occurred during the previous semi-annual period to the Compliance Authority.

   {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 60.4420]

32. 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 April 1st of each year. [Rule 62-210.370(2), F.A.C.]

B. AUXILIARY BOILER AND TEMPORARY CONSTRUCTION BOILER (009 AND 014)

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
009	One nominal 85,000 pounds per hour (lb/hr) natural gas fueled auxiliary boiler (99.8 mmBtu/hr)
014	One temporary 110 mmBtu/hr natural gas-fueled boiler to be used only during construction

AUXILIARY BOILER REQUIREMENTS

1. Equipment: The permittee is authorized to install, operate, and maintain one auxiliary boiler with a maximum design heat input of 99.8 mmBtu/hr (85,000 lb/hr) to produce steam during start up of the CTG. The permittee is authorized to operate the auxiliary boiler during the construction period of Unit 3, as well as during permanent operation after the completion of construction.
[Applicant Request; Rule 62-210.200(PTE), F.A.C.]

2. Hours of Operation: The hours of operation of the auxiliary boiler shall not exceed 1000 hours per year.
[Applicant Request; Rule 62-210.200(PTE), F.A.C.]

3. NSPS Subpart Dc Applicability: The auxiliary boiler is subject to all applicable requirements of 40 CFR 60, Subpart Dc which applies to Small Industrial, Commercial, or Institutional Steam Generating Units. Specifically, this emission unit shall comply with 40 CFR60.48c Reporting and Recordkeeping Requirements. [40 CFR 60, NSPS-Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, attached as Appendix Dc].

4. Auxiliary Boiler Emissions Limits: The auxiliary boiler shall comply with the following emission limits.

NO_X	CO	VOC, SO_2, PM/PM_{10}
0.05 lb/mmBtu	0.08 lb/mmBtu	2 gr S/100 SCF natural gas spec and 10% Opacity

[Applicant request; Rule 62-4.070(3), F.A.C.]

{Permitting note: There are no Subpart Dc emission standards for auxiliary boilers fueled by natural gas.}

5. Auxiliary Boiler Testing Requirements: The auxiliary boiler shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X 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. [Rule 62-297.310(7)(a)1, F.A.C.]

Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources

6. Notification: Initial notification is required for the auxiliary boiler pursuant to 40 CFR 60.7.

7. Reporting: The permittee shall maintain records of the amount of natural gas used in the auxiliary boiler. These records shall be submitted to the Compliance Authority on an annual basis or upon request.
[Rule 62-4.070(3), F.A.C.]

B. AUXILIARY BOILER AND TEMPORARY CONSTRUCTION BOILER (009 AND 014)

TEMPORARY BOILER REQUIREMENTS

8. Equipment: The permittee is authorized to install, operate, and maintain a temporary boiler during the construction of the CCEC with a maximum design heat input of 110 mmBtu/hr.
[Applicant Request; Rule 62-210.200(PTE), F.A.C.]

9. Hours of Operation: The hours of operation of the temporary boiler shall not exceed 1,000 hours per year and the temporary boiler shall not operate beyond the expiration date of this permit.
[Applicant Request; Rule 62-210.200(PTE), F.A.C.]

10. NSPS Subpart Db Applicability: The temporary 110 mmBtu natural gas-fueled boiler is subject to all applicable requirements of 40 CFR 60, Subpart Db which applies to Industrial, Commercial, or Institutional Steam Generating Units.
[40 CFR 60, NSPS-Subpart Db - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, attached as Appendix Db].

C. PROCESS HEATERS (EU 010)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
010	Two nominal 10 mmBtu/hr natural gas-fired process heaters (one is a spare)

1. Equipment: The permittee is authorized to install, operate, and maintain two 10 mmBtu/hr process heaters for the purpose of heating the natural gas supply to the CTG.
[Applicant Request and Rule 62-210.200(PTE), F.A.C.]

2. Hours of Operation: The two natural gas-fueled process heaters are allowed to operate a combined total of 8760 hours per year. [Applicant Request and Rule 62-210.200(PTE), F.A.C.]

3. NSPS Subpart Dc Applicability: Each process heater is subject to all applicable requirements of 40 CFR 60, Subpart Dc which applies to Small Industrial, Commercial, or Institutional Boiler. Specifically, each emission unit shall comply with 40 CFR60.48c Reporting and Recordkeeping Requirements.
[40 CFR 60, NSPS-Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, attached as Appendix Dc]

4. Emission Limits: Each natural gas fired process heater shall comply with the following emission limits.

NO_X	CO	VOC, SO_2, PM/PM_{10}
0.095 lb/mmBtu	0.08 lb/mmBtu	2 gr S/100 SCF natural gas spec and 10% Opacity

[Applicant request; Rule 62-4.070(3), F.A.C.]

{Permitting note: There are no Subpart Dc emission standards for gas-fired process heaters fueled by natural gas.}

5. Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X 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. As an alternative, a Manufacturer certification of emissions characteristics of the purchased model that are at least as stringent as the emission limits values can be used to fulfill this requirement.
[Rule 62-297.310(7)(a)1, F.A.C.]

Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources

6. Notification, Recordkeeping and Reporting Requirements: The permittee shall maintain records of the amount of natural gas used in the process heaters and shall comply with the notification, recordkeeping and reporting requirements pursuant to 40 CFR 60.48c and 40 CFR 60.7. These records shall be submitted to the Compliance Authority on an annual basis or upon request.
[Rule 62-4.070(3), F.A.C.; 40 CFR 60, Subparts A and Dc]

D. COMPRESSOR STATION (EU 011)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
011	Seven nominal 1,340 horsepower (hp) natural gas compressors

1. Equipment: The permittee is authorized to install, operate, and maintain seven nominal 1,340 horsepower (hp) natural gas compressors. Maximum heat input shall not exceed 10.11 mmBtu/hr each.
[Applicant Request and Rule 62-210.200(PTE), F.A.C.]

2. Hours of Operation and Fuel Specifications: Each compressor is allowed to operate continuously (8760 hr/yr). The compressors are allowed to burn natural gas only.
[Applicant Request and Rule 62-210.200(PTE), F.A.C.]

3. NSPS Subpart JJJJ Applicability: These compressors are Stationary Spark Ignition Internal Combustion Engines and shall comply with applicable provisions of 40 CFR 60, Subpart JJJJ.
[40 CFR 60, Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines]

4. NESHAPS Subpart ZZZZ Applicability: These compressors are Reciprocating Internal Combustion Engines (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the compressors must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart JJJJ.
[40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)]

5. Pollution Control Equipment: Each gas compressor shall be equipped with an oxidation catalyst to control CO and VOC/hydrocarbons. [Applicant request; Rule 62-4.070(3), F.A.C.]

6. Visible Emission (VE) Limit: Each natural gas compressor shall comply with a visible emission limit of 10% opacity. [Applicant request; Rule 62-4.070(3), F.A.C.]

7. Emissions Limits: Each natural gas compressors shall comply with the following emission limits.

Standard (manufacture date)	CO (g/hp-hr)[a]	VOC (g/hp-hr)	NO_X (g/hp-hr)	PM (g/hp-hr)	SO_2 (gas S spec.)
Permit Emission Limit	0.10	0.16	1.5[b]	0.034	2 gr/100 SCF
Subpart JJJJ (1/1/2008)	4.0	1.0	2.0	NA	
Subpart JJJJ (7/1/2010)	2.0	0.7	1.0		

a. grams per horsepower-hour (g/hp-hr)

b. Reduced to 1.0 g/hp-hr if manufacture date is 7/1/2010 or later to insure compliance with Subpart JJJJ.

{Permitting note: Installation of an oxidation catalyst and adherence to the visible emission standard and fuel specification shall be considered sufficient to insure compliance with the listed PM limit.}

[Applicant request; 40 CFR 60, Subpart JJJJ; Rule 62-4.070(3), F.A.C.]

8. Compressor Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO, VOC, NO_X 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. With the exception of visible emissions testing, manufacturer certification can be provided to the Department in lieu of actual testing.
[Rule 62-297.310(7)(a)1, F.A.C.; 40 CFR 60.8 and 40 CFR 60.4244]

9. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources
18	Determination of Volatile Organic Compounds Emissions from Stationary Sources

[Rule 62-4.070(3), F.A.C.; 40 CFR 60, Subpart JJJJ and 40 CFR 60.8]

10. Notification, Recordkeeping and Reporting Requirements: The permittee shall maintain records of the amount of natural gas used in the compressor station and shall comply with the notification, recordkeeping and reporting requirements pursuant to 40 CFR 60.4245 and 40 CFR 60.7. These records shall be submitted to the Compliance Authority on an annual basis or upon request.
[Rule 62-4.070(3), F.A.C.; 40 CFR 60, Subparts A and JJJJ]

E. EMERGENCY GENERATORS (012)

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
012	Two nominal 2,250 kilowatts (kW) liquid fueled emergency generators

1. Equipment: The permittee is authorized to install, operate, and maintain two 2,250 kW emergency generators. [Applicant Request and Rule 62-210.200(PTE), F.A.C.]
2. Hours of Operation and Fuel Specifications: The hours of operation shall not exceed 160 hours per year per generator. The generators shall burn ultralow sulfur diesel fuel oil (0.0015% sulfur). [Applicant Request and Rule 62-210.200(PTE), F.A.C.]
3. NSPS Subpart IIII Applicability: These emergency generators are Stationary Compression Ignition Internal Combustion Engines (Stationary ICE) and shall comply with applicable provisions of 40 CFR 60, Subpart IIII, including emission testing or certification. [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines]
4. NESHAPS Subpart ZZZZ Applicability: These emergency generators are Liquid Fueled Reciprocating Internal Combustion Engines (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the compressors must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII.
[40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)]
5. Emissions Limits: Each emergency generator shall comply with the following emission limits and demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII. Manufacturer certification can be provided to the Department in lieu of actual stack testing.

Source (model year)	CO (g/hp-hr)	PM (g/hp-hr)	Hydrocarbons (g/hp-hr)	NO_X (g/hp-hr)
Subpart IIII (2007-2010)	8.5	0.4	1.0	6.9
Subpart IIII (2011 and later)	2.6	0.15	4.8 (NMHC[a]+NO_X)	

a. NMHC means Non-Methane Hydrocarbons.

[Applicant Request; 40 CFR 60, Subpart IIII and Rule 62-4.070(3), F.A.C.]

6. Visible Emission (VE) Limit: Each liquid-fueled emergency generator shall comply with a visible emission limit of 10% opacity. An initial VE test shall be conducted in accordance with EPA Method 9 within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after initial startup. [Applicant request; Rule 62-4.070(3), F.A.C.]
7. Notification, Recordkeeping and Reporting Requirements: The permittee shall maintain records of the amount of fuel oil used in the emergency generators and shall comply with the notification, recordkeeping and reporting requirements pursuant to 40 CFR 60.4214 and 40 CFR 60.7. These records shall be submitted to the Compliance Authority on an annual basis or upon request.
[Rule 62-4.070(3), F.A.C.; 40 CFR 60, Subparts A and IIII]

F. EMERGENCY FIRE PUMP (013)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
013	One emergency diesel fire pump engine (≤ 300 hp) and a nominal 500 gallon fuel oil storage tank

1. Equipment: The permittee is authorized to install, operate, and maintain one diesel engine driven fire pump (≤ 300 hp) and an associated nominal 500 gallon fuel oil storage tank.
[Applicant Request and Rule 62-210.200(PTE), F.A.C.]

2. Hours of Operation: The fire pump may operate in response to emergency conditions and 80 non-emergency hours per year for maintenance testing. [Applicant Request; Rule 62-210.200 (PTE), F.A.C.]

3. Authorized Fuel: This unit shall fire ULSD fuel oil, which shall contain no more than 0.0015% sulfur by weight. [Applicant Request]

4. NSPS Subpart IIII Applicability: The fire pump engine is an Emergency Stationary Compression Ignition Internal Combustion Engine (Stationary ICE) and shall comply with applicable provisions of 40 CFR 60, Subpart IIII. [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines]

5. Emissions Limits: The emergency fire pump engine shall comply with the following emission limits and demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII.

Model Year	CO (g/hp-hr)	NMHC + NO_X (g/hp-hr)	PM (g/hp-hr)
Subpart IIII (2008)	2.6	7.8	0.40
Subpart IIII (2009 or later)	NA	3.0	0.15

[Applicant Request; 40 CFR 60, Subpart IIII and Rule 62-4.070(3), F.A.C.]

6. Fire Pump Engine Certification: Manufacturer certification shall be provided to the Department in lieu of actual testing. [40 CFR 60.4211 and Rule 62-4.070(3), F.A.C.]

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Rick Scott
Governor

Jennifer Carroll
Lt. Governor

Herschel T. Vinyard Jr.
Secretary

Mr. Randall R. LaBauve, Vice President
Florida Power and Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Re: Project No. 0090006-007-AC
Florida Power and Light Company, Cape Canaveral Energy Center
Air Construction Permit Revision
Changes to Excess Emissions Provisions for the Gas Turbines, Maximum Heat Input for the Process Heaters and Hours of Operation for the Emergency Generators

Dear Mr. LaBauve:

On September 8, 2011, you submitted a permit revision application requesting changes to the current air construction permit (0090006-005-AC) for excess emissions provisions for the gas turbines, the maximum heat input for the process heaters and the hours of operation for the emergency generators at the facility. The facility is located in Brevard County, at 6000 North U.S. Highway 1 between Cocoa and Titusville, Florida. Enclosed are the following documents: the Technical Evaluation and Preliminary Determination; the Draft Permit Revision; the Written Notice of Intent to Issue Air Permit; and the Public Notice of Intent to Issue Air Permit. The Public Notice of Intent to Issue Air Permit is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project. If you have any questions, please contact the project engineer, Tom Cascio, at 850-717-9077.

Sincerely,

for Jeffery F. Koerner, Program Administrator — 10/10/11 Date
Office of Permitting and Compliance
Division of Air Resource Management

Enclosures

JFK/jkh/tbc

In the Matter of an
Application for Air Permit by:

Florida Power and Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:
Mr. Randall R. LaBauve, Vice President

Project No. 0090006-007-AC
Air Construction Permit Revision
Brevard County, Florida

Cape Canaveral Energy Center
Excess Emissions for Gas Turbines, Heat Input for Process Heaters and the Hours of Operation for Emergency Generators

Facility Location: Florida Power and Light Company operates the existing Cape Canaveral Energy Center, which is located in Brevard County at 6000 North U.S. Highway 1 between Cocoa and Titusville, Florida.

Project: The project will revise permit conditions related to excess emissions provisions for the gas turbines (clarified), the maximum heat input for the process heaters (decreased) and the hours of operation (decreased) for the emergency generators. There will be no emissions increases and the project is not subject to prevention of significant deterioration (PSD) preconstruction review. Details of the project are provided in the application and the enclosed Technical Evaluation and Preliminary Determination.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Permitting Authority responsible for making a permit determination for this project is the Department of Environmental Protection's Office of Air Permitting and Compliance in Tallahassee. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida. The Permitting Authority's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/717-9000.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the draft permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address or phone number listed above.

Notice of Intent to Issue Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of the proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a final permit in accordance with the conditions of the draft permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Section 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Permit (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet the requirements of Sections 50.011 and 50.031, F.S. in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Permitting Authority at above address or phone number. Pursuant to Rule 62-110.106(5) and (9), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within 7 days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the draft permit for a period of 14 days from the date of publication of the Public Notice. Written comments must be received by the Permitting Authority by close of business (5:00 p.m.) on or before the end of the 14-day period. If written comments received result in a significant change to the draft permit, the Permitting Authority shall revise the draft permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241). Petitions filed by the applicant or any of the parties listed below must be filed within 14 days of receipt of this Written Notice of Intent to Issue Air Permit. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of the attached Public Notice or within 14 days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within 14 days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of when and how each petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Written Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Jon D Holton 10/10/11

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

Date

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Written Notice of Intent to Issue Air Permit package (including the Written Notice of Intent to Issue Air Permit, the Public Notice of Intent to Issue Air Permit, the Technical Evaluation and Preliminary Determination and the Draft Permit Revision) was sent by electronic mail (or a link to these documents made available electronically on a publicly accessible server) with received receipt requested before the close of business on 10-10-11 to the persons listed below.

Mr. Randall R. LaBauve, FPL: Randall.R.LaBauve@fpl.com
Ms. Mary Archer, FPL: mary.archer@fpl.com
Mr. Kennard F. Kosky, P.E., Golder Associates, Inc.: ken_kosky@golder.com
Ms. Caroline Shine, DEP Central District: caroline.shine@dep.state.fl.us
Ms. Cindy Mulkey, DEP Siting Office: cindy.mulkey@dep.state.fl.us
Ms. Heather Abrams, U.S. EPA Region 4: abrams.heather@epa.gov
Ms. Katy R. Forney, U.S. EPA Region 4: forney.kathleen@epa.epa.gov
Ms. Ana Oquendo-Vazquez, U.S. EPA Region 4: oquendo.ana@epa.gov
Ms. Barbara Friday, DEP OPC: barbara.friday@dep.state.fl.us (for posting with U.S. EPA, Region 4)
Ms. Lynn Scearce, DEP OPC: lynn.scearce@dep.state.fl.us (for reading file)

Clerk Stamp

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

Lynn Scearce October 10, 2011

(Clerk) (Date)

PERMITTEE

Florida Power and Light Company (FPL)
Cape Canaveral Energy Center

Authorized Representative:
Mr. Randall R. LaBauve, Vice President

Draft Permit No. 0090006-007-AC
Air Construction Permit Revision -
Changes to Excess Emissions Provisions for the Gas Turbines, Maximum Heat Input for the Process Heaters and Hours of Operation for the Emergency Generators

Cape Canaveral Energy Center
Brevard County, Florida

PROJECT

This is the final air construction permit revision which revises specific conditions of Permit No. 0090006-005-AC for the 1,250 megawatt (MW) combined cycle unit at the Cape Canaveral Energy Center. The revised permit conditions are related to excess emissions provisions for the gas turbines, the maximum heat input for the process heaters and the hours of operation for the emergency generators. The existing plant is a power plant categorized under Standard Industrial Classification No. 4911. The plant is located at 6000 North U.S. Highway 1 between Cocoa and Titusville in Brevard County. The Universal Transverse Mercator (UTM) coordinates are Zone 17, 523.1 kilometers (km) East and 3,149 km North. This final permit is organized into the following sections: Section 1 (General Information) and Section 2 (Permit Revisions). As noted in the Final Determination provided with this final permit, only minor changes and clarifications were made to the draft permit.

STATEMENT OF BASIS

This air pollution construction permit revision 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.). This project is subject to the general preconstruction review requirements in Rule 62-212.300, F.A.C. and is not subject to the preconstruction review requirements for major stationary sources in Rule 62-212.400, F.A.C., for the Prevention of Significant Deterioration (PSD) of Air Quality. A copy of this permit revision shall be filed with the referenced permit and shall become part of the permit.

Upon issuance of this final permit revision, any party to this 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 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida

(DRAFT)

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

JFK/jkh/tbc

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Final Air Permit package (including the Final Determination and Final Permit Revision) was sent by electronic mail, or a link to these documents made available electronically on a publicly accessible server, with received receipt requested before the close of business on ________________ to the persons listed below.

Mr. Randall R. LaBauve, FPL: Randall.R.LaBauve@fpl.com
Ms. Mary Archer, FPL: mary.archer@fpl.com
Mr. Kennard F. Kosky, P.E., Golder Associates, Inc.: ken_kosky@golder.com
Ms. Caroline Shine, DEP Central District: caroline.shine@dep.state.fl.us
Ms. Cindy Mulkey, DEP Siting Office: cindy.mulkey@dep.state.fl.us
Ms. Heather Abrams, U.S. EPA Region 4: abrams.heather@epa.gov
Ms. Katy R. Forney, U.S. EPA Region 4: forney.kathleen@epa.epa.gov
Ms. Ana Oquendo-Vazquez, U.S. EPA Region 4: oquendo.ana@epa.gov
Ms. Barbara Friday, DEP OPC: barbara.friday@dep.state.fl.us (for posting with U.S. EPA, Region 4)
Ms. Lynn Scearce, DEP OPC: lynn.scearce@dep.state.fl.us (for reading file)

Clerk Stamp

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

_________________________ Clerk   ____________ Date

FACILITY DESCRIPTION

The project authorized by 0090006-005-AC was a plant conversion that included the construction of a nominal 1,250 MW natural gas-fueled combined cycle unit (Unit 3) and ancillary equipment and required the permanent shutdown and dismantling of Units 1 and 2 at the facility. Unit 3 consists of:

- Three nominal 265 MW combustion turbine-electrical generators (CTG) with evaporative inlet cooling systems;
- Three supplementary-fired heat recovery steam generators (HRSG) with selective catalytic reduction (SCR) reactors;
- Three maximum 460 million Btu per hour, lower heating value (mmBtu/hr, LHV), natural gas-fueled duct burners (DB) located in the three HRSG (one DB/HRSG);
- Three 149-feet exhaust stacks; and
- One common nominal 500 MW steam-electrical generator (STG).

Unit 3 uses ultralow sulfur distillate (ULSD) fuel oil as backup fuel. Unit 3 relies on some of the existing infrastructure including one of the fuel oil storage tanks.

Additional ancillary equipment installed includes: a permanent auxiliary boiler; a temporary boiler used during the construction phase; two emergency generators; two process (fuel) heaters; a diesel fire pump; and a gas compression station.

FACILITY REGULATORY CLASSIFICATION

- This facility is a major source of hazardous air pollutants (HAP).
- This facility operates units subject to the acid rain provisions of the Clean Air Act (CAA).
- The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400 (PSD), F.A.C.

PROPOSED PROJECT

For the current project, the applicant has requested an air construction permit revision to change several of the underlying construction permit conditions related to the gas turbine excess emissions provisions, the heat input for the process heaters and the hours of operation for the emergency generators.

The following facility unit description table and permit specific conditions are revised as indicated. ~~Strikethrough~~ is used to denote the deletion of text. Double-underlines are used to denote the addition of text.

Air Construction Permit Being Revised: Permit No. 0090006-005-AC (expiration date December 31, 2014)

Emission Unit Description

ID	Emission Unit Description
006	Unit 3A – one nominal 265 MW CTG with supplementary-fired HRSG
007	Unit 3B – one nominal 265 MW CTG with supplementary-fired HRSG
008	Unit 3C – one nominal 265 MW CTG with supplementary-fired HRSG
009	One nominal 85,000 pounds per hour (lb/hr) auxiliary boiler (99.8 mmBtu/hr)
010	Two nominal ~~10~~ 9.9 mmBtu/hr natural gas-fired process heaters (one is a spare)
011	Seven nominal 1,340 horsepower (hp) natural gas compressors
012	Two nominal 2,250 kilowatts (kW) liquid fueled emergency generators
013	One nominal 300-hp emergency diesel fire pump engine and 500 gallon fuel oil storage tank
014	One temporary 110 mmBtu/hr natural gas-fueled boiler to be used only during construction

1. **Affected Emissions Units:** Combined Cycle Combustion Turbines (CT) and Heat Recovery Steam Generators (HRSG) (E.U. ID Nos. 006 - 008)

Specific Conditions **A.12., 15., 17., 24.** and **31.** of Permit No. 0090006-005-AC are hereby changed as follows (the remainder of the permit remains unchanged as a result of this permitting action):

A.12. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, fuel switches 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. [Applicant Request and Rule 62-212.400(BACT), F.A.C.]

A.15. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, fuel switching and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. ~~For each CTG/HRSG system, excess emissions of NO_x and CO resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the specific cases listed below.~~ For each gas turbine/HRSG System, excess emissions of NO_x and CO resulting from startup, shutdown, or malfunction shall be excluded from CEMS data in any 24-hour period ("any 24-hour period" means a calendar day, midnight to midnight) for the following conditions (these conditions are considered separate events and each event may occur independently within any 24-hour period): ~~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. ~~*STG/HRSG System Cold Startup:*~~ Steam Turbine Cold Startup: For cold startup of the steam turbine ~~system~~, ~~excess NO_x and CO~~ excluded emissions from any ~~CTG~~ 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 3-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 ~~STG system~~ steam turbine, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the ~~STG~~ 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. *~~CTG~~ Gas Turbine/HRSG System Cold Startup*: For cold startup of a gas turbine/HRSG system, excluded emissions shall not exceed four hours in any 24-hour period. "Cold startup of a ~~CTG~~ gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 pounds per square inch gauge (psig) for at least a one-hour period.

c. *Gas Turbine/HRSG System Warm Startup*: For warm startup of a gas turbine/HRSG system, excluded emissions shall not exceed two hours in any 24-hour period. "Warm startup of a gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum is above 450 psig.

d. *Shutdown ~~Steam Turbine System~~ Combined Cycle Operation*: For shutdown of ~~steam turbine system~~ combined cycle operation, ~~excess NO_X and CO~~ excluded emissions from any ~~CTG~~ gas turbine/HRSG system shall not exceed three (3) hours in any 24-hour period.

e. *Gas Turbine/HRSG System Shutdown*: For shutdown of the gas turbine/HRSG operation, excluded emissions from any gas turbine/HRSG system shall not exceed two hours in any 24-hour period.

f. *Fuel Switching*: For fuel switching, ~~excess NO_X and CO~~ excluded emissions shall not exceed 2 hours in any 24-hour period for each fuel switch and no more than four hours in any 24-hour period for any gas turbine/HRSG system.

g. *Documented Malfunction*: For the gas turbine/HSRG system, excess emissions of NO_X and CO resulting from documented malfunctions shall not exceed two hours in any 24-hour period. 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.17. DLN Tuning / FSNL Testing: CEMS data collected during initial or other major DLN tuning sessions and during manufacturer required Full Speed No Load (FSNL) trip tests shall be excluded by the permittee 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 major repair or other similar circumstances. Prior to performing any major tuning session, where the intent is to exclude data from the CEMS compliance demonstration, the permittee shall provide the Compliance Authority with an advance notice of at least ~~7 days~~ one working (business) day 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.]

A.24. Continuous Emissions Monitoring System(s) (CEMS): …

a. *CO Monitors*. For each CTG, 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. If "H" technology CTG are utilized, the described certification shall be performed on the CEMS associated with the first, and only with the first, installed CTG within 180 calendar days of achieving permitted capacity, but no later than 300 calendar days after initial startup. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F or 40 CFR Part 75, and the Data Assessment Report in 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.

A.31. 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 and NO_X emissions in excess of the BACT permit emissions standards, and the amounts of authorized data excluded following the ~~NSPS~~ format in ~~40 CFR 60.7(c), Subpart A~~ Figure XSE attached to this permit. Periods of startup, shutdown ~~and~~, malfunction, fuel switching and tuning shall be monitored, ~~,~~ and recorded at all times ~~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.

c. *NSPS Semi-Annual Excess Emissions Reports*: For purposes of reporting emissions in excess of NSPS Subpart KKKK, excess emissions from the gas turbine are defined as: a specified averaging period over which either the NOx emissions are ~~higher than the applicable emission limit in 60.4320~~ greater than 15 ppm at 15% O_2 on a 30-day rolling average while firing natural gas and greater than 42 ppm at 15% O_2 on a 30-day rolling average while firing ultra low sulfur distillate; or the total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in 60.4330. Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions that occurred during the previous semi-annual period to the Compliance Authority.

{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., and 40 CFR 60.7, and 60.4420]

2. **Affected Emissions Unit:** Two nominal 10 mmBtu/hr natural gas-fired process heaters (one is a spare) (E.U. ID No. 010)

Specific Condition Nos. **C.3. C.4., C.5.** and **C.6.** from Permit No. 0090006-005-AC are hereby changed as follows:

ID	Emission Unit Description
010	Two nominal ~~10~~ 9.9 mmBtu/hr natural gas-fired process heaters (one is a spare)

Equipment: The permittee is authorized to install, operate, and maintain two ~~10~~ 9.9 mmBtu/hr process heaters for the purpose of heating the natural gas supply to the CTG.
[Applicant Request and Rule 62-210.200(PTE), F.A.C.]

C.3. ~~NSPS Subpart Dc Applicability: Each process heater is subject to all applicable requirements of 40 CFR 60, Subpart Dc which applies to Small Industrial, Commercial, or Institutional Boiler. Specifically, each emission unit shall comply with 40 CFR60.48c Reporting and Recordkeeping Requirements. [40 CFR 60, NSPS Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, attached as Appendix Dc]~~

C.4. ~~Emission Limits: Each natural gas fired process heater shall comply with the following emission limits.~~

~~NO_X~~	~~CO~~	~~VOC, SO_2, PM/PM_{10}~~
~~0.095 lb/mmBtu~~	~~0.08 lb/mmBtu~~	~~2 gr S/100 SCF natural gas spec and 10% Opacity~~

~~[Applicant request; Rule 62-4.070(3), F.A.C.]~~

~~*{Permitting note: There are no Subpart Dc emission standards for gas fired process heaters fueled by natural gas.}*~~

C.5. ~~Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X 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. As an alternative, a Manufacturer certification of emissions characteristics of the purchased model that are at least as stringent as the emission limits values can be used to fulfill this requirement.~~
~~[Rule 62-297.310(7)(a)1, F.A.C.]~~

~~Test Methods: Any required tests shall be performed in accordance with the following reference methods.~~

~~Method~~	~~Description of Method and Comments~~
~~7E~~	~~Determination of Nitrogen Oxide Emissions from Stationary Sources~~
~~9~~	~~Visual Determination of the Opacity of Emissions from Stationary Sources~~
~~10~~	~~Determination of Carbon Monoxide Emissions from Stationary Sources~~

C.6. Notification, Recordkeeping and Reporting Requirements: The permittee shall maintain records of the amount of natural gas used in the process heaters ~~and shall comply with the notification, recordkeeping and reporting requirements pursuant to 40 CFR 60.48c and 40 CFR 60.7~~. These records shall be submitted to the Compliance Authority on an annual basis or upon request.
[Rule 62-4.070(3), F.A.C.~~; 40 CFR 60, Subparts A and Dc~~]

3. **Affected Emissions Unit:** Two nominal 2,250 kilowatts (kW) liquid fueled emergency generators (E.U. ID No. 012)

Specific Condition No. **E.2.** from Permit No. 0090006-005-AC is hereby changed as follows:

E.2. Hours of Operation and Fuel Specifications: The hours of operation shall not exceed ~~160 hours per year per generator~~ 100 hours per year for each engine for the purpose of maintenance checks and readiness test with unlimited operation for emergency use. The generators shall burn ultralow sulfur diesel fuel oil (0.0015% sulfur).
[Applicant Request and Rule 62-210.200(PTE), F.A.C.]

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Rick Scott
Governor

Jennifer Carroll
Lt. Governor

Herschel T. Vinyard Jr.
Secretary

NOTICE OF ADMINISTRATIVELY CORRECTED PERMIT

In the Matter of Processing an Administrative Correction:

Mr. Randall R. LaBauve
Vice President
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Project No. 0090006-008-AC
Administrative Correction to Permit No. 0090006-007-AC
Cape Canaveral Energy Center
Brevard County

Enclosed is Administratively Corrected Emission Unit Description language contained in Air Construction Permit No. 0090006-007-AC, for the construction of the Cape Canaveral Energy Center located in Brevard County at 6000 North U.S. Highway 1 between Cocoa and Titusville, Florida. This correction is issued pursuant to Rule 62-210.360, Florida Administrative Code (F.A.C.), and Chapter 403, Florida Statutes (F.S.). This change is made with the permitee's concurrence dated December 5, 2011. This corrective action does not alter the effective dates of the existing permit.

The Department of Environmental Protection (Department) will consider the above-noted action final unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S. Mediation under Section 120.573, F.S., will not be available for this proposed action.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) by the Agency Clerk in the Department's Office of General Counsel, 3900 Commonwealth Boulevard, MS #35, Tallahassee, Florida 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within 14 (fourteen) days of receipt of this notice. Petitions filed by any other person must be filed within 14 (fourteen) days of receipt of this proposed action. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of when and how each petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact.

If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the permitting authority's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the permitting authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Any party to this order (permit) has the right to seek judicial review of it under Section 120.68, F.S., by the filing of a Notice of Appeal, under Rule 9.110 of the Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000; and, by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal.

The Notice of Appeal must be filed within thirty days from the date this notice is filed with the Clerk of the permitting authority.

Executed in Tallahassee, Florida.
Electronically Signed

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Administratively Corrected Permit (including the corrected page) or a link to these documents available electronically on a publicly accessible server, was sent by electronic mail with received receipt requested to the persons listed below:

Mr. Randall R. LaBauve, FPL: randall.r.labauve@fpl.com
Ms. Mary Archer, FPL: mary.archer@fpl.com
Mr. Kennard F. Kosky, P.E., Golder Associates, Inc.: ken_kosky@golder.com
Ms. Caroline Shine, DEP Central District: caroline.shine@dep.state.fl.us
Ms. Cindy Mulkey, DEP Siting Office: cindy.mulkey@dep.state.fl.us
Ms. Heather Ceron, U.S. EPA Region 4: ceron.heather@epa.gov
Ms. Katy Forney, U.S. EPA Region 4: forney.kathleen@epa.gov
Ms. Ana Oquendo, EPA Region 4: oquendo.ana@.epa.gov
Ms. Barbara Friday, DEP OPC: barbara.friday@dep.state.fl.us (for posting with U.S. EPA, Region 4)
Ms. Lynn Scearce, DEP OPC: lynn.scearce@dep.state.fl.us (for reading file)

Clerk Stamp

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

Pursuant to the permitee's concurrence, conditions /requirements contained in permit No. 0090006-007-AC have been corrected as indicated below. ~~Strikethrough~~ is used to denote the deletion of text. Double-underlines are used to denote the addition of text. All changes are emphasized with yellow highlight.

1. The Department recently issued air construction permit No. 0090006-007-AC that revised 0090006-005-AC. In doing the database update, it was discovered that there is a discrepancy between the emissions units (EU) identification numbers listed in the AC permits and our database EU numbers. To correct the problem, this administrative permit correction changes the permit EU numbers in the permit to correspond to the database numbers. Please see the table below.
2. The Emission Unit Description is hereby changed as follows:

Emission Unit Description

ID	Emission Unit Description
~~006~~ 009	Unit 3A – one nominal 265 MW CTG with supplementary-fired HRSG
~~007~~010	Unit 3B – one nominal 265 MW CTG with supplementary-fired HRSG
~~008~~011	Unit 3C – one nominal 265 MW CTG with supplementary-fired HRSG
~~009~~012	One nominal 85,000 pounds per hour (lb/hr) auxiliary boiler (99.8 mmBtu/hr)
~~010~~013	Two nominal 9.9 mmBtu/hr natural gas-fired process heaters (one is a spare)
~~011~~014	Seven nominal 1,340 horsepower (hp) natural gas compressors
~~012~~015	Two nominal 2,250 kilowatts (kW) liquid fueled emergency generators
~~013~~016	One nominal 300-hp emergency diesel fire pump engine and 500 gallon fuel oil storage tank
~~014~~017	One temporary 110 mmBtu/hr natural gas-fueled boiler to be used only during construction

ATTACHMENT CCEC-EU1-IV3

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT CCEC-EU1-IV3

ALTERNATIVE METHODS OF OPERATION
COMBINED CYCLE UNIT 3

Cape Canaveral Energy Center (CCEC) combined-cycle Unit 3 (3A, 3B & 3C) fires both natural gas as primary fuel and Ultra Low Sulfur Diesel (ULSD) oil as a restricted alternate fuel. The maximum sulfur content of natural gas is limited to 2 grains per 100 standard cubic feet (scf) and of the ULSD oil to 0.0015 percent by weight. Each CT can operate for the entire year (i.e., 8,760 hours) with natural gas and for 3,000 hours/year aggregated over the tree combustion turbines with fuel oil. These units may also operate at various loads. Evaporative cooling may be used to lower the inlet air temperature and provide additional electric power.

Maximum heat input to each CT is limited to 2,586 million British thermal units per hour (MMBtu/hr) when firing natural gas and 2,440 MMBtu/hr when firing fuel oil based on 59°F ambient temperature, 100-percent load, and lower heating value (LHV) of each fuel. The heat input rate varies with inlet temperatures. Each CT/HRSG units is equipped with a duct burner rated at 460 MMBtu/hr (LHV). The duct burners are fired with natural gas only. Duct firing is limited to 3,697,920 MMBtu/yr for all three CT/HRSGs combined.

Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternative methods of operation, and evaporative cooling.

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.)

☒ 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).

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

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

2. Description of Emissions Unit Addressed in this Section:
Two nominal 3,000 kW diesel emergency generators

3. Emissions Unit Identification Number: **015**

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

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

☐ Acid Rain Unit

☐ CAIR Unit

9. Package Unit:
Manufacturer: **Caterpillar** Model Number: **C175**

10. Generator Nameplate Rating: **6** MW

11. Emissions Unit Comment:
Two nominal 3,000 kW Caterpillar C175 diesel generator sets for black start purposes. Sales agreement has been completed. However the units are not on-site yet. FDEP will be notified as soon as the units are installed and ready for service. A compliance plan been attached. Note that these units are larger than the permitted units at 2,250 kW each. Emissions calculation for the 3,000 kW units are attached.

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: **58.0** 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 **100** hours/year	
6. Operating Capacity/Schedule Comment: **Maximum heat input rate for each generator is 29.0 MMBtu/hr based on a fuel consumption rate of 209.8 gal/hr and diesel fuel heat content of 138,000 Btu/hr.** **Maximum operation time for each generator is 100 hr/yr (operation during emergency is not limited).**			

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): **Internal Combustion Engines; Electric Generation; Distillate Oil; Reciprocating**		
2. Source Classification Code (SCC): **2-01-001-02**	3. SCC Units: **1000 Gallons Burned**	
4. Maximum Hourly Rate: **0.42**	5. Maximum Annual Rate: **67.1**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.0015%**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **138**
10. Segment Comment: **Max annual rate = 209.8 gal/hr x 160 hr/yr x 2 engines x 1 kgal/1000 gal= 67.1 kgal/yr** **Max hourly rate = 209.8 gal/hr x 2 engines x 1 kgal/1000 gal= 0.42 kgal/hr** **Unit is limited to firing ultra low sulfur diesel fuel with maximum 0.0015% S.**		

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:		

EMISSIONS UNIT INFORMATION
Section [2]
Emergency 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			EL
PM10			NS
PM2.5			NS
SO2			EL
CO			EL
VOC			NS
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.

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

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **46.2** lb/hour **2.31** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2.6 g/hp-hr** Reference: **Permit No. 0090006-005-AC**	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 Table CCEC-EU2-F1.10.**	
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: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2.6 g/hp-hr (NSPS Subpart IIII, 2011 or later)**	4. Equivalent Allowable Emissions: **46.2** lb/hour **2.31** tons/year
5. Method of Compliance: **Manufacturer Certification of Subpart IIII Standards**	
6. Allowable Emissions Comment (Description of Operating Method): **See Table CCEC-EU2-F1.10 for equivalent allowable emissions.**	

Allowable Emissions Allowable Emissions _ of _

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

Allowable Emissions Allowable Emissions _ of _

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.66** lb/hour **0.13** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.15 g/hp-hr** Reference: **Permit No. 0090006-005-AC**	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 Table CCEC-EU2-F1.10.**	
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: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.15 g/hp-hr (NSPS Subpart IIII, 2010 or later)**	4. Equivalent Allowable Emissions: **2.66** lb/hour **0.13** tons/year
5. Method of Compliance: **Manufacturer Certification of Subpart IIII Standards**	
6. Allowable Emissions Comment (Description of Operating Method): **See Table CCEC-EU2-F1.10 for equivalent allowable emissions.**	

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: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.045** lb/hour **0.0022** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0015% S fuel** Reference: **Permit No. 009006-005-AC and 40 CFR 60 Subpart IIII**	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 Table CCEC-EU2-F1.10.**	
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: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Maximum S content 0.0015% by weight**	4. Equivalent Allowable Emissions: **0.045** lb/hour **0.0022** tons/year
5. Method of Compliance: **Fuel Specification**	
6. Allowable Emissions Comment (Description of Operating Method): **See Table CCEC-EU2-F1.10 for equivalent allowable emissions.**	

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: **85.2** lb/hour **4.26** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **4.8 g/hp-hr** Reference: **Permit No. 0090006-005-AC**	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 Table CCEC-EU2-F1.10.**	
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: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **4.8 g/hp-hr (NSPS Subpart IIII, 2010 or later)**	4. Equivalent Allowable Emissions: **85.2** lb/hour **4.26** tons/year
5. Method of Compliance: **Manufacturer Certification of Subpart IIII Standards**	
6. Allowable Emissions Comment (Description of Operating Method): **See Table CCEC-EU2-F1.10 for equivalent allowable emissions.**	

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: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Initial testing using EPA Method 9**	
5. Visible Emissions Comment: **Permit No. 0090006-005-AC**	

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: **CCEC-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: ________ ☐ 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: **CCEC-EU1-I4** ☐ Previously Submitted, Date ________ ☐ Not Applicable (construction application)
5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ________ ☐ Previously Submitted, Date ________ ☒ 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 will be conducted within 180 days after intial startup** 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: CCEC-EU1-IV1	
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

ATTACHMENT CCEC-EU2-F1.10

CALCULATION OF EMISSIONS

TABLE CCEC-EU2-F1.10
POTENTIAL EMISSIONS FROM THE EMERGENCY ENGINE
CATERPILLAR MODEL C175

Pollutants	Emission Factor	Ref.	Activity Factor[a] Engine Power (kW)	Activity Factor[a] Engine Power (bhp)	Activity Factor[a] Fuel Consumption (gal/hr)	Activity Factor[a] Maximum Heat Input (MMBtu/hr)	Activity Factor[a] Operating Hours	Potential Emissions (per engine) (lb/hr)	Potential Emissions (per engine) (TPY)	Potential Emissions (Two Engines) (lb/hr)	Potential Emissions (Two Engines) (TPY)
Carbon Monoxide (CO)	2.60 g/hp-hr	b	3,000	4,026.8	209.8	28.95	100	23.08	1.15	46.16	2.31
Nitrogen Oxides (NOx)	4.80 g/hp-hr	b	3,000	4,026.8	209.8	28.95	100	42.61	2.13	85.22	4.26
Particulate Matter (PM)	0.15 g/hp-hr	b	3,000	4,026.8	209.8	28.95	100	1.33	0.07	2.66	0.13
Particulate Matter (PM_{10})	0.15 g/hp-hr	c	3,000	4,026.8	209.8	28.95	100	1.33	0.07	2.66	0.13
Particulate Matter ($PM_{2.5}$)	0.15 g/hp-hr	c	3,000	4,026.8	209.8	28.95	100	1.33	0.07	2.66	0.13
Sulfur Dioxide (SO_2)	0.0015 % S	b	3,000	4,026.8	209.8	28.95	100	0.022	0.0011	0.045	0.0022
Volatile Organic Compounds (VOC)	7.05E-04 lb/hp-hr	d	3,000	4,026.8	209.8	28.95	100	2.84	0.14	5.68	0.28

[a] Engine power and fuel consumption based on manufacturer data. Heat input calculated based on diesel fuel heat content of 138,000 Btu/gal.
[b] Permit No. 0090006-005-AC.
[c] Assumed equal to PM emissions.
[d] Based on AP-42, Chapter 3.4, Large Stationary Diesel Engines (10/96).
[e] 40 CFR 98 Table C-1.
[f] 40 CFR 98 Table C-2.
[g] Carbon dioxide equivalent (CO_2e) calculated using the following formula: CO_2e (TPY) = CO_2 (TPY) x 1 + N_2O (TPY) x 210 + CH_4 (TPY) x 21

Golder Associates

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.)

   ☒ 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).

   ☐ 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:
   One 315 hp Emergency Diesel Fire Pump Engine

3. Emissions Unit Identification Number: **016**

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

9. Package Unit:
   Manufacturer: John Deere   Model Number: JU6H-UFAD98

10. Generator Nameplate Rating: **0.235** MW

11. Emissions Unit Comment:
    315 hp Emergency diesel fine pump engine. The Unit is larger than the permitted size of 300 hp. Emissions calculation for the 315 hp engine are attached.

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: **0.72** 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 **100** hours/year	
6. Operating Capacity/Schedule Comment: **No limit in response to emergency conditions;** **100 non-emergency hours per year for maintenance testing (proposed in this application).** **Maximum heat input rate based on a fuel consumption rate of 5.2 gal/hr and diesel fuel heat content of 138,000 Btu/hr.**			

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): **Internal Combustion Engines; Electric Generation; Distillate Oil; Reciprocating**		
2. Source Classification Code (SCC): **2-01-001-02**	3. SCC Units: **1000 Gallons Burned**	
4. Maximum Hourly Rate: **0.005**	5. Maximum Annual Rate: **0.52**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.0015%**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **138**
10. Segment Comment: **Max hourly rate= 5.2 gal/hr x 1 kgal/1,000 gal = 0.005 kgal/yr** **Max annual rate= 5.2 gal/hr x 100 hr/yr x 1 kgal/1,000 gal = 0.52 kgal/yr** **Hourly fuel usage based on manufacturer data.**		

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			EL
PM10			NS
PM2.5			NS
SO2			EL
CO			NS
VOC			NS
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**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.10** lb/hour **0.005** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.15 g/hp-hr** Reference: **Permit No. 0090006-005-AC**	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 Table CCEC-EU3-F1.10.**	
11. Potential, Fugitive, and Actual Emissions Comment: **The emergency diesel fire pump engine has a nominal power of 300 hp.**	

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: **0.15 g/hp-hr (NSPS Subpart IIII, 2009 or later)**	4. Equivalent Allowable Emissions: **0.10** lb/hour **0.005** tons/year
5. Method of Compliance: **Manufacturer Certification of Subpart IIII Standards**	
6. Allowable Emissions Comment (Description of Operating Method): **See Table CCEC-EU3-F1.10 for equivalent allowable emissions.**	

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: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.0006** lb/hour **0.00003** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0015% S fuel** Reference: **Permit No. 0090006-005-AC and 40 CFR 60 Subpart IIII**	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 Table CCEC-EU3-F1.10.**	
11. Potential, Fugitive, and Actual Emissions Comment: **The emergency diesel fire pump engine has a nominal power of 315 hp.** **Emission Limit of the total of NMHC and NOx is permitted to be 3.0 g/hp-hr.**	

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: **Maximum S content 0.0015% by weight**	4. Equivalent Allowable Emissions: **0.0006** lb/hour **0.00003** tons/year
5. Method of Compliance: **Fuel Specification**	
6. Allowable Emissions Comment (Description of Operating Method): **See Table CCEC-EU3-F1.10 for equivalent allowable emissions.**	

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: **2.08** lb/hour **0.104** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **3.0 g/hp-hr** Reference: **Permit No. 0090006-005-AC**	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 Table CCEC-EU3-F1.10.**	
11. Potential, Fugitive, and Actual Emissions Comment: **The emergency diesel fire pump engine has a nominal power of 315 hp. Emission Limit of the total of NMHC and NOx is permitted to be 3.0 g/hp-hr.**	

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: **3.0 g/hp-hr (NSPS Subpart IIII 2009 or later)**	4. Equivalent Allowable Emissions: **2.08** lb/hour **0.104** tons/year
5. Method of Compliance: **Manufacturer Certification of Subpart IIII Standards**	
6. Allowable Emissions Comment (Description of Operating Method): **See Table CCEC-EU3-F1.10 for equivalent allowable emissions.**	

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: FPL-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: ______ ☐ 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: CCEC-EU1-IV1	
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

ATTACHMENT CCEC-EU3-F1.10

CALCULATION OF EMISSIONS

TABLE CCEC-EU3-F1.10
POTENTIAL EMISSIONS FROM THE EMERGENCY FIRE-PUMP ENGINE
JOHN DEERE JU6H-UFAD9B

			Activity Factor[a]					Potential Emissions (per engine)	
Pollutants	Emission Factor	Ref.	Engine Power (kW)	Engine Power (bhp)	Fuel Consumption (gal/hr)	Maximum Heat Input (MMBtu/hr)	Operating Hours	(lb/hr)	(TPY)
Carbon Monoxide (CO)	0.70 g/kWhr	b	235.0	315.0	5.2	0.72	80	0.36	0.015
Nitrogen Oxides (NOx)	3.00 g/hp-hr	c	235.0	315.0	5.2	0.72	80	2.08	0.083
Particulate Matter (PM)	0.15 g/hp-hr	c	235.0	315.0	5.2	0.72	80	0.10	0.004
Particulate Matter (PM_{10})	0.15 g/hp-hr	d	235.0	315.0	5.2	0.72	80	0.10	0.004
Particulate Matter ($PM_{2.5}$)	0.15 g/hp-hr	d	235.0	315.0	5.2	0.72	80	0.10	0.004
Sulfur Dioxide (SO_2)	0.0015 % S	c	235.0	315.0	5.2	0.72	80	0.0006	0.00002
Volatile Organic Compounds (VOC)	0.00247 g/hp-hr	e	235.0	315.0	5.2	0.72	80	0.78	0.031

[a] Engine power and fuel consumption based on manufacturer data. Heat input calculated based on diesel fuel heat content of 138,000 Btu/gal.
[b] Manufacturer emissions certification.
[c] Permit No. 0090006-005-AC.
[d] Assumed equal to PM emissions.
[e] Table 3.3-1, AP-42 Section 3.3.
[f] 40 CFR 98 Table C-1.
[g] 40 CFR 98 Table C-2.
[h] Carbon dioxide equivalent (CO2e) calculated using the following formula: CO2e (TPY) = CO2 (TPY) x 1 + N2O (TPY) x 210 + CH4 (TPY) x 21

At Golder Associates we strive to be the most respected global group of companies specializing in ground engineering and environmental services. Employee owned since our formation in 1960, we have created a unique culture with pride in ownership, resulting in long-term organizational stability. Golder professionals take the time to build an understanding of client needs and of the specific environments in which they operate. We continue to expand our technical capabilities and have experienced steady growth with employees now operating from offices located throughout Africa, Asia, Australasia, Europe, North America and South America.

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