Permit Application

TITLE V PERMIT RENEWAL APPLICATION

Lakeland Electric
C.D. McIntosh, Jr. Power Plant

Prepared For: Lakeland Electric
501 East Lemon Street
Lakeland, FL 33801

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

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May 2013

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Golder Associates

APPLICATION FOR AIR PERMIT

LONG FORM

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

RECEIVED
MAY 17 2013
DIVISION OF AIR RESOURCE MANAGEMENT

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: **Lakeland Electric**	
2. Site Name: **C.D. McIntosh, Jr. Power Plant**	
3. Facility Identification Number: **1050004**	
4. Facility Location... Street Address or Other Locator: **3030 East Lake Parker Drive** City: **Lakeland** County: **Polk** Zip Code: **33805**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Ms. Farzie Shelton, Associate General Manager of Technical Support**
2. Application Contact Mailing Address... Organization/Firm: **Lakeland Electric** Street Address: **501 East Lemon Street** City: **Lakeland** State: **FL** Zip Code: **33801-5079**
3. Application Contact Telephone Numbers... Telephone: **(863) 834-6603** ext. Fax: **(863) 834-6362**
4. Application Contact E-mail Address: **farzie.shelton@lakelandelectric.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 5/20/13	3. PSD Number (if applicable):
2. Project Number(s): 1050004-033-AV	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☐ Air construction permit.

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).

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

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☒ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

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

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

☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

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

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

Application Comment

This application is for the renewal of Title V Permit No. 1050004-031-AV for the Lakeland Electric C.D. Mcintosh, Jr. Power plant, which expires on December 31, 2013.

Lakeland Electric is also requesting that the hours of operation for the diesel engine peaking Units 2 and 3 be limited to 100 hr/yr each according to the definition of "Limited Use Stationary Reciprocating Internal Combustion Engine" contained in 40 CFR 63.6675. (Note: Diesel Engine peaking Units 2 and 3 have been operating over the past several years as "limited use" engines.)

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
001	McIntosh Unit 1 – Fossil Fuel Fired Steam Generator	AF2A	N/A
005	McIntosh Unit 2 – Fossil Fuel Fired Steam Generator	AF2A	N/A
006	McIntosh Unit 3 – Fossil Fuel Fired Steam Generator	AF2A	N/A
002, 003	Diesel Engine Peaking Units 2 and 3	AF2C	N/A
004	Gas Turbine Peaking Unit 1	AF2C	N/A
028	McIntosh Unit 5 – 370 MW Combined Cycle CT	AF2A	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:
   Tony Candales, Asst. General Manager of Production

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: **Lakeland Electric**
   Street Address: **501 E. Lemon Street**
   City: **Lakeland** State: **FL** Zip Code: **33801**

4. Application Responsible Official Telephone Numbers...
   Telephone: **(863) 834-6559** ext. Fax: **(863) 834-6362**

5. Application Responsible Official E-mail Address: **tony.candales@lakelandelectric.com**

6. Application Responsible Official Certification:

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

Signature

5/15/13
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. **21156** 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.

Signature 5/2/13
Date

(seal)

* 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) **409.0** North (km) **3,106.2**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **28/04/50** Longitude (DD/MM/SS) **81/55/32**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment : **The McIntosh Power Plant consists of three fossil fuel-fired steam generators (FFSG), two diesel powered generators, one gas turbine peaking unit, and one combined-cycle combustion turbine (Unit 5). FFSG Unit 1 is fired with No.6 fuel oil, natural gas, and on-specification used oil. FFSG Unit 2 is fired with natural gas, No.6 fuel oil, and No.2 fuel oil. FFSG Unit 3 is primarily fired with coal, residual oil, natural gas, and petroleum coke. Unit 5 consists of a Siemens 501G combustion turbine and is primarily fired with natural gas with distillate oil as backup.**			

Facility Contact

1. Facility Contact Name: **Ms. Farzie Shelton, Associate General Manager of Technical Support**
2. Facility Contact Mailing Address... Organization/Firm: **Lakeland Electric** Street Address: **501 E. Lemon Street** City: **Lakeland** State: **FL** Zip Code: **33801-5079**
3. Facility Contact Telephone Numbers: Telephone: **(863) 834-6603** ext. Fax: **(863) 834-6362**
4. Facility Contact E-mail Address: **farzie.shelton@lakelandelectric.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:

Unit 1 (EU 001), Unit 2 (EU 005), Unit 3 (EU 006), and Unit 5 (EU 028) are regulated under Acid Rain Phase II.

Unit 2 and Unit 3 are subject to NSPS Subpart D, Standards of Performance for Fossil Fuel-Fired Steam Generators (Construction after August 17, 1971).

Unit 5 is subject to Subpart GG, Standards of Performance for New Stationary Gas Turbines.

The facility has several Reciprocating Internal Combustion Engines (RICE) subject to 40 CFR 63 Subpart ZZZZ. A list of these engines is provided in Attachment MC-FI-CV6.

Lakeland Electric intends to comply with 40 CFR 63 Subpart UUUUU, National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (Compliance date April 15, 2015).

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
PM	A	N
PM10	A	N
PM2.5	A	N
VOC	A	N
SO2	A	N
NOx	A	N
CO	A	N
HAPs	A	N
HCl	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: **MC-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: **MC-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: **MC-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: **MC-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: **MC-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:_____
   ☐ 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: **MC-FI-CV5** ☐ Not Applicable

6. Requested Changes to Current Title V Air Operation Permit:
   ☒ Attached, Document ID: **MC-FI-CV6** ☐ 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: **MC-FI-CA1a** ☐ 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: **MC-FI-CA1b** ☐ Previously Submitted, Date:_____
   ☐ Not Applicable

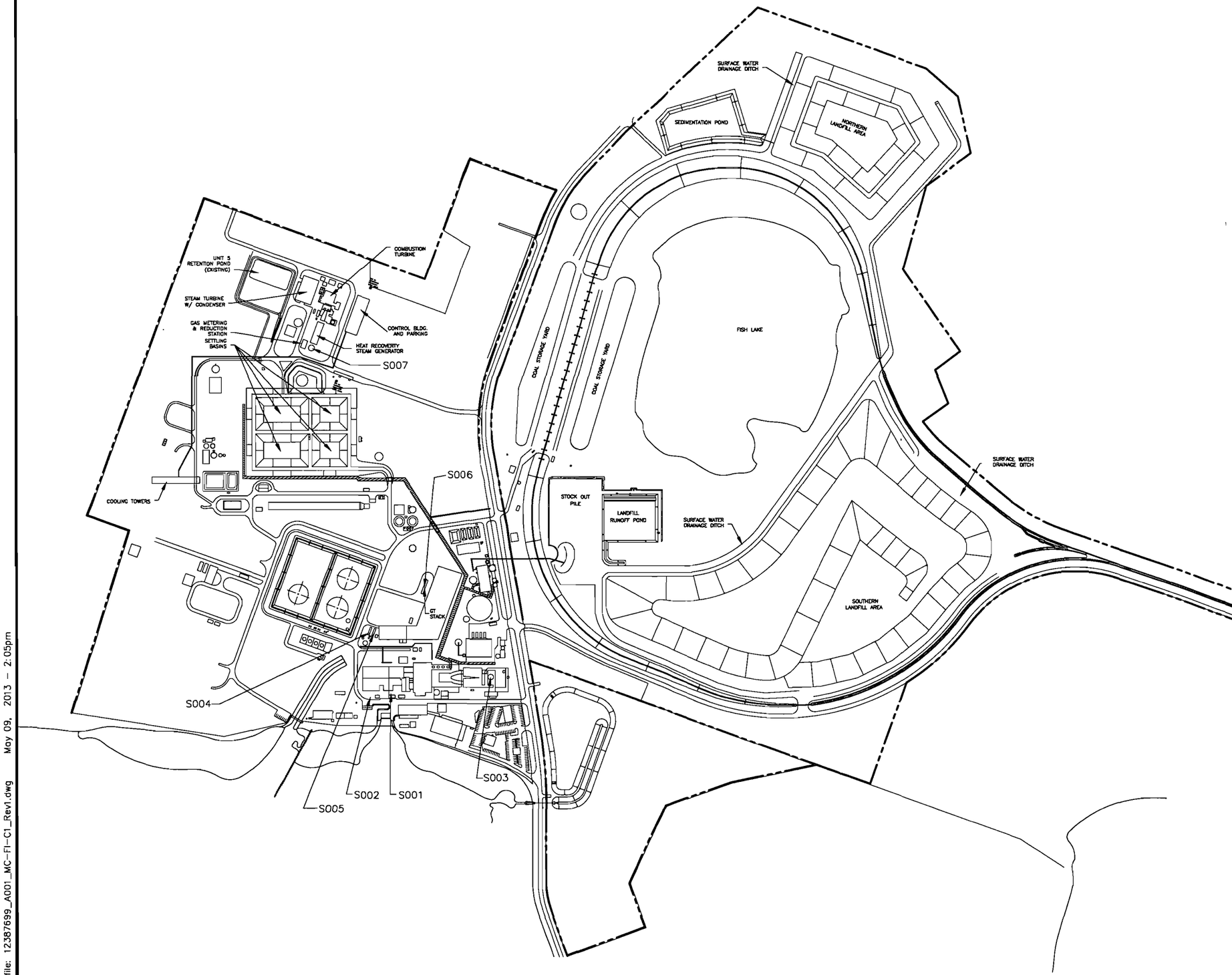
   New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.):
   ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____
   ☒ Not Applicable

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

Additional Requirements Comment

ATTACHMENT MC-FI-C1

FACILITY PLOT PLAN



LEGEND

----------	PROPERTY BOUNDARY
S001	UNIT 1
S002	UNIT 2
S003	UNIT 3
S004	DIESEL ENGINE PEAKING UNIT 2
S005	DIESEL ENGINE PEAKING UNIT 3
S006	GAS TURBINE PEAKING UNIT 1
S007	UNIT 5

600 0 600
SCALE FEET

PROJECT
COL/McINTOSH POWER PLANT/FL

TITLE
ATTACHMENT MC-FI-C1
FACILITY PLOT PLAN

Golder Associates
123-87699/COL/MC-FI-C1.DWG

PROJECT No.		123-87699	FILE No.		12387699_A001
DESIGN	SM	05/08/2013	SCALE	AS SHOWN	REV. 1
CADD	NRL	05/09/2013			
CHECK	RI	05/09/2013	MC-FI-C1		
REVIEW	SM	05/09/2013			

Drawing file: 12387699_A001_MC-FI-C1_Rev1.dwg May 09, 2013 - 2:05pm

ATTACHMENT MC-FI-C3

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

ATTACHMENT MC-FI-C3

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

The facility has small amounts of unconfined particulate matter as a result of the operation of the facility. The particulate matter includes:

- Fugitive dust from paved and unpaved roads
- Fugitive particulates from the use of bagged chemical products
- Coal handling and storage
- Limestone handling and storage
- FGD/ash by-products/handling and storage
- Municipal solid waste
- Ash cleaning
- Paint removal

Operational measures are undertaken at the facility which also minimize particulate emissions, in accordance with Rule 62-296.320(4)(c), F.A.C. (Condition FW5, Section II, Title V Permit):

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

ATTACHMENT MC-FI-CV1

LIST OF INSIGNIFICANT ACTIVITIES

ATTACHMENT MC-FI-CV1
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 Rules 62-210.300(3)(a) and 62-210.300(3)(b)1, which would not exceed the thresholds in Rule 62-213.430(6)(b)3.

Brief Description of Emissions Units and/or Activities:

1. Diesel Storage Tank (T-021).
2. Low Sulfur Diesel Storage Tank (T-023).
3. Heavy Oil Tank (T-113).
4. Heavy Oil Tank (T-114).
5. Heavy Oil Tank (T-115).
6. Used Oil Tank (T-116).
7. Comfort Heating <1 MMBtu/hr.
8. Non-Industrial Vacuum Cleaning.
9. Refrigeration Units.
10. Vacuum Pumps for Labs.
11. Steam Cleaning Equipment.
12. Sanders <5 square feet.
13. Space Heating Equipment; non-boilers.
14. Bakery Ovens.
15. Lab Equipment.
16. Brazing, Soldering, or Welding.
17. Laundry Dryers.
18. Fire and Safety Equipment.
19. Surface Coating <5% VOC, by volume.
20. Two fuel additives for McIntosh Unit 3 – FUELSOLV FMG 2970 and FMG 2301.
21. Any other emissions unit or activity that:
    a. Is exempted from the requirement to obtain an air construction permit as cited in Rule 62-213.430(6)(a), F.A.C.

    And meets all of the following criteria pursuant to Rule 62-213.430(6)(b), F.A.C.:

    b. Is not subject to a unit-specific applicable requirement.
    c. In combination with other units and activities proposed as insignificant, would not cause the facility to exceed any major source threshold(s) as defined by Rule 62-213.420(3)(c)1., F.A.C. unless acknowledged in a permit application.
    d. Would neither emit nor have the potential to emit
        i. 500 pounds per year of lead and lead compounds expressed as lead;
        ii. 1,000 pounds per year or more of any hazardous air pollutant;
        iii. 2,500 pounds per year or more of total hazardous air pollutants; or
        iv. 5.0 tons per year or more of any other regulated pollutant.

ATTACHMENT MC-FI-CV2

IDENTIFICATION OF APPLICABLE REQUIREMENTS

ATTACHMENT MC-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)***

40 CFR 60, Subpart GG: Standards of Performance for Stationary gas turbines.
40 CFR 60, Subpart D: Standards of Performance for Fossil-Fuel Fired Steam Generators for which construction commenced after August 17, 1971.
40 CFR 63, Subpart ZZZZ: National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

40 CFR 82: Protection of Stratospheric Ozone.
40 CFR 82, Subpart B: Servicing of Motor Vehicle Air Conditioners (MVAC).
40 CFR 82, Subpart F: Recycling and Emissions Reduction.
40 CFR 98, Subpart A: Mandatory Reporting of Greenhouse Gases.
40 CFR 98, Subpart C: General Stationary Combustion Sources.
40 CFR 98, Subpart D: Electricity Generation.

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.: Plant Operation – Problems.
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.
62-210.650, 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
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 10-12-08
CHAPTER 62-281, F.A.C.: Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling, effective 09-10-96

ATTACHMENT MC-FI-CV3

COMPLIANCE REPORT AND PLAN

ATTACHMENT MC-FI-CV3a
COMPLIANCE REPORT AND PLAN

Lakeland Electric certifies that the C.D. McIntosh, Jr. Power Plant in Lakeland, Florida, as of the date of this application, is in compliance with each applicable requirement addressed in this Title V air permit renewal application, except as described in the attached Compliance Plan.

I, the undersigned, am the responsible official as designated 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, on or before March 1 of each year.

	5/15/13
Signature, Responsible Official	Date

LAKELAND ELECTRIC

Your Essential Link to a Quality Life

CERTIFIED MAIL – RECEIPT REQUESTED

February 22, 2013

Ms. Susan Pelz
Compliance Manager
Florida Department of Environmental Protection
13051 North Telecom Parkway
Temple Terrace, FL 33637

RE: **C.D. McIntosh, Jr. Power Plant, Facility ID No. 1050004**

Subject: **Annual Statement of Compliance – Calendar Year 2012**

Dear Ms. Pelz:

In compliance with the Title V permit for the above-referenced facility, enclosed please find the annual Statement of Compliance (SOC) for calendar year 2012.

Accordingly, the SOC has been certified by Mr. Antonio D. Candales, the Responsible Official and Designated Representative. Additionally, a copy of this document has been forwarded to the Environmental Protection Agency, per the instructions provided in DEP Form No. 62-213.900(7).

If you should have any questions, please don't hesitate to contact me at (863) 834-8180.

Sincerely,

Nedin Bahtic

Nedin Bahtic
Environmental Permitting
nedin.bahtic@lakelandelectric.com

Enclosures

cc: U.S. EPA Region IV
Air and EPCRA Enforcement Branch
61 Forsyth St.
Atlanta, GA 30303

501 E. Lemon St. ✦ Lakeland, Florida 33801
Phone: 863.834.6300 ✦ Fax: 863.834.6344

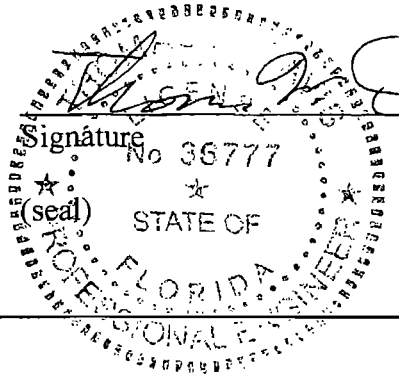
LAKELAND ELECTRIC
2012 ANNUAL STATEMENT OF COMPLIANCE

Winston Peaking Station, Facility ID 1050352
Charles Larsen Memorial Power Plant, Facility ID 1050003
C. D. McIntosh, Jr., Power Plant, Facility ID 1050004

Professional Engineer Certification

1. Professional Engineer Name: **Thomas W. Davis**
   Registration Number: **36777**
2. Professional Engineer Mailing Address:
   Organization/Firm: **Environmental Consulting & Technology, Inc.**
   Street Address: **3701 NW 98th Street**
   City: **Gainesville** State: **FL** Zip Code: **32606**
3. Professional Engineer Telephone Numbers:
   Telephone: **(352) 248-3351** Fax: **(352) 332-6722**
4. Professional Engineer Email Address: **tdavis@ectinc.com**
5. Professional Engineer Statement:

I, the undersigned, hereby certify that to the best of my knowledge, based on the information and belief formed after reasonable inquiry, that the statements made and data contained in this Lakeland Electric 2012 Statement of Compliance are true, accurate, and complete.



Signature (seal)

February 15, 2013
Date

CITY OF LAKELAND -- LAKELAND ELECTRIC
C.D. MCINTOSH, JR. POWER PLANT
FACILITY ID 1050004

2012 STATEMENT OF COMPLIANCE
TITLE V SOURCE

Department of Environmental Protection

Division of Air Resource Management

STATEMENT OF COMPLIANCE - TITLE V SOURCE

REASON FOR SUBMISSION (Check one to indicate why this statement of compliance is being submitted)

■ Annual Requirement	☐ Transfer of Permit	☐ Permanent Facility Shutdown

REPORTING PERIOD*	REPORT DEADLINE**
January 1 through December 31 of 2012 (year)	March 1, 2013

*The statement of compliance must cover all conditions that were in effect during the indicated reporting period, including any conditions that were added, deleted, or changed through permit revision.

**See Rule 62-213.440(3)(a)2., F.A.C.

Facility Owner/Company Name: City of Lakeland – Lakeland Electric

Site Name: C.D. McIntosh, Jr. Power Plant Facility ID No. 1050004 County: Polk

COMPLIANCE STATEMENT (Check only one of the following three options)

____ **A.** This facility was in compliance with all terms and conditions of the Title V Air Operation Permit and, if applicable, the Acid Rain Part, and there were no reportable incidents of deviations from applicable requirements associated with any malfunction or breakdown of process, fuel burning or emission control equipment, or monitoring systems during the reporting period identified above.

✔ **B.** This facility was in compliance with all terms and conditions of the Title V Air Operation Permit and, if applicable, the Acid Rain Part; however, there were one or more reportable incidents of deviations from applicable requirements associated with malfunctions or breakdowns of process, fuel burning or emission control equipment, or monitoring systems during the reporting period identified above, which were reported to the Department. For each incident of deviation, the following information is included:

1. Date of report previously submitted identifying the incident of deviation.
2. Description of the incident.

____ **C.** This facility was in compliance with all terms and conditions of the Title V Air Operation Permit and, if applicable, the Acid Rain Part, EXCEPT those identified in the pages attached to this report and any reportable incidents of deviations from applicable requirements associated with malfunctions or breakdowns of process, fuel burning or emission control equipment, or monitoring systems during the reporting period identified above, which were reported to the Department. For each item of noncompliance, the following information is included:

1. Emissions unit identification number.
2. Specific permit condition number (note whether the permit condition has been added, deleted, or changed during certification period).
3. Description of the requirement of the permit condition.
4. Basis for the determination of noncompliance (for monitored parameters, indicate whether monitoring was continuous, i.e., recorded at least every 15 minutes, or intermittent).
5. Beginning and ending dates of periods of noncompliance.
6. Identification of the probable cause of noncompliance and description of corrective action or preventative measures implemented.
7. Dates of any reports previously submitted identifying this incident of noncompliance.

For each incident of deviation, as described in paragraph **B.** above, the following information is included:

1. Date of report previously submitted identifying the incident of deviation.
2. Description of the incident.

STATEMENT OF COMPLIANCE - TITLE V SOURCE

RESPONSIBLE OFFICIAL CERTIFICATION

I, the undersigned, am a responsible official (Title V air permit application or responsible official notification form on file with the Department) of the Title V source for which this document is being submitted. With respect to all matters other than Acid Rain program requirements, I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made and data contained in this document are true, accurate, and complete.

(Signature of Title V Source Responsible Official) 2/20/13 *(Date)*

Name: **Antonio D. Candales** Title: **Assistant General Manager of Production**

DESIGNATED REPRESENTATIVE CERTIFICATION (only applicable to Acid Rain source)

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

(Signature of Acid Rain Source Designated Representative) 2/20/13 *(Date)*

Name: **Antonio D. Candales** Title: **Assistant General Manager of Production**

{Note: Attachments, if required, are created by a responsible official or designated representative, as appropriate, and should consist of the information specified and any supporting records. Additional information may also be attached by a responsible official or designated representative when elaboration is required for clarity. This report is to be submitted to both the compliance authority (DEP district or local air program) and the U.S. Environmental Protection Agency (EPA) (U.S. EPA Region 4, Air and EPCRA Enforcement Branch, 61 Forsyth Street, Atlanta GA 30303).}

LAKELAND ELECTRIC
C. D. MCINTOSH, JR. POWER PLANT
2012 STATEMENT OF COMPLIANCE – TITLE V SOURCE
Prior Incident Reports

Date of Prior Report	Description of Incident
First Quarter 2012 Excess Emission Report, 4/30/12	Unit #1 - Monitor downtime due to equipment malfunction.
First Quarter 2012 Excess Emission Report, 4/30/12	Unit #2 - Excess opacity during startup/shutdown; also monitor downtime due to equipment malfunction
First Quarter 2012 Excess Emission Report, 4/30/12	Unit #2 - SO_2 monitor downtime due to equipment malfunction
First Quarter 2012 Excess Emission Report, 4/30/12	Unit #3 - Excess opacity during startup/shutdown, and monitor downtime due to equipment malfunction
First Quarter 2012 Excess Emission Report, 4/30/12	Unit #3 - CO monitor downtime due to equipment malfunction and QA
First Quarter 2012 Excess Emission Report, 4/30/12	Unit #3 - SO_2 monitor downtime due to equipment malfunction and QA
First Quarter 2012 Excess Emission Report, 4/30/12	Unit #5 - NO_x monitor downtime due to equipment malfunction and QA
Second Quarter 2012 Excess Emission Report, 7/30/12	Unit #2 - Excess opacity during startup/shutdown, and monitor downtime due to equipment malfunction
Second Quarter 2012 Excess Emission Report, 7/30/12	Unit #2 - SO_2 monitor downtime due to equipment malfunction and QA
Second Quarter 2012 Excess Emission Report, 7/30/12	Unit #3 -Excess opacity during startup/shutdown, and opacity monitor downtime due to equipment malfunction and QA
Second Quarter 2012 Excess Emission Report, 7/30/12	Unit #3 - SO_2 monitor downtime due to equipment malfunction and QA
Second Quarter 2012 Excess Emission Report, 7/30/12	Unit #3 - CO monitor downtime due to equipment malfunction and other
Second Quarter 2012 Excess Emission Report, 7/30/12	Unit #5 - NO_x monitors downtime due to equipment malfunctions (monitors for 3-hr avg. and 24-hr avg.)

LAKELAND ELECTRIC
C. D. MCINTOSH, JR. POWER PLANT
2012 STATEMENT OF COMPLIANCE – TITLE V SOURCE
Prior Incident Reports

Date of Prior Report	Description of Incident
Third Quarter 2012 Excess Emission Report, 10/24/12	Unit #3 - Opacity monitor downtime due to monitor equipment malfunction and QA
Third Quarter 2012 Excess Emission Report, 10/24/12	Unit #3 - CO monitor downtime due to equipment malfunction and QA
Third Quarter 2012 Excess Emission Report, 10/24/12	Unit #3 - SO_2 monitor downtime due to equipment malfunction and QA
Third Quarter 2012 Excess Emission Report, 10/24/12	Unit #5 - NO_x monitor downtime due to equipment malfunction and QA (24-hour average)
Third Quarter 2012 Excess Emission Report, 10/24/12	Unit #5 - NO_x monitor downtime due to equipment malfunction and QA (3-hour average)
Fourth Quarter 2012 Excess Emission Report, 1/29/13	Unit #3 - Excess opacity during startup/shutdown, and process malfunction
Fourth Quarter 2012 Excess Emission Report, 1/29/13	Unit #2 - SO_2 monitor downtime due to misc. (0.53 hours)
Fourth Quarter 2012 Excess Emission Report, 1/29/13	Unit #3 - SO_2 monitor downtime due to equipment malfunctions and QA
Fourth Quarter 2012 Excess Emission Report, 1/29/13	Unit #3 - CO monitor downtime due to equipment malfunction and QA
Fourth Quarter 2012 Excess Emission Report, 1/29/13	Unit #5 - NO_x monitors downtime due to equipment malfunctions (monitors for 3-hr avg. and 24-hr avg.)

ATTACHMENT MC-FI-CV3b
COMPLIANCE REPORT AND PLAN

McIntosh Unit 1 (EU 001) Annual Testing for Visible Emissions (VE)

On behalf of Lakeland Electric (LE), Golder Associates (Golder) has prepared this compliance plan for VE testing for McIntosh Unit 1 (EU 001).

Deviations from Applicable Requirements

Specific Condition A.17 of Permit No. 1050004-031-AV, effective date March 9, 2012 requires that a compliance test be conducted for particulate matter (PM) and VE prior to permit renewal. During the last 10 years, Unit 1 was tested for PM and VE emissions during the period from 2003 to 2007 and for only VE emissions in 2008. All tests showed compliance with PM and VE emissions limits. The unit has not been tested for either PM or VE emissions since 2008. Following are the operating hours of Unit 1 since 2009:

Federal Fiscal Year (FFY)	Gas (hr/yr)	Oil (hr/yr)
2009	52.3	0.6
2010	0	0
2011	100.5	0.6
2012	117.6	2.0

Unit 1 is not expected to operate unless there is demand for it, which is highly unlikely. Unit 1 is currently not operating and therefore, VE testing for Unit 1 has not been completed.

Compliance Plan

Because there is no demand, LE does not plan to operate this unit at the present time. Should business conditions lead to the utilization of the emission unit, LE proposes to conduct a visible emissions compliance test within a day of the start of the operation. Please note that based on Specific Condition No. A.24., annual VE testing is not required if only natural gas fuel is used or if fuel oil is used for less than 400 hr/yr. Unlike VE, both annual and renewal PM testing are not required if only natural gas fuel is used or if fuel oil is used for less than 400 hours.

ATTACHMENT MC-FI-CV5

VERIFICATION OF RISK MANAGEMENT PLAN SUBMISSION TO EPA

LAKELAND ELECTRIC

Your Essential Link to a Quality Life

October 21, 2009

Risk Management Plan (RMP) Reporting Center
C/O CGI Federal
12601 Fair Lakes Circle
Fairfax, VA 22033

Attn: Updated Risk Management Plans
Via: Certified Mail

RE: Update of RMP Submittal and Certification Statement
EPA ID #1000-0009-4738
McIntosh/Northside-City of Lakeland
3600 East Lake Parker Drive
Lakeland, Florida 33805

Dear Sir or Madam:

Please find enclosed the diskette containing the updated RMP information for Lakeland Electric, Lakeland, Florida. The facility, McIntosh/Northside is required to register, submit, and update in accordance with the CAAA section 112(r). Also, enclosed is the signed certification letter for the referenced facility.

Sincerely,

Douglas Doerr
Environmental Coordinator

501 E. Lemon St. ✦ Lakeland, Florida 33801
Phone: 863.834.6300 ✦ Fax: 863.834.6344

ATTACHMENT MC-FI-CV6

REQUESTED CHANGES TO CURRENT TITLE V AIR OPERATION PERMIT

ATTACHMENT MC-FI-CV6
REQUESTED ADMINISTRATIVE CHANGES

A. 40 CFR 63 Subpart ZZZZ Applicability

On behalf of Lakeland Electric (LE), Golder Associates (Golder) has prepared an inventory of stationary Reciprocating Internal Combustion Engines (RICE) at the C.D. Mcintosh, Jr. Power Plant, which consists of an electric power generation plant and an adjacent Northside Wastewater Treatment Plant (WWTP). The purpose of the inventory was to analyze applicability of Title 40, Part 63 of the Code of Federal Regulations (40 CFR 63), Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants (NESHAP) for stationary RICE to these engines. Based on the applicability analysis, following are the three stationary RICE at the facility subject to Subpart ZZZZ:

- Coal Tunnel Sump Engine (EU 008)
- Fire Water Pump UPS Diesel Engine No. 32 (EU 010)
- CT Startup Diesel Engine (EU 011)

The four diesel generators at the Northside WWTP are existing emergency stationary RICE with a site rating of more than 500 Horsepower (HP) located at a major source of HAP emissions and are therefore exempt from 40 CFR 63 Subpart ZZZZ per Rule § 63.6590(b)(3)(iii).

Please note that LE is requesting FDEP to change the status of Diesel Engine Peaking Units 1 and 2 (EU 002 and EU 003) to limited use as defined by 40 CFR 63.6675. As a result, these units are exempt from 40 CFR 63 Subpart ZZZZ as per Rule 63.6590(b)(3)(iv).

The attached Tables 1 through 10 present detailed information on the engines, including manufacturer, serial number, horsepower rating, and an applicability analysis for the 40 CFR 63 Subpart ZZZZ requirements.

Also, the startup diesel engine is used solely for the purpose of starting Unit 3.

LE requests that the Subpart ZZZZ applicability requirements for these engines be included in the renewed Title V permit.

B. Removal of CO RATA requirement for Unit 5

Specific Condition No. F.23 of the current Title V Permit No. 1050004-031-AV states that CO and NO_x RATA may be used to demonstrate compliance with the emission standards for the annual test requirement. However, LE does not have a CO monitor for Unit 5 and therefore requests to remove the reference of the CO RATA from the annual compliance demonstration requirement.

C. Appendix U – List of Unregulated Emission Units and/or Activities

LE has reviewed the list of unregulated emission units and requests the following changes:

- Fire water UPS diesel No. 31 (EU ID No. 009) no longer exists at the facility and hence should be removed.
- The general purpose diesel engines (EU ID No. 012) and emergency generators (EU ID No. 013) are basically portable pumps and welding equipment utilized at the facility [exempt from 40 CFR 63 Subpart ZZZZ per Rule 63.6585(a)], and should therefore be classified as "*Portable pumps and welding equipment*" under a single emission unit ID.
- Modify "*Northside Waste Water Treatment Facility – Two emergency diesel generators*" (EU ID No. 020) to "*Northside Waste Water Treatment Facility – Four emergency diesel generators*".

D. Appendix I – List of Insignificant Emission Units and/or Activities

LE requests that a "25 kW propane fired emergency engine" be added to the list of insignificant emission units. The attached Table 11 presents emissions calculations for the engine, which show that annual emissions for all the regulated pollutants are less than 5 TPY. (Rule 62-213.430(6), F.A.C.).

TABLE 1
LIST OF UNITS SUBJECT TO 40 CFR 63 SUBPART ZZZZ
MCINTOSH POWER PLANT

	Unit 1 Sump Pump (008)	Unit 2 Fire Pump (010)	Unit 3 Black-Start (011)	Unit 4 NGEN 01 (020)	Unit 5 NGEN 02 (020)	Unit 6 NGEN 03 (020)	Unit 7 NGEN 04 (020)	Unit 8 Peaking Unit No. 1	Unit 9 Peaking Unit No. 2
Engine Description	Coal Tunnel Sump Engine	Fire Water UPS Disel No. 32	CT Startup Diesel	Northside WWTP Emergency Generator 1	Northside WWTP Emergency Generator 2	Northside WWTP Emergency Generator 3	Northside WWTP Emergency Generator 4	Diesel No. 2	Diesel No. 3
Fuel Used	Diesel	Diesel	Diesel	Diesel	Diesel	Diesel	Diesel	Diesel	Diesel
CI or SI	CI	CI	CI	CI	CI	CI	CI	CI	CI
Located in an Area Source or Major Source of HAPS	Major Source	Major Source	Major Source	Major Source	Major Source	Major Source	Major Source	Major Source	Major Source
Use (Emergency, Non-Emergency, Black-Start, Limited-Use)	Non-Emergency	Emergency	Black-Start	Emergency	Emergency	Emergency	Emergency	Limited-Use	Limited-Use
Engine Serial Number	25M55A1C20	69827	CH8118	6DA01475	6DA01473	6FA04463	6JM00564	69-B1-1050	69-B1-1020
Engine Manufacturer	LISTER	Cummins	Detroit Diesel	CAT	CAT	CAT	CAT	GM Electromotive	GM Electromotive
Engine Model	HS-468	NT-855-F3	V-71	3412	3412	3412	3406	20-645-E4	20-645-E5
Generator Power (kW)	19	224	373	600	600	600	400	2,685	2,685
Engine Power (bhp)	25	300	500	805	805	805	536	3,600	3,600
No. of Cylinders	--	6	--	--	--	--	--	--	--
Cylinder Displacement (l)	--	14	--	--	--	--	--	--	--
Engine Construction Date	--	--	--	--	--	--	1995	--	--
Engine Installation Date	1981	April 1989	1969	--	--	--	--	--	--
Existing, New, or Reconstructed	Existing	Existing	Existing	Existing	Existing	Existing	Existing	Existing	Existing

TABLE 2
APPLICABLE REQUIREMENTS OF 40 CFR 63 SUBPART ZZZZ
MCINTOSH JR. POWER PLANT: UNIT 1 - SUMP PUMP (008)

	Engine Data/Subpart ZZZZ Requirements	Rule Citation
Engine Description	Coal Tunnel Sump Engine	--
Fuel Used	Diesel	--
CI or SI	CI	--
Located in an Area Source or Major Source of HAPS	Major Source	--
Use (Emergency, Non-Emergency, Black-Start, Limited-Use)	Non-Emergency	--
Engine Serial Number	25M55A1C20	--
Engine Manufacturer	LISTER	--
Engine Model	HS-468	--
Engine Power (kW)	19	--
Engine Power (bhp)	25	--
No. of Cylinders	--	--
Cylinder Displacement (l)	--	--
Engine Construction Date	--	--
Engine Installation Date	1981	--
Existing, New, or Reconstructed	Existing	--
Compliance Date	May 3rd, 2013	Rule § 63.6595(a)(1)
Emissions Limitations	(a) Change oil and filter every 1,000 hrs of operation or annually, whichever first (b) Inspect air cleaner every 1,000 hrs of operation or annually, whichever first (c) Inspect and replace (if necessary) hoses and belts every 500 hrs of operation or annually, whichever first	Rule § 63.6602, Table 2c (2)
Operating Limitations	None	Rule § 63.6602
Fuel Requirements	None	Rule § 63.6604
Initial Performance Tests	None	Rule § 63.6612(a)
Monitoring, installation, collection, operation, and maintenance requirements	Operate and maintain according to manufacturer's instructions or develop and follow GCP Minimize idle time to <30 min	Rule § 63.6625(e)(1) Rule § 63.6625(h)
Initial Compliance	None	Rule § 63.6630
Continuous Compliance	Must report each instance in which operating limitation from Table 2c were not met	Rule § 63.6640
Notification Requirements	None	Rule § 63.6645
Reporting Requirements	None	Rule § 63.6650
Recordkeeping Requirements	Records to demonstrate compliance with work or management practices listed in Table 6(9) Records of maintenance	Rule § 63.6655

TABLE 3
APPLICABLE REQUIREMENTS OF 40 CFR 63 SUBPART ZZZZ
MCINTOSH JR. POWER PLANT: UNIT 2 - FIRE PUMP (010)

	Engine Data/Subpart ZZZZ Requirements	Rule Citation
Engine Description	Fire Water UPS Disel No. 32	--
Fuel Used	Diesel	--
CI or SI	CI	--
Located in an Area Source or Major Source of HAPS	Major Source	--
Use (Emergency, Non-Emergency, Black-Start, Limited-Use)	Emergency	--
Engine Serial Number	69827	--
Engine Manufacturer	Cummins	--
Engine Model	NT-855-F3	--
Engine Power (kW)	224	--
Engine Power (bhp)	300	--
No. of Cylinders	6	--
Cylinder Displacement (l)	14	--
Engine Construction Date	--	--
Engine Installation Date	April 1989	--
Existing, New, or Reconstructed	Existing	--
Compliance Date	May 3rd, 2013	Rule § 63.6595(a)(1)
Emissions Limitations	(a) Change oil and filter every 500 hrs of operation or annually, whichever first (b) Inspect air cleaner every 1,000 hrs of operation or annually, whichever first (c) Inspect and replace (if necessary) hoses and belts every 500 hrs of operation or annually, whichever first	Rule § 63.6602, Table 2c (1)
Operating Limitations	None	Rule § 63.6602
Fuel Requirements	None	Rule § 63.6604
Initial Performance Tests	None	Rule § 63.6612(a)
Monitoring, installation, collection, operation, and maintenance requirements	Operate and maintain according to manufacturer's instructions or develop and follow GCP Install a non-resettable hour meter Minimize idle time to <30 min	Rule § 63.6625(e)(2) Rule § 63.6625(f) Rule § 63.6625(h)
Initial Compliance	None	Rule § 63.6630
Continuous Compliance	Non-emergency use including maintenance checks and readiness testing limited to 100 hr/yr. Non-emergency use limited to 50 hr/yr. No limit during emergencies Demonstrate compliance with work or management practices in Table 6(9)	Rule § 63.6640(f), Table 6(9)
Notification Requirements	Applicable notifications must be submitted	Rule § 63.6645
Reporting Requirements	None	Rule § 63.6650
Recordkeeping Requirements	Copies of each notification and report to comply with the subpart Records to demonstrate compliance with work or management practices listed in Table 6(9) Records of maintenance conducted Records of operating hours	Rule § 63.6655(d) Rule § 63.6655(e)(2) Rule § 63.6655(f)

TABLE 4
APPLICABLE REQUIREMENTS OF 40 CFR 63 SUBPART ZZZZ
MCINTOSH JR. POWER PLANT: UNIT 3 - BLACK-START (011)

	Engine Data/Subpart ZZZZ Requirements	Rule Citation
Engine Description	CT Startup Diesel	--
Fuel Used	Diesel	--
CI or SI	CI	--
Located in an Area Source or Major Source of HAPS	Major Source	--
Use (Emergency, Non-Emergency, Black-Start, Limited-Use)	Black-Start	--
Engine Serial Number	CH8118	--
Engine Manufacturer	Detroit Diesel	--
Engine Model	V-71	--
Engine Power (kW)	373	--
Engine Power (bhp)	500	--
No. of Cylinders	--	--
Cylinder Displacement (l)	--	--
Engine Construction Date	--	--
Engine Installation Date	1969	--
Existing, New, or Reconstructed	Existing	--
Compliance Date	May 3rd, 2013	Rule § 63.6595(a)(1)
Emissions Limitations	(a) Change oil and filter every 500 hrs of operation or annually, whichever first (b) Inspect air cleaner every 1,000 hrs of operation or annually, whichever first (c) Inspect and replace (if necessary) hoses and belts every 500 hrs of operation or annually, whichever first	Rule § 63.6602, Table 2c (1)
Operating Limitations	None	Rule § 63.6602
Fuel Requirements	None	Rule § 63.6604
Initial Performance Tests	None	Rule § 63.6612
Monitoring, installation, collection, operation, and maintenance requirements	Operate and maintain according to manufacturer's instructions or develop and follow GCP Minimize idle time to <30 min	Rule § 63.6625(e)(2) Rule § 63.6625(h)
Initial Compliance	None	Rule § 63.6630
Continuous Compliance	Must report each instance in which operating limitation from Table 2c were not met Demonstrate compliance with work or management practices in Table 6(9)	Rule § 63.6640, Table 6(9)
Notification Requirements	Applicable notifications must be submitted	Rule § 63.6645
Reporting Requirements	None	Rule § 63.6650
Recordkeeping Requirements	Copies of each notification and report to comply with the subpart Records to demonstrate compliance with work or management practices listed in Table 6(9)	Rule § 63.6655

TABLE 5
APPLICABLE REQUIREMENTS OF 40 CFR 63 SUBPART ZZZZ
MCINTOSH JR. POWER PLANT: UNIT 4 - NGEN 01 (020)

	Engine Data/Subpart ZZZZ Requirements	Rule Citation
Engine Description	Northside WWTP Emergency Generator 1	--
Fuel Used	Diesel	--
CI or SI	CI	--
Located in an Area Source or Major Source of HAPS	Major Source	--
Use (Emergency, Non-Emergency, Black-Start, Limited-Use)	Emergency	--
Engine Serial Number	6DA01475	--
Engine Manufacturer	CAT	--
Engine Model	3412	--
Engine Power (kW)	600	--
Engine Power (bhp)	805	--
No. of Cylinders	--	--
Cylinder Displacement (l)	--	--
Engine Construction Date	--	--
Engine Installation Date	--	--
Existing, New, or Reconstructed	Existing	--
Compliance Date	*	
Emissions Limitations	*	
Operating Limitations	*	
Fuel Requirements	*	
Initial Performance Tests	*	
Monitoring, installation, collection, operation, and maintenance requirements	*	
Initial Compliance	*	
Continuous Compliance	*	
Notification Requirements	*	
Reporting Requirements	*	
Recordkeeping Requirements	*	

* The engine is an existing emergency stationary RICE with a site rating of more than 500 HP located at a major source of HAP emissions and therefore, is exempt from 40 CFR 63 Subpart ZZZZ per Rule § 63.6590(b)(3)(iii).

TABLE 6
APPLICABLE REQUIREMENTS OF 40 CFR 63 SUBPART ZZZZ
MCINTOSH JR. POWER PLANT: UNIT 5 - NGEN 02 (020)

	Engine Data/Subpart ZZZZ Requirements	Rule Citation
Engine Description	Northside WWTP Emergency Generator 2	--
Fuel Used	Diesel	--
CI or SI	CI	--
Located in an Area Source or Major Source of HAPS	Major Source	--
Use (Emergency, Non-Emergency, Black-Start, Limited-Use)	Emergency	--
Engine Serial Number	6DA01473	--
Engine Manufacturer	CAT	--
Engine Model	3412	--
Engine Power (kW)	600	--
Engine Power (bhp)	805	--
No. of Cylinders	--	--
Cylinder Displacement (l)	--	--
Engine Construction Date	--	--
Engine Installation Date	--	--
Existing, New, or Reconstructed	Existing	--
Compliance Date	*	
Emissions Limitations	*	
Operating Limitations	*	
Fuel Requirements	*	
Initial Performance Tests	*	
Monitoring, installation, collection, operation, and maintenance requirements	*	
Initial Compliance	*	
Continuous Compliance	*	
Notification Requirements	*	
Reporting Requirements	*	
Recordkeeping Requirements	*	

* The engine is an existing emergency stationary RICE with a site rating of more than 500 HP located at a major source of HAP emissions and therefore, is exempt from 40 CFR 63 Subpart ZZZZ per Rule § 63.6590(b)(3)(iii).

TABLE 7
APPLICABLE REQUIREMENTS OF 40 CFR 63 SUBPART ZZZZ
MCINTOSH JR. POWER PLANT: UNIT 6 - NGEN 03 (020)

	Engine Data/Subpart ZZZZ Requirements	Rule Citation
Engine Description	Northside WWTP Emergency Generator 3	--
Fuel Used	Diesel	--
CI or SI	CI	--
Located in an Area Source or Major Source of HAPS	Major Source	--
Use (Emergency, Non-Emergency, Black-Start, Limited-Use)	Emergency	--
Engine Serial Number	6FA04463	--
Engine Manufacturer	CAT	--
Engine Model	3412	--
Engine Power (kW)	600	--
Engine Power (bhp)	805	--
No. of Cylinders	--	--
Cylinder Displacement (l)	--	--
Engine Construction Date	--	--
Engine Installation Date	--	--
Existing, New, or Reconstructed	Existing	--
Compliance Date	*	
Emissions Limitations	*	
Operating Limitations	*	
Fuel Requirements	*	
Initial Performance Tests	*	
Monitoring, installation, collection, operation, and maintenance requirements	*	
Initial Compliance	*	
Continuous Compliance	*	
Notification Requirements	*	
Reporting Requirements	*	
Recordkeeping Requirements	*	

* The engine is an existing emergency stationary RICE with a site rating of more than 500 HP located at a major source of HAP emissions and therefore, is exempt from 40 CFR 63 Subpart ZZZZ per Rule § 63.6590(b)(3)(iii).

TABLE 8
APPLICABLE REQUIREMENTS OF 40 CFR 63 SUBPART ZZZZ
MCINTOSH JR. POWER PLANT: UNIT 7 - NGEN 04 (020)

	Engine Data/Subpart ZZZZ Requirements	Rule Citation
Engine Description	Northside WWTP Emergency Generator 4	--
Fuel Used	Diesel	--
CI or SI	CI	--
Located in an Area Source or Major Source of HAPS	Major Source	--
Use (Emergency, Non-Emergency, Black-Start, Limited-Use)	Emergency	--
Engine Serial Number	6JM00564	--
Engine Manufacturer	CAT	--
Engine Model	3406	--
Engine Power (kW)	400	--
Engine Power (bhp)	536	--
No. of Cylinders	--	--
Cylinder Displacement (l)	--	--
Engine Construction Date	1995	--
Engine Installation Date	--	--
Existing, New, or Reconstructed	Existing	--
Compliance Date	*	
Emissions Limitations	*	
Operating Limitations	*	
Fuel Requirements	*	
Initial Performance Tests	*	
Monitoring, installation, collection, operation, and maintenance requirements	*	
Initial Compliance	*	
Continuous Compliance	*	
Notification Requirements	*	
Reporting Requirements	*	
Recordkeeping Requirements	*	

* The engine is an existing emergency stationary RICE with a site rating of more than 500 HP located at a major source of HAP emissions and therefore, is exempt from 40 CFR 63 Subpart ZZZZ per Rule § 63.6590(b)(3)(iii).

TABLE 9
APPLICABLE REQUIREMENTS OF 40 CFR 63 SUBPART ZZZZ
MCINTOSH POWER PLANT: UNIT 8 - DIESEL NO. 2

	Engine Data/Subpart ZZZZ Requirements	Rule Citation
Engine Description	Diesel No. 2	--
Fuel Used	Diesel	--
CI or SI	CI	--
Located in an Area Source or Major Source of HAPS	Major Source	--
Use (Emergency, Non-Emergency, Black-Start, Limited-Use)	Limited-Use	--
Engine Serial Number	69-B1-1050	--
Engine Manufacturer	GM Electromotive	--
Engine Model	20-645-E4	--
Engine Power (kW)	2685	--
Engine Power (bhp)	3600	--
No. of Cylinders	--	--
Cylinder Displacement (l)	--	--
Engine Construction Date	--	--
Engine Installation Date	--	--
Existing, New, or Reconstructed	Existing	--
Compliance Date	*	
Emissions Limitations	*	
Operating Limitations	*	
Fuel Requirements	*	
Initial Performance Tests	*	
Monitoring, installation, collection, operation, and maintenance requirements	*	
Initial Compliance	*	
Continuous Compliance	*	
Notification Requirements	*	
Reporting Requirements	*	
Recordkeeping Requirements	*	

* The engine is an existing limited use stationary RICE with a site rating of more than 500 HP located at a major source of HAP emissions and therefore, is exempt from 40 CFR 63 Subpart ZZZZ per Rule § 63.6590(b)(3)(iv).

TABLE 10
APPLICABLE REQUIREMENTS OF 40 CFR 63 SUBPART ZZZZ
MCINTOSH POWER PLANT: UNIT 9 - DIESEL NO. 3

	Engine Data/Subpart ZZZZ Requirements	Rule Citation
Engine Description	Diesel No. 3	--
Fuel Used	Diesel	--
CI or SI	CI	--
Located in an Area Source or Major Source of HAPS	Major Source	--
Use (Emergency, Non-Emergency, Black-Start, Limited-Use)	Limited-Use	--
Engine Serial Number	69-B1-1020	--
Engine Manufacturer	GM Electromotive	--
Engine Model	20-645-E5	--
Engine Power (kW)	2685	--
Engine Power (bhp)	3600	--
No. of Cylinders	--	--
Cylinder Displacement (l)	--	--
Engine Construction Date	--	--
Engine Installation Date	--	--
Existing, New, or Reconstructed	Existing	--
Compliance Date	*	
Emissions Limitations	*	
Operating Limitations	*	
Fuel Requirements	*	
Initial Performance Tests	*	
Monitoring, installation, collection, operation, and maintenance requirements	*	
Initial Compliance	*	
Continuous Compliance	*	
Notification Requirements	*	
Reporting Requirements	*	
Recordkeeping Requirements	*	

* The engine is an existing limited use stationary RICE with a site rating of more than 500 HP located at a major source of HAP emissions and therefore, is exempt from 40 CFR 63 Subpart ZZZZ per Rule § 63.6590(b)(3)(iv).

TABLE 11
Emissions Calculations for Propane-fired Emergency Engine
C.D.McIntosh Jr. Power Plant

Parameter	Units	
Performance		
Number of Units		1
Fuel		Propane
Engine Rating [a]	KW	25
Engine Rating [a]	HP	33.5
Maximum operation/yr [a]	hours	8,760
Emissions		
PM_{10} - Basis [b]	lb/hp-hr	0.0022
Emissions	TPY	0.32
SO_2 -Basis [b]	lb/hp-hr	0.00205
Emissions	TPY	0.30
NO_x - Basis [b]	lb/hp-hr	0.0310
Emissions	TPY	4.55
CO - Basis [b]	lb/hp-hr	0.00668
Emissions	TPY	0.98
VOC - Basis [b,c]		
Emissions	lb/hp-hr	0.00247
	TPY	0.36

Notes:
Engine manufactured in 2008 therefore exempt from 40 CFR 63 Subpart ZZZZ and exempt from 40 CFR 63 Subpart JJJJ per Rule §60.4230 (a)(2)(ii).

[a] Lakeland Electric (2013); Golder Associates (2013)

[b] Based on AP-42 Table 3.3-1 (USEPA 10/96), For uncontrolled gasoline and disesel industrial engines

[c] Based on emissions from exhaust.

ATTACHMENT MC-FI-CA1A

ACID RAIN PART APPLICATION

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.

C.D. McIntosh, Jr. Power Plant Plant name	FL State	0676 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
EU 001	No	Yes	N/A	N/A
EU 005	No	Yes	N/A	N/A
EU 006	No	Yes	N/A	N/A
EU 028	No	Yes	N/A	N/A

C.D. McIntosh, Jr. Power Plant

Plant Name (from STEP 1)

STEP 3

Read the standard requirements.

Acid Rain Part Requirements.

(1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Submit a complete Acid Rain Part application (including a compliance plan) under 40 CFR Part 72 and Rules 62-214.320 and 330, F.A.C., in accordance with the deadlines specified in Rule 62-214.320, F.A.C.; and
(ii) Submit in a timely manner any supplemental information that the 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 Part77; 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,

C.D. McIntosh, Jr. Power Plant

Plant Name (from STEP 1)

STEP 3, Continued.

Recordkeeping and Reporting Requirements (cont)

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

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

Liability.

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

Effect on Other Authorities.

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

STEP 4
For SO_2 Opt-in units only.

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

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

In column "h" enter the hours.

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

C.D. McIntosh, Jr. Power Plant
Plant Name (from STEP 1)

STEP 5

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

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

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

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

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 N/A	Date N/A 5/15/13

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.

Subject: Acid Rain Part Application (C.D.McIntosh, Jr. Power Plant)

Name Mr. Tony Candales	Title Assistant General Manager of Production
Owner Company Name Lakeland Electric	
Phone (863) 834-6559	E-mail address tony.candales@lakelandelectric.com
Signature	Date 5/15/13

ATTACHMENT MC-FI-CA1B

PHASE II NOX AVERAGING PLAN

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Phase II NO_x Compliance Plan

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

This submission is : [X] New [ ] Revised

Step 1
Indicate plant name, State, and ORIS code from NADB, if applicable

C.D. McIntosh, Jr. Power Plant	FL	0676
Plant Name	State	ORIS Code

Step 2

Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "GB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom. Indicate the compliance option selected for each unit.

	ID# 03 (EU006) Type DBW	ID# Type	ID# Type	ID# Type	ID# Type	ID# Type
(a) Standard annual average emission limitation of 05.0 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(c) EPA-approved early election plan under 40 CFR 76.8 through 12/31/07 (also indicate above emission limit specified in	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(d) standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)	[X]	[ ]	[ ]	[ ]	[ ]	[ ]
(e) Standard annual average emission limitation of 4.0 lb/mmBtu (for Phase II tangentially fired boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(f) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(g) Standard annual average emission limitation of .086 lb/mmBtu (for cyclone boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(h) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(i) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(j) NO_x Averaging Plan (include NO_x Averaging form)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A)(check the standard emission limitation applicable to any unit utilizing stack)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
(l) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NOX Averaging (check the NOX Averaging Plan box and include NOX Averaging form)	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]

EPA Form 7610-28 (3-97)

C.D. McIntosh, Jr. Power Plant Plant Name (from Step 1)	NOX Compliance – Page 2 Page 2 of 2

Step 2, cont'd

	ID# / Type	ID# / Type	ID# / Type	ID# / Type	ID# / Type	ID# / Type
(m) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17 (a)(2)(i)(C), (a)(2)(ii)(B), or (b)(2)						
(n) AEL (include Phase II AEL Demonstration Period, Final AEL Petition, or AEL Renewal form as appropriate)	☐	☐	☐	☐	☐	☐
(o) Petition for AEL demonstration period or final AEL under review by U.S. EPA or demonstration period ongoing	☐	☐	☐	☐	☐	☐
(p) Repowering extension plan approved or under review	☐	☐	☐	☐	☐	☐

Step 3
Read the standard requirements and certification, enter the name of the designated representative, sign &

Standard Requirements

General. This source is subject to the standard requirement in 40 CFR 72.9 (consistent with 40 CFR 76.8(e)(1)(I)). These requirements are listed in this source's Acid Rain Permit.

Special Provisions for Early Election Units

Nitrogen Oxides. A unit that is governed by approved early election plan shall be subject to an emissions limitation for NO_x as provided under 40 CFR 76.8(a)(2) except as provided under 40 CFR 76.8(e)(3)(ii).
Liability. The owners and operators of a unit governed by an approved early election plan shall be liable for any violation of the plan or 40 CFR 76.8 at that unit. The owners and operators shall be liable, beginning January 1,200, for fulfilling the obligations specified in 40 CFR part 77.
Termination. An approved early election plan shall be in effect only until the earlier of January 1, 2008 or january1 of the calendar year for which a termination of the plan takes effect. If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under 40 CFR 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year for which there is a failure to demonstrate compliance, and the designated representative may no submit a new early election plan. The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated reprsentive must submit a notice under 40 CFR 72.40(d) by January 1 of the year for which the termination is to take effect. If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NO_x for phase II units with Group 1boilers under 40 CFR 76.7 If an early election plan is terminated on or after 2000,the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7.

Certification

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

Subject: C.D. McIntosh, Jr. Power Plant Renewal Phase II NOx Compliance Plan Form

Name Timothy Bachand, P. E.	
Signature 	Date 6/16/08

EPA Form 7610-28 (3-97)

ATTACHMENT MC-FI-CA2

CAIR PART

Clean Air Interstate Rule (CAIR) Part

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

This submission is: ☐ New ☐ Revised ■ Renewal

STEP 1

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

Plant Name:	State: Florida	ORIS or EIA Plant Code:
C.D. McIntosh, Jr. Power Plant		0676

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
EU 001	x	x	x	N/A	N/A
EU 005	x	x	x	N/A	N/A
EU 006	x	x	x	N/A	N/A
EU 028	x	x	x	N/A	N/A

C.D. McIntosh, Jr. Power Plant

Plant Name (from STEP 1)

STEP 3

Read the standard requirements.

CAIR NO_X ANNUAL TRADING PROGRAM

CAIR Part Requirements.

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

Monitoring, Reporting, and Recordkeeping Requirements.

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

NO_X Emission Requirements.

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

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

C.D. McIntosh Jr. Power Plant

Plant Name (from STEP 1)

STEP 3, Continued

Liability.

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

Effect on Other Authorities.

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

CAIR SO_2 TRADING PROGRAM

CAIR Part Requirements.

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

Monitoring, Reporting, and Recordkeeping Requirements.

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

SO_2 Emission Requirements.

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

Excess Emissions Requirements.

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

C.D. McIntosh Jr. Power Plant

Plant Name (from STEP 1)

STEP 3, Continued

Recordkeeping and Reporting Requirements.

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

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

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

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

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

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

Liability.

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

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

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

Effect on Other Authorities.

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

CAIR NO_x OZONE SEASON TRADING PROGRAM

CAIR Part Requirements.

(1) The CAIR designated representative of each CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source shall:
(i) Submit to the DEP a complete and certified CAIR Part form under 40 CFR 96.322 and Rule 62-296.470, F.A.C., in accordance with the deadlines specified in Rule 62-213.420, F.A.C.; and
(ii) [Reserved];

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

Monitoring, Reporting, and Recordkeeping Requirements.

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

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

NO_x Ozone Season Emission Requirements.

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

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

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

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

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

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

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

C.D. McIntosh Jr. Power Plant
Plant Name (from STEP 1)

STEP 3, Continued

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

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

Liability.

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

Effect on Other Authorities.

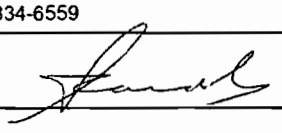
No provision of the CAIR NO_X Ozone Season Trading Program, a CAIR Part, or an exemption under 40 CFR 96.305 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X Ozone Season source or CAIR NO_X Ozone Season unit from compliance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

STEP 4

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

Certification (for designated representative or alternate designated representative only)

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

Name Mr. Tony Candales	Title Assistant General Manager of Production
Company Owner Name Lakeland Electric	
Phone (863) 834-6559	E-mail Address tony.candales@lakelandelectric.com
Signature 	Date 5/15/13

III. EMISSIONS UNIT INFORMATION

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

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

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

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

EMISSIONS UNIT INFORMATION
Section [1]
McIntosh Unit 1 – Fossil Fuel Fired Steam Generator

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:
   McIntosh Unit 1 – Fossil Fuel Fired Steam Generator

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

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**February 1971**	**49**

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

   ☒ Acid Rain Unit

   ☒ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: **90** MW

11. Emissions Unit Comment:
    The emission unit is a natural gas and No. 6 fuel oil-fired steam generating unit. This unit is also permitted to burn "on-specification" used oil generated by the City of Lakeland.

EMISSIONS UNIT INFORMATION
Section [1]
McIntosh Unit 1 – Fossil Fuel Fired Steam Generator

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: **985** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	**7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Heat input rates: Natural gas firing – 985 MMBtu/hr** **No. 6 fuel oil firing – 950 MMBtu/hr** **Used oil firing – 950 MMBtu/hr** **Maximum heat input based on higher heating value (HHV) of natural gas. Heat inputs based on fuel flow and sampling.**	

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: **S001**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Exhausts through a single stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **150** feet	7. Exit Diameter: **9.0** feet
8. Exit Temperature: **277°F**	9. Actual Volumetric Flow Rate: **310,000** 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: **Stack parameters based on Title V Permit No. 1050004-031-AV.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

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

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Natural-Gas Boilers > 100 MMBtu/hr**		
2. Source Classification Code (SCC): **1-01-006-01**	3. SCC Units: **Million cubic feet natural gas burned**	
4. Maximum Hourly Rate: **0.96**	5. Maximum Annual Rate: **8,427**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,024**
10. Segment Comment: **Maximum hourly rate = 985 MMBtu/hr / 1,024 MMBtu/MM ft^3 = 0.962 MM ft^3/hr** **Maximum annual rate = 0.962 MM ft^3/hr x 8,760 hr/yr = 8,427.1 MM ft^3/yr** **Propane is used for ignition only (SCC 1-01-010-02)**		

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

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Residual Oil No. 6 – Normal Firing**		
2. Source Classification Code (SCC): **1-01-004-01**	3. SCC Units: **1,000 gallons burned**	
4. Maximum Hourly Rate: **6.33**	5. Maximum Annual Rate: **55,451**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2.5**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **150**
10. Segment Comment: **Maximum hourly rate = 950 MMBtu/hr / (150 MMBtu / 1,000 gallons) = 6,333.3 gallons/hr** **Maximum annual rate = 6.33 x 10^3 gallons/hr x 8,760 hr/yr = 55,450.8 x 10^3 gallons/yr** **Please note that Permit No. 1050004-032-AC limits sulfur content of the fuel oil to 0.7% by weight effective from the date of EPA's approval of Specific Condition No. A.1 in the Florida Regional Haze State Implementation Plan.**		

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

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

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Liquid Waste; Waste Oil (On-specification used oil as defined in 40 CFR 279.11 and generated by the City of Lakeland)**		
2. Source Classification Code (SCC): **1-01-013-02**	3. SCC Units: **1,000 Gallons Burned**	
4. Maximum Hourly Rate: **7.31**	5. Maximum Annual Rate: **42**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**
10. Segment Comment: **Maximum hourly rate = 950 MMBtu/hr / 130 MMBtu / 1,000 gallons = 7,307.7 gallons/hr Maximum Annual Rate based on Condition A.29, Section III of Title V Permit No. 1050004-031-AV.**		

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
CO			NS
VOC			NS
SO2			EL
NOx			NS

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **285.0** lb/hour **520** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.3 lb/MMBtu** Reference: **Rule 62-210.700(3), F.A.C., and Permit No. 1050004-031-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly emissions = 0.3 lb/MMBtu x 950 MMBtu/hr = 285.0 lb/hr (Oil firing, soot blowing scenario)

Hourly emissions = 0.1 lb/MMBtu x 985 MMBtu/hr = 98.5 lb/hr (NG firing, normal operation)

Annual emissions = (0.3 lb/MMBtu x 950 MMBtu/hr x 3 hr/day) + (0.1 lb/MMBtu x 950 MMBtu/hr x 21 hours/day) x 365 days/yr x 1 TPY/2,000 lbs = 520.1 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential hourly emissions based on soot blowing while firing No. 6 fuel oil.

Annual emissions based on 3 hours of soot blowing during a 24-hour period and normal operation for 21 hours in any 24-hour period.

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: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.1 lb/MMBtu**	4. Equivalent Allowable Emissions: **95.0** lb/hour **416** tons/year
5. Method of Compliance: **Annual stack test; EPA Methods 17, 5, 5B, or 5F.**	
6. Allowable Emissions Comment (Description of Operating Method): **Equivalent allowable emissions based on oil firing during normal operations. Rule 62-296.405(1)(b), F.A.C. and Permit No. 1050004-031-AV. Annual or renewal compliance test not required if firing only gaseous fuel(s) or if oil firing < 400 hr/yr.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.3 lb/MMBtu**	4. Equivalent Allowable Emissions: **285.0** lb/hour **156** tons/year
5. Method of Compliance: **Annual stack test; EPA Methods 17, 5, 5B, or 5F.**	
6. Allowable Emissions Comment (Description of Operating Method): **Soot blowing and load change: 0.3 lb/MMBtu during 3 hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load changes. Rule 62-296.700(3), F.A.C. and Permit No. 1050004-031-AV. Annual or renewal compliance test required only if oil firing > 400 hr/yr.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.1 lb/MMBtu**	4. Equivalent Allowable Emissions: **98.5** lb/hour **431** tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): **Equivalent allowance emissions based on NG firing during normal operations. Rule 62-296.405(1)(b), F.A.C., and Permit No. 1060004-031-AV.**	

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: **2,613** lb/hour **11,443** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2.75 lb/MMBtu** Reference: **Rule 62-296.405(1)(c)1.j., F.A.C. and Permit No. 1050004-031-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
Hourly emissions = 2.75 lb/MMBtu x 950 MMBtu/hr = 2,612.5 lb/hr (Oil firing scenario)

Annual emissions = (2,612.5 lb/hr x 8760 hr/yr) x 1 Ton/2,000 lbs = 11,442.8 TPY

11. Potential, Fugitive, and Actual Emissions Comment:
Hourly emissions based on oil firing. Fuel sulfur content limited to 2.5 percent by weight.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2.75 lb/MMBtu**	4. Equivalent Allowable Emissions: **2,613** lb/hour **11,443** tons/year
5. Method of Compliance: **CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Equivalent allowable emissions based on No. 6 fuel oil firing. Fuel sampling will be used to demonstrate compliance when CEMS data is not available. Rule 62-296.405(1)(c)1.j., F.A.C. and Permit No. 1050004-031-AV. Please note that Permit No. 1050004-032-AC limits sulfur content of the fuel oil to 0.7% by weight effective from the date of EPA's approval of Specific Condition No. A.1 in the Florida Regional Haze State Implementation Plan.**	

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 **3**

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **40** % Maximum Period of Excess Opacity Allowed: **2** min/hour	
4. Method of Compliance: **Annual compliance test; EPA Method 9**	
5. Visible Emissions Comment: **Rule 62-296.405(1)(a), F.A.C. and Permit No. 1050004-031-AV Annual compliance test not required if firing only gaseous fuel(s) or if fuel oil operation < 400 hr/yr oil operation.**	

Visible Emissions Limitation: Visible Emissions Limitation **2** of **3**

1. Visible Emissions Subtype: **VE60**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **60** % Exceptional Conditions: **>60** % Maximum Period of Excess Opacity Allowed: **4 periods of 6** min/hour	
4. Method of Compliance: **VE test using EPA Method 9**	
5. Visible Emissions Comment: **Rule 62-210.700(3), F.A.C. and Permit No. 1050004-031-AV** **60 percent opacity during load changing and boiler cleaning (soot blowing) for 3 hours during any 24-hour period.** **Annual compliance test not required if firing only gaseous fuel(s) or if fuel oil operation < 400 hr/yr.**	

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 **3** of **3**

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100%** Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment: **Excess emissions for startup, shutdown, or malfunction. See Rule 62-210.700(1) and (2), F.A.C. Permit No. 1050004-031-AV.**	

Visible Emissions Limitation: Visible Emissions Limitation _ of _

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

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor **1** of **5**

1. Parameter Code: **EM**	2. Pollutant(s): **SO_2**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo Electron Corp.** Model Number: **43I-ANSAB** Serial Number: **0608716017**	
5. Installation Date: **30 May 2008**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR 75.**	

Continuous Monitoring System: Continuous Monitor **2** of **5**

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo Electron Corp.** Model Number: **42I-ANMSDAA** Serial Number: **0532513176**	
5. Installation Date: **30 May 2008**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR 75.**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor **3** of **5**

1. Parameter Code: **VE**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Ametek Land** Model Number: **4500 MKIII**	Serial Number: **166692 01**
5. Installation Date: **14 Sep 2010**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR 75.**	

Continuous Monitoring System: Continuous Monitor **4** of **5**

1. Parameter Code: **CO_2**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo Electron Corp.** Model Number: **410I-ANPDAB**	Serial Number: **0534013549**
5. Installation Date: **30 May 2008**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR 75.**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor **5** of **5**

1. Parameter Code: **FLOW**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Teledyne** Model Number: **ULTRAFLOW 150**	Serial Number: **1500386**
5. Installation Date: **30 May 2008**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 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: **MC-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: **MC-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: **MC-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 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

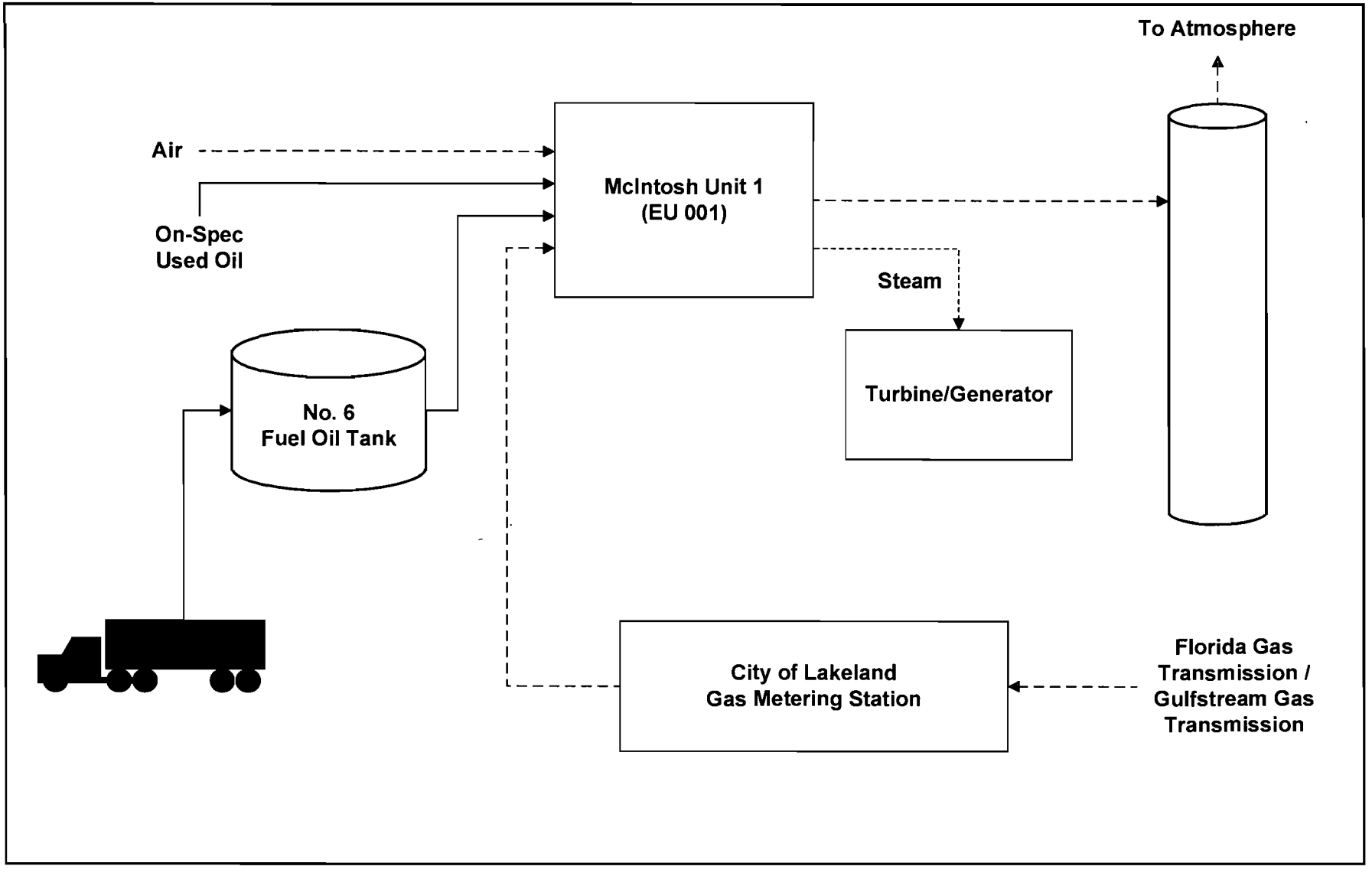
Additional Requirements for Title V Air Operation Permit Applications

1.	Identification of Applicable Requirements: ☒ Attached, Document ID: **MC-EU1-IV1**
2.	Compliance Assurance Monitoring: ☐ Attached, Document ID: _____ ☒ Not Applicable
3.	Alternative Methods of Operation: ☒ Attached, Document ID: **MC-EU1-IV3** ☐ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements Comment

ATTACHMENT MC-EU1-I1

PROCESS FLOW DIAGRAM



Attachment MC-EU1-I1
McIntosh Unit 1
Process Flow Diagram

Process Flow Legend
Solid/Liquid
Gas
Steam

Golder Associates

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ATTACHMENT MC-EU1-I2

FUEL ANALYSIS OR SPECIFICATION

FUEL OIL INVENTORY

STRAP READING

ENDING MONTH: Feb-13

PLANT		LARSEN		McINTOSH				WINSTON
PARAMETERS		T02	T01	T114	T115	T116	T021	WD1
		L/S DIESEL	L/S DIESEL	H/S #6	L/S #6	ON SPEC	DIESEL	L/S DIESEL
SAMPLE ID NUMBER		3022802-06	3022802-07	2123105-05	2123105-04	3022802-02	3022802-03	3022802-01
STRAP MEASUREMENT INCHES		205.25	323.50	327.00	372.50	47.25	196.50	308.88
% OF 95% CAPACITY		80.15%	71.31%	59.78%	68.16%	27.74%	74.95%	84.35%
LPP F 3' from BOTTOM	MPP F @ 5'			63.0	59.0			
LPP F @ CENTER	MPP F @ 15'	69.0	70.0	66.0	62.0	70.0	72.0	69.0
LPP F 3' from TOP	MPP F @ 25'			62.0	63.0			
	MPP F @ 35'							
AVERAGE TEMPERATURE		69.0	70.0	63.7	61.3	70.0	72.0	69.0
API GRAVITY		36.8	37.3	11.7	18.4	14.4	34.0	37.0
POUNDS/GALLON		7.001	6.980	8.229	7.861	8.076	7.119	6.993
TEMP. CORRECTION FACTOR		0.9958	0.9953	0.9986	0.9995	0.9961	0.9945	0.9958
GROSS - BARRELS		6,467.43	6,806.44	54,936.000	62,580.000	141.75	1,699.73	5,920.04
NET - BARRELS		6,440.26	6,774.45	54,859.090	62,548.710	141.20	1,690.38	5,895.18
NET-GALLONS		270,491.10	284,526.89	2,304,081.76	2,627,045.82	5,930.28	70,995.81	247,597.42
NET-POUNDS		1,893,708	1,985,998	18,960,289	20,651,207	47,893	505,419	1,731,449
GAUGE READING		16' 7"	26' 2"	26.91	30.93	7' 0"	16' 3"	25.82
MAX TANK CAPACITY(95%) INCHES		255.00	452.00	546.00	546.00	170.00	274.00	364.00
MAX (95%) TANK CAP (GALLONS)		337,472	399,000	3,854,340	3,854,340	21,375	94,723	293,523
CONTROL ROOM READING								
BTU/GALLON		136,914	136,767	150,585	146,401	139,044	138,425	136,896
MMBTU / BBL		5.750	5.744	6.325	6.149	5.840	5.814	5.750
% ASH				0.049	0.031			
% SULFUR		0.06	0.05	2.48	0.73	2.03	0.06	0.05
MEASURE @ LIP ON PORT		40' 4 3/8"	41' 6"	48' 7 3/4"	48' 7 1/4"	16' 10.5"	23' 2"	33' 2"

COMMENTS:

VALUES CARRIED OVER FROM LAST MONTH

Samples turned in to MPP lab: T01, T02, T021, T116, Winston

Tanks strapped: T01, T02, T021, T116, Winston

TECHNICIANS: Ken Lindsey / John Durbin

Tanner

Natural Gas Combined Annual Average % Sulfur

0.913	ppm
0.00009	%S

Natural Gas Day	FGT S1 ppm	Gulfstream Bowling Green ppm	
1/1/2012	0.9454	0.073	1.168
1/2/2012	0.9044	0.058	0.928
1/3/2012	0.9672	0.041	0.656
1/4/2012	0.8361	0.047	0.752
1/5/2012	1.0495	0.054	0.864
1/6/2012	0.7797	0.055	0.88
1/7/2012	0.9388	0.051	0.816
1/8/2012	0.9838	0.048	0.768
1/9/2012	0.9682	0.043	0.688
1/10/2012	1.0364	0.044	0.704
1/11/2012	0.836	0.05	0.8
1/12/2012	0.8926	0.053	0.848
1/13/2012	0.8327	0.044	0.704
1/14/2012	0.8782	0.039	0.624
1/15/2012	0.849	0.047	0.752
1/16/2012	0.7774	0.05	0.8
1/17/2012	0.744	0.05	0.8
1/18/2012	0.6907	0.058	0.928
1/19/2012	0.6705	0.052	0.832
1/20/2012	0.8435	0.056	0.896
1/21/2012	0.8608	0.052	0.832
1/22/2012	0.7958	0.06	0.96
1/23/2012	1.0341	0.122	1.952
1/24/2012	1.0587	0.056	0.896
1/25/2012	0.898	0.052	0.832
1/26/2012	0.8532	0.061	0.976
1/27/2012	0.8642	0.058	0.928
1/28/2012	0.7725	0.053	0.848
1/29/2012	0.7612	0.046	0.736
1/30/2012	0.7828	0.045	0.72
1/31/2012	0.7765	0.05	0.8
Average	*0.867*	*0.054*	*0.861*
	Combined Monthly Average		0.460

Natural Gas Combined Annual Average % Sulfur

0.913	ppm
0.00009	%S

Natural Gas Day	FGT S1 ppm	Gulfstream Bowling Green ppm	
2/1/2012	0.8544	0.053	0.848
2/2/2012	0.8495	0.056	0.896
2/3/2012	0.8984	0.076	1.216
2/4/2012	0.8447	0.06	0.96
2/5/2012	0.9049	0.062	0.992
2/6/2012	0.9329	0.06	0.96
2/7/2012	1.0408	0.064	1.024
2/8/2012	1.0291	0.054	0.864
2/9/2012	1.0656	0.047	0.752
2/10/2012	1.0558	0.061	0.976
2/11/2012	0.9651	0.049	0.784
2/12/2012	0.8715	0.036	0.576
2/13/2012	0.8446	0.046	0.736
2/14/2012	0.7824	0.055	0.88
2/15/2012	0.9087	0.062	0.992
2/16/2012	0.9987	0.062	0.992
2/17/2012	0.9591	0.068	1.088
2/18/2012	0.8995	0.062	0.992
2/19/2012	0.942	0.09	1.44
2/20/2012	1.0136	0.067	1.072
2/21/2012	1.0328	0.073	1.168
2/22/2012	1.036	0.08	1.28
2/23/2012	1.013	0.074	1.184
2/24/2012	1.0603	0.07	1.12
2/25/2012	1.0831	0.052	0.832
2/26/2012	1.127	0.055	0.88
2/27/2012	1.1392	0.069	1.104
2/28/2012	1.1278	0.063	1.008
2/29/2012	1.0655	0.061	0.976
Average	0.977	0.062	0.986
	Combined Monthly Average		0.520

Natural Gas Combined Annual Average % Sulfur

0.913	ppm
0.00009	%S

Natural Gas Day	FGT S1 ppm	Gulfstream Bowling Green ppm	
3/1/2012	1.1579	0.056	0.896
3/2/2012	1.0981	0.06	0.96
3/3/2012	1.1269	0.064	1.024
3/4/2012	1.1632	0.049	0.784
3/5/2012	1.1533	0.048	0.768
3/6/2012	1.268	0.067	1.072
3/7/2012	1.1985	0.063	1.008
3/8/2012	1.1983	0.066	1.056
3/9/2012	1.2404	0.063	1.008
3/10/2012	1.1409	0.063	1.008
3/11/2012	1.152	0.066	1.056
3/12/2012	1.1354	0.07	1.12
3/13/2012	1.1271	0.134	2.144
3/14/2012	1.0949	0.07	1.12
3/15/2012	1.2225	0.068	1.088
3/16/2012	1.1759	0.072	1.152
3/17/2012	1.1703	0.063	1.008
3/18/2012	1.0787	0.066	1.056
3/19/2012	1.0649	0.067	1.072
3/20/2012	1.109	0.067	1.072
3/21/2012	1.0744	0.064	1.024
3/22/2012	0.9794	0.059	0.944
3/23/2012	1.0673	0.066	1.056
3/24/2012	1.0479	0.068	1.088
3/25/2012	1.0564	0.073	1.168
3/26/2012	1.0192	0.055	0.88
3/27/2012	1.0844	0.058	0.928
3/28/2012	1.1094	0.057	0.912
3/29/2012	1.0195	0.061	0.976
3/30/2012	0.9666	0.064	1.024
3/31/2012	0.9653	0.068	1.088
Average	**1.112**	**0.066**	**1.050**
	Combined Monthly Average		**0.589**

Natural Gas Combined Annual Average % Sulfur

0.913	ppm
0.00009	%S

Natural Gas Day	FGT S1 ppm	Gulfstream Bowling Green ppm	
4/1/2012	0.9374	0.07	1.12
4/2/2012	0.9092	0.07	1.12
4/3/2012	0.8669	0.098	1.568
4/4/2012	0.907	0.077	1.232
4/5/2012	0.9091	0.139	2.224
4/6/2012	0.8868	0.064	1.024
4/7/2012	0.8831	0.078	1.248
4/8/2012	0.827	0.09	1.44
4/9/2012	0.8244	0.094	1.504
4/10/2012	0.7814	0.081	1.296
4/11/2012	1.2401	0.106	1.696
4/12/2012	1.4904	0.119	1.904
4/13/2012	1.568	0.125	2
4/14/2012	1.2994	0.118	1.888
4/15/2012	1.3617	0.115	1.84
4/16/2012	1.5966	0.121	1.936
4/17/2012	1.2187	0.133	2.128
4/18/2012	1.4607	0.139	2.224
4/19/2012	0.8627	0.12	1.92
4/20/2012	0.69	0.109	1.744
4/21/2012	0.7166	0.104	1.664
4/22/2012	0.7648	0.087	1.392
4/23/2012	0.6302	0.051	0.816
4/24/2012	0.6295	0.054	0.864
4/25/2012	0.6234	0.057	0.912
4/26/2012	0.6298	0.076	1.216
4/27/2012	0.6412	0.078	1.248
4/28/2012	0.6928	0.083	1.328
4/29/2012	0.6967	0.078	1.248
4/30/2012	0.7278	0.08	1.28
Average	**0.942**	**0.094**	**1.501**
	Combined Monthly Average		**0.518**

Natural Gas Combined Annual Average % Sulfur

0.913	ppm
0.00009	%S

Natural Gas Day	FGT S1 ppm	Gulfstream Bowling Green ppm	
5/1/2012	0.7077	0.08	1.28
5/2/2012	0.6994	0.079	1.264
5/3/2012	0.7515	0.068	1.088
5/4/2012	0.6967	0.071	1.136
5/5/2012	0.6614	0.067	1.072
5/6/2012	0.7192	0.068	1.088
5/7/2012	0.7637	0.07	1.12
5/8/2012	0.7484	0.068	1.088
5/9/2012	0.7381	0.066	1.056
5/10/2012	0.7627	0.056	0.896
5/11/2012	0.7905	0.056	0.896
5/12/2012	0.7718	0.06	0.96
5/13/2012	0.7951	0.062	0.992
5/14/2012	0.8092	0.065	1.04
5/15/2012	0.8069	0.06	0.96
5/16/2012	0.8887	0.074	1.184
5/17/2012	0.8436	0.091	1.456
5/18/2012	0.835	0.074	1.184
5/19/2012	0.8287	0.077	1.232
5/20/2012	0.8402	0.074	1.184
5/21/2012	0.7658	0.07	1.12
5/22/2012	0.8219	0.074	1.184
5/23/2012	0.796	0.073	1.168
5/24/2012	0.6846	0.076	1.216
5/25/2012	0.575	0.071	1.136
5/26/2012	0.5353	0.074	1.184
5/27/2012	0.6252	0.079	1.264
5/28/2012	0.9514	0.075	1.2
5/29/2012	0.7717	0.073	1.168
5/30/2012	0.6141	0.071	1.136
5/31/2012	0.7429	0.067	1.072
Average	**0.753**	**0.071**	**1.130**
	Combined Monthly Average		**0.412**

Natural Gas Combined Annual Average % Sulfur

0.913	ppm
0.00009	%S

Natural Gas Day	FGT S1 ppm	Gulfstream Bowling Green ppm
6/1/2012	0.9161	1.04
6/2/2012	0.6718	1.184
6/3/2012	0.623	1.344
6/4/2012	0.5511	1.344
6/5/2012	0.5526	1.36
6/6/2012	0.5372	1.168
6/7/2012	0.5545	2.176
6/8/2012	0.7319	1.2
6/9/2012	0.7307	1.392
6/10/2012	0.7001	1.264
6/11/2012	0.796	1.248
6/12/2012	0.82	1.216
6/13/2012	0.8117	1.248
6/14/2012	0.8336	1.248
6/15/2012	0.782	1.184
6/16/2012	0.8981	1.024
6/17/2012	0.927	1.024
6/18/2012	0.9142	1.12
6/19/2012	0.9488	1.136
6/20/2012	0.9315	1.312
6/21/2012	0.9145	1.376
6/22/2012	0.9418	1.552
6/23/2012	0.9101	1.408
6/24/2012	0.9089	1.168
6/25/2012	0.9088	1.376
6/26/2012	1.0073	1.68
6/27/2012	1.0386	1.84
6/28/2012	0.9483	1.808
6/29/2012	1.0044	1.568
6/30/2012	0.9524	1.488
Average	0.826	1.350
Combined Monthly Average		1.088

Natural Gas Combined Annual Average % Sulfur

0.913	ppm
0.00009	%S

Natural Gas Day	FGT S1 ppm	Gulfstream Bowling Green ppm
7/1/2012	0.8802	1.44
7/2/2012	0.9089	1.184
7/3/2012	0.9141	1.44
7/4/2012	0.932	1.456
7/5/2012	0.9774	1.264
7/6/2012	1.0951	1.232
7/7/2012	1.1171	1.216
7/8/2012	1.0401	1.28
7/9/2012	0.9892	1.392
7/10/2012	1.0196	1.376
7/11/2012	0.951	1.44
7/12/2012	0.9121	1.36
7/13/2012	1.0252	1.376
7/14/2012	0.9819	1.36
7/15/2012	1.0136	1.28
7/16/2012	1.0564	1.28
7/17/2012	1.0191	1.36
7/18/2012	0.9517	1.424
7/19/2012	0.99	1.616
7/20/2012	1.0338	1.392
7/21/2012	0.9626	1.36
7/22/2012	0.9395	1.36
7/23/2012	0.9395	1.264
7/24/2012	0.9386	2.304
7/25/2012	0.9435	1.232
7/26/2012	0.9552	1.392
7/27/2012	0.9719	1.456
7/28/2012	0.9223	1.312
7/29/2012	0.8646	1.184
7/30/2012	0.9492	1.184
7/31/2012	0.9466	1.168
Average	0.972	1.367
Combined Monthly Average		1.170

Natural Gas Combined Annual Average % Sulfur

0.913	ppm
0.00009	%S

Natural Gas Day	FGT S1 ppm	Gulfstream Bowling Green ppm
8/1/2012	0.9713	1.26
8/2/2012	0.9693	1.12
8/3/2012	0.9712	1.18
8/4/2012	0.9621	1.18
8/5/2012	0.9827	1.17
8/6/2012	0.9857	1.33
8/7/2012	0.9907	1.33
8/8/2012	0.9907	1.33
8/9/2012	1.0169	1.28
8/10/2012	1.0439	1.25
8/11/2012	0.9942	1.18
8/12/2012	0.9247	0.96
8/13/2012	0.9452	1.20
8/14/2012	0.9038	1.07
8/15/2012	0.9752	1.12
8/16/2012	0.9755	1.10
8/17/2012	1.014	2.08
8/18/2012	1.0136	1.22
8/19/2012	0.9997	1.34
8/20/2012	1.0705	1.30
8/21/2012	1.0338	1.52
8/22/2012	1.0463	1.46
8/23/2012	1.0518	1.33
8/24/2012	1.0671	1.26
8/25/2012	1.0597	1.23
8/26/2012	1.0005	1.36
8/27/2012	0.9246	1.62
8/28/2012	1.0282	1.76
8/29/2012	1.2406	1.76
8/30/2012	1.3415	1.76
8/31/2012	1.2084	1.76
Average	**1.023**	**1.349**
	Combined Monthly Average	**1.186**

Natural Gas Combined Annual Average % Sulfur

0.913	ppm
0.00009	%S

Natural Gas Day	FGT S1 ppm	Gulfstream Bowling Green ppm
9/1/2012	1.147	1.90
9/2/2012	1.12	1.90
9/3/2012	1.1962	1.87
9/4/2012	0.9028	1.89
9/5/2012	5.0147	2.66
9/6/2012	1.0722	3.15
9/7/2012	1.1069	2.10
9/8/2012	1.0859	1.68
9/9/2012	1.4092	2.10
9/10/2012	1.3447	2.22
9/11/2012	1.3091	15.46
9/12/2012	1.1384	2.42
9/13/2012	1.3267	2.10
9/14/2012	1.1086	1.60
9/15/2012	1.0349	1.42
9/16/2012	1.0308	1.66
9/17/2012	1.1437	1.82
9/18/2012	1.2601	3.82
9/19/2012	1.1541	15.47
9/20/2012	1.3865	1.20
9/21/2012	1.2132	1.25
9/22/2012	1.1163	1.14
9/23/2012	1.0984	1.17
9/24/2012	1.1295	1.04
9/25/2012	1.1553	1.09
9/26/2012	1.2704	1.15
9/27/2012	1.0864	1.02
9/28/2012	1.1329	1.12
9/29/2012	1.1512	1.12
9/30/2012	1.1923	1.33
Average	**1.295**	**2.662**

Combined Monthly Average **1.979**

Natural Gas Combined Annual Average % Sulfur

0.913	ppm
0.00009	%S

Natural Gas Day	FGT S1 ppm	Gulfstream Bowling Green ppm
10/1/2012	1.1824	
10/2/2012	1.4221	1.18
10/3/2012	1.2746	1.10
10/4/2012	1.3208	2.11
10/5/2012	1.2657	1.01
10/6/2012	1.2341	0.99
10/7/2012	1.1831	1.07
10/8/2012	1.1784	0.94
10/9/2012	1.1745	0.96
10/10/2012	1.2058	1.07
10/11/2012	1.1312	0.80
10/12/2012	1.1096	0.91
10/13/2012	1.0752	0.75
10/14/2012	1.2138	0.77
10/15/2012	1.6376	0.85
10/16/2012	1.4956	0.99
10/17/2012	1.1097	1.06
10/18/2012	1.1986	1.17
10/19/2012	1.1576	0.88
10/20/2012	1.093	0.75
10/21/2012	1.0413	0.83
10/22/2012	1.0337	0.77
10/23/2012	1.0129	0.75
10/24/2012	1.0764	0.82
10/25/2012	0.8856	1.71
10/26/2012	1.0103	0.54
10/27/2012	1.0596	0.74
10/28/2012	1.0305	0.88
10/29/2012	1.03	0.67
10/30/2012	1.03	0.69
10/31/2012	1.0213	0.69
Average	**1.158**	**0.949**
Combined Monthly Average		**1.053**

Natural Gas Combined Annual Average % Sulfur

0.913	ppm
0.00009	%S

Natural Gas Day	FGT S1 ppm	Gulfstream Bowling Green ppm
11/1/2012	1.0437	0.83
11/2/2012	1.1216	0.78
11/3/2012	1.1061	1.10
11/4/2012	1.0722	1.15
11/5/2012	1.1589	1.10
11/6/2012	1.1485	1.18
11/7/2012	1.1767	1.06
11/8/2012	1.1379	0.91
11/9/2012	1.0667	0.86
11/10/2012	0.96	0.85
11/11/2012	0.974	0.86
11/12/2012	0.9617	0.96
11/13/2012	1.0274	0.91
11/14/2012	1.0568	1.01
11/15/2012	1.0876	0.96
11/16/2012	1.0199	0.88
11/17/2012	1.0818	1.02
11/18/2012	1.0462	1.94
11/19/2012	1.0321	0.90
11/20/2012	0.9991	0.98
11/21/2012	0.9705	0.90
11/22/2012	0.8489	0.70
11/23/2012	0.8202	0.66
11/24/2012	0.8356	0.77
11/25/2012	0.9437	0.64
11/26/2012	0.9813	0.78
11/27/2012	0.9666	0.83
11/28/2012	0.9685	0.67
11/29/2012	1.0252	0.77
11/30/2012	0.9721	0.66
Average	1.020	0.921
Combined Monthly Average		0.971

Natural Gas Combined Annual Average % Sulfur

0.913	ppm
0.00009	%S

Natural Gas Day	FGT S1 ppm	Gulfstream Bowling Green ppm
12/1/2012	0.9165	0.72
12/2/2012	0.9134	0.99
12/3/2012	0.7669	0.85
12/4/2012	0.889	0.77
12/5/2012	0.9594	0.85
12/6/2012	0.9667	0.93
12/7/2012	0.9099	1.09
12/8/2012	0.9014	0.91
12/9/2012	0.9657	0.86
12/10/2012	0.9752	1.10
12/11/2012	0.9705	1.15
12/12/2012	1.0521	1.20
12/13/2012	1.1259	1.04
12/14/2012	1.0876	0.94
12/15/2012	1.0041	1.06
12/16/2012	0.9428	1.01
12/17/2012	1.0136	1.12
12/18/2012	0.9974	1.07
12/19/2012	1.0529	1.02
12/20/2012	1.0996	1.02
12/21/2012	1.0447	0.98
12/22/2012	1.1361	0.98
12/23/2012	1.1404	1.04
12/24/2012	1.1264	1.02
12/25/2012	1.0374	1.17
12/26/2012	1.0209	1.07
12/27/2012	1.0549	0.94
12/28/2012	1.1239	1.23
12/29/2012	1.0595	1.25
12/30/2012	1.0509	0.85
12/31/2012	1.0691	1.07
Average	1.012	1.010
Combined Monthly Average		1.011

	McINTOSH #6 TANK 2 (T114)						
	VISCOSITY	SP.GRAV.	WT/GAL.	%SULFUR	%ASH	BTU/LB	MMBTU/BBL
Jan-12							
Feb-12							
Mar-12	254.9	0.9833	8.189	2.270	0.023	18163	6.25
Apr-12							
May-12	179.8	0.9888	8.235	2.290	0.055	18427	6.370
Jun-12							
Jul-12							
Aug-12							
Sep-12	252.8	0.9930	8.270	2.350	0.073	18255	6.340
Oct-12							
Nov-12							
Dec-12	246.4	0.9881	8.229	2.480	0.049	18299	6.320
AVGS	**233.5**	**0.9883**	**8.231**	**2.35**	**0.050**	**18,286**	**6.320**

	McINTOSH #6 TANK 3 (T115)						
	VISCOSITY	SP.GRAV.	WT/GAL.	%SULFUR	%ASH	BTU/LB	MMBTU/BBL
Jan-12							
Feb-12							
Mar-12	26.8	0.9497	7.909	0.72	0.027	18,777	6.23
Apr-12							
May-12							
Jun-12	26.0	0.9459	7.877	0.75	0.029	18,764	6.200
Jul-12							
Aug-12							
Sep-12	25.9	0.9930	7.861	0.62	0.018	18,653	6.150
Oct-12							
Nov-12							
Dec-12	26.5	0.9440	7.861	0.730	0.031	18624	6.140
AVGS	**26.3**	**0.9582**	**7.877**	**0.705**	**0.026**	**18,704**	**6.180**

	McINTOSH #6 TANK 2 (T114)						
	VISCOSITY	SP.GRAV.	WT/GAL.	%SULFUR	%ASH	BTU/LB	MMBTU/BBL
Jan-11							
Feb-11	250.2	0.9895	8.241	2.21	0.045	18,452	6.390
Mar-11							
Apr-11							
May-11	252.5	0.9888	8.235	2.240	0.055	18426	6.370
Jun-11							
Jul-11							
Aug-11							
Sep-11	251.4	0.9895	8.241	1.990	0.061	18396	6.370
Oct-11							
Nov-11							
Dec-11	244.5	0.9861	8.212	2.370	0.043	18303	6.310
AVGS	**249.7**	**0.9885**	**8.232**	**2.20**	**0.051**	**18,394**	**6.360**

	McINTOSH #6 TANK 3 (T115)						
	VISCOSITY	SP.GRAV.	WT/GAL.	%SULFUR	%ASH	BTU/LB	MMBTU/BBL
Jan-11							
Feb-11	25.8	0.9478	7.893	0.68	0.024	18,837	6.240
Mar-11							
Apr-11							
May-11							
Jun-11	25.3	0.9440	7.861	0.62	0.025	18,828	6.220
Jul-11	25.9	0.9415	7.841	0.55	0.010	18,733	6.170
Aug-11	25.3	0.9415	7.841	0.62	0.044	18,721	6.170
Sep-11	26.1	0.9440	7.861	0.64	0.027	18,921	6.250
Oct-11							
Nov-11							
Dec-11	25.3	0.9433	7.856	0.60	0.047	18,824	6.210
AVGS	**25.6**	**0.9437**	**7.859**	**0.618**	**0.030**	**18,811**	**6.210**

	McINTOSH #6 TANK 2 (T114)						
	VISCOSITY	SP.GRAV.	WT/GAL.	%SULFUR	%ASH	BTU/LB	MMBTU/BBL
Jan-10							
Feb-10							
Mar-10	124.0	0.9888	8.235	2.15	0.049	18,449	6.381
Apr-10							
May-10	228.0	0.9868	8.218	2.14	0.034	18,225	6.290
Jun-10							
Jul-10							
Aug-10							
Sep-10	228.0	0.9868	8.218	2.14	0.034	18,225	6.377
Oct-10							
Nov-10							
Dec-10	228.0	0.9868	8.218	2.14	0.034	18,225	6.363
AVGS	**202.0**	**0.9873**	**8.222**	**2.14**	**0.038**	**18,281**	**6.353**

	McINTOSH #6 TANK 3 (T115)						
	VISCOSITY	SP.GRAV.	WT/GAL.	%SULFUR	%ASH	BTU/LB	MMBTU/BBL
Jan-10	28.6	0.9522	7.930	0.58	0.050	18,888	6.291
Feb-10							
Mar-10							
Apr-10							
May-10							
Jun-10	25.8	0.9433	7.856	0.53	0.044	18,895	6.234
Jul-10	25.2	0.9459	7.877	0.67	0.026	18,734	6.198
Aug-10	49.8	0.9365	7.799	0.67	0.054	18,788	6.154
Sep-10	45.0	0.9459	7.877	0.69	0.032	18,818	6.226
Oct-10							
Nov-10							
Dec-10	26.3	0.9446	7.866	0.67	0.020	18,819	6.217
AVGS	**33.5**	**0.9447**	**7.868**	**0.637**	**0.038**	**18,824**	**6.220**

	McINTOSH #6 TANK 2 (T114)						
	VISCOSITY	SP.GRAV.	WT/GAL.	%SULFUR	%ASH	BTU/LB	MMBTU/BBL
Jan-09							
Feb-09							
Mar-09	119.1	0.9895	8.241	2.31	0.045	18,235	6.312
Apr-09	136.0	0.9923	8.264	2.47	0.045	18,221	6.324
May-09							
Jun-09							
Jul-09							
Aug-09							
Sep-09	212.0	0.9902	8.246	2.29	0.044	18,374	6.364
Oct-09							
Nov-09							
Dec-09	17.3	0.9895	8.241	2.25	0.220	18,514	6.408
AVGS	**121.1**	**0.9904**	**8.248**	**2.33**	**0.089**	**18,336**	**6.352**

	McINTOSH #6 TANK 3 (T115)						
	VISCOSITY	SP.GRAV.	WT/GAL.	%SULFUR	%ASH	BTU/LB	MMBTU/BBL
Jan-09							
Feb-09							
Mar-09	20.1	0.9503	7.914	0.61	0.041	18,777	6.241
Apr-09							
May-09							
Jun-09	20.9	0.9516	7.925	0.37	0.146	18,566	6.180
Jul-09	18.5	0.9484	7.898	0.60	0.028	18,753	6.221
Aug-09							
Sep-09							
Oct-09							
Nov-09							
Dec-09	28.0	0.9503	7.914	0.69	0.280	18,464	6.137
AVGS	**21.9**	**0.9502**	**7.913**	**0.568**	**0.124**	**18,640**	**6.195**

ATTACHMENT MC-EU1-I4

PROCEDURES FOR STARTUP AND SHUTDOWN

ATTACHMENT MC-EU1-I4

PROCEDURES FOR STARTUP AND SHUTDOWN MINIMIZING EXCESS EMISSIONS

Startup of the fossil-fuel boilers begins when fuel (propane, natural gas, spec used oil or No. 2 fuel oil) is introduced into one or more burners within the boiler and lighted (commencement of combustion). Startup is complete and steady-state operation begins when the combustion process has stabilized and the megawatt load on the unit is stable and above 10 to 15 percent load.

Shutdown of the fossil-fuel boilers begins when unit megawatt load is decreased to below 10 to 15 percent of maximum and continues until the final burner gun is removed from service.

Emissions may be detected during all modes of boiler operation by various continuous emissions monitors. Continuous monitors are currently in place for NO_x, CO_2, SO_2, flow, and opacity. Audible and visual alarms are activated whenever the permitted value for opacity is approached.

Countermeasures which may be taken in the event of excess emissions include, but are not limited to:

- Burner elevation loading
- Proper excess air adjustments
- Recognizing and removal of faulty burners
- Fuel oil temperature adjustments
- Proper and timely operation of boiler cleaning devices
- Removal of the unit from system-dispatch mode (load control)
- Reduction of unit megawatt load
- Stopping and restarting of boiler cleaning devices
- Lowering load ramp rate
- Pressure rate changes
- Placing boiler controls on manual
- Adjusting burner dampers to increase windbox/furnace air pressure

Knowledge of the appropriate countermeasures to take when excess emissions occur is a part of the routine operator training for those who operate the boilers. Topics include current permit limits, maximum allowable duration of excess emissions, appropriate countermeasures for excess emissions, duty to notify, and fuels and combustion training.

ATTACHMENT MC-EU1-IV1

IDENTIFICATION OF APPLICABLE REQUIREMENTS

City of Lakeland Electric
C.D. McIntosh, Jr. Power Plant

Facility ID No. 1050004
Polk County

Title V Air Operation Permit Revision

Permit No. 1050004-031-AV
(2nd Revision of Title V Air Operation Permit No. 1050004-023-AV)

Permitting Authority:
State of Florida
Department of Environmental Protection
Division of Air Resource Management
Office of Permitting and Compliance
2600 Blair Stone Road
Mail Station #5505
Tallahassee, Florida 32399-2400

Telephone: (850) 717-9000
Fax: (850) 717-9097

Compliance Authority:
Southwest District Office
13051 N. Telecom Parkway
Temple Terrace, Florida 33637-0926
Telephone: (813) 632-7600
Fax: (813) 744-6084

Title V Air Operation Permit Renewal
Permit No. 1050004-029-AV

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Florida Department of Environmental Protection

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

PERMITTEE:
City of Lakeland Electric
501 East Lemon Street
Lakeland, Florida 33801-5079

Permit No. 1050004-031-AV
C. D. McIntosh, Jr. Power Plant
Facility ID No. 1050004
Title V Air Operation Permit Revision

The purpose of this permit is to revise Title V Air Operation Permit No. 1050004-023-AV for the above referenced facility in order to change the method of compliance for SO_2 to CEMS for Units 1 and 2, and to remove one of the fuel options, refuse derived fuel, from Unit 3.

The existing C. D. McIntosh, Jr. Power Plant is located at 3030 East Lake Parker Drive, Lakeland, Polk County; UTM Coordinates: Zone 17, 409.0 km East and 3106.2 km North; Latitude: 28° 04' 50" North and Longitude: 81° 55' 32" West.

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

1050004-023-AV Effective Date: January 1, 2009
1050004-029-AV Effective Date: April 6, 2011
1050004-031-AV Effective Date: March 9, 2012
Renewal Application Due Date: May 20, 2013
Expiration Date: December 31, 2013

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

JFK/jkh/mc

Subsection A. Facility Description.

This facility consists of three fossil fuel fired steam generators, two diesel powered generators, and two gas turbines. Fossil fuel fired steam generator Unit 1 is fired with natural gas, No. 6 fuel oil or on-specification used oil generated by the City of Lakeland. Fossil fuel fired steam generator Unit 2 is fired with natural gas, propane, No. 2 fuel oil or No. 6 fuel oil. Fossil fuel fired steam generator 3 is fired with coal, natural gas and petroleum coke. Gas Turbine Peaking Unit 1 is primarily fired with natural gas, or No. 2 fuel oil with a maximum sulfur content of 0.5 percent by weight. McIntosh Unit 5, a 370 MW combined cycle stationary combustion turbine, is fired with natural gas, or No. 2 or superior grade fuel oil with a maximum sulfur content of 0.05 percent by weight. Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Subsection B. Summary of Emissions Units.

E.U. ID No.	Brief Description
Regulated Emissions Units	
-001	McIntosh Unit 1 - Fossil Fuel Fired Steam Generator
-002	Diesel Engine Peaking Unit 2
-003	Diesel Engine Peaking Unit 3
-004	Gas Turbine Peaking Unit 1
-005	McIntosh Unit 2 - Fossil Fuel Fired Steam Generator
-006	McIntosh Unit 3 - Fossil Fuel Fired Steam Generator
-028	McIntosh Unit 5 - 370 MW Combined Cycle Stationary Combustion Turbine
Unregulated Emissions Units and Activities	
-007	Tanks with greater than 10,000 gallon capacity installed prior to July 23, 1984
-008	Diesel drive coal tunnel sump engine
-009	Fire water UPS diesel No. 31
-010	Fire water UPS diesel No. 32
-011	CT startup diesel
-012	General purpose diesel engines
-013	Emergency generators
-014	General purpose painting
-015	Parts Cleaning
-016	Sand Blasting (Maintenance only)
-017	Wastewater Treatment Tank
-018	Three Cooling Towers (Units 2 and 3)
-019	Northside Waste Water Treatment Facility - Wastewater treatment processes and tanks
-020	Northside Waste Water Treatment Facility - Two emergency diesel generators
-021	Northside Waste Water Treatment Facility - Chemical and petroleum storage
-022	Northside Waste Water Treatment Facility - Miscellaneous activities
-023	Coal processing and conveying system

-024	Coal storage system
-025	Coal transfer and loading system
-026	Limestone handling and storage system
-027	Fly ash handling and storage system
-029	1.05 million gallon storage tank for McIntosh Unit 5, subject only to the reporting requirements of 40 CFR 60, Subpart Kb
-030	Mechanical Draft Cooling Tower

Subsection C. Applicable Regulations.

Based on the Title V Air Operation Permit Renewal application received on July 3, 2008, this facility is a major source of hazardous air pollutants (HAP). This facility is classified as a Prevention of Significant Deterioration (PSD) major facility. A summary of important applicable regulations is shown in the following table.

Regulation	E.U. ID No(s).
Rule 62-210.300, F.A.C., Permits Required	-002, -003 & -004
Rule 62-296.405(1), F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input	-001
Rule 62-296.405(2), F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input	-005, -006
Acid Rain, Phase II SO_2	-001, -005, -006, -028
Acid Rain, Phase II NO_X	-006
Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR)	-001, -005, -006, -028
40 CFR 60, Subpart A, Standards of Performance for New Stationary Sources (NSPS) General Provisions	-005, -006, -028
40 CFR 60, NSPS Subpart D, Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971	-005, -006
40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines	-028
Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD)	-006, -028
Compliance Assurance Monitoring (CAM)	-006

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

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

Emissions and Controls

FW2. Not federally Enforceable. Objectionable Odor Prohibited. No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rule 62-296.320(2) and 62-210.200(Definitions), F.A.C.]

FW3. General Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. Containers shall be kept closed. [Rule 62-296.320(1)(a), F.A.C.; and, proposed by applicant in Title V air operation permit renewal application received on July 3, 2008.]

FW4. General Visible Emissions. No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1., F.A.C.]

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

a. maintenance of paved areas;
b. regular mowing of grass and care of vegetation; and,
c. limiting access to plant property by unnecessary vehicles.

[Rule 62-296.320(4)(c), F.A.C.; and, proposed by applicant in Title V air operation permit renewal application received on July 3, 2008.]

Annual Reports and Fees

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

FW6. Annual Operating Report. The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by May 1, 2009 and April 1st of each year, thereafter. [Rule 62-210.370(3), F.A.C.]

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

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

FW9. Prevention of Accidental Releases (Section 112(r) of CAA).

a. As required by Section 112(r)(7)(B)(iii) of the CAA and 40 CFR 68, the owner or operator shall submit an updated Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center.

b. As required under Section 252.941(1)(c), F.S., the owner or operator shall report to the appropriate representative of the Department of Community Affairs (DCA), as established by department rule, within one working day of discovery of an accidental release of a regulated substance from the stationary source, if the owner or operator is required to report the release to the United States Environmental Protection Agency under Section 112(r)(6) of the CAA.

c. The owner or operator shall submit the required annual registration fee to the DCA on or before April 1, in accordance with Part IV, Chapter 252, F.S., and Rule 9G-21, F.A.C.

d. Any required written reports, notifications, certifications, and data required to be sent to the DCA, should be sent to: Department of Community Affairs, Division of Emergency Management, 2555 Shumard Oak Boulevard, Tallahassee, FL 32399-2100, Telephone: (850) 413-9921, Fax: (850) 488-1739.

e. Any Risk Management Plans, original submittals, revisions, or updates to submittals, should be sent to: RMP Reporting Center, Post Office Box 1515, Lanham-Seabrook, MD 20703-1515, Telephone: (301) 429-5018.

Any required reports to be sent to the National Response Center, should be sent to: National Response Center, EPA Office of Solid Waste and Emergency Response, USEPA (5305 W), 401 M Street SW, Washington, D.C. 20460, Telephone: (800) 424-8802.

Send the required annual registration fee using approved forms made payable to: Cashier, Department of Community Affairs, State Emergency Response Commission, 2555 Shumard Oak Boulevard, Tallahassee, FL 32399-2149

[Part IV, Chapter 252, F.S.; and, Rule 9G-21, F.A.C.]

FW10. Clean Air Interstate Rule (CAIR) Applicable Units. This facility contains emissions units that are subject to CAIR. On July 11, 2008, the U.S. Court of Appeals for the District of Columbia recommended vacature of the Clean Air Interstate Rule. Because of this decision, the applicable CAIR requirements that were identified in the renewal application are not being included in the permit at this time. If, and at such time that, CAIR is ultimately upheld, you must begin complying with the CAIR program requirements contained in the renewal application and the Title V air operation permit must be revised accordingly. [Rules 62-213.440 and 62-296.470, F.A.C.]

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

E.U. ID No.	Brief Description
-001	McIntosh Unit 1 - Fossil Fuel Fired Steam Generator

McIntosh Unit 1 is a forced draft boiler rated at a nominal load of 90 megawatts. The unit is fired with natural gas at a maximum heat input rate of 985 million Btu per hour (approximately 970 million cubic feet per hour), or No. 6 fuel oil, having a maximum sulfur content of 2.5 percent by weight, at a maximum heat input rate of 950 million Btu per hour (approximately 6,300 gallons per hour). This unit is also permitted to burn on-specification used oil generated by the City of Lakeland, at a maximum heat input rate of 950 million Btu per hour. McIntosh Unit 1 began commercial service in February, 1971. The stack parameters are: height, 150 feet: diameter, 9.0 feet; exit temperature, 277 degrees F; and, actual stack gas flow rate, 310,000 acfm.

{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II; Rule 62-296.405(1), F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input; and, Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR).}

Essential Potential to Emit (PTE) Parameters

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

Unit No.	MMBtu/hr Heat Input	Fuel Type
1	985	Natural Gas
	950	No. 6 Fuel Oil
	950	Used Oil

When a blend of fuel oil, on-specification used oil or natural gas is fired, the heat input is prorated based on the percent heat input of each fuel. The Acid Rain CEMS will not be a method of compliance for the determination of the heat input rate. [Rules 62-4.160(2), 62-210.200 (Definitions - Potential to Emit (PTE)); and, 62-296.405, F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

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

A.3. Methods of Operation - Fuels. The only fuels allowed to be burned are natural gas, propane, No. 6 Fuel Oil, On-Specification Used Oil, No. 2 Fuel Oil and combinations of natural gas, propane, No. 6 Fuel Oil, No. 2 Fuel Oil and/or On-Specification Used Oil. On-Specification used oil containing any quantifiable levels of PCBs can only be fired when the emissions unit is at normal operating temperatures. [Rule 62-213.410, F.A.C.; and, 40 CFR 271.20(e)(3)]

A.4. Hours of Operation. This emissions unit may operate continuously, i.e., 8,760 hours/year. [Rules 62-4.160(2) and 62-210.200 (Definitions - PTE), F.A.C.]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Conditions **A.5.** - **A.9.** are based on the specified averaging time of the applicable test method.

A.5. Visible Emissions. Visible emissions shall not exceed 20 percent opacity, except for one two-minute period per hour during which opacity shall not exceed 40 percent. Emissions units governed by this visible emissions limit shall compliance test for particulate matter emissions annually and as otherwise required by Chapter 62-297, F.A.C. [Rule 62-296.405(1)(a), F.A.C.]

A.6. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more. [Rule 62-210.700(3), F.A.C.]

A.7. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods. [Rule 62-296.405(1)(b), F.A.C.]

A.8. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. [Rule 62-210.700(3), F.A.C.]

A.9. Sulfur Dioxide. When burning liquid fuel, sulfur dioxide emissions shall not exceed 2.75 pounds per million Btu heat input, as measured by applicable compliance methods. [Rule 62-296.405(1) (c)1.j., F.A.C.]

*{Permitting Note: Applicant has elected to use the Part 75 CEMS as the primary method for determining compliance with the above emission limit. Fuel sampling as specified in Specific Conditions **A.22.** and **A.23.** may be used when CEMS data is not available. }*

A.10. Sulfur Dioxide - Sulfur Content. The No. 6 fuel oil sulfur content shall not exceed 2.5 percent, by weight when CEMS are not utilized for compliance. [Rule 62-296.405(1)(e)3.& 62-213.440(1), F.A.C.]

Excess Emissions

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

A.11. Excess Emissions Allowed - Malfunctions. Excess emissions resulting from malfunction shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

A.12. Excess Emissions Allowed - Startup And Shutdown. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized. [Rule 62-210.700(2), F.A.C.]

A.13. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

Continuous Monitoring Requirements

A.14. Sulfur Dioxide. The permittee elected to demonstrate compliance by accepting a liquid fuel sulfur limit that will be verified with fuel analysis provided by the vendor or the permittee upon each fuel delivery. This protocol is allowed because the emissions unit does not have an operating flue gas desulfurization device. As an alternative, the acid rain required continuous emission monitoring system for sulfur dioxide may be used for emissions determination and reporting. [40 CFR 75; and, Rules 62-213.440(1) & 62-296.405(1)(f)1.b., F.A.C.]

Test Methods and Procedures

A.15. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
EPA Methods 1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
EPA Methods 17, 5, 5B, or 5F	Methods for Determining Particulate Matter Emissions
EPA Method 19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.)
DEP Method 9	Visual Determination of the Opacity of Emissions

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Chapter 62-297, F.A.C.]

A.16. Annual Compliance Tests. Unless otherwise specified by this permit, during each federal fiscal year (October 1st to September 30th), this emissions unit shall be tested to demonstrate compliance with the emission limitations and standards for visible emissions (VE) and particulate matter (PM) emissions. [Rule 62-297.310(7), F.A.C.]

A.17. Compliance Tests Prior To Renewal. Prior to permit renewal, compliance tests shall be performed for the following pollutants: VE and PM. [Rule 62-297.310(7)(a)3., F.A.C.]

A.18. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

A.19. Visible emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C. [Rule 62-296.405(1)(e)1., F.A.C.]

A.20. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

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

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

A.21. Particulate Matter. The test methods for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 or 3A with Orsat analysis shall be used when the oxygen based F-factor, computed according to EPA Method 19, is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17. [Rules 62-296.405(1)(e)2. and 62-297.401, F.A.C.]

A.22. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C., or methods from the acid rain rule. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards. The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by permit, the permittee elected to demonstrate compliance by accepting a liquid fuel sulfur limit that will be verified with a fuel analysis provided by the vendor or the permittee upon each fuel delivery. As an alternative, the acid rain required continuous emission monitoring system for sulfur dioxide may be used for emissions determination and reporting. [40 CFR Part 75; and, Rules 62-213.440(1), 62-296.405(1)(e)3. & 62-297.401, F.A.C.]

A.23. Sulfur Content Sampling Methods. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91, or the respective successor ASTM method(s). [Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

A.24. VE Testing Not Required. By this permit, annual emissions compliance testing for visible emissions is not required for this emissions unit while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
See Specific Condition **TR7.** [Rule 62-297.310(7)(a)4., F.A.C.]

A.25. PM Testing Not Required. Annual and permit renewal compliance testing for particulate matter emissions is not required for this emissions unit while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
See Specific Condition **TR7.** [Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

Record keeping and Reporting Requirements

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

A.26. Reporting Schedule. The following report shall be submitted to the Compliance Authority:

Report	Reporting Deadline(s)	Related Condition(s)
Quarterly Excess Emissions	Every 3 months (quarter)	**A.28.**

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

A.27. Reporting of Excess Emissions Due to Malfunctions. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department or the appropriate Local Program. [Rule 62-210.700(6), F.A.C.]

A.28. Quarterly Excess Emissions Report. Submit to the Department a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years. [Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

Other Requirements

A.29. On-Specification Used Oil. Burning of on-specification used oil is allowed in this emissions unit in accordance with all other conditions of this permit and the following conditions:
a. *On-Specification Used Oil Emissions Limitations.* This emissions unit is permitted to burn on-specification used oil, which contains a Polychlorinated Biphenyl (PCB) concentration of less than 50 parts per million (ppm). On-specification used oil is defined as used oil that meets the specifications of 40 CFR 279 - Standards for the Management of Used Oil, listed below. "Off-specification" used oil shall not be burned. Used oil which fails to comply with any of these specification levels is considered "off-specification" used oil.

CONSTITUENT/PROPERTY	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flash point	100 degrees F minimum

b. *Quantity Limitation.* This emissions unit is permitted to burn on-specification used oil that is generated by the City of Lakeland in the production and distribution of electricity, not to exceed 42,000 gallons (1,000 barrels) during any calendar year.

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

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

e. *Testing Requirements.* For each batch of used oil to be burned, the owner or operator must be able to demonstrate that the used oil qualifies as on-specification used oil and that the PCB content is less than 50 ppm.

The requirements of this demonstration are governed by the following federal regulations:

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

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

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

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

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

[40 CFR 761.20(e)(2)]

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

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

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

f. *Recordkeeping Requirements.* The owner or operator shall obtain, make, and keep the following records related to the use of used oil in a form suitable for inspection at the facility by the Department:
(1) The gallons of on-specification used oil placed into inventory to be burned and the gallons of on-specification used oil burned each month.
(2) Results of the analyses of each deposit of used oil, as required by the above conditions.
(3) Other information, besides testing, used to make a claim that the used oil meets the requirements of on-specification used oil or that the used oil contains less than 50 ppm of PCBs.
[40 CFR 279.72(b), 40 CFR 279.74(b) and 40 CFR 761.20(e)]

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

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

E.U. ID No.	Brief Description
-002	Diesel Engine Peaking Unit 2
-003	Diesel Engine Peaking Unit 3

Diesel Engine Peaking Units 2 and 3 are diesel fired internal combustion engines, which each drives a generator capable of producing electric power at a maximum rating of 2.5 megawatts. These units are each fired on No. 2 fuel oil, with a maximum sulfur content of 0.5 percent by weight, at a maximum firing rate of 201.6 gallons per hour. This corresponds to a maximum heat input of 28 million Btu per hour. Each diesel engine peaking unit has its own stack. The stack parameters are: height, 20 feet: diameter, 2.6 feet; exit temperature, 715 degrees F; and, actual stack gas flow rate, 24,529 acfm. Diesel Engine Peaking Units 2 and 3 began commercial service in 1970.

{Permitting note: The emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required.}

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity.
a. The maximum heat input rate of each diesel engine peaking unit is 28 million Btu per hour
b. **Not federally enforceable.** The maximum firing rate of each diesel engine peaking unit is 201.6 gallons per hour firing No. 2 fuel oil.
[Rules 62-4.160(2) and 62-210.200 (Definitions - Potential to Emit (PTE)), F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

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

B.3. Methods of Operation - Fuels. Only distillate (No. 2) fuel oil shall be fired in the diesel engine peaking units. [Rule 62-213.410, F.A.C.]

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

Emission Limitations and Standards

Unless otherwise specified, the averaging time for Specific Condition **B.5.** is based on the specified averaging time of the applicable test method.

B.5. Visible Emissions. Visible emissions from each diesel engine peaking unit shall not be equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1., F.A.C.]

B.6. **Not federally enforceable.** Sulfur Dioxide - Sulfur Content. The sulfur content of the No. 2 fuel oil shall not exceed 0.5 percent, by weight. [Rule 62-213.440, F.A.C. and Applicant request.]

Excess Emissions

B.7. Excess Emissions Allowed. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

B.8. Best Operational Practices to Minimize Excess Emissions. The permittee shall follow the best operational practices to minimize excess emissions during startup and shutdown as described in the most recent Title V air operation permit application. [Rule 62-210.700(1), F.A.C. and, proposed by applicant in Title V air operation permit renewal application received on July 3, 2008.]

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

Monitoring of Operations

B.10. Fuel Sulfur Monitoring. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis provided by the vendor or the permittee upon each fuel delivery. [Rule 62-213.440, F.A.C.]

Test Methods and Procedures

B.11. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
EPA Method 9	Visual Determination of the Opacity of Emissions

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Chapter 62-297, F.A.C.]

B.12. Annual Compliance Tests. Unless otherwise specified by this permit, during each federal fiscal year (October 1st to September 30th), this emissions unit shall be tested to demonstrate compliance with the emission limitations and standards for visible emissions (VE). [Rule 62-297.310(7), F.A.C.]

B.13. Compliance Tests Prior To Renewal. Prior to permit renewal, compliance tests shall be performed for the following pollutant: VE. [Rule 62-297.310(7)(a)3., F.A.C.]

B.14. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

B.15. VE Tests Method. The test method for visible emissions shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C. [Rules 62-204.800, 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.]

B.16. Sulfur Content Sampling Methods. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91, or the respective successor ASTM method(s). [Rules 62-213.440 and 62-297.440, F.A.C.]

B.17. VE Testing Not Required. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
See Specific Condition **TR7.** [Rule 62-297.310(7)(a)4., F.A.C.]

Recordkeeping and Reporting Requirements

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

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

E.U. ID No.	Brief Description
-004	Gas Turbine Peaking Unit 1

Gas Turbine Peaking Unit 1 consists of a gas turbine, which drives a generator producing electrical power at a nominal nameplate rating of 20 megawatts. The gas turbine is fired with natural gas, or No. 2 fuel oil with a maximum sulfur content of 0.5 percent by weight. The maximum fuel firing rate is 320 million cubic feet per hour of natural gas (approximately 330 million Btu per hour) or 2,310 gallons per hour of No. 2 fuel oil (approximately 320 million Btu per hour). Gas Turbine Peaking Unit 1 began commercial service in 1973. The stack parameters are: height, 35 feet: diameter (rectangular), 13'2" x 10'11" feet; exit temperature, 900 degrees F; actual stack gas flow rate (gas), 742,174 acfm: and, actual stack gas flow rate (oil), 682,334 acfm.

{Permitting notes: This emissions unit is regulated under Rule 62-210.300, F.A.C., Permits Required. This unit is not subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines.}

Essential Potential to Emit (PTE) Parameters

C.1. Permitted Capacity.
a. The maximum heat input rate of the turbine is 330 million Btu per hour (lower heating value) at 30 degrees F while firing natural gas and 320 million Btu per hour (lower heating value) at 30 degrees F while firing No. 2 fuel oil.
b. **Not federally enforceable.** The maximum firing rate of the turbine is 320 million cubic feet per hour when firing natural gas or 2,310 gallons per hour when firing No. 2 fuel oil.
[Rules 62-4.160(2) and 62-210.200 (Definitions - Potential to Emit (PTE)), F.A.C.]

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

C.3. Methods of Operation - Fuels. Only natural gas or distillate (No. 2) fuel oil shall be fired in the combustion turbine. [Rule 62-213.410, F.A.C.]

C.4. Hours of Operation. These emissions unit(s) may operate continuously, i.e., 8,760 hours/year. [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

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

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

C.6. **Not federally enforceable.** Sulfur Dioxide - Sulfur Content. The sulfur content of the No. 2 fuel oil shall not exceed 0.5 percent, by weight. [Rule 62-213.440, F.A.C. and Applicant request.]

Excess Emissions

C.7. Excess Emissions Allowed. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted providing (1) that best operational practices to minimize

emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

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

Monitoring of Operations

C.9. Fuel Sulfur Monitoring. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis provided by the vendor or the permittee upon each fuel delivery. [Rule 62-213.440, F.A.C.]

Test Methods and Procedures

C.10. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
EPA Method 9	Visual Determination of the Opacity of Emissions

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Chapter 62-297, F.A.C.]

C.11. Annual Compliance Tests. Unless otherwise specified by this permit, during each federal fiscal year (October 1st to September 30th), this emissions unit shall be tested to demonstrate compliance with the emission limitations and standards for visible emissions (VE). [Rule 62-297.310(7), F.A.C.]

C.12. Compliance Tests Prior To Renewal. Prior to permit renewal, compliance tests shall be performed for the following pollutants: VE. [Rule 62-297.310(7)(a)3., F.A.C.]

C.13. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

C.14. The test method for visible emissions shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C. [Rules 62-204.800, 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.]

C.15. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91, or the respective successor ASTM method(s). [Rules 62-213.440 and 62-297.440, F.A.C.]

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

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

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

Recordkeeping and Reporting Requirements

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

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

E.U. ID No.	Brief Description
-005	McIntosh Unit 2 - Fossil Fuel Fired Steam Generator

McIntosh Unit 2 is a nominal 114.7 megawatt (electric) fossil fuel fired steam generator. The unit is fired on low sulfur No. 6 or No. 2 fuel oil with a maximum heat input of 1,115 million Btu per hour, or natural gas with a maximum heat input of 1,184.5 million Btu per hour. The stack parameters are: height, 157 feet: diameter, 10.5 feet; exit temperature, 277 degrees F; and, actual stack gas flow rate, 380,200 acfm. McIntosh Unit 2 began commercial service in June, 1976.

{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II; Rule 62-296.405(2), F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input; and NSPS - 40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971, adopted and incorporated by reference in Rule 62-204.800(8)1., F.A.C.; and, Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR).}

Essential Potential to Emit (PTE) Parameters

D.1. Permitted Capacity. The maximum operation heat input rate is as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
2	1,184.5	Natural Gas
	1,115	No. 6 Fuel Oil
	1,115	No. 2 Fuel Oil

When a blend of fuel oil and natural gas is fired, the heat input is prorated based on the percent heat input of each fuel. The Acid Rain CEM will not be a method of compliance for the determination of the heat input rate.
[Rules 62-4.160(2) and 62-210.200 (Definitions - Potential to Emit (PTE)), F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

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

D.3. Methods of Operation. Fuels. The only fuels allowed to be burned are natural gas, propane, No. 6 fuel oil, No. 2 fuel oil and combinations of natural gas, propane, No. 6 fuel oil and/or No. 2 fuel oil. [Rule 62-213.410, F.A.C.]

D.4. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year. [Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Conditions **D.5. - D.6.**; and, **D.8. - D.9.** are based on the specified averaging time of the applicable test method.

D.5. Particulate Matter. On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of 43 nanograms per joule heat input (0.10 lb per million Btu). [40 CFR 60.42(a)(1)]

D.6. Visible Emissions. On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity. [40 CFR 60.42(a)(2)]

D.7. Sulfur Dioxide. On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of 340 nanograms per joule heat input (0.80 lb per million Btu) derived from liquid fossil fuel. [40 CFR 60.43(a)(1)]

D.8. Sulfur Dioxide. Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels. [40 CFR 60.43(c)]

D.9. Nitrogen Oxides. On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2 in excess of:

a. 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel.
b. 129 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel.

[40 CFR 60.44(a)(1) & (2)]

D.9. Nitrogen Oxides. When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NOx} = \frac{w(260)+x(86)+y(130)+z(300)}{w+x+y+z}$$

where:
PS_{NOx} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;
w = is the percentage of total heat input derived from lignite;
x = is the percentage of total heat input derived from gaseous fossil fuel;
y = is the percentage of total heat input derived from liquid fossil fuel; and,
z = is the percentage of total heat input derived from solid fossil fuel (except lignite).

[40 CFR 60.44(b)]

Excess Emissions

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

D.10. Excess Emissions Allowed. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted providing (1) that best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

D.11. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

Continuous Monitoring Requirements

D.12. Sulfur Dioxide. For a fossil fuel fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis under 40 CFR 60.45(d). The applicant has elected to utilize either fuel sampling and analysis or the acid rain required continuous emission monitoring system for determining compliance with the sulfur dioxide emission limit in Specific Condition D.7. [40 CFR 60.45(b)(2) & 40 CFR 75; and, Rule 62-213.440(1) F.A.C.]

Test Methods and Procedures

D.13. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
EPA Methods 1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
EPA Methods 17, 5, 5B, or 5F	Methods for Determining Particulate Matter Emissions
EPA Methods 6, 6A, 6B, or 6C	Methods for Determining Sulfur Dioxide Emissions
Method 7, Method 7A, 7C, 7D, or 7E	Determination of Nitrogen Oxide Emissions
EPA Method 19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.)
EPA Method 9	Visual Determination of the Opacity of Emissions

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Chapter 62-297, F.A.C.]

D.14. Annual Compliance Tests. Unless otherwise specified by this permit, during each federal fiscal year (October 1st to September 30th), this emissions unit shall be tested to demonstrate compliance with the emission limitations and standards for particulate matter, nitrogen oxides and visible emissions. The NO_X

RATA test data may be used to demonstrate compliance with the annual test requirement, provided the testing requirements (notification, procedures & reporting) of Chapter 62-297, F.A.C. are met. [Rule 62-297.310(7), F.A.C.]

D.15. Compliance Tests Prior To Renewal. Prior to permit renewal, compliance tests shall be performed for the following pollutants: VE, PM, SO_2 and NO_X. The SO_2 and NO_X RATA test data may be used to demonstrate compliance, provided the testing requirements (notification, procedures & reporting) of Chapter 62-297, F.A.C. are met. [Rule 62-297.310(7)(a)3., F.A.C.]

D.16. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

D.17. SO_2 Compliance. Compliance with the sulfur dioxide emission standard of specific condition **D.7.** shall be demonstrated using the fuel sampling and analysis procedures of specific condition **D.18.** or the acid rain required continuous emission monitoring system, based on a 3-hour rolling average. [40 CFR 75 and Rule 62-213.440(1), F.A.C.]

D.18. Fuel Sampling. The following fuel sampling and analysis program may be used to demonstrate compliance with the sulfur dioxide standard and as the substitute for the sulfur dioxide continuous monitoring system:

a. Determine and record the as-fired fuel sulfur content, percent by weight, (1) for liquid fuels using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91, or the respective successor ASTM method(s), to analyze a representative sample of the blended fuel following each fuel delivery, (2) for gaseous fuels using ASTM D1072-90, or the respective successor ASTM method.
b. Record daily the amount of each fuel fired, the density of each fuel, and the percent sulfur content by weight of each fuel.
c. Utilize the information in a. and b., above, to calculate the SO_2 emission rate to ensure compliance at all times.

[Rule 62-213.440(1), F.A.C.]

D.19. VE Testing Not Required. By this permit, annual emissions compliance testing for visible emissions is not required for this emissions unit while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.

See Specific Condition **TR7.** [Rule 62-297.310(7)(a)4., F.A.C.]

D.20. PM Testing Not Required. Annual and permit renewal compliance testing for particulate matter emissions is not required for this emissions unit while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.

See Specific Condition **TR7.** [Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

Recordkeeping and Reporting Requirements

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

D.21. Reporting Schedule. The following report shall be submitted to the Compliance Authority:

Report	Reporting Deadline(s)	Related Condition(s)
NSPS Excess Emissions and Monitoring System Performance	Every 6 months (semi-annual), except when more frequent reporting is specifically required	**D.23.**
Quarterly Excess Emissions	Every 3 months (quarter)	**D.22.**

[40 CFR 60 Subpart A; and, Rule 62-210.700(6), F.A.C.]

D.22. Quarterly Excess Emissions Report. Submit to the Department a written report of emissions in excess of emission limiting standards for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years. [Rule 62-210.700(6), F.A.C.]

Miscellaneous Requirements

D.23. NSPS Requirements - Subpart A. These emissions units shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions, including:

40 CFR 60.7, Notification and Recordkeeping
40 CFR 60.8, Performance Tests
40 CFR 60.11, Compliance with Standards and Maintenance Requirements
40 CFR 60.12, Circumvention
40 CFR 60.13, Monitoring Requirements
40 CFR 60.19, General Notification and Reporting requirements,

which have been adopted by reference in Rule 62-204.800(8)(d), F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 60.4, 40 CFR 60.8(b)(2) and (3), 40 CFR 60.11(e)(7) and (8), 40 CFR 60.13(g), (i) and (j)(2), and 40 CFR 60.16. These emissions units shall comply with **Appendix 40 CFR 60 Subpart A** included with this permit. [Rule 62-204.800(8)(d), F.A.C.]

D.24. NSPS Requirements - Subpart D. Except as otherwise provided in this permit, this fossil-fuel fired steam generator shall comply with all applicable provisions of 40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971, adopted by reference in Rule 62-204.800(8)(b)1., F.A.C. This emissions unit shall comply with **Appendix 40 CFR 60 Subpart D** included with this permit. [Rule 62-204.800(8)(b)1., F.A.C.]

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

E.U. ID No.	Brief Description
-006	McIntosh Unit 3 - Fossil Fuel Fired Steam Generator

McIntosh Unit 3 is a nominal 364 megawatt (electric) dry bottom wall-fired fossil fuel fired steam generator. The unit is fired on coal, residual oil, natural gas and petroleum coke. The maximum heat input rate is 3,640 million Btu per hour. Unit 3 is equipped with an electrostatic precipitator (ESP), a flue gas desulfurization system (FGD), and low NO_X burners (LNB) and an overfire air (OFA) system to control emissions. McIntosh Unit 3 began commercial service in September, 1982. Compliance Assurance Monitoring (CAM) requirements for the ESP are included in Appendix CAM. The FGD is exempted from CAM because the Acid Rain SO_2 continuous emissions monitor will be used to demonstrate continuous compliance. The stack parameters are: height, 250 feet: diameter, 18 feet; exit temperature, 125 degrees F; and, actual stack gas flow rate, 1,260,536 acfm.

{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II; Rule 62-296.405(2), F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input; and NSPS - 40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971, adopted and incorporated by reference in Rule 62-204.800(8)(b)1., F.A.C.; Rule 212.400(6), F.A.C., Prevention of Significant Deterioration (PSD); Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination; Compliance Assurance Monitoring (CAM), adopted and incorporated by reference in Rule 62-204.800, F.A.C.; and, Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR).}

In addition to the requirements listed below, these emissions units are also subject to the standards and requirements contained in the Acid Rain Part of this permit (see Section IV).

Essential Potential to Emit (PTE) Parameters

E.1. Capacity. The maximum heat input rate is 3,640 MMBtu per hour. The Acid Rain CEMS will not be a method of compliance for the determination of the heat input rate. [Rules 62-4.160(2) and 62-210.200 (Definitions - Potential to Emit (PTE)), F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

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

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

a. Coal only;

b. Low sulfur fuel oil only (≤ 0.5 percent sulfur by weight);
c. Coal and up to 20 percent petroleum coke (based on weight);
d. High sulfur fuel oil (> 0.5 percent sulfur by weight); and,
e. Natural gas or propane only, or in combination with any of the other fuels or fuel combinations listed above.
[Rules 62-4.160(2), 62-210.200 (Definitions - PTE), and 62-213.440(1), F.A.C.; and, PSD-FL-008(B)]

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

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Conditions **E.5.-E.7.; E.9.-E.11.;** and, **E.13.-E.14.** are based on the specified averaging time of the applicable test method.

E.5. Particulate Matter. Particulate matter emitted to the atmosphere from the boiler shall not exceed:

Mode of Firing	Pound / MMBtu Heat Input
Coal	0.044
Coal/Petroleum Coke	0.044
Oil	0.070

[40 CFR 60.42(a)(2); and, PSD-FL-008(B)]

E.6. Visible Emissions. Visible emissions shall not exceed 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity. [40 CFR 60.42(a)(2); and, PSD-FL-008(B)]

E.7. Sulfur Dioxide. On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of: (1) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from liquid fossil fuel or liquid fossil fuel and wood residue, or (2) 520 nanograms per joule heat input (1.2 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue, except as provided in 40 CFR 60.43(e). [40 CFR 60.43(a)(1) and (2)]

E.8. Sulfur Dioxide. When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$PS_{SO2} = [y(340) + z(520)]/(y+z)$

where:
PS_{SO2} is the prorated standard for sulfur dioxide when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired,
y is the percentage of total heat input derived from liquid fossil fuel, and
z is the percentage of total heat input derived from solid fossil fuel.
[40 CFR 60.43(b)]
Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels. [40 CFR 60.43(c)]

E.9. Sulfur Dioxide. A flue gas desulfurization system will be installed to treat exhaust gases and will operate such that whenever coal or blends of coal and petroleum coke are burned, sulfur dioxide gases discharged to

the atmosphere from the boiler shall not exceed 10 percent of the potential combustion concentration (90 percent reduction), or 35 percent of the potential combustion concentration (65 percent reduction) when emissions are less than 0.75 pound per million Btu heat input. Compliance with the percent reduction requirement shall be determined on a 30-day rolling average. This compliance information shall be retained for a period of five years and made available by the City upon request of the Department. Whenever blends of petroleum coke with other fuels are co-fired, sulfur dioxide emissions shall not exceed 0.718 pound per million Btu heat input based on a 30-day rolling average and shall comply with the reduction requirements given above. [PSD-FL-008(B); and, Rule 62-213.440, F.A.C.]

E.10. Sulfur Dioxide. The burning of high sulfur oil (greater than 0.5 percent sulfur by weight) or a combination of high sulfur oil as an emergency fuel without the use of the SO_2 scrubber will be allowed only when the flue gas desulfurization system malfunctions to the extent that the burning of coal would cause emission limitations to be exceeded. Sulfur dioxide emitted to the atmosphere from the boiler shall not exceed 0.8 pound per million Btu heat input under this condition. [PSD-FL-008(B)]

E.11. Sulfur Dioxide. During malfunctions of equipment which cause an interruption of the coal feed to the boiler, the burning of high sulfur oil (greater than 0.5 percent sulfur by weight) will be allowed only if all flue gases are fully scrubbed by the SO_2 scrubber. Sulfur dioxide emitted to the atmosphere from the boiler shall not exceed 0.8 pound per million Btu heat input under this condition. [PSD-FL-008(B)]

E.12. Sulfur Dioxide. Continuous burning of natural gas, low sulfur fuel oil (less than or equal to 0.5 percent sulfur by weight), or combinations of these two fuels with or without the use of the SO_2 scrubber will be allowed. [PSD-FL-008(B)]

E.13. Nitrogen Oxides. On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2 in excess of:

a. 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel.
b. 129 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.
c. 300 nanograms per joule heat input (0.70 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

[40 CFR 60.44(a)(1), (2) & (3)]

E.14. Nitrogen Oxides. Except as provided under paragraphs 40 CFR 60.44(c) and (d), when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NOx} = \frac{w(260)+x(86)+y(130)+z(300)}{w+x+y+z}$$

where:
PS_{NOx} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;
w = is the percentage of total heat input derived from lignite;

x = is the percentage of total heat input derived from gaseous fossil fuel;
y = is the percentage of total heat input derived from liquid fossil fuel; and,
z = is the percentage of total heat input derived from solid fossil fuel (except lignite).
[40 CFR 60.44(b)]

E.15. Ammonia Emissions (Slip). Subject to the requirements of Condition 36 in this section, the SCR system shall be operated for an ammonia slip target of less than 5 ppmv based on the average of three, 1-hour test runs. [Air Construction Permit No. 1050004-026-AC, Specific Condition 12.]

E.16. CO Emission Limit Subject to Revision. Emissions of carbon monoxide (CO) from Unit 3 shall not exceed 0.20 pounds per million Btu heat input (lb/MMBtu) on a 30-day rolling average as described in air construction permit 1050004-018-AC. Based on results of compliance tests and analysis of 12 months worth of continuous monitoring data, the Department will reassess the previously issued best available control technology (BACT) determination. The emission limit may be adjusted downward to make this limit more stringent provided that overall control attained for all air pollutants including CO, SO_2, NO_X, PM/PM_{10}, sulfuric acid mist, and VOC is optimized. Such revision shall be based on data that represents a full range of operating conditions and a representative period of time. Such revision, if required by the Department, shall be in the form of an air construction permit following the Department's procedures in Rules 62-210.300 and 62-4.055, F.A.C. [Air Construction Permit Nos. 1050004-019-AC, Specific Condition 13.a and 1050004-026-AC, Specific Condition 13.]

E.17. NO_X Emission Limit. NO_X emissions from Unit 3 shall not exceed 0.22 lb/MMBtu of heat input based on a calendar year average of all periods of operation, including startup, shutdown and malfunction. The permittee shall begin collecting and averaging data towards a demonstration of compliance with the new NO_X emissions limitation beginning January 1, 2011. [Air Construction Permit No. 1050004-026-AC, Specific Condition 13.b.]

Excess Emissions

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

E.18. Excess Emissions Allowed. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted providing (1) that best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

E.19. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

E.20. CAM Plan. This emissions unit is subject to the Compliance Assurance Monitoring (CAM) requirements contained in the attached Appendix CAM for the controlled emissions of particulate matter. Failure to adhere to the monitoring requirements specified does not necessarily indicate an exceedance of a specific emissions

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

E.21. Use of SO_2 CEMS For Continuous Compliance. Pursuant to 40 CFR 64.2(b)(1)(vi), the applicant has elected to use the existing certified Acid Rain SO_2 continuous emissions monitor for continuous compliance in order to be exempted from the Compliance Assurance Monitoring (CAM) requirements contained in 40 CFR 64. [40 CFR 64.2(b)(vi); and, Applicant request]

Continuous Monitoring Requirements

E.22. Performance Specifications and Quality Assurance. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A within 180 calendar days of commencing operation following installation of the Low-NO_X burners and overfire air system. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F. The required RATA tests 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 expected range of emissions and corresponding emission standards. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.; and, PSD-FL-387.]

E.23. CEMS Data Requirements for CO BACT Standard.

a. *Data Collection.* The CO CEMS shall monitor and record emissions during all operations and whenever emissions are being generated, including during episodes of startups, shutdowns, and malfunctions. All data shall be used, except for invalid measurements taken during monitor system breakdowns, repairs, calibration checks, zero adjustments, and span adjustments.

b. *Operating Hours and Operating Days.* An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Any day with at least one operating hour for an emissions unit is an operating day for that emission unit.

c. *Valid Hourly Averages.* The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.
   (1) Hours that are not operating hours are not valid hours.
   (2) For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data, the 1-hour block average is not valid, and the hour is considered as "monitor unavailable."

d. *Rolling 30-day average.* 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.

e. *Monitor Availability.* The quarterly excess emissions report shall identify monitor availability for each quarter in which the unit operated. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter in which the unit operated for more than 760 hours. In the event the applicable availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving the required availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

[Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.; and, PSD-FL-387.]

E.24. CEM Requirements. Continuous monitors shall be installed and operated in accordance with 40 CFR 60.45 and 60.13. In addition, an ASTM-certified automatic solid fossil fuel sampler shall be installed which produces a representative daily sample for analysis of sulfur, moisture, heating value and ash. The solid fossil fuel data shall be used in conjunction with emissions factors and the continuous monitoring data to calculate SO_2 reduction. [PSD-FL-008(B)]

E.25. CEMS Annual Emissions Requirement. The owner or operator shall use data from the CO CEMS when calculating annual emissions for purposes of computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for purposes of computing emissions pursuant to the reporting requirements of Rule 62-210.370(3), F.A.C. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit. [Rules 62-210.200, and 62-210.370(3), F.A.C.; and, PSD-FL-387.]

E.26. Ammonia Monitoring Requirements. In accordance with the manufacturer's specifications, the permittee shall calibrate, operate, and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. [Air Construction Permit No. 1050004-019-AC, Specific Condition 22.]

Test Methods and Procedures

E.27. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
EPA Methods 1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
EPA Methods 17, 5, 5B or 5F	Methods for Determining Particulate Matter Emissions
EPA Methods 6, 6A, 6B or 6C	Methods for Determining Sulfur Dioxide Emissions
Method 7, Method 7A, 7C, 7D or 7E	Determination of Nitrogen Oxide Emissions
10	Determination of Carbon Monoxide Emissions
EPA Method 19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.)
EPA Method 9	Visual Determination of the Opacity of Emissions

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Chapter 62-297, F.A.C.]

E.28. Annual Compliance Tests. Unless otherwise specified by this permit, during each federal fiscal year (October 1st to September 30th), this emissions unit shall be tested to demonstrate compliance with the emission limitations and standards for particulate matter (PM), nitrogen oxides (NO_X), sulfur dioxide (SO_2) and visible emissions (VE). The NO_X and SO_2 RATA test data may be used to demonstrate compliance with the annual test requirement, provided the testing requirements (notification, procedures & reporting) of Chapter 62-297, F.A.C. are met. [Rule 62-297.310(7), F.A.C.]

E.29. Compliance Tests Prior To Renewal. Prior to permit renewal, compliance tests shall be performed for the following pollutants: VE, PM, SO_2 and NO_X. [Rule 62-297.310(7)(a)3., F.A.C.]

E.30. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

E.31. Continuous Compliance with CO limits. Compliance with the 30 operating day rolling average shall be demonstrated using data collected from the required CEMS. [Rule 62-4.070(3), F.A.C.; and, PSD-FL-387.]

E.32. VE Tests Not Required. By this permit, annual emissions compliance testing for visible emissions is not required for this emissions unit while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
See Specific Condition **TR7.** [Rule 62-297.310(7)(a)4., F.A.C.]

E.33. PM Tests Not Required. Annual and permit renewal compliance testing for particulate matter emissions is not required for this emissions unit while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
See Specific Condition **TR7.** [Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

E.34. Determining Actual SAM Emissions. The permittee must demonstrate on an annual basis, for a period of 5 years from the date of the maximum sulfur content tested, that SAM emissions increases as a result of this project are less than 7 TPY. The permittee shall operate the sorbent injection system at a frequency and injection rate for SAM control to satisfy this requirement. An automated control system will be used to adjust the sorbent flow rate for the given set of operating conditions based on the most recent performance test results. Actual SAM emissions shall be calculated using the information available for the given operating conditions (e.g., the sulfur content of fuel blend, the SO_2 emission rate prior to the SCR catalyst, the unit load, the flue gas flow rate, the sorbent injection rate and the current catalyst oxidation rate). If performance testing shows that it is unnecessary to operate the sorbent injection system for a given coal blend or the sorbent injection system is removed, the permittee shall determine actual SAM emissions based on emissions factors developed through the performance tests. [Air Construction Permit No. 1050004-026-AC, Specific Condition 16 and Rule 62-212.300(1)(e), F.A.C.]

E.35. SAM Performance Tests and Sorbent Injection for SAM Emissions Control. The permittee conducted stack tests to determine the uncontrolled sulfuric acid mist emission rate, the controlled sulfuric acid mist emission rate, and actual control efficiency of the installed sorbent injection system. Tests were conducted while firing the fuel blend with the highest sulfur content that will be fired in the unit. During each test run, the permittee continuously monitored and recorded the sorbent injection rate. The purpose of these tests were to determine actual control efficiency of the installed systems and to establish the correlation between SAM emissions and the sorbent injection rate, which will be used to calculate the actual annual emissions. If the permittee desires to alter the injection rate of the system that has been previously determined (due to lower sulfur coal being burned, to turn off the system, or any other situation the permittee feels the system can be adjusted for), then the following tests shall be conducted. Within 45 days of firing a fuel blend with a sulfur content that is 0.20% sulfur by weight (based on a 14-operational day rolling average) higher than the

maximum sulfur content previously tested or if the permittee desires a new injection rate, then the permittee shall conduct the following additional SAM performance tests.

a. Conduct the SAM performance tests in accordance with the following requirements, or
   (1) For each set of operating conditions being evaluated, the permittee shall conduct at least a 1-hour test run to determine SAM emissions. At least nine such test runs shall be conducted to evaluate the effect on SAM emissions from such parameters as the SO_2 emission rate prior to the SCR catalyst (and FGD system), the unit load, the flue gas flow rate, the sorbent injection rate and the current catalyst oxidation rate.
   (2) Tests shall be conducted under a variety of fuel blends and load rates that are representative of the actual operating conditions. Sufficient tests shall be conducted to establish the SAM emissions rates for the following scenarios: SCR reactor in service (ammonia injection) without sorbent injection, and SCR reactor in service (ammonia injection) under varying operating conditions and levels of sorbent injection.
   (3) At least 15 days prior to initiating the performance tests, the permittee shall submit a test notification, preliminary test schedule and test protocol to the Bureau of Air Regulation and the Compliance Authority.
   (4) Within 45 days following the last test run conducted, the permittee shall provide a report summarizing the emissions tests and results. All SAM emissions test data shall be provided with this report.
   (5) Within 45 days following the submittal of the emissions test report and no later than 90 days following the last test run conducted, the permittee shall submit a project report summarizing the following:
      (a) Identify each set of operating conditions evaluated;
      (b) Identify each operating parameter evaluated;
      (c) Identify the relative influence of each operating parameter, describe how the automated control system will adjust the sorbent injection rate based on the selected parameters;
      (d) Identify the frequency with which operational parameters will be reevaluated and adjusted within the automated control system;
      (e) Provide the algorithm used for the automated control system or a series of related performance curves; and
      (f) Provide details for calculating and estimating the SAM emissions rate based on the level of sorbent injection and operating conditions. The test results shall be used to adjust the sorbent injection control system and estimate SAM emissions.

b. If the sorbent injection system is removed or is determined to be unnecessary for a given coal blend, conduct at least three, 1-hour test runs at permitted capacity to determine the SAM emissions rate.

The permittee shall use the data collected to calculate the actual SAM emissions when operating under the given conditions, including the period of time from first fire of the fuel blend until the performance test results are known. [Air Construction Permit No. 1050004-026-AC, Specific Condition 15.]

E.36. Ammonia Slip Tests. Annual compliance with the ammonia (NH_3) slip target shall be determined using EPA conditional test method (CTM-027), EPA method 320, or other methods approved by the Department. If the tested ammonia slip rate exceeds 5 ppmv during the test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;
b. Before the ammonia slip exceeds 7 ppmv, take corrective actions that result in lowering the ammonia slip to less than 5 ppmv; and
c. Test and demonstrate that the ammonia slip is less than 5 ppmv within 30 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is less than 5 ppmv, testing

and reporting shall resume on an annual basis. [Air Construction Permit No. 1050004-026-AC, Specific Condition 18.]

Recordkeeping and Reporting Requirements

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

E.37. Reporting Schedule. The following report shall be submitted to the Compliance Authority:

Report	Reporting Deadline(s)	Related Condition(s)
NSPS Excess Emissions and Monitoring System Performance	Every 6 months (semi-annual), except when more frequent reporting is specifically required	**E.37. & E.39.**
Quarterly Excess Emissions	Every 3 months (quarter)	**E.33., E.34., E.35.**
Monthly CO CEMS		**E.36.**

{Note: If there are no periods of excess emissions as defined in 40 CFR 60 Subpart D, a statement to that effect may be submitted with the SIP Quarterly Excess Report to suffice for the NSPS Report.}
[40 CFR 60 Subpart A; and, Rule 62-210.700(6), F.A.C.]

E.38. Excess Emissions Reports - Malfunctions. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]

E.39. Quarterly Excess Emissions Reports. Submit to the Department a written report of emissions in excess of emission limiting standards for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years. [Rule 62-210.700(6), F.A.C.]

E.40. Excess Emissions Reporting- *SIP Quarterly Report*. Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO emissions in excess of the BACT permit standard following the NSPS format in 40 CFR 60.7(c), Subpart A. In addition, the report shall summarize the CO CEMS system monitor availability for the previous quarter. [Rules 62-4.130, 62-210.700(6) and 62-212.400(BACT), F.A.C.]

E.41. Monthly CO CEMS Report. The permittee shall submit, on a monthly basis, a report in electronic file format which includes Unit 3 CO, NO_X, and heat input data. The report shall be submitted by the 15th of each month by mailing a compact disc to the Department's Bureau of Air Regulation Title V Permitting Section and shall include all hourly readings from the previous month. Alternatively, upon contacting the Bureau's project engineer, the file may be emailed to the appropriate BAR personnel. [Rule 62-4.070(3), F.A.C.; and, PSD-FL-387.]

E.42. Excess Emissions Report. In addition to the requirements of 40 CFR 60.7, each excess emissions report shall include the periods of oil consumption due to flue gas desulfurization system malfunction. [PSD-FL-008]

Miscellaneous Requirements

E.43. NSPS Requirements - Subpart A. These emissions units shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions, including:

40 CFR 60.7, Notification and Recordkeeping
40 CFR 60.8, Performance Tests
40 CFR 60.11, Compliance with Standards and Maintenance Requirements
40 CFR 60.12, Circumvention
40 CFR 60.13, Monitoring Requirements
40 CFR 60.19, General Notification and Reporting requirements,

which have been adopted by reference in Rule 62-204.800(8)(d), F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 60.4, 40 CFR 60.8(b)(2) and (3), 40 CFR 60.11(e)(7) and (8), 40 CFR 60.13(g), (i) and (j)(2), and 40 CFR 60.16. These emissions units shall comply with **Appendix 40 CFR 60 Subpart A** included with this permit. [Rule 62-204.800(8)(d), F.A.C.]

E.44. NSPS Requirements - Subpart D. Except as otherwise provided in this permit, this fossil-fuel fired steam generator shall comply with all applicable provisions of 40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971, adopted by reference in Rule 62-204.800(8)(b)1., F.A.C. This emissions unit shall comply with **Appendix 40 CFR 60 Subpart D** included with this permit. [Rule 62-204.800(8)(b)1., F.A.C.]

E.45. Future Actual Emissions Reporting. The permittee shall maintain and submit to the Department on an annual basis for a period of 5 years from the date the SCR systems are initially operated, information demonstrating in accordance with Rule 62-212.300(1)(e), F.A.C., using the emissions computation and reporting procedures in Rule 62-210.370, F.A.C., that the installation of LNB, OFA and SCR did not result in an emissions increase of PM or SAM that would equal or exceed the respective significant emission rates as defined in Rule 62-210.300, F.A.C. The future emissions shall be compared with the baseline actual emissions for the period 2001-2002 for SAM and 2002-2003 for PM as reported in the annual operating reports (AOR) using EPA Method 5B for PM and Method 8A (controlled condensate) for SAM. [Air Construction Permit No. 1050004-019-AC, Specific Condition 14.]

E.46. New Control Equipment. In accordance with Rule 62-210.300(1)(a), F.A.C., if the sorbent injection system is removed, the permittee shall obtain an air construction permit to install new acid mist mitigation equipment or to reinstall the sorbent injection system if required to maintain SAM emissions below a 7 TPY increase above the baseline emissions, which were estimated at 136 TPY. [Air Construction Permit No. 1050004-026-AC]

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

E.U. ID No.	Brief Description
-028	McIntosh Unit 5 - 370 MW Combined Cycle Stationary Combustion Turbine

McIntosh Unit 5 is a Westinghouse 501G combustion turbine operating in combined cycle with a HRSG and 120 MW steam electric turbine. The turbine is fired with natural gas or a maximum 0.05 percent, by weight, sulfur content No. 2 or superior grade of distillate fuel oil. NO_X emissions are controlled by low NO_X burners, water injection and a selective catalytic reduction (SCR) system. An oxidation catalyst was installed to control carbon monoxide (CO) and volatile organic compound (VOC) emissions in 2003. The stack parameters are: height, 300 feet; diameter, 20 feet; exit temperature, 187 degrees F; actual stack gas flow rate (gas), 1,271,428 acfm; and, actual stack gas flow rate (oil), 1,291,502 acfm.

{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II; NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800(8)(b), F.A.C.; Rule 62-212.400(5), F.A.C., Prevention of Significant Deterioration (PSD); Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination, dated July 10, 1998; and, Rule 62-296.470, F.A.C., Clean Air Interstate Rule (CAIR). Simple cycle combustion turbine operation began in March, 2000. Combined cycle combustion turbine operation began in January, 2002.}

Essential Potential to Emit (PTE) Parameters

F.1. Permitted Capacity. The maximum heat input rates, based on the lower heating value (LHV) of each fuel to Unit 5 at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 2,407 million Btu per hour when firing natural gas, nor 2,236 million Btu per hour when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves approved by the Department, attached in Appendix W501G McIntosh #5, Lakeland FL - Maximum Heat Input as a Function of Compressor Inlet Temperature (1/5/01), for the heat input correction to other temperatures may be utilized to establish heat input rates over a range of temperatures for compliance determination. Monitoring required under 40 CFR 60.334(a) shall satisfy periodic monitoring requirements for heat input. [Rules 62-4.160(2), 62-210.200 (Definitions - Potential to Emit (PTE)); and 62-213.440(1)(b)1.b., F.A.C.; and, PSD-FL-245C.]

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

F.3. Methods of Operation - Fuels. Only pipeline natural gas or a maximum 0.05 percent, by weight, sulfur content No. 2 or superior grade of distillate fuel oil shall be fired in this unit. [Rules 62-212.400, 62-212.410, and 62-213.410, F.A.C.; and, PSD-FL-245.]

F.4. Hours of Operation. This emissions unit may operate continuously, i.e., 8,760 hours/year. [Rule 62-210.200 (Definitions - PTE), F.A.C.; and, PSD-FL-245.]

F.5. Fuel Usage as Heat Input - Fuel Oil. Fuel usage as heat input shall not exceed 599×10^9 Btu (LHV) per year (rolled monthly). [PSD-FL-245.]

Control Technology

F.6. Selective Catalytic Reduction. The permittee shall operate SCR equipment and operate an oxidation catalyst. The oxidation catalyst shall be designed for a minimum 90% destruction efficiency at base load. [PSD Permit Modification dated October 8, 2002, specific condition 17.]

F.7. Water Injection for Oil Firing. A water injection system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions. [PSD-FL-245.]

Emission Limitations and Standards

Unless otherwise specified, the averaging times for Specific Conditions **F.9.-F.13.** are based on the specified averaging time of the applicable test method.

F.8. Summary of Emission Standards & Limits and Performance Criteria. The following table is a summary of the BACT determination and is followed by the applicable specific conditions **F.9.** through **F.13.** Values for NO_X are corrected to 15% O_2. Values for CO are corrected to 15% O_2.

Operational Mode	NO_X (ppm)	CO (ppm)	VOC (ppm)	PM/Visibility (% Opacity)	Technology and Comments
Combined	7.5 - NG (3 hr avg) 15 - FO (3-hr avg)	Oxidation Catalyst (annual test 2 ppm criteria at full load firing natural gas.)	Oxidation Catalyst	10	Conventional SCR with Oxidation Catalyst. Clean fuels, good combustion.

[PSD Permit Modification dated October 8, 2002, specific condition 20.]

F.9. Nitrogen Oxides. NO_X emissions shall not exceed 7.5 ppmvd at 15% O_2 when firing natural gas and 15 ppmvd at 15% O_2 when firing fuel oil on the basis of a 3-hour average, as measured by the CEMS. In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 71.1 pounds per hour (when firing natural gas) and 148 pounds per hour (when firing fuel oil) to be demonstrated by stack tests. [PSD-FL-245.]

F.10. Carbon Monoxide Performance Criteria. The concentration of CO in the exhaust gas shall be additionally controlled by the use of an oxidation catalyst with a minimum of 90% CO removal efficiency (based upon design at base load). The CO emissions shall be tested annually at full load and shall not exceed 2 ppmvd when firing natural gas as measured by EPA Method 10. The oxidation catalyst shall be maintained according to manufacturer's recommendations, however in the event that CO emissions exceed 2 ppmvd (as demonstrated by annual testing above) the permittee shall implement a remedy and re-test within 90 days of operation. Should the re-test result in CO emissions exceeding 2 ppmvd, the remedy shall be to completely replace the oxidation catalyst. [PSD Permit Modification dated October 8, 2002, specific condition 22.]

F.11. Sulfur Dioxide. SO_2 emissions (at ISO conditions) shall not exceed 8 pounds per hour when firing pipeline natural gas and 127 pounds per hour when firing maximum 0.05 percent, by weight, sulfur content No. 2 or superior grade distillate fuel oil, as measured by applicable compliance methods. Emissions of SO_2 shall not exceed 38.4 tons per year. [PSD-FL-245C and Applicant request to Escape PSD Review.]

F.12. Visible Emissions. Visible emissions shall not exceed 10 percent opacity. [PSD-FL-245.]

F.13. Volatile Organic Compounds. VOC emissions shall be additionally controlled through the use of an oxidation catalyst. CO emissions shall be employed as a surrogate for VOC emissions and no further annual testing will be required. [PSD Permit Modification dated October 8, 2002, specific condition 25.]

Excess Emissions

The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS, NESHAP, or Acid Rain program provision.

F.14. Excess Emissions Allowed. Excess emissions from this emissions unit resulting from startup, shutdown, malfunction or fuel switching shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed four hours in any 24 hour period for cold startup or two hours in any 24 hour period for other reasons unless specifically authorized by the Department for longer duration. During any calendar day in which a start-up, shutdown, or fuel change occurs, the following alternative NO_X limit applies:

a. 100 lbs/hr on the basis of a 24-hour average
b. 200 lbs/hr on the basis of a 24-hour average if fuel oil is fired during a start-up or shut-down within the 24-hour period.

[Rule 62-210.700(1), F.A.C.; and, PSD Permit Modification dated October 8, 2002, specific condition 26.]

F.15. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

F.16. Fuel Oil Monitoring Schedule. The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 or superior grade fuel oil received at the C. D. McIntosh, Jr. Power Plant, an analysis which reports the sulfur content and the nitrogen content of the fuel shall be provided by the vendor. The analysis shall also specify the methods by which the analysis was conducted and shall comply with the requirements of 40 CFR 60.335(d). [PSD-FL-245.]

F.17. Natural Gas Monitoring Schedule. The following custom monitoring schedule for natural gas is approved (pending EPA concurrence) in lieu of the daily sampling requirements of 40 CFR 60.334(b)(2):

a. Monitoring of natural gas nitrogen content shall not be required.
b. Analysis of the sulfur content of natural gas shall be conducted using one of the EPA-approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternate method. Monitoring of the sulfur content of the natural gas shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333, then fuel sulfur monitoring shall be conducted once per quarter for six quarters and after that, semiannually.
c. Should any sulfur analysis indicate noncompliance with 40 CFR 60.333, the City shall notify DEP of such excess emissions and the custom fuel monitoring schedule shall be reexamined. The sulfur content of the natural gas will be monitored weekly during the interim period while the monitoring schedule is reexamined.
d. The City shall notify DEP of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than one grain per 100 cubic feet of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.

e. Records of sampling analyses and natural gas supply pertinent to this monitoring schedule shall be retained by the City for a period of five years, and shall be made available for inspection by the appropriate regulatory personnel.
f. The City may obtain the sulfur content of the natural gas from the fuel supplier (Florida Gas Transmission or Gulfstream) provided the approved test methods are used.
[PSD-FL-245.]

{Permitting note: The permittee may satisfy this custom monitoring schedule for natural gas in accordance with **Appendix GG** attached to this permit.}

Continuous Monitoring Requirements

F.18. Continuous Monitoring System. The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from Unit 5. Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards, listed in specific conditions **F.8.** and **F.9.**, shall be reported to the DEP Southwest District office pursuant to Rule 62-4.160(8), F.A.C. Following the format of 40 CFR 60.7, periods of startup, shutdown, malfunction and fuel switching shall be monitored, recorded and reported as excess emissions when emission levels exceed the BACT standards listed in specific conditions **F.8.** and **F.9.** [PSD-FL-245 and 40 CFR 60.7.]

F.19. CEMS in lieu of Water to Fuel Ratio. Subject to EPA approval, the NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1). Subject to EPA approval, calibration of the water/fuel monitoring device required in 40 CFR 60.335(c)(2) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from DEP, the CEMS emissions rates for NO_X on Unit 5 shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332. [PSD-FL-245.]

{Permitting note: The permittee may satisfy this condition for using the NOx CEMS in accordance with Appendix GG attached to this permit.}

F.20. Missing Data Substitution. When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time. [PSD-FL-245.]

F.21. Continuous Monitoring System. The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40 CFR 75. [PSD-FL-245.]

Test Methods and Procedures

F.22. Test Methods. Required tests shall be performed in accordance with the following reference methods:

Method(s)	Description of Method(s) and Comment(s)
ASTM D2880-71 or D4294 (or latest version) for the sulfur content of liquid fuels and D1072-80, D3031-81,	Methods for Evaluating Fuel Sulfur Content

Method(s)	Description of Method(s) and Comment(s)
D4084-82 or D3246-81 (or latest version)	
EPA Method 9	Visual Determination of the Opacity of Emissions
EPA Method 10	Determination of Carbon Monoxide Emissions
EPA Reference Method 18, 25 and/or 25A	Determination of Volatile Organic Concentrations
EPA Method 7E	Determination of Nitrogen Oxide Emissions
EPA Method 20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

The above methods are described in Chapter 62-297, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Chapter 62-297, F.A.C.]

F.23. Annual Compliance Tests. During each federal fiscal year (October 1st to September 30th), this emissions unit shall be tested to demonstrate compliance with the emissions standards for VE, CO and NO_X. The CO and NO_X RATA test data may be used to demonstrate compliance with the annual test requirement, provided the testing requirements (notification, procedures & reporting) of Chapter 62-297, F.A.C. are met. [Rule 62-297.310(7), F.A.C.]

F.24. Compliance Tests Prior To Renewal. Prior to permit renewal, compliance test shall be performed for the following pollutants: VE, CO and NO_X. [Rule 62-297.310(7)(a)3., F.A.C.]

F.25. Common Testing Requirements. Unless otherwise specified, tests shall be conducted in accordance with the requirements and procedures specified in Appendix TR, Facility-Wide Testing Requirements, of this permit. [Rule 62-297.310, F.A.C.]

F.26. Compliance with the Allowable Emission Limiting Standards - Each Fuel. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, for each fuel, at which this unit will be operated, but not later than 180 days after initial operation of the unit for that fuel, and annually thereafter as indicated in this permit, by using the reference methods as described in the latest edition of 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C. [PSD-FL-245.]

F.27. Compliance Testing. Initial (I) performance tests shall be performed on Unit 5 while firing natural gas as well as while firing fuel oil. Initial tests shall also be conducted after any modifications (and shakedown period not to exceed 100 days after restarting the combustion turbine) of air pollution control equipment, including installation of Ultra Low NO_X burners, Hot SCR, or conventional SCR. [PSD-FL-245.]

F.28. Continuous Compliance with the NO_X Emission Limits. Continuous compliance with the NO_X emission limits shall be demonstrated with the CEMS based on the applicable averaging time of 24-hr block average (DLN or ULN technology) or a 3-hr average (if SCR is used). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day (or 3-hr period when applicable) and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day (or 3-hr period when applicable). Valid hourly emission rates shall not included periods of startup (including fuel switching), shutdown, or malfunction as defined in Rule 62-210.200, F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be

reported as required. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. [PSD-FL-245.]

F.29. Compliance with the SO_2 and PM/PM_{10} Emission Limits. Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas and maximum 0.05 percent sulfur (by weight) No. 2 or superior grade distillate fuel oil, is the method for determining compliance for SO_2 and PM/PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard and the 0.05% S limit, fuel oil analysis using ASTM D2880-71 or D4294 (or latest version) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or latest version) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule. The applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e). [PSD-FL-245.]

F.30. Compliance with CO Emissions/Performance Criteria. Annual compliance testing for CO may be conducted concurrent with the annual RATA testing for NO_X required pursuant to 40 CFR 75 (required for gas only). [PSD-FL-245.]

F.31. Compliance with the VOC Emissions/Performance Criteria. The CO emission limit will be employed as a surrogate and no annual testing for VOC emissions is required. [PSD-FL-245.]

Record Keeping and Reporting Requirements

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

F.32. Reporting Schedule. The following report shall be submitted to the Compliance Authority:

Report	Reporting Deadline(s)	Related Condition(s)
NSPS Excess Emissions and Monitoring System Performance	Every 6 months (semi-annual), except when more frequent reporting is specifically required	**F.36.**
Quarterly Excess Emissions, if requested	Every 3 months (quarter)	**F.33.**

[40 CFR 60 Subpart A; and, Rule 62-210.700(6), F.A.C.]

F.33. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department's Southwest District office within one (1) working day of: the nature, extent, and duration of the excess emissions; and, the actions taken to correct the problem. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.; and, PSD-FL-245.]

Miscellaneous Requirements

F.34. Operating Procedures. Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [PSD-FL-245.]

F.35. Compliance Plan. Based on the application for Permit No. 1050004-016-AV, initial compliance has been demonstrated for natural gas firing, but not for distillate fuel oil firing. **Appendix CP, Compliance Plan** for McIntosh Unit 5, is attached as a part of this permit. [Rule 62-213.440(2), F.A.C.]

F.36. NSPS Requirements - Subpart A. These emissions units shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions, including:

40 CFR 60.7, Notification and Recordkeeping
40 CFR 60.8, Performance Tests
40 CFR 60.11, Compliance with Standards and Maintenance Requirements
40 CFR 60.12, Circumvention
40 CFR 60.13, Monitoring Requirements
40 CFR 60.19, General Notification and Reporting requirements,

which have been adopted by reference in Rule 62-204.800(8)(d), F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 60.4, 40 CFR 60.8(b)(2) and (3), 40 CFR 60.11(e)(7) and (8), 40 CFR 60.13(g), (i) and (j)(2), and 40 CFR 60.16. This emissions unit shall comply with **Appendix 40 CFR 60 Subpart A** included with this permit. [Rule 62-204.800(8)(d), F.A.C.]

F.37. NSPS Requirements - Subpart GG. Except as otherwise provided in this permit, the combustion turbine shall comply with all applicable provisions of 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(8)(b), F.A.C., except that the Secretary is not the Administrator for purposes of 40 CFR 60.334(b)(2) and 40 CFR 60.335(f)(1). The Subpart GG requirement to correct test data to ISO conditions applies, but such correction is not required to demonstrate compliance with the non-NSPS permit standard(s). This emissions unit shall comply with **Appendix 40 CFR 60 Subpart GG** attached to this permit. [Rule 62-204.800(8)(b)39., F.A.C.]

ATTACHMENT MC-EU1-IV3

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT MC-EU1-IV3

ALTERNATIVE METHODS OF OPERATION
FOSSIL FUEL STEAM GENERATOR

The fossil fuel steam generator Unit 1 can operate on both natural gas and No. 6 fuel oil (No. 6 through No. 2 fuel oil). The maximum sulfur content in the fuel oil is limited to 2.5 percent. The No. 2 fuel oil is used as pilot fuel during startup, shutdown, and malfunctions. On-spec oil is co-fired with other fuels. This unit can operate for the entire year at varying loads (i.e., 8,760 hours 0 to 100 percent load) and can fire fuels, alone or in combination, with no restrictions on hours of operation.

III. EMISSIONS UNIT INFORMATION

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

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

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

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

EMISSIONS UNIT INFORMATION
Section [2]
McIntosh Unit 2 – Fossil Fuel Fired Steam Generator

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:
   McIntosh Unit 2 – Fossil Fuel Fired Steam Generator

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

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**June 1976**	**49**

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

   ☒ Acid Rain Unit

   ☒ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: **115** MW

11. Emissions Unit Comment:
    Emission unit is a natural gas, No. 6 fuel oil, or No. 2 fuel oil-fired steam generator.

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

1. Control Equipment/Method Description: **NO_x control incorporated in furnace design through use of flue gas recirculation (FGR).**
2. Control Device or Method Code: **026**

Emissions Unit Control Equipment/Method: Control ____ of ____

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

Emissions Unit Control Equipment/Method: Control ____ of ____

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

Emissions Unit Control Equipment/Method: Control ____ of ____

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

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **1,184.5** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	
24 hours/day	**7** days/week
52 weeks/year	**8760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input rates:** **Natural gas firing – 1,184.5 MMBtu/hr (HHV)** **No. 6 fuel oil firing – 1,115 MMBtu/hr (HHV)** **No. 2 fuel oil firing – 1,115 MMBtu/hr (HHV)**	

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: **S002**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Exhausts through a single stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **005**		
5. Discharge Type Code: **V**	6. Stack Height: **157** feet	7. Exit Diameter: **10.5** Feet
8. Exit Temperature: **277°F**	9. Actual Volumetric Flow Rate: **380,200** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: Feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack parameters based on Title V Permit No. 1050004-031-AV.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 3

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Natural-Gas Boilers > 100 MMBtu/hr**		
2. Source Classification Code (SCC): **1-01-006-01**	3. SCC Units: **Million cubic feet natural gas burned**	
4. Maximum Hourly Rate: **1.16**	5. Maximum Annual Rate: **10,162**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,024**
10. Segment Comment: **Maximum hourly rate = 1,184.5 MMBtu/hr / (1,024 MMBtu/MM ft^3) = 1.16 MM ft^3/hr** **Maximum annual rate = 1.16 MM ft^3/hr x 8,760 hr/yr = 10,161.6 MM ft^3/yr** **Propane is used for ignition/startup only (SCC 1-01-010-02).**		

Segment Description and Rate: Segment 2 of 3

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Residual Oil No. 6 – Normal Firing**		
2. Source Classification Code (SCC): **1-01-004-01**	3. SCC Units: **1,000 gallons burned**	
4. Maximum Hourly Rate: **7.43**	5. Maximum Annual Rate: **65,116**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **150**
10. Segment Comment: **Maximum hourly rate = 1,115 MMBtu/hr / (150 MMBtu/1000 gallons) = 7,433.3 gallons/hr** **Maximum annual rate = 7,433.3 gallons/hr x 8,760 hr/yr = 65,116 x 10^3 gallons/yr**		

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

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

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Distillate Oil No. 2 – Normal Firing**		
2. Source Classification Code (SCC): **1-01-005-01**	3. SCC Units: **1,000 Gallons Burned**	
4. Maximum Hourly Rate: **7.96**	5. Maximum Annual Rate: **69,767**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **140**
10. Segment Comment: **Maximum hourly rate = 1,115MMBtu/hr/(140 MMBtu/1000 gallon) = 7,964.3 gallons/hr** **Maximum annual rate = 7,964.3 gallons/hr x 8,760 hr/yr = 69,767.3 x 10^3 gallons/yr**		

Segment Description and Rate: Segment _____ of _____

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

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
PM10			NS
CO			NS
VOC			NS
SO2			EL
NOx	026		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: **118.5** lb/hour **518.8** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.1 lb/MMBtu** Reference: **40 CFR 60.42(a)(1) and Permit No. 1050004-031-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly emissions = 0.1 lb/MMBtu x 1,115.0 MMBtu/hr = 111.5 lb/hr (No. 6 or No. 2 fuel oil firing scenario)

Hourly emissions = 0.1 lb/MMBtu x 1,184.5 MMBtu/hr = 118.45 lb/hr (Natural gas firing scenario)

Annual emissions = 118.45 lb/hr x 8760 hr/yr x 1 TPY/2,000 lbs = 518.8 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions based on maximum heat input of natural gas = 1,184.5 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 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.1 lb/MMBtu**	4. Equivalent Allowable Emissions: **111.5** lb/hour **488.4** tons/year
5. Method of Compliance: **Annual stack test; EPA Methods 5, 5B, 5F or 17, if greater than 400 hr/yr oil firing.**	
6. Allowable Emissions Comment (Description of Operating Method): **Equivalent allowable emissions based on No. 6 or No. 2 fuel oil firing during normal operations. 40 CFR 60.42(a)(1)&(2) and Permit No. 1050004-031-AV. Annual or renewal compliance test not required if firing only gaseous fuel(s).**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.1 lb/MMBtu**	4. Equivalent Allowable Emissions: **118.5** lb/hour **518.8** tons/year
5. Method of Compliance: **None**	
6. Allowable Emissions Comment (Description of Operating Method): **Equivalent allowable emissions based on natural gas firing during normal operations.**	

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **892** lb/hour **3,907** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.8 lb/MMBtu** Reference: **Permit No. 1050004-031-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Hourly emissions = 0.8 lb/MMBtu x 1115 MMBtu/hr = 892 lb/hr (Oil firing scenario)** **Annual emissions = (892 lb/hr x 8760 hr/yr) x 1 Ton/2,000 lbs = 3,907.0 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Hourly emissions based on oil firing.**	

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: **0.8 lb/MMBtu**	4. Equivalent Allowable Emissions: **892** lb/hour **3,907** tons/year
5. Method of Compliance: **CEMS (3-hour rolling average) or fuel sampling**	
6. Allowable Emissions Comment (Description of Operating Method): **Equivalent allowable emissions based on oil firing. Fuel oil analysis and total heat input from all fossil fuels burned including gaseous fuels may be used when CEMS data is not available.** **40 CFR 60.43a(1) and Permit No. 1050004-031-AV.**	

Allowable Emissions Allowable Emissions _____ of _____

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

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: **334.5** lb/hour **1,465.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.3 lb/MMBtu (Oil Firing)** Reference: **40 CFR 60.44(a)(2) and Permit No. 1050004-031-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly emissions = 0.3 lb/MMBtu x 1,115 MMBtu/hr = 334.5 lb/hr (Oil firing scenario)

Hourly emissions = 0.2 lb/MMBtu x 1184.5 MMBtu/hr = 236.9 lb/hr (Natural gas firing scenario)

Annual emissions = (334.5 lb/hr x 8760 hr/yr) x 1 Ton/2,000 lbs = 1,465.1 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Hourly emissions based on oil firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

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

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.3 lb/MMBtu**	4. Equivalent Allowable Emissions: **334.5** lb/hour **1,465.1** tons/year
5. Method of Compliance: **Annual stack test; EPA Method 7, 7A, 7C, 7D, or 7E.**	
6. Allowable Emissions Comment (Description of Operating Method): **Equivalent allowable emissions based on fuel oil firing.** **40 CFR 60.44(a)(1)&(2) and Permit No. 1050004-031-AV.**	

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

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.2 lb/MMBtu**	4. Equivalent Allowable Emissions: **2,36.9** lb/hour **1,037.6** tons/year
5. Method of Compliance: **Annual stack test; EPA Method 7, 7A, 7C, 7D, or 7E.**	
6. Allowable Emissions Comment (Description of Operating Method): **Equivalent allowable emissions based on natural gas firing.** **40 CFR 60.44(a)(1)&(2) and Permit No. 1050004-031-AV.**	

Allowable Emissions Allowable Emissions _____ of _____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **VE test using EPA Method 9**	
5. Visible Emissions Comment: **40 CFR 60.42(a)(1)&(2) and Permit No. 1050004-031-AV. Annual compliance test not required if firing only gaseous fuel(s) or if fuel oil firing < 400 hr/yr.**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment: **Excess emissions for startup, shutdown, or malfunction, see Rule 62-296.700 (1) and (2), F.A.C. Permit No. 1050004-031-AV.**	

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 **5**

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo Electron Corp.** Model Number: **42I-ANMSDAB**	Serial Number: **0534013551**
5. Installation Date: **30 May 2008**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR 75.**	

Continuous Monitoring System: Continuous Monitor **2** of **5**

1. Parameter Code: **EM**	2. Pollutant(s): **SO_2**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo Electron Corp.** Model Number: **43I-ANSAB**	Serial Number: **0534013552**
5. Installation Date: **30 May 2008**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR 75.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor **3** of **5**

1. Parameter Code: **VE**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Ametek Land** Model Number: **4500 MKIII** Serial Number: **172530 04**	
5. Installation Date: **5 Nov 2010**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR 75.**	

Continuous Monitoring System: Continuous Monitor **4** of **5**

1. Parameter Code: **CO_2**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo Electron Corp.** Model Number: **410I-ANPDAB** Serial Number: **053413548**	
5. Installation Date: **30 May 2008**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR 75.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor **5** of **5**

1. Parameter Code: **FLOW**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Teledyne** Model Number: **Ultraflow 150X**	Serial Number: **1500387**
5. Installation Date: **30 May 2008**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 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: **MC-EU2-I1** ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **MC-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: **MC-EU2-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: **MC-EU2-I6**
   Test Date(s)/Pollutant(s) Tested: **June 14-15, 2012; VE, NO_x RATA ,SO_2 RATA**
   ☐ 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

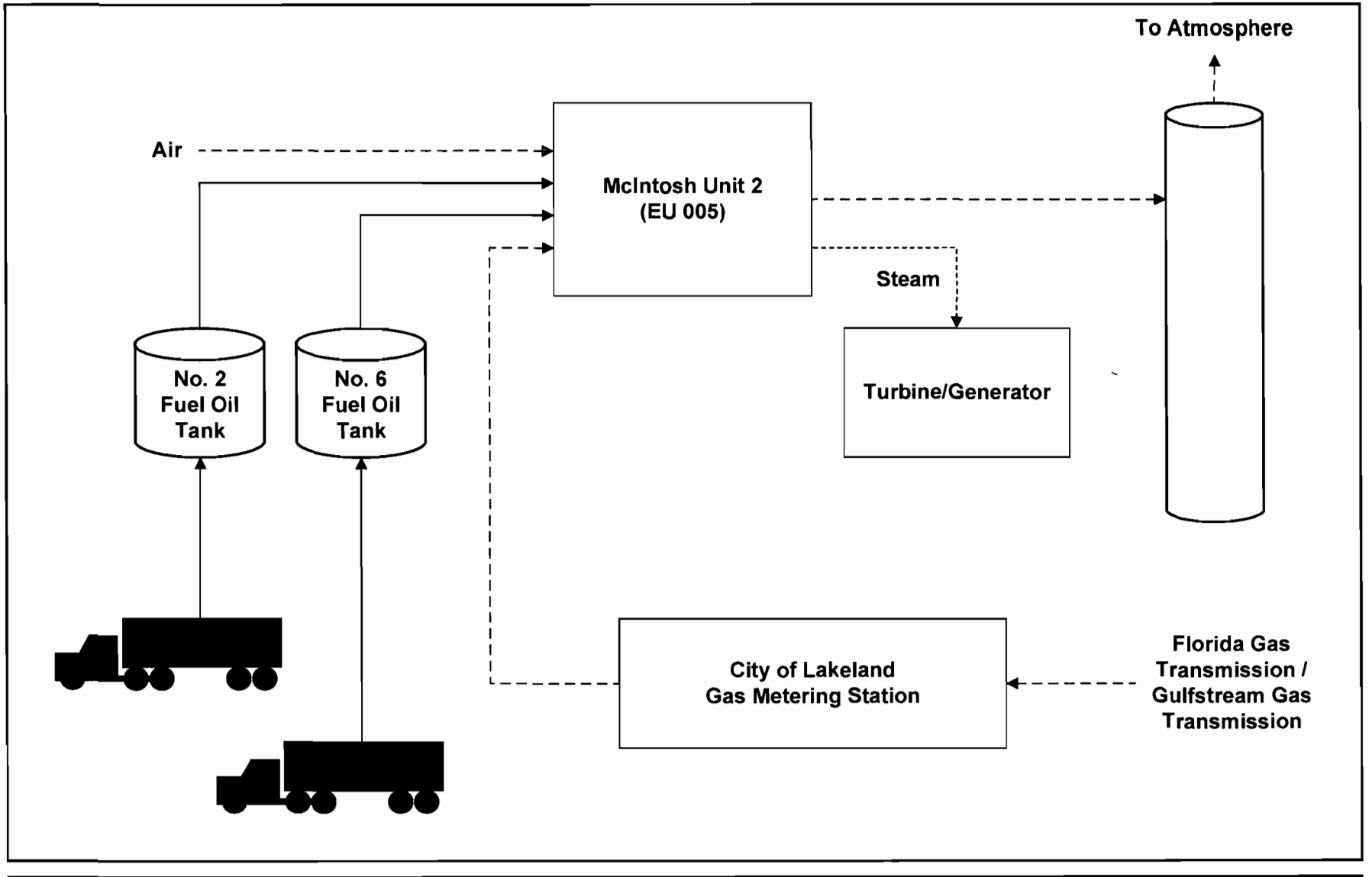
Additional Requirements for Title V Air Operation Permit Applications

1.	Identification of Applicable Requirements: ☒ Attached, Document ID: **MC-EU1-IV1**
2.	Compliance Assurance Monitoring: ☐ Attached, Document ID: _____ ☒ Not Applicable
3.	Alternative Methods of Operation: ☒ Attached, Document ID: **MC-EU2-IV3** ☐ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements Comment

ATTACHMENT MC-EU2-I1

PROCESS FLOW DIAGRAM



Attachment MC-EU2-I1
McIntosh Unit 2
Process Flow Diagram

Process Flow Legend
Solid/Liquid
Gas
Steam

Golder Associates

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ATTACHMENT MC-EU2-I4

PROCEDURES FOR STARTUP AND SHUTDOWN

ATTACHMENT MC-EU2-I4

PROCEDURES FOR STARTUP AND SHUTDOWN MINIMIZING EXCESS EMISSIONS

Startup of the fossil-fuel boilers begins when fuel (propane, natural gas, spec used oil or No. 2 fuel oil) is introduced into one or more burners within the boiler and lighted (commencement of combustion). Startup is complete and steady-state operation begins when the combustion process has stabilized and the megawatt load on the unit is stable and above 10 to 15 percent load.

Shutdown of the fossil-fuel boilers begins when unit megawatt load is decreased to below 10 to 15 percent of maximum and continues until the final burner gun is removed from service.

Emissions may be detected during all modes of boiler operation by various continuous emissions monitors. Continuous monitors are currently in place for NO_x, CO_2, SO_2, flow, and opacity. Audible and visual alarms are activated whenever the permitted value for opacity is approached.

Countermeasures which may be taken in the event of excess emissions include, but are not limited to:

- Burner elevation loading
- Proper excess air adjustments
- Recognizing and removal of faulty burners
- Fuel oil temperature adjustments
- Proper and timely operation of boiler cleaning devices
- Removal of the unit from system-dispatch mode (load control)
- Reduction of unit megawatt load
- Stopping and restarting of boiler cleaning devices
- Lowering load ramp rate
- Pressure rate changes
- Placing boiler controls on manual
- Adjusting burner dampers to increase windbox/furnace air pressure

Knowledge of the appropriate countermeasures to take when excess emissions occur is a part of the routine operator training for those who operate the boilers. Topics include current permit limits, maximum allowable duration of excess emissions, appropriate countermeasures for excess emissions, duty to notify, and fuels and combustion training.

ATTACHMENT MC-EU2-I6

COMPLIANCE DEMONSTRATION REPORTS/RECORDS

CATALYST
AIR MANAGEMENT, INC.

LAKELAND ELECTRIC
C.D. McINTOSH POWER PLANT
UNIT 2

RELATIVE ACCURACY TEST AUDIT REPORT
&
COMPLIANCE EMISSIONS TEST REPORT

CATALYST AIR MANAGEMENT, INC.
REPORT NUMBER 138-171

JULY 23, 2012
Test Date: June 14-15, 2012

Prepared for
Lakeland Electric
C.D. McIntosh Power Plant
3030 East Lake Parker Drive
Lakeland, FL 33805

1.0 Introduction

Catalyst Air Management, Inc. (Catalyst) was contracted by the City of Lakeland to determine the relative accuracy of the Continuous Emissions Monitoring Systems (CEMS) and to perform the annual NOx and visible emissions compliance testing at C.D. McIntosh Unit 2.

The sampling program was conducted June 14-15, 2012. The testing was performed by Messrs. Josh Nicely, Dale Kendrick, Huedon Love and Aiden Reidy of Catalyst, with the assistance of personnel assigned by Lakeland. Ms. Wendi Wilcox coordinated plant operation during the testing.

2.0 Summary of Test Results

A summary of test results developed by this source-sampling program are presented in Tables 1 through 9. The summary tables are presented as follows:

Relative Accuracy Testing

TABLE 1
Relative Accuracy Summary
C.D McIntosh Unit 2

MONITOR: EPA Performance Specification -≤10% semi-annual; ≤ 7.5% annual

LOAD	RELATIVE ACCURACY	BIAS
HIGH	1.79 %	1.012
MID	1.98 %	1.00
LOW	5.65 %	1.00

PARAMETER	RELATIVE ACCURACY	BIAS
SO_2 ppm	1.96 ppm	1.000
NOx lb/mmBtu	5.20 %	1.000
CO_2 %	3.75 %	NA

TABLE 2
Summary of Emissions
C.D McIntosh Unit 2

Parameter	Emission Rate (lb/mmBtu)	Permit (lb/mmBtu)
NOx	0.21	0.247*

*Fuel weighted for combined gas and oil operation

TABLE 3
Summary of Visible Emissions
C.D. McIntosh Unit 2

Source	Average VE (%)	Highest 6 min (%)	Permitted (%)
Unit 2	0	0	20

3.0 Results of Testing

The results from the RATA are tabulated in Appendices 1 and 3. They indicate that the CEMS meet the criteria for annual testing. The NOx and SO_2 systems passed the bias test and a bias adjustment factor of 1.000 was assigned. The mid load flow RATA passed the bias test and a bias adjustment factor of 1.000 was assigned to all three operating loads according to 40 CFR Part 75, Appendix A 7.6.5(c).

The individual test run results for the Compliance testing are shown in Tables 4 and 5, and are tabulated in Appendix 4. The results indicate that Unit 2 is in compliance with the emission limits of Permit No. 1050004-031-AV.

4.0 Description Of Combustion Units

C.D. McIntosh Unit 2 boiler is a fossil fuel fired electric utility steam generator. The boiler provides steam to the turbine/generator with an output of approximately 115 MW. The unit burns natural gas, No. 6 and No. 2 fuel oil or a combination of the fuels. The maximum heat input is 1,115 MMBtu/hr for fuel oil and 1,184.5 MMBtu/hr for natural gas. The flue gas is exhausted into the Unit 2 stack.

The Unit 2 stack elevation is approximately 156 feet. The testing platform is located on the stack approximately 27 feet above the inlet duct. Four test ports facilitate the

ATTACHMENT MC-EU2-IV3

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT MC-EU2-IV3

ALTERNATIVE METHODS OF OPERATION
FOSSIL FUEL STEAM GENERATOR

The fossil fuel steam generator Unit 2 can operate on both natural gas and fuel oil (No. 6 through No. 2 fuel oil). Propane is used as pilot fuel during startup, shutdown, and malfunctions. This unit can operate for the entire year at varying loads (i.e., 8,760 hours 0 to 100 percent load) and can fire fuels, alone or in combination, with no restrictions on hours of operation.

III. EMISSIONS UNIT INFORMATION

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

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

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

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

EMISSIONS UNIT INFORMATION
Section [3]
McIntosh Unit 3 – Fossil Fuel Fired Steam Generator

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:
McIntosh Unit 3 – Fossil Fuel Fired Steam Generator

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

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**Sept, 1982**	**49**

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

   ☒ Acid Rain Unit

   ☒ CAIR Unit

   ☐ Hg Budget Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: **364** MW

11. Emissions Unit Comment:
This emission unit is a coal, residual oil, natural gas, or petroleum coke-fired steam-generating unit.
Permit No. 1050004-032-AC curtails petroleum coke firing effective from the date of EPA's approval of Specific Condition No. B.1 in the Florida Regional Haze State Implementation Plan.

EMISSIONS UNIT INFORMATION
Section [3]
McIntosh Unit 3 – Fossil Fuel Fired Steam Generator

Emissions Unit Control Equipment/Method: Control **1** of **5**

1. Control Equipment/Method Description:
   PM – Electrostatic Precipitator (ESP)

2. Control Device or Method Code: **010**

Emissions Unit Control Equipment/Method: Control **2** of **5**

1. Control Equipment/Method Description:
   SO2 – Flue Gas Desulfurization (FGD) system.

2. Control Device or Method Code: **067**

Emissions Unit Control Equipment/Method: Control **3** of **5**

1. Control Equipment/Method Description:
   NOx – Low NOx burners (LNB), Overfire air (OFA) system

2. Control Device or Method Code: **205, 204**

Emissions Unit Control Equipment/Method: Control **4** of **5**

1. Control Equipment/Method Description:
   Selective Catalytic Reduction
   (installed voluntarily for CAIR purposes)

2. Control Device or Method Code: **139**

Emissions Unit Control Equipment/Method: Control **5** of **5**

1. Control Equipment/Method Description:
   Sorbent Injection for SAM control.
   (As required per Specific Condition E.35, Permit No. 1050004-031-AV.)

2. Control Device or Method Code: **206**

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: **3,640** million Btu/hr	
4. Maximum Incineration Rate:	pounds/hr tons/day
5. Requested Maximum Operating Schedule:	
24 hours/day	**7** days/week
52 weeks/year	**8760** hours/year
6. Operating Capacity/Schedule Comment: **Emission unit fires coal, residual oil, natural gas, and coal/petroleum coke. Heat input based on fuel flow sampling.** **Maximum heat input based on Permit No. 1050004-031-AV.**	

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: **S003**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Exhausts through a single stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **006**		
5. Discharge Type Code: **V**	6. Stack Height: **250** feet	7. Exit Diameter: **18** Feet
8. Exit Temperature: **125**°F	9. Actual Volumetric Flow Rate: **1,260,536** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: Feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack parameters based on Title V permit No. 1050004-031-AV.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 4

1. Segment Description (Process/Fuel Type): **External combustion Boilers; Electric Generation, Coal.**		
2. Source Classification Code (SCC): **1-01-001-01**	3. SCC Units: **Tons**	
4. Maximum Hourly Rate: **165.5**	5. Maximum Annual Rate: **1,449,780**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **1.6 (as received)**	8. Maximum % Ash: **8.5 (as received)**	9. Million Btu per SCC Unit: **22**
10. Segment Comment: **Up to 20 percent petroleum coke is authorized to be co-fired with coal. Maximum hourly rate = 3,640 MMBtu/hr / 22 MMBtu/ton (HHV) = 165.5 tons/hr. Maximum annual rate = 165.5 ton/hr x 8,760 hr/yr = 1,449,780 tons/year**		

Segment Description and Rate: Segment 2 of 4

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Residual Oil.**		
2. Source Classification Code (SCC): **1-01-004-01**	3. SCC Units: **1,000 Gallons Burned**	
4. Maximum Hourly Rate: **24.27**	5. Maximum Annual Rate: **212,579**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.73**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **150**
Maximum hourly rate = 3,640 MMBtu/hr / (150 MMBtu/1000 gallons) = 24,267 gallons/hr Maximum annual rate = 24,267 gal/hr x 8,760 hr/yr = 212,578.9x10^3 gallons/year		

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

Segment Description and Rate: Segment 3 of 4

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Petroleum Coke.**		
2. Source Classification Code (SCC): **1-01-008-01**	3. SCC Units: **Tons**	
4. Maximum Hourly Rate: **33.1**	5. Maximum Annual Rate: **289,956**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **Up to 20 percent petroleum coke is authorized to be co-fired with coal. Maximum hourly rate = 165.5 tons/hr (coal) x 0.2 = 33.1 ton/hr Maximum annual rate = 33.1 ton/hr x 8,760 hr/yr = 289,956 tons/year Please note that Petroleum coke firing would be curtailed effective from the date of EPA's approval of Specific Condition No. B.1 in the Florida Regional Haze State Implementation Plan per Permit No. 1050004-032-AC.**		

Segment Description and Rate: Segment 4 of 4

1. Segment Description (Process/Fuel Type): **External combustion Boilers; Electric Generation, Natural Gas**		
2. Source Classification Code (SCC): **1-01-006-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **3.56**	5. Maximum Annual Rate: **31,139**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,024**
10. Segment Comment: **Natural gas or propane only or in combination with any other fuels or fuel combinations. Maximum hourly rate = 3,640 MMBtu/hr / (1,024 MMBtu/MMft^3) = 3.56 MMft^3/hr**		

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	010		EL
SO2	067		EL
NOx	205, 204		EL
CO			EL
VOC			NS
PM10	067		NS
HCl	067		NS
H107	010		NS
NH3	139		EL*
SAM	206	010	WP

* Not Federally Enforceable

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: **254** lb/hour **1,116** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.070 lb/MMBtu (Oil firing)** Reference: **PSD-FL-008(B) and Permit No. 1050004-031-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly emissions = 0.070 lb/MMBtu x 3,640 MMBtu/hr = 254.8 lb/hr (Oil firing Scenario)

Hourly emissions = 0.044 lb/MMBtu x 3,640 MMBtu/hr = 160.16 lb/hr (Coal & Coal/ Petroleum Coke firing Scenario)

Annual emissions = (254.8 lb/hr x 8760 hr/yr) x 1 Ton/2,000 lbs = 1,116.02 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential hourly emissions based on oil firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

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

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.070 lb/MMBtu**	4. Equivalent Allowable Emissions: **254** lb/hour **1,116** tons/year
5. Method of Compliance: **Annual stack test; EPA Method 5, 5B, or 17, if greater than 400 hours on oil.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on oil firing.** **Permit No. 1050004-031-AV and PSD-FL-008(B)**	

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: **0.044 lb/MMBtu**	4. Equivalent Allowable Emissions: **160.2** lb/hour **702** tons/year
5. Method of Compliance: **Annual stack test; EPA Method 5, 5B, or 17.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on coal firing and coal/petroleum coke firing.** **Permit No. 1050004-031-AV and PSD-FL-008(B)**	

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: **4,368** lb/hour **19,131.8** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **1.2 lb/MMBtu** Reference: **40 CFR 60.43(a)(2) and Permit 1050004-031-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly emissions = 1.2 lb/MMBtu x 3,640 MMBtu/hr = 4,368 lb/hr

Annual emissions = (4,368 lb/hr x 8760 hr/yr) x 1 Ton/2,000 lbs = 19,132 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions based on coal firing.

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: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.2 lb/MMBtu**	4. Equivalent Allowable Emissions: **4,368** lb/hour **19,132** tons/year
5. Method of Compliance: **CEMS (3-hour average)**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on solid fuel firing. Allowable emissions based on 40 CFR 60, Subpart D for solid fuel firing and Permit No. 1050004-031-AV**	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.80 lb/MMBtu**	4. Equivalent Allowable Emissions: **2,912** lb/hour **12,755** tons/year
5. Method of Compliance: **CEMS (3-Hour average)**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on oil firing. Allowable emissions based on 40 CFR 60, Subpart D for oil firing.**	

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: **0.718 lb/MMBtu**	4. Equivalent Allowable Emissions: **2,613.5** lb/hour **11,447** tons/year
5. Method of Compliance: **CEMS (30-day rolling average)**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable when blends of petroleum coke with other fuels are co-fired, based on 30-day rolling average [PSD-FL-008(B) and Permit No. 1050004-031-AV]. Please note that petroleum coke firing would be curtailed effective from the date of EPA's approval of Specific Condition No. B.1 in the Florida Regional Haze State Implementation Plan per Permit No. 1050004-032-AC.**	

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: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **65 percent reduction**	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): **Allowable when firing coal or co-firing blends of petroleum coke with other fuels, based on 30-day rolling average [PSD-FL-008(B) and Permit No. 1050004-031-AV]. (Rule 62-213.440, F.A.C.) Please note that petroleum coke firing would be curtailed effective from the date of EPA's approval of Specific Condition No. B.1 in the Florida Regional Haze State Implementation Plan per Permit No. 1050004-032-AC.**	

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: **2,548** lb/hour **11,160** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.7 lb/MMBtu** Reference: **40 CFR 60.44(a)(3) and Permit No. 1050004-031-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly emissions = 0.7 lb/MMBtu x 3,640 MMBtu/hr = 2,548 lb/hr

Annual emissions = (2,548 lb/hr x 8760 hr/yr) x 1 Ton/2,000 lbs = 11,160 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions based on coal-firing.

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: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.7 lb/MMBtu**	4. Equivalent Allowable Emissions: **2,548** lb/hour **11,160** tons/year
5. Method of Compliance: **CEM (3-hour average)**	
6. Allowable Emissions Comment (Description of Operating Method): From Permit: **Allowable emissions based on solid fossil fuel or solid fossil fuel and wood residue.**	

Allowable Emissions Allowable Emissions **2** of **4**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.30 lb/MMBtu**	4. Equivalent Allowable Emissions: **1,092** lb/hour **4,783** tons/year
5. Method of Compliance: **CEM (3-Hour average)**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.**	

Allowable Emissions Allowable Emissions **3** of **4**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.22 lb/MMBtu**	4. Equivalent Allowable Emissions: **801** lb/hour **3,507.5** tons/year
5. Method of Compliance: **CEM (calendar year average)**	
6. Allowable Emissions Comment (Description of Operating Method): **Includes all periods of operation including startup, shutdown and malfunction. Permit Nos. 1050004-026-AC and 1050004-031-AV.**	

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: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.2 lb/MMBtu**	4. Equivalent Allowable Emissions: **728** lb/hour **3,189** tons/year
5. Method of Compliance: **CEM (3-hour average)**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on gaseous fossil fuel.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **728** lb/hour **3,189** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.20 lb/MMBtu** Reference: **Permit 1050004-018-AC (PSD-FL-387) and 1050004-031-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly emissions = 0.20 lb/MMBtu x 3,640 MMBtu/hr = 728.0 lb/hr

Annual emissions = (728.0 lb/hr x 8760 hr/yr) x 1 Ton/2,000 lbs = 3,188.6 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

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

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.20 lb/MMBtu**	4. Equivalent Allowable Emissions: **728** lb/hour **3,189** tons/year
5. Method of Compliance: **CEMS (30-operating-day rolling average)**	
6. Allowable Emissions Comment (Description of Operating Method): From Permit: **Permit No. 1050004-018-AC (PSD-FL-387) and 1050004-031-AV.**	

Allowable Emissions Allowable Emissions _____ of _____

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

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: lb/hour tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **< 5 ppmv (3- 1 hour Average runs)** Reference: **Permit No. 1050004-026-AC and Permit No. 1050004-031-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions:	
11. Potential, Fugitive, and Actual Emissions Comment: **Ammonia slip limited to less than 5 ppmv based on the average of three, 1-hour test runs.**	

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: **< 5 ppmv**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: **Average of 3, 1-hour tests using EPA conditional test method (CTM - 027), EPA Method 320**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on Condition E.15 in Permit No. 1050004-031-AV. (FDEP requirement, not federally enforceable.)**	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

G. VISIBLE EMISSIONS INFORMATION

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

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

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **VE test using DEP Method 9**	
5. Visible Emissions Comment: **40 CFR 60.42(a)(2) and Permit No. 1050004-031-AV**	

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

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment: **Excess VE emissions allowed under FDEP Rule 62-210.700(1) and 40 CFR 60.8(c), and 60.11(c) for 2 hours per 24-hour period for startup, shutdown, and malfunction.**	

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 6

1. Parameter Code: **EM**	2. Pollutant(s): **SO_2**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo Electron Corp.** Model Number: **43I-ANSAB**	Serial Number: **0608716018**
5. Installation Date: **23 May 2008**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR 75, PSD-FL-008(B), and Title V Permit No. 1050004-031-AV.**	

Continuous Monitoring System: Continuous Monitor 2 of 6

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo Electron Corp.** Model Number: **42I-ANMSDAB**	Serial Number: **0608716016**
5. Installation Date: **23 May 2008**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR 75, PSD-FL-008(B), and Title V Permit No. 1050004-031-AV.**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor **3** of **6**

1. Parameter Code: **VE**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Ametek Land** Model Number: **4500 MKIII**	Serial Number: **166693 01**
5. Installation Date: **23 Apr 2010**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR 75, PSD-FL-008(B), and Title V Permit No. 1050004-031-AV.**	

Continuous Monitoring System: Continuous Monitor **4** of **6**

1. Parameter Code: **CO2**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo Electron Corp.** Model Number: **410I-ANPDAB**	Serial Number: **0608716015**
5. Installation Date: **23 May 2008**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR 75.**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor **5** of **6**

1. Parameter Code: **FLOW**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **United Science, Inc.** Model Number: **ULTRAFLOW 100**	Serial Number: **1001060**
5. Installation Date: **19 Mar 2000**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **FLOW monitor required pursuant to 40 CFR 75.**	

Continuous Monitoring System: Continuous Monitor **6** of **6**

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo Electron Corp.** Model Number: **48I-TLE**	Serial Number: **0712221616**
5. Installation Date: **6 Oct 2007**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Rule 62-4.070(3) and 62-210.200(BACT), F.A.C.; and PSD-FL-387.**	

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: **MC-EU3-I1** ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **MC-EU3-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: **MC-EU3-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: **MC-EU3-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: **MC-EU3-I6**
   Test Date(s)/Pollutant(s) Tested: **5/30/2012, VE, NO_x, PM, SO_2, NH_3**
   ☐ 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

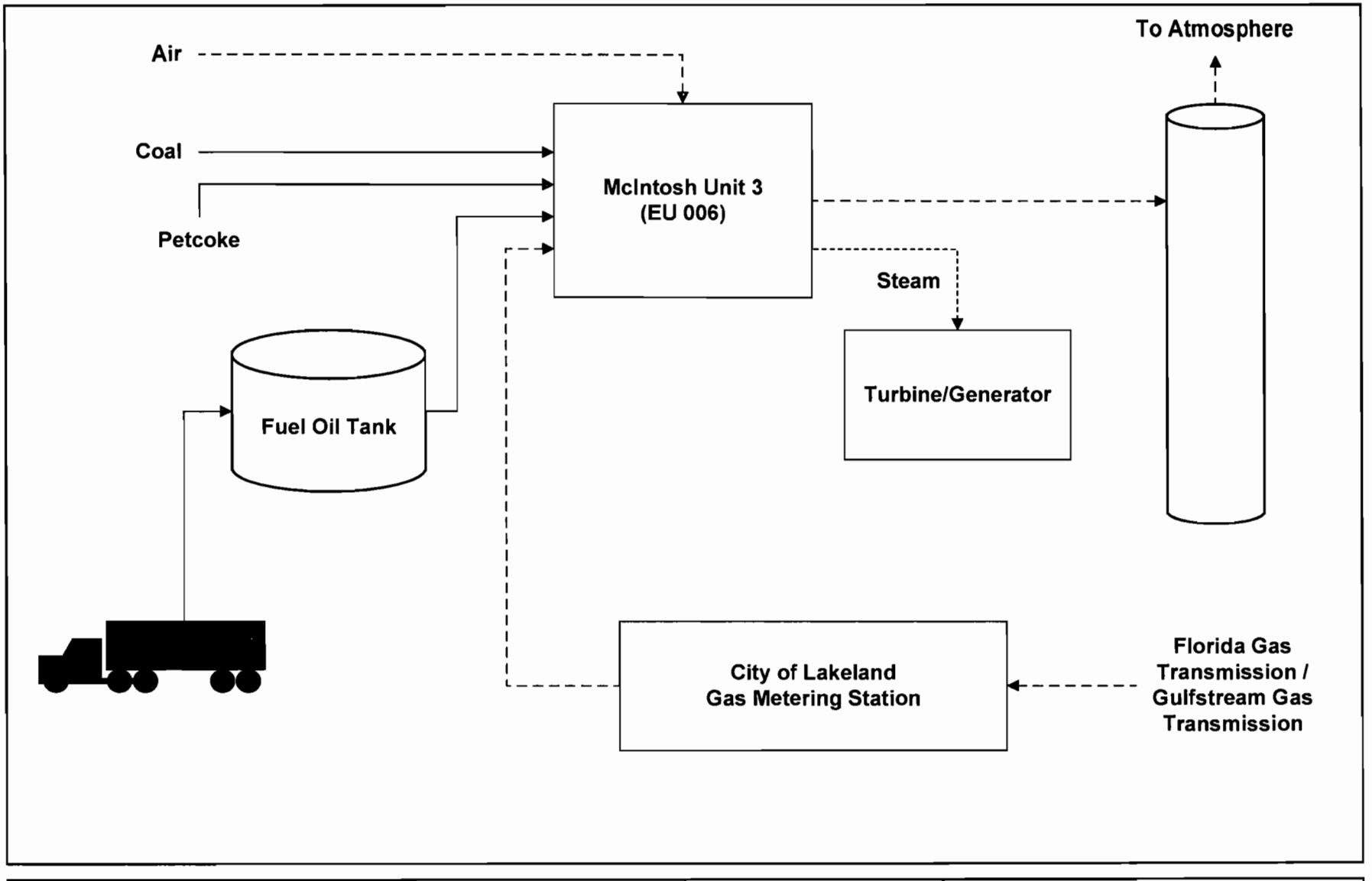
Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements: ☒ Attached, Document ID: **MC-EU1-IV1**
2. Compliance Assurance Monitoring: ☒ Attached, Document ID: **MC-EU3-IV2** ☐ Not Applicable
3. Alternative Methods of Operation: ☒ Attached, Document ID: **MC-EU3-IV3** ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements Comment

ATTACHMENT MC-EU3-I1

PROCESS FLOW DIAGRAM



Attachment MC-EU3-I1
McIntosh Unit 3
Process Flow Diagram

Process Flow Legend
Solid/Liquid
Gas
Steam

Golder Associates

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ATTACHMENT MC-EU3-I2

FUEL ANALYSIS OR SPECIFICATION

MINERAL LABS INC.

Box 549
Salyersville, Kentucky 41465
Phone (606) 349-6145

4728

Certificate of Analysis

COMPANY REQUESTING ANALYSIS:		
Lakeland Electric ATTN: Kelly Parrish 501 East Lemon Street Lakeland, FL 33801	**Date Analyzed:**	1/14/2013
	Lab No.	013002278
	Sampled By/Type:	Customer

ID: PO# 248887: 2120801-01E: C-3 Auto: 12-8-12:

PROXIMATE ANALYSIS	As Received	Dry Basis
% Moisture (3302)	15.83	
% Ash (D3174)	8.52	10.12
% Volatile (D3175)	32.09	38.12
% Fixed Carbon (Calculated)	43.57	51.76
B.T.U (D5865)	10986	13052
M.A.F.B.T.U. (Calculated)	14522	
% Sulfur (D4239)	1.59	1.89
lbs. SO_2/mmBtu	2.90	
lbs. Ash/mmBtu	7.75	

ULTIMATE ANALYSIS (ASTM D5373)	As Received	Dry Basis
Moisture	15.83	
Carbon	61.56	73.14
Hydrogen	4.09	4.86
Nitrogen	1.30	1.55
Sulfur	1.59	1.89
Ash	8.52	10.12
Oxygen (diff.)	7.10	8.44

SULFUR FORMS (ASTM D2492)	As Received	Dry Basis
% Pyritic Sulfur	xxxxx	xxxxx
% Sulfate Sulfur	xxxxx	xxxxx
% Organic Sulfur	xxxxx	xxxxx
% Total Sulfur	xxxxx	xxxxx

MINERAL ANALYSIS (ASTM D4326)		% Wt. Ignited Basis
Silicon dioxide	SiO_2	49.45
Aluminum oxide	Al_2O_3	23.84
Titanium dioxide	TiO_2	1.26
Iron oxide	Fe_2O_3	13.66
Calcium oxide	CaO	1.66
Magnesium oxide	MgO	1.04
Potassium oxide	K_2O	2.45
Sodium oxide	Na_2O	0.82
Sulfur trioxide	SO_3	1.40
Phosphorus pentoxide	P_2O_5	0.27
Strontium oxide	SrO	0.08
Barium oxide	BaO	0.11
Manganese oxide	MnO	0.03
Undetermined		3.94

FUSION TEMPERATURE OF ASH (D1857)	Reducing (°F)	Oxidizing (°F)
Initial Temp.	xxxxx	xxxxx
Softening Temp. H=W	xxxxx	xxxxx
Hemispherical Temp. H=1/2 W	xxxxx	xxxxx
Fluid Temp	xxxxx	xxxxx

T-250 Temp. of Ash	2600

Base/Acid Ratio	0.2632
Fouling Factor	0.2163
Slagging Factor	0.4975

WATER SOLUBLE ALKALIES (Reported in %)	
CaO	xxxxx
K_2O	xxxxx
Na_2O	xxxxx

Arsenic ppm (ASTM D6357)	xxxxx
Chlorine ppm (ASTM D4208)	xxxxx
Mercury ppm (ASTM D6722)	xxxxx
Oxidation (ASTM D5263)	xxxxx
Selenium ppm (ASTM D6357;MOD)	xxxxx
Free Swelling Index (D720)	xxxxx
***Equilibrium Moisture* (ASTM D1412)**	xxxxx
Grindability Index (D409)	xxxxx

Submitted By: *Eric Hamilton*

ATTACHMENT MC-EU3-I3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

ATTACHMENT MC-EU3-I3
DETAILED DESCRIPTION OF CONTROL EQUIPMENT

McIntosh Unit 3 has air pollution control equipment for nitrogen oxides (NO_x), particulate matter (PM), and sulfur dioxide (SO_2). The information that follows presents a description of the equipment controlling these pollutants.

NITROGEN OXIDES

NO_x is controlled by Low NO_x burners (LNB), an overfire air (OFA) system, and selective catalytic reduction (SCR) system with ammonia injection. The boiler and burner was manufactured by Babcock and Wilcox (B&W). A detailed description of the SCR and NH_3 injection system was provided in the PSD application dated December 29, 2006 (PSD-FL-387).

PARTICULATE MATTER

The PM from the combustion of fuels in Unit 3 is controlled by an electrostatic precipitator (ESP). The ESP has the following design parameters:

Plate Height – 47.6 ft.
Number of Casings – 2
Field Depth – 16.4 ft
Number of Lanes per Casing – 50
Number of Fields/Casing – 5
Effective Area/Plate – 1,559.3 ft^2
Total Effective Area – 779,700 ft^2

SULFUR DIOXIDE

SO_2 is controlled using a wet limestone scrubbing system. The scrubber is of a tray tower type consisting of two absorber modules. Each module provides a 55-percent capacity of total unit output. The components of the scrubbing system are listed below.

Quencher – Flue gases exiting the ESP enter the quenchers for each absorber, which condition the flue gas. Each absorber has a venturi-type quencher with a throat of 27 feet long and 5 feet wide. The quench water is recirculated from the quencher sump.

Absorber Tray Tower – After adiabatic saturation in the quencher, the gases pass up through the tray tower absorber for SO_2 removal. The limestone slurry is introduced at the top of the tray absorber from a series of spray headers. The flow is countercurrent through the 36 ft wide (diameter) absorber.

Demister – Before exiting the absorber, aerosols in the flue gas are removed in a z-shaped demister made from reinforced fiberglass material.

Associated Equipment – Supporting the operation of the scrubber are the following equipment: absorber recirculation tank, quencher recirculation tank, and quencher and absorber recirculation pumps. The scrubber is equipped with a hot air reheat system (steam coil) and a bypass flue. The latter bypasses flue gases around the absorber system and mixes with air exiting the absorber tower. This increases the exit gas temperatures. A continuous emission monitoring system is installed to assure compliance with the SO_2 emission limit.

Additional equipment/processes supporting the scrubber system include limestone slurry preparation system, slurry storage and transfer system, and dewatering system.

The scrubber is of a Babcock & Wilcox design.

ATTACHMENT MC-EU3-I4

PROCEDURES FOR STARTUP AND SHUTDOWN

ATTACHMENT MC-EU3-I4

PROCEDURES FOR STARTUP AND SHUTDOWN MINIMIZING EXCESS EMISSIONS

Startup of the fossil-fuel boilers begins when fuel (No. 2 fuel oil, natural gas or propane) is introduced into one or more burners within the boiler and lighted (commencement of combustion). Startup is complete and steady-state operation begins when the combustion process has stabilized and the megawatt load on the unit is stable and above 10-15 percent load.

Shutdown of the fossil-fuel boilers begins when unit megawatt load is decreased to below 10 percent of maximum and continues until the final burner gun is removed from service.

Emissions may be detected during all modes of boiler operation by various continuous emissions monitors. Continuous monitors are currently in place for NO_x, CO_2, SO_2, flow, and opacity. Audible and visual alarms are activated whenever the permitted value for opacity is approached.

Countermeasures which may be taken in the event of excess emissions include, but are not limited to:

- Burner elevation loading
- Proper excess air adjustments
- Recognizing and removal of faulty burners
- Fuel oil temperature adjustments
- Proper and timely operation of boiler cleaning devices
- Removal of the unit from system-dispatch mode (load control)
- Reduction of unit megawatt load
- Stopping and restarting of boiler cleaning devices
- Lowering load ramp rate
- Pressure rate changes
- Placing boiler controls on manual
- Adjusting burner dampers to increase windbox/furnace air pressure

Knowledge of the appropriate countermeasures to take when excess emissions occur is a part of the routine operator training for those who operate the boilers. Topics include current permit limits, maximum allowable duration of excess emissions, appropriate countermeasures for excess emissions, duty to notify, and fuels and combustion training.

ATTACHMENT MC-EU3-I6

COMPLIANCE DEMONSTRATION REPORTS/RECORDS

Air Emissions Test Report

City of Lakeland
Lakeland Electric

C.D. McIntosh, Jr. Power Plant
Unit 3 (EU -006)
Lakeland, Florida

C.E.M. Solutions Project No.: 5365

Testing Completed: May 30, 2012

C.E.M. Solutions, Inc. Report Number: 20-5365-03-001

C.E.M. Solutions, Inc.
1183 E. Overdrive Circle
Hernando, Florida 34442
Phone: 352-489-4337

1.0 Introduction

Lakeland Electric retained C.E.M. Solutions, Inc. to perform emissions testing to determine levels of nitrogen oxides (NO_X), Sulfur Dioxide (SO_2), particulate matter (PM), ammonia slip (NH_3) and visible emission (VE) from Unit 3 boiler exhaust (EU -006) located at the McIntosh Power Plant in Lakeland, Florida.

The test program was used to determine the compliance status of Unit 3 in regards to its emissions limitations and standards outlined in Title V Air Operating Permit 1050004-031-AV. The test program and results are presented and discussed in this report. Target pollutants include the following:

- NO_X (in lb/mmBtu)
- SO_2 (in lb/mmbtu)
- PM (in lb/mmBtu and lb/hr)
- VE (in percent)
- NH_3 (in ppmv)

Laura Jackson of Lakeland Electric coordinated plant operations throughout the test program. All testing was conducted in accordance with test methods promulgated by the Florida Department of Environmental Protection (FDEP).

Unit 3 was found to be in compliance with the permitted emissions limitations as summarized in Table 1.

The test program and results are presented and discussed in this report.

Table 1: Compliance Test Results
Lakeland Electric
McIntosh Power Plant
Unit 3

Pollutant	Reported Emissions Rate	Permitted Emissions Rate	Compliance Test Status (Pass/Fail)
NO_X	0.164 lb/mmbtu	0.70 lb/mmbtu	PASS
SO_2	0.658 lb/mmbtu	1.2 lb/mmbtu	PASS
PM	0.011 lb/mmBtu	0.044 lb/mmBtu	PASS
NH_3	0.02 ppmv	5 ppmv	PASS
VE	0.0 %	≤20 %	PASS

ATTACHMENT MC-EU3-IV2

COMPLIANCE ASSURANCE MONITORING

ATTACHMENT MC-EU3-IV2

COMPLIANCE ASSURANCE MONITORING (CAM)
FOSSIL FUEL STEAM GENERATOR

Lakeland Electric is requesting no change to the following current CAM approach contained in Appendix CAM of Title V Permit No.1050004-031-AV. The electrostatic precipitator (ESP) controlling PM emissions from McIntosh Unit 3 (EU 006) is subject to the CAM requirements contained in 40 CFR 64.

Table 1: Monitoring Approach

		Compliance Indicator
I.	Indicator	Opacity.
	Measurement Approach	Continuous opacity monitoring system (COMS).
II.	Indicator Range	An excursion is defined as any 1-hour average of opacity greater than 12.0%, excluding periods of startup, shutdown and malfunction pursuant to Rule 62-210.700, F.A.C. An excursion will trigger an evaluation of operation of the boiler and ESP. Corrective action will be taken as necessary. Any excursion will trigger recordkeeping and reporting requirements.
III.	Performance Criteria	
	A. Data Representativeness	VE measurements are made in the stack.
	B. Verification of Operational Status	N/A
	C. QA/QC Practices and Criteria	The COMS is automatically calibrated every 24 hours. Calibration information is recorded through a data acquisition system (DAS). A neutral density filter test is performed quarterly, as well as, preventative maintenance items; replace filters, clean optics, etc., as prescribed by the manufacturer.
	D. Monitoring Frequency	Opacity is monitored continuously.
	E. Data Collection Procedures	Six-minute averages are recorded through DAS. Daily reports with all six-minute and hourly averages are generated. One-hour averages are determined every six minutes from the average of the previous ten consecutive six-minute averages.
	F. Averaging Period	The averaging period for opacity observations is a 6-minute block average.

ATTACHMENT MC-EU3-IV3

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT MC-EU3-IV3

ALTERNATIVE METHODS OF OPERATION
FOSSIL FUEL STEAM GENERATOR

The unit can be fired with multiple fuels up to 3,640 MMBtu/hour and operate 8,760 hr/yr. The following fuels and fuel combinations may be burned:

1. Coal only
2. Low sulfur fuel oil only (≤0.5 percent sulfur by weight)
3. Coal and up to 20 percent petroleum coke (based on weight)
4. High sulfur fuel oil (>0.5 percent sulfur by weight)
5. Natural gas only, or in combination with any of the other fuels or fuel combinations listed above.

Note: Petroleum coke firing would be curtailed effective from the date of EPA's approval of Specific Condition No. B.1 in the Florida Regional Haze Implementation Plan Permit No. 1050004-032-AC.

III. EMISSIONS UNIT INFORMATION

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

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

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

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

EMISSIONS UNIT INFORMATION
Section [4]
Diesel Engine Peaking Units 2 and 3

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:
   Diesel Engine Peaking Units 2 and 3

3. Emissions Unit Identification Number: **EU 002 and EU 003**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**January 1970**	**49**

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

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: **5 MW (2.5 MW per unit)**

11. Emissions Unit Comment:
    Each diesel electric generating unit rated at 2.5 MW fired with diesel (No. 2 distillate) fuel only. LE is requesting a change in the status of Diesel Engine Peaking Units 2 and 3 to "Limited Use" according to the definition contained in 40 CFR 63.6675. Please note that these units have been operating as "limited use" engines over the past several years.

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: **28.0** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day weeks/year	 days/week **100** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input per diesel peaking unit.** **According to the definition of "Limited Use" (40 CFR 63.6675), operation of EU 002 and EU 003 will be limited to 100 hr/yr for each.**	

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: **S004, S005**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Each emission unit (diesel) has a separate stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **S004 = Diesel Unit 2** **S005 = Diesel Unit 3**		
5. Discharge Type Code: **V**	6. Stack Height: **20** feet	7. Exit Diameter: **2.6** Feet
8. Exit Temperature: **715°F**	9. Actual Volumetric Flow Rate: **24,529** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: Feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Stack parameters are for each unit and are based on Title V Permit No. 1050004-031-AV.**		

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 (Diesel); Turbine**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **1,000 gallons burned**	
4. Maximum Hourly Rate: **0.203**	5. Maximum Annual Rate: **20.3**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.5**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **138**
10. Segment Comment: **Maximum hourly and annual rates are for each gas turbine. Maximum hourly rate = 28 MMBtu/hr / (138 MMBtu/1,000 gallons) = 202.9 gallons/hr. Maximum annual rate = 202.9 gallons/hr x 100 hr/yr = 20.29×10^3 gallons/yr.**		

Segment Description and Rate: Segment _____ of _____

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

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

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

*Sulfur content limited to 0.5%; not federally enforceable.

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: **14.4** lb/hour **0.72** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor **0.5% sulfur fuel oil** Reference: **Permit No. 1050004-031-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Potential hourly emissions:
202.9 gallons/hr x 7.1 lb/gallon x (0.5/100) x 2 lb SO_2/lb S = 14.4 lb/hr

Potential annual emissions:
14.4 lb/hr x 100 hr/yr x ton/2,000 lb = 0.72 TPY

11. Potential, Fugitive, and Actual Emissions Comment:

Potential emissions are for each unit.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE testing using EPA Method 9 if >400 hr/yr oil operation.**	
5. Visible Emissions Comment: **Rule 62-296.320(4)(b)1. and Permit No. 1050004-031-AV.**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment: **FDEP Rule 62-210.700(1) allows up to 100% for 2 hr (120 minutes) per 24-hour period for startup, shutdown, or malfunction.**	

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: **MC-EU4-I1** ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **MC-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: **MC-EU4-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): **Within 45 days of testing**
   Test Date(s)/Pollutant(s) Tested: **3/25/13, VE**
   ☐ 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

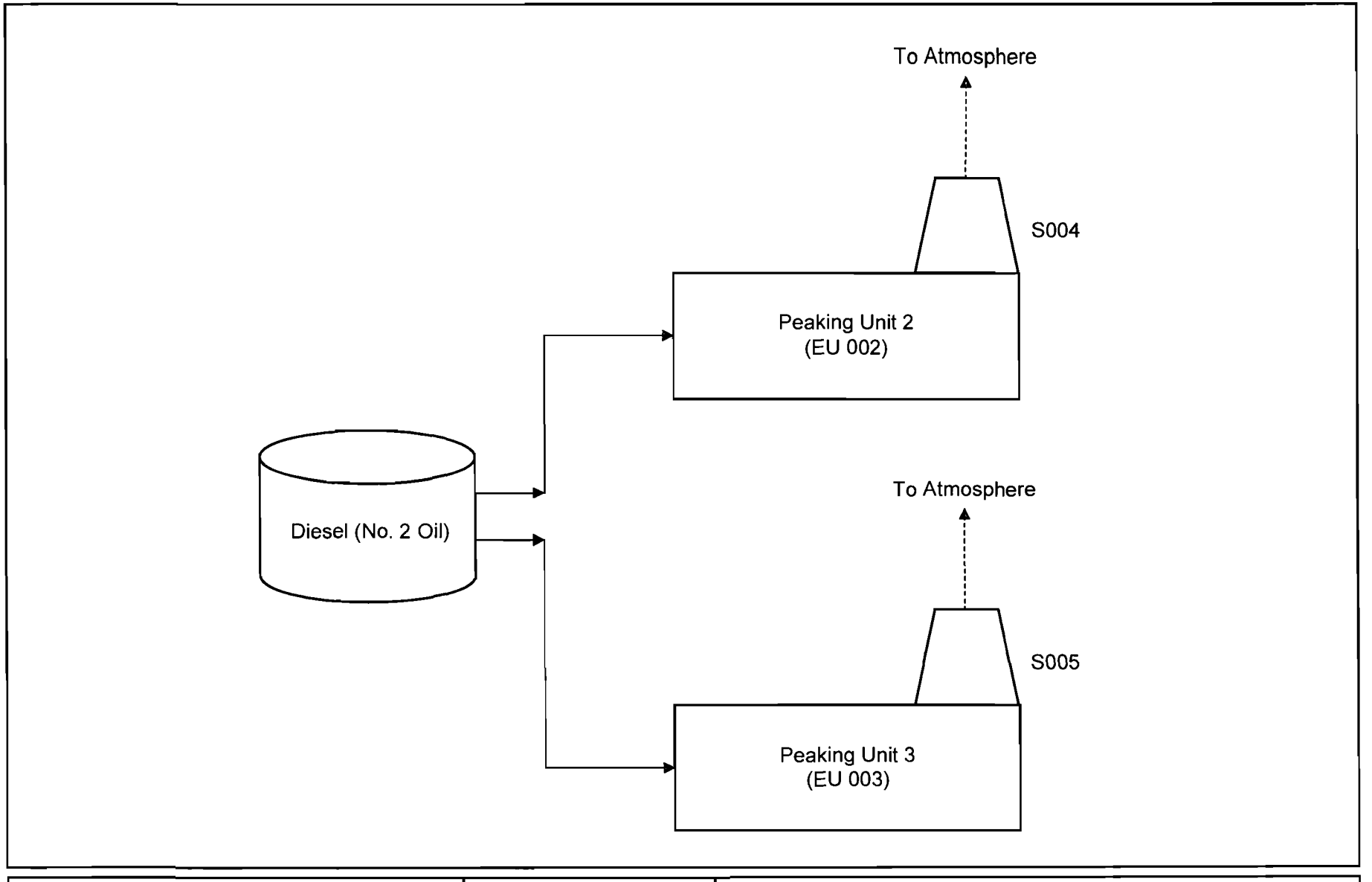
Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements: ☒ Attached, Document ID: **MC-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 MC-EU4-I1

PROCESS FLOW DIAGRAM



Attachment MC-EU4-I1
Process Flow Diagram
City of Lakeland

Process Flow Legend
Solid/Liquid
Gas
Steam

Golder Associates

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ATTACHMENT MC-EU4-I4

PROCEDURES FOR STARTUP AND SHUTDOWN

ATTACHMENT MC-EU4-I4
PROCEDURES FOR STARTUP AND SHUTDOWN

Startup and shutdown for these units are fully automatic. Startup for the diesel units begin at low loads using distillate oil (i.e., diesel).

Corrective actions may include switching the unit from automatic (remote) to local control or changing load conditions. Best Operating Practices based on manufacturer recommendations are adhered to and all efforts to minimize both the level and duration of excess emissions are undertaken.

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

III. EMISSIONS UNIT INFORMATION

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

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

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

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

EMISSIONS UNIT INFORMATION
Section [5]
Gas Turbine Peaking Unit 1

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:
Gas Turbine Peaking Unit 1

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

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**January 1973**	**49**

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

☐ Acid Rain Unit

☐ CAIR Unit

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: **20** MW

11. Emissions Unit Comment:
The gas turbine is fired with natural gas or No. 2 fuel oil.

EMISSIONS UNIT INFORMATION
Section [5]
Gas Turbine Peaking Unit 1

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: **330** 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 **8760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input based on Natural gas firing at 30 F – 330 MMBtu/hr (LHV)** **Maximum heat input based on No. 2 fuel oil firing – 320 MMBtu/hr (LHV)**	

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: **S006**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **35** feet	7. Exit Diameter: **13.5** Feet
8. Exit Temperature: **900**°F	9. Actual Volumetric Flow Rate: **682,334** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: Feet	
13. Emission Point UTM Coordinates... Zone: **17** East (km): **409.2** North (km): **3106.4**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Exit diameter based on equivalent diameter calculated from opening area. Stack dimensions: rectangular 13'2" x 10'11". Volumetric flow for distillate oil: natural gas = 742,174 acfm.** **Stack parameters based on Title V Permit No. 1050004-031-AV.**		

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**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million cubic feet natural gas burned**	
4. Maximum Hourly Rate: **0.34**	5. Maximum Annual Rate: **2,978.4**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950 (LHV)**
10. Segment Comment: **Natural gas firing limited to 320 MM ft^3/hr. (Not federally enforceable based on Condition C.1.b. per Permit No.1050004-031-AV.)**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Internal Combustion Engines; Electric Generation; Distillate Oil (Diesel); Turbine**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **1,000 gallons burned**	
4. Maximum Hourly Rate: **2.31**	5. Maximum Annual Rate: **20,235.6**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **136 (LHV)**
10. Segment Comment: **Distillate oil firing limited to 2,310 gallons/hr. (Not federally enforceable based on Condition C.1.b. per Permit No.1050004-031-AV.)**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

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

*Sulfur content limited to 0.5%; not federally enforceable.

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: **164** lb/hour **718.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.5% sulfur fuel** Reference: **Permit No. 1050004-031-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Potential hourly emissions = 2,310 gallons/hr x 7.1 lb/gallon
x (0.5/100) lb S/lb fuel
x 2 lb SO_2/lb S = 164 lb/hr

Potential annual emissions = 164 lb/hr x 8,760 hr/yr x ton/2000 lb
= 718.4 TPY

11. Potential, Fugitive, and Actual Emissions Comment:
Potential emissions based on No. 2 fuel oil firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

G. VISIBLE EMISSIONS INFORMATION

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

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

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **VE test using EPA Method 9, if > 400 hr/yr oil operation.**	
5. Visible Emissions Comment: **Rule 62-296.320(4)(b)1. F.A.C., and Permit No. 1050004-031-AV.**	

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

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment: **FDEP Rule 62-210.700(1), startup, shutdown or malfunction. Excess emissions allowed for 2 hours (120 minutes) in any 24-hour period.**	

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: **MC-EU5-I1** ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **MC-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: **MC-EU5-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): **Within 45 days of testing**
   Test Date(s)/Pollutant(s) Tested: **03/25/13, VE**
   ☐ 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

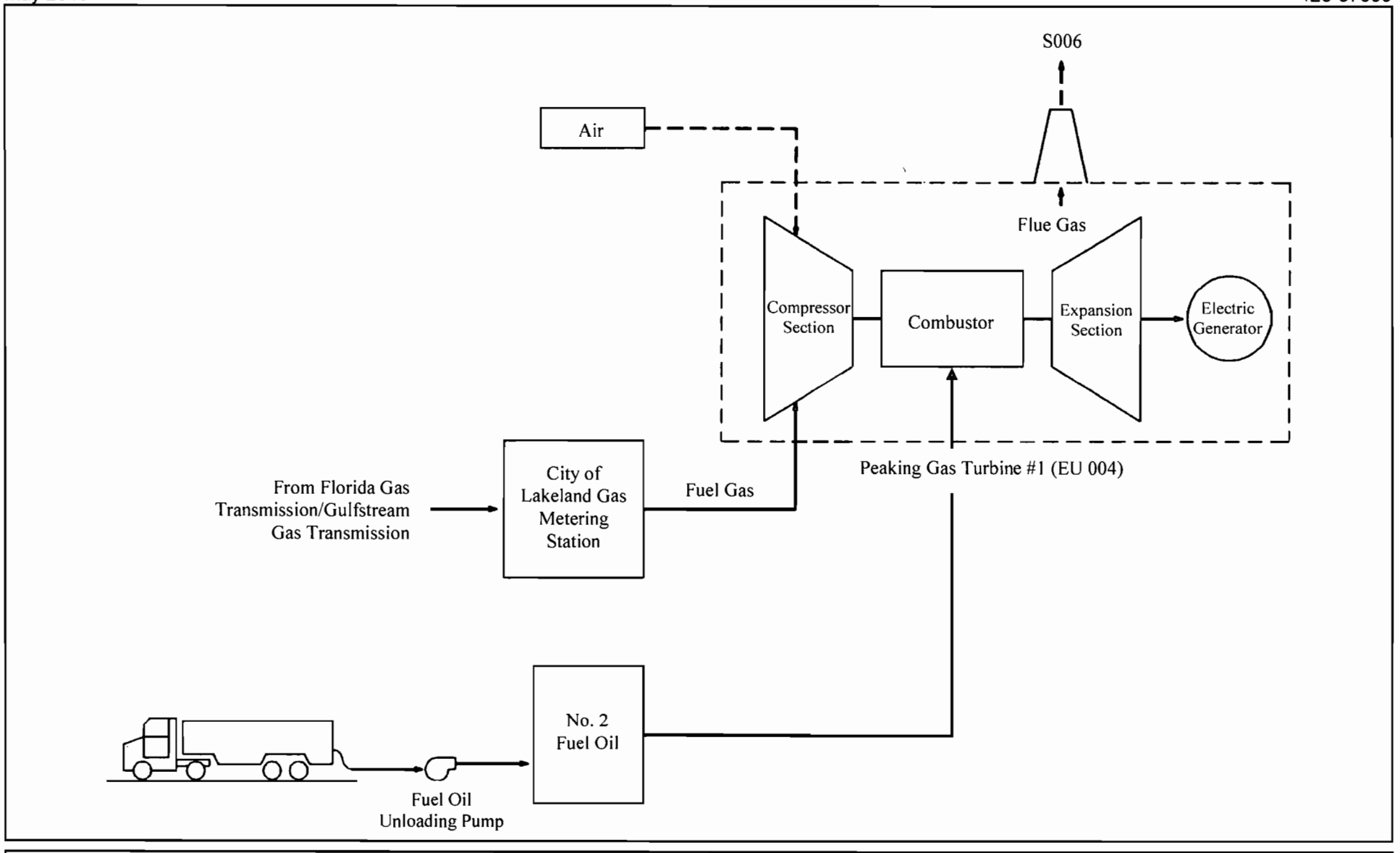
Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements: ☒ Attached, Document ID: **MC-EU1-IV1**
2. Compliance Assurance Monitoring: ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Alternative Methods of Operation: ☒ Attached, Document ID: **MC-EU5-IV3** ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements Comment

ATTACHMENT MC-EU5-I1

PROCESS FLOW DIAGRAM



Attachment MC-EU5-I1
Lakeland Electric & Water Utilities, McIntosh Power Plant
Gas Turbine Peaking Unit 1, Title V Process Flow Diagram

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Source: Golder, 2013.

Golder Associates

ATTACHMENT MC-EU5-I4

PROCEDURES FOR STARTUP AND SHUTDOWN

ATTACHMENT MC-EU5-I4
PROCEDURES FOR STARTUP AND SHUTDOWN

Startup for the gas turbine begins with an electric control system using a switch to initiate the unit startup cycle. The unit generator is synchronized with the grid and can be "on line" (electrical power production) within 5 minutes from startup.

The gas turbine has no emission controls. If excess emissions are encountered during startup or shutdown, the nature and cause of any malfunction is identified, along with the corrective action taken or preventative measures adopted. Corrective actions may include switching the unit from automatic (remote) to local control. Best Operating Practices are adhered to and all efforts to minimize both the level and duration of excess emissions are undertaken.

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 MC-EU5-IV3

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT MC-EU5-IV3

ALTERNATIVE METHODS OF OPERATION
GAS TURBINE PEAKING UNIT 1

The gas turbine can operate on both natural gas and fuel oil (No. 2 fuel). The maximum sulfur content in the fuel oil will not exceed 0.5 percent. This unit can operate from 0 to 100 percent load for the entire year (i.e., 8,760 hours) and can fire either fuel oil or natural gas fire with no restrictions on hours of operation.

III. EMISSIONS UNIT INFORMATION

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

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

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

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

EMISSIONS UNIT INFORMATION
Section [6]
McIntosh Unit 5 – 370 MW Combined Cycle CT

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:
McIntosh Unit 5 – Combined Cycle Stationary Combustion Turbine

3. Emissions Unit Identification Number: **028**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**January 2002**	**49**

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

☒ Acid Rain Unit

☒ CAIR Unit

9. Package Unit:
Manufacturer: **Westinghouse** Model Number: **501G**

10. Generator Nameplate Rating: **370** MW

11. Emissions Unit Comment:
Emission unit is a Westinghouse 501G combustion turbine operating in combined cycle mode with a HRSG and 120 MW steam electric turbine. The Turbine is fired with natural gas or a maximum 0.05 percent sulfur No. 2 fuel oil. The diesel fuel may contain the additive Soltron as recommended by the manufacturer.

EMISSIONS UNIT INFORMATION
Section [6]
McIntosh Unit 5 – 370 MW Combined Cycle CT

Emissions Unit Control Equipment/Method: Control 1 of 4

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

Emissions Unit Control Equipment/Method: Control 2 of 4

1. Control Equipment/Method Description: **Selective Catalytic Reduction (SCR) – Natural gas firing.**
2. Control Device or Method Code: **139**

Emissions Unit Control Equipment/Method: Control 3 of 4

1. Control Equipment/Method Description: **Dry Low NO_x combustion – Natural gas firing.**
2. Control Device or Method Code: **205**

Emissions Unit Control Equipment/Method: Control 4 of 4

1. Control Equipment/Method Description: **Oxidation catalyst.**
2. Control Device or Method Code: **039**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **2,407** million Btu/hr	
4. Maximum Incineration Rate:	pounds/hr tons/day
5. Requested Maximum Operating Schedule:	
24 hours/day	**7** days/week
52 weeks/year	**8760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input rates: Natural gas firing – 2,407 MMBtu/hr (LHV, at baseload)** **No. 2 fuel oil firing – 2,236 MMBtu/hr (LHV, at baseload)** **Heat input rates are based on the lower heating value of the fuels at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure.** **Based on application for Permit No. 1050004-031-AV.**	

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: **S007**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Exhausts through a single stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **300** feet	7. Exit Diameter: **20** Feet
8. Exit Temperature: **187°F**	9. Actual Volumetric Flow Rate: **1,271,428** acfm	10. Water Vapor: **12.44** %
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: **Actual volumetric flow rate for fuel oil firing is 1,291,502 acfm. Stack parameters based on Permit No. 1050004-031-AV.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Natural-Gas Boilers; Turbine**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million cubic feet natural gas burned**	
4. Maximum Hourly Rate: **2.53**	5. Maximum Annual Rate: **22,163**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950 (LHV)**
10. Segment Comment: **Maximum hourly rate = 2,407 MMBtu/hr / 950 MMBtu/MM ft^3 (LHV) = 2.53 MM ft^3/hr Max hourly a function of turbine inlet temperature. See Permit Nos. PSD-FL-245 and 1050004-031-AV.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Distillate Oil (Diesel); Turbine.**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **1,000 gallons burned**	
4. Maximum Hourly Rate: **17.0**	5. Maximum Annual Rate: **4,555**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **131.5 (LHV)**
10. Segment Comment: **Maximum hourly rate = 2,236 MMBtu/hr x 1,000 gallons / 131.5 MMBtu = 17,003 gallons/hr Annual rate limited by Permit No. 1050004-031-AV to 599x10^9 Btu (LHV) per year. 599x10^9 Btu/yr / 131.5x10^6 Btu/Mgal = 4,555 Mgal/yr**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			NS
PM10			NS
CO	039		EL
VOC	039		WP
SO2			EL
NOx	205, 028, 139		EL
SAM			NS

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **139.6** lb/hour **49** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Permit No. 1050004-031-AV, and PSD-FL-245.**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
(8,510 hr gas x 8.8 lb/hr + 250 hr oil x 92.8 lb/hr)/2,000 lb/ton = 49.0 TPY

11. Potential, Fugitive, and Actual Emissions Comment:
Hourly based on oil firing, baseload. Annual based on 8,510 hr/yr gas firing and 250 hr/yr oil firing, 59°F conditions. Based on application for PSD-FL-245 dated 2/21/2001.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 % Opacity**	4. Equivalent Allowable Emissions: **139.6** lb/hour **11.6** tons/year
5. Method of Compliance: **Annual VE test; EPA Method 9.**	
6. Allowable Emissions Comment (Description of Operating Method): **Equivalent allowable emissions based on oil firing during normal operations. PSD-FL-245 and Permit No. 1050004-031-AV. Oil firing; annual based on 250 hr/yr at ISO conditions.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **9.1** lb/hour **38.5** tons/year
5. Method of Compliance: **Annual VE test; EPA Method 9.**	
6. Allowable Emissions Comment (Description of Operating Method): **PSD-FL-245 and Permit No. 1050004-031-AV. Gas firing - 30°F, 100% load; annual based on 59°F; 100% load, 8,760 hr/yr.**	

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: **148** lb/hour **321** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **15 ppmvd @ 15% O_2 (Oil)** **7.5 ppmvd @ 15% O_2 (Gas)** Reference: **Permit No. 1050004-031-AV, and PSD-FL-245.**	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: **Annual Emissions = [(71.1 lb/hr x 8,510 hr/yr) + (148 lb/hr x 250 hr/yr)] / 2,000 lb/ton = 321 TPY**	
11. Potential, Fugitive, and Actual Emissions Comment: **Hourly based on oil firing baseload; Annual based on 8,510 hr/yr gas firing and 250 hr/yr oil firing = 321 tons/yr, PSD-FL-245.**	

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: **15 ppmvd@15% O_2**	4. Equivalent Allowable Emissions: **148** lb/hour **18.5** tons/year
5. Method of Compliance: **Stack tests and CEMS.** **3-Hr Average (if SCR used) or 24-Hr block average (DLN OD ULN technology).**	
6. Allowable Emissions Comment (Description of Operating Method): **Equivalent allowable emissions based on oil firing during normal operations.** **PSD-FL-245 and Permit No. 1050004-031-AV.** **Oil firing baseload; annual based on 250 hr/yr. (18.5 tons/year).** **200 lb/hr 24-hr Block Average, authorized for startup or shutdown if fuel oil is fired.**	

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: **7.5 ppmvd@15% O_2**	4. Equivalent Allowable Emissions: **71.1** lb/hour **311.4** tons/year
5. Method of Compliance: **CEM 3-Hr Average (if SCR used) or 24-Hr block average (DLN OD ULN technology).**	
6. Allowable Emissions Comment (Description of Operating Method): **Equivalent allowable emissions based on natural gas firing during normal operations.** **Annual based on 8,760 hr/yr. 100 lb/hr, 24-hr block average, authorized for startup,** **Shutdown when firing natural gas.** **PSD-FL-245 and Permit No. 1050004-031-AV.**	

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **38.6** lb/hour **41** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2 ppmvd** Reference: **Permit No. 1050004-031-AV**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions:	
11. Potential, Fugitive, and Actual Emissions Comment: **Hourly based on oil firing; annual based on 8,510 hr/yr gas firing and 250 hr/yr oil firing. Potential emissions based on Title V revision application submitted 11/27/2002.**	

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: **Oxidation Catalyst (8/1/03)**	4. Equivalent Allowable Emissions: **38.6** lb/hour **4.8** tons/year
5. Method of Compliance: **None**	
6. Allowable Emissions Comment (Description of Operating Method): **Equivalent allowable emissions based on Title V revision application submitted 11/27/2002.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2 ppmvd at full load**	4. Equivalent Allowable Emissions: **8.5** lb/hour **37.2** tons/year
5. Method of Compliance: **Annual test using EPA Method 10 for 2 ppmvd criteria at full loading.**	
6. Allowable Emissions Comment (Description of Operating Method): **Equivalent allowable emissions based on Title V revision application submitted 11/27/2002.**	

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: **127** lb/hour **38.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **127 lb/hr** Reference: **Permit No. 1050004-031-AV and PSD-FL-245.**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions:	
11. Potential, Fugitive, and Actual Emissions Comment: **Hourly emissions based on fuel oil firing, at a maximum of 0.05 percent sulfur. Annual emissions limited to 38.4 TPY (PSD-FL-245C and Permit No. 1050004-031-AV).**	

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: **127 lb/hr**	4. Equivalent Allowable Emissions: **127** lb/hour **15.9** tons/year
5. Method of Compliance: **Fuel Sampling**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable Emissions based on firing maximum 0.05 percent S No. 2 fuel oil only. PSD-FL-245.** **Based on Permit No. 1050004-031-AV**	

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: **8 lb/hr**	4. Equivalent Allowable Emissions: **8** lb/hour **35.0** tons/year
5. Method of Compliance: **Fuel Sampling**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable Emissions based on natural gas firing only. PSD-FL-245** **Based on Permit No. 1050004-031-AV**	

Allowable Emissions Allowable Emissions **3** of **3**

1. Basis for Allowable Emissions Code: **ESCPSD**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **38.4 TPY**	4. Equivalent Allowable Emissions: lb/hour **38.4** tons/year
5. Method of Compliance: **Fuel Sampling**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 1050004-031-AV and PSD-FL-245C.**	

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: **NA** lb/hour **NA** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Permit No. 1050004-031-AV and PSD-FL-245.**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions:	
11. Potential, Fugitive, and Actual Emissions Comment: **VOC emissions controlled by the use of an oxidation catalyst system.**	

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: **Oxidation Catalyst (8/1/03)**	4. Equivalent Allowable Emissions: **NA** lb/hour **NA** tons/year
5. Method of Compliance: **Meeting CO emission limit.**	
6. Allowable Emissions Comment (Description of Operating Method): **PSD-FL-245. Gas and oil firing. Oxidation Catalyst, CO emissions shall be employed as a surrogate for VOC emissions and no further annual testing will be required.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment: **FDEP Rule 62-210.700(1), which allows 2 hr (120 minutes) per 24 hr for startup, shutdown and malfunction.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor **1** of **2**

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo Electron Corp.** Model Number: **42I** Serial Number: **1030645076**	
5. Installation Date: **17 Dec 2010**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR 75.**	

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

1. Parameter Code: **O_2**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo Electron Corp.** Model Number: **42I** Serial Number: **1030645076**	
5. Installation Date: **17 Dec 2010**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitor is an O2 analyzer for NOx emissions determination.**	

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: **MC-EU6-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: **MC-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: **MC-EU6-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: **MC-EU6-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: **MC-EU6-I6**
   Test Date(s)/Pollutant(s) Tested: **1/18/2012, VE, NO_x, CO**
   ☐ 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

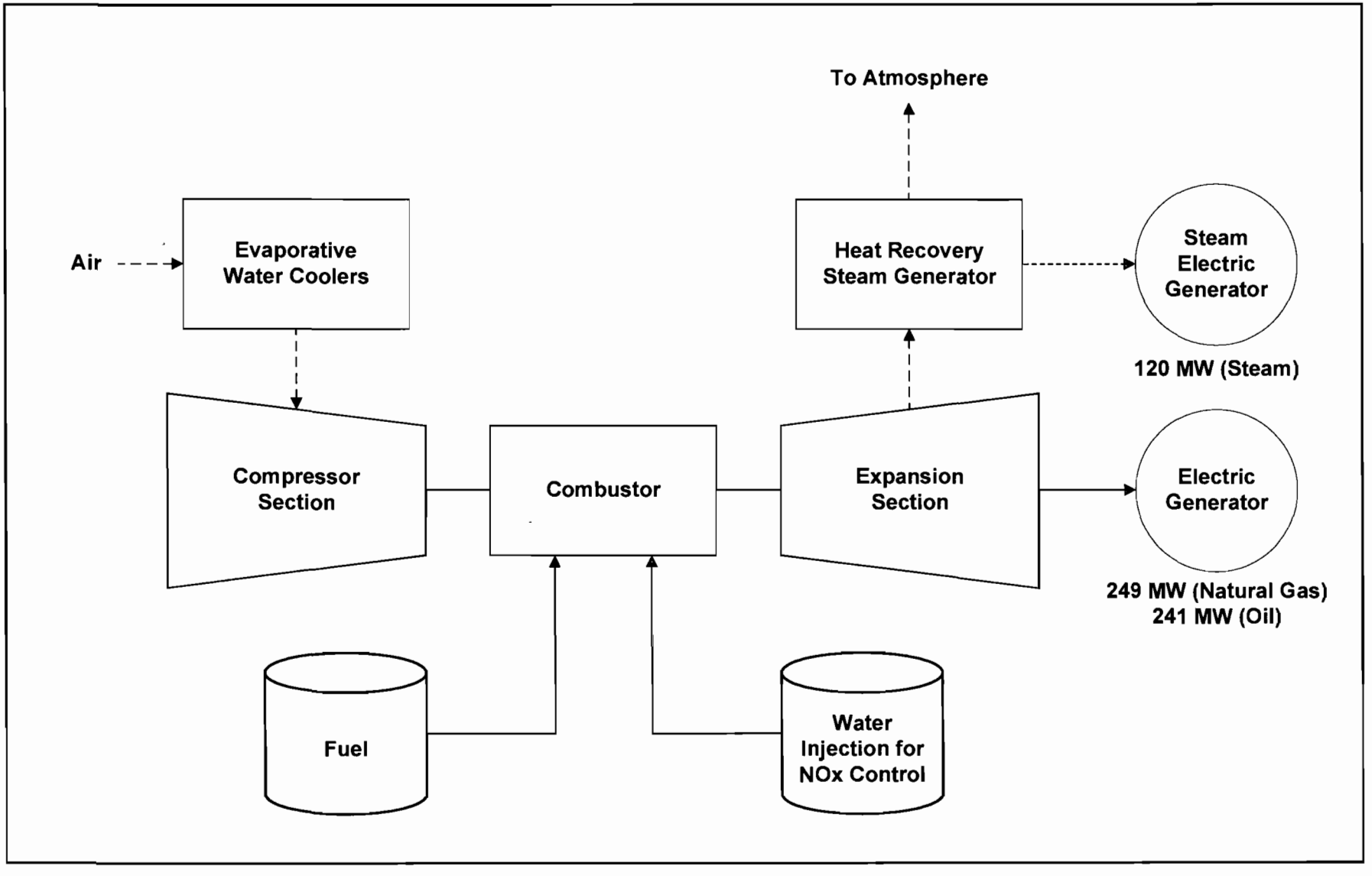
Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements: ☒ Attached, Document ID: **MC-EU1-IV1**
2. Compliance Assurance Monitoring: ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Alternative Methods of Operation: ☒ Attached, Document ID: **MC-EU6-IV3** ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements Comment

ATTACHMENT MC-EU6-I1

PROCESS FLOW DIAGRAM



Attachment MC-EU6-I1
McIntosh Unit 5
Process Flow Diagram

Process Flow Legend
Solid/Liquid
Gas
Steam

Golder Associates

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ATTACHMENT MC-EU6-I3

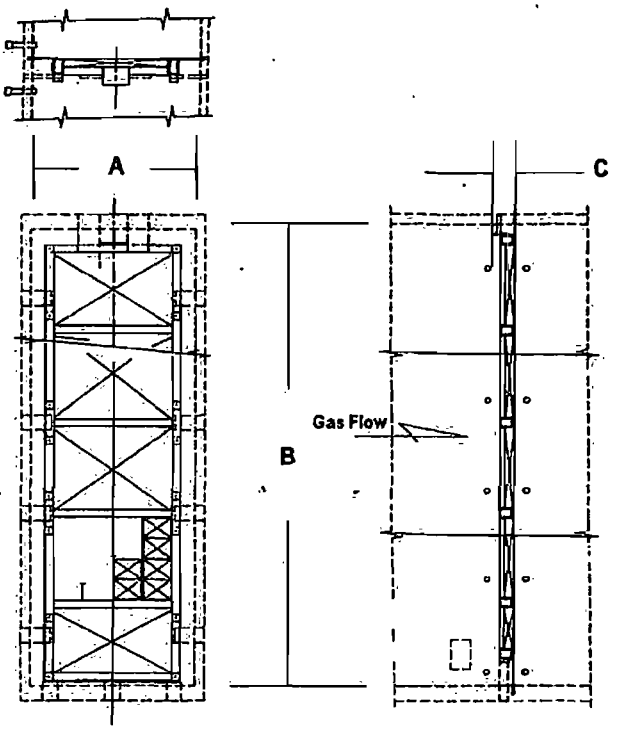
DETAILED DESCRIPTION OF CONTROL EQUIPMENT

CO SYSTEM DESIGN BASIS:

Gas Flow from:	Combustion Turbine – Combined Cycle
Gas Flow:	Horizontal
Fuel:	Natural Gas and Oil
Gas Flow Rate (At catalyst face):	Designed for gas velocities within ±15% of the mean velocity at the catalyst face
Temperature (At catalyst face):	Designed for gas temperatures within range ±25°F of given average temperatures at all points at the catalyst face
CO Concentration (At catalyst face):	226 lb/hr (NG) // 320 lb/hr (Oil)
CO Reduction:	Design 1 - 90% CO Reduction-Full Load Design 2 – 95% CO Reduction-Full Load Design 3 – 98% CO Reduction-Full Load
VOC Concentration (At catalyst face):	Not Given
VOC Reduction:	Advise – all designs
VOC Composition:	Non-Methane / Non-Ethane – 50% Saturated
HRSG Dimensions:	62.5 ft H x 37 ft W (Gas Path – 58.5 H)

CATALYST MODULES

The CO Catalyst is manufactured with a special stainless steel foil substrate which is corrugated and coated with an alumina washcoat. The washcoat is impregnated with platinum group metals. The catalyzed foil is folded and encased in welded steel frames, approximately 2 ft. square, to form individual modules. Nine (9) of the modules are provided with four removable and replaceable test buttons which provide ability to monitor catalyst life – 36 total test buttons provided.



INTERNAL SUPPORT FRAME & SEALS

The internal support frame and internal gas seals are fabricated from standard structural Carbon Steel members and shapes. Mechanical gas and groove expansion seals around the perimeter of the frame and inside the liner sheet prevent bypass around the catalyst. Design accommodates movement of the frame due to thermal expansion while maintaining a continuous seal. The internal frame system interfaces with two types of customer provided connections; ductplate mounted slide plates and liner sheet grooves, both designed by Engelhard.

Dimensions:

Inside Liner Width	**(A) 37 ft**
Inside Liner Height	**(B) 62.5 ft**
Gas Path Height	**58.5 ft**
Catalyst + frame depth	**(C) 18" Max.**

Estimated Weights:
Frame and Seals + Catalyst Modules –

Design 1	Design 2	Design 3
57,000 lb	62,000 lb	70,000 lb

The materials are supplied by Engelhard and installed by others in accordance with the Engelhard design and installation instructions. The frame and seal installation must be inspected by Engelhard prior to initial turbine firing. The CO Catalyst modules should be installed after initial turbine firing.

QUALITY ASSURANCE and SAFETY

Engelhard's manufacturing is carried out under strict adherence to published quality control and statistical process control programs. and strict adherence to Corporate safety practices and procedures.

ATTACHMENT MC-EU6-I4

PROCEDURES FOR STARTUP AND SHUTDOWN

ATTACHMENT MC-EU6-I4
PROCEDURES FOR STARTUP AND SHUTDOWN

Startup for the gas turbine begins with an electric control system using a switch to initiate the unit startup cycle. The unit generator is synchronized with the grid and can be "on line" (electrical power production) within 5 minutes from startup.

The gas turbine utilizes water injection for controlling NOx emissions from Oil firing. Initiation of water injection occurs when the turbine reaches stabilized load. The amount of water is a function of load based on preset algorithms in the CT digital control system. If excess emissions are encountered during startup or shutdown, the nature and cause of any malfunction is identified, along with the corrective action taken or preventative measures adopted. Corrective actions may include switching the unit from automatic (remote) to local control. Best operating practices are adhered to and all efforts to minimize both the level and duration of excess emissions are undertaken.

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 MC-EU6-I6

COMPLIANCE DEMONSTRATION REPORTS/RECORDS

CATALYST
AIR MANAGEMENT, INC.

LAKELAND ELECTRIC
C.D. McINTOSH POWER PLANT
UNIT 5

NOx, CO and VISIBLE EMISSIONS TEST REPORT

CATALYST AIR MANAGEMENT, INC.
REPORT NUMBER 138-167

FEBRUARY 17, 2012
Test Date: January 18, 2012

Prepared for
Lakeland Electric
C.D. McIntosh Power Plant
3030 East Lake Parker Drive
Lakeland, FL 33805

1.0 Introduction

Catalyst Air Management, Inc. (Catalyst) was contracted by Lakeland Electric to perform the annual CO and NOx compliance testing at C.D. McIntosh, Unit 5.

The sampling program was conducted January 18, 2012. The testing was performed by Messrs. Josh Nicely and Dale Kendrick and Aiden Reidy of Catalyst with the assistance of personnel assigned by Lakeland Electric. Ms. Wendi Wilcox of Lakeland Electric coordinated plant operation during the testing.

2.0 Summary of Test Results

A summary of test results developed by this source sampling program is presented in Tables 1 and 2. The summary tables are presented as follows:

3.0 Results of Testing

The results from the compliance test are tabulated in Appendix 1. They demonstrate that the facility is in compliance with Title V Permit Number 1050004-023-AV.

TABLE 1
Emissions Summary
C.D. McIntosh Unit 5

Parameter	Results	Permitted
NOx	6.4 ppm @ 15% O_2	7.5 ppm@ 15% O_2
CO	0.2 ppm @ 15% O_2	2.0 ppm@ 15% O_2
VE	5%	10%

4.0 Description of Combustion Units

McIntosh Unit 5 is a Westinghouse 501G combustion turbine (CT) with a heat recovery steam generator (HRSG). The CT can be fired with natural gas and No.2 distillate fuel oil. NOx emissions are controlled by low NOx combustion and selective catalytic reduction (SCR). CO emissions are controlled by an oxidation catalyst.

ATTACHMENT MC-EU6-IV3

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT MC-EU6-IV3

ALTERNATIVE METHODS OF OPERATION
COMBINED CYCLE STATIONARY COMBUSTION TURBINE

The gas turbine (Unit 5) can operate on both natural gas and No. 2 fuel oil. The maximum sulfur content in the fuel oil shall not exceed 0.05 percent. This unit can operate for the entire year (i.e., 8,760 hours) with natural gas or using up to 599×10^9 Btu (LHV) of heat input per year of for oil firing. The unit may operate at various loads.

During base load operation and at an inlet temperature of 59°F, maximum heat input is limited to 2,407 MMBtu/hr (LHV) and 2,236 MMBtu/hr (LHV) for natural gas and No. 2 fuel oil, respectively.

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