Module AB 109

21 West Church Street
Jacksonville, Florida 32202-3139

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DIVISION OF AIR RESOURCE MANAGEMENT

August 9, 2012

JEA

ELECTRIC

WATER

SEWER

Mr. Jeffery Koerner, P.E., Program Administrator
Division of Air Resource Management
Florida Department of Environmental Protection
2600 Blair Stone Road, Mail Station 5505
Tallahassee, FL 32399

RE: St. Johns River Power Park (SJRPP) / Northside Generating Station (NGS)
Facility Identification Number: 0310045
Minor Source Air Construction Application

Attn: Jonathan Holtom, P.E. Administrator Power Plants

Dear Mr. Holtom: Project No: 0310045-037-AC

As previously discussed, JEA is seeking authorization from the Florida Department of Environmental Protection (FDEP) for a minor source air construction permit for the following:

1. Use up to a maximum of 240 tons per day (TPD) of biomass (i.e., wood chips from tree trimmings and similar plant materials) in each of NGS Units 1 & 2. These units are currently authorized to utilize 33 TPD of biomass.
2. Remove the voluntary requirements for the continuous emission monitoring systems (CEMS) installed to measure mercury emissions from NGS Units 1 and 2.
3. Clarify that SJRPP Units 1 and 2 flue gas desulfurization (FGD) systems may use one scrubber tower while operating at low loads.

If there are any further questions concerning this request please contact me at (904) 665-8729 or our environmental consultant Mr. Kennard Kosky, Golder Associates, at (352) 336-5600. The Department's expeditious review of this request is appreciated.

Sincerely,

Jay Worley
Director, Environmental Programs

Enclosures

cc: Ms. Cindy Mulkey, Siting Coordination Office

Module AB109

Permit Application

APPLICATION FOR AIR CONSTRUCTION PERMIT

JEA Northside Generating Station and St. Johns River Power Park

Project No; 0310045-037-AC

Prepared For: JEA
21 West Church Street
Jacksonville, FL 32202

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

Distribution: 4 copies – FDEP
2 copies – JEA
1 copy – Golder Associates Inc.

August 2012

123-87587

Golder Associates

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APPLICATION FOR AIR PERMIT

LONG FORM

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

RECEIVED
AUG 14 2012
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: **JEA**	
2. Site Name: **Northside Generating Station (NGS) & St. Johns River Power Park (SJRPP)**	
3. Facility Identification Number: **0310045**	
4. Facility Location... Street Address or Other Locator: **4377 Heckscher Drive** City: **Jacksonville** County: **Duval** Zip Code: **32226**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Facility Contact Name: **Jay A. Worley, Director of Environmental Programs**	
2. Facility Contact Mailing Address... Organization/Firm: **JEA** Street Address: **21 West Church Street** City: **Jacksonville** State: **FL** Zip Code: **32202**	
3. Facility Contact Telephone Numbers: Telephone: **(904) 665-8729** ext. Fax: **(904) 665-7376**	
4. Facility Contact E-mail Address: **worlja@jea.com**	

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 8-14-12	3. PSD Number (if applicable):
2. Project Number(s): 0310045-037-AC	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☒ Air construction permit.

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

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

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

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

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

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

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

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

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

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

Application Comment

Application for an air construction permit to:

1) **Allow firing of up to 240 tons per day (TPD) of biomass (wood chips from tree trimmings and similar plant materials) for each of NGS Boiler Nos. 1 and 2 (EU IDs 027 and 026).**
2) **Remove the voluntary conditions regarding the mercury Continuous Emission Monitoring System (CEMS) requirements for NGS Boiler Nos. 1 and 2.**
3) **Clarify that Units 1 and 2 are authorized for one scrubber tower operation for SJRPP Units 1 and 2 at low loads.**

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
027	NGS Boiler No. 1	AC1B	N/A
026	NGS Boiler No. 2	AC1B	N/A
016	SJRPP Boiler No. 1	AC1B	N/A
017	SJRPP Boiler No. 2	AC1B	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 : **Michael J. Brost, V.P., Electric System**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **JEA** Street Address: **21 West Church Street** City: **Jacksonville** State: **FL** Zip Code: **33202**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(904) 665-6537** ext. Fax: **(904) 665-7376**
4.	Owner/Authorized Representative E-mail Address: **brosmj@jea.com**
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] 8-9-12 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:
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: Street Address: City: State: Zip Code:
4. Application Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
5. Application Responsible Official E-mail Address:
6. Application Responsible Official Certification: I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application. ________________ ____________ Signature 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: **Ken_Kosky@golder.com**	

5. Professional Engineer Statement:

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

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

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

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

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

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

Kennard F. Kosky 8/10/12

Signature Date

(seal)

LICENSE No. 14996 STATE OF FLORIDA

* 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) **446.90** North (km) **3359.15**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **30/21/52** Longitude (DD/MM/SS) **81/37/25**	
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 facility includes NGS, SJRPP, and the Separations Technology, LLC facility.**			

Facility Contact

1. Facility Contact Name: **Jay A. Worley, Director of Environmental Programs**
2. Facility Contact Mailing Address... Organization/Firm: **JEA** Street Address: **21 West Church Street** City: **Jacksonville** State: **FL** Zip Code: **32202**
3. Facility Contact Telephone Numbers: Telephone: **(904) 665-8729** ext. Fax: **(904) 665-7376**
4. Facility Contact E-mail Address: **worlja@jea.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: **SJRPP and NGS Boiler Nos. 1 and 2 are subject to NSPS 40 CFR 60 Subpart Da.**	

List of Pollutants Emitted by Facility

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

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

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

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

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID:____ ☒ Previously Submitted, Date: July 2008
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:____ ☒ Previously Submitted, Date: July 2008
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:____ ☒ Previously Submitted, Date: July 2008

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: Part II
3.	Rule Applicability Analysis: ☒ Attached, Document ID: Part II
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:__________ ☐ 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:__________ ☐ 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:__________ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4.	List of Equipment/Activities Regulated under Title VI: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☐ Equipment/Activities Onsite but Not Required to be Individually Listed ☐ Not Applicable
5.	Verification of Risk Management Plan Submission to EPA: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☐ Not Applicable
6.	Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:__________ ☐ 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:__________ ☒ Previously Submitted, Date: **July 2008**
   ☐ Not Applicable (not an Acid Rain source)

   Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.):
   ☐ Attached, Document ID:__________ ☒ Previously Submitted, Date: **July 2008**
   ☐ 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:__________ ☒ Previously Submitted, Date: **July 2008**
   ☐ Not Applicable (not a CAIR source)

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

   ☐ 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:
   NGS Circulating Fluidized Bed Boiler No. 2 (EU 026)
   NGS Circulating Fluidized Bed Boiler No. 1 (EU 027)

3. Emissions Unit Identification Number: **026, 027**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**02/02**	**49**

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

   ☒ Acid Rain Unit

   ☒ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: **297.5** MW

11. Emissions Unit Comment:
   Initial Startup Date for Boiler No. 2 was February 2002. Boiler No. 1 began commercial operation in May 2002.

Emissions Unit Control Equipment/Method: Control 1 of 4

1. Control Equipment/Method Description: **Dry Limestone Injection**	
2. Control Device or Method Code: **041**	

Emissions Unit Control Equipment/Method: Control 2 of 4

1. Control Equipment/Method Description: **Spray Dryer Absorber (SDA) polishing scrubber**	
2. Control Device or Method Code: **013**	

Emissions Unit Control Equipment/Method: Control 3 of 4

1. Control Equipment/Method Description: **Selective Noncatalytic Reduction (SNCR) for NOx**	
2. Control Device or Method Code: **107**	

Emissions Unit Control Equipment/Method: Control 4 of 4

1. Control Equipment/Method Description: **Fabric Filter - Low Temperature (T < 180F)**	
2. Control Device or Method Code: **018**	

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: **5,528** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input for each boiler is 2,764 MMBtu/hr.**	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **EU026 and EU027**		2. Emission Point Type Code: **2**
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: **NGS Boiler No. 2 (EU026) and Boiler No. 1 (EU027) share a common stack. The common stack contains two separate flues, one for each CFB boiler.**		
5. Discharge Type Code: **V**	6. Stack Height: **495** feet	7. Exit Diameter: **15** feet
8. Exit Temperature: **144**°F	9. Actual Volumetric Flow Rate: **700,000** 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: **Each boiler exhausts through its own flue but through a common stack. Stack parameters are for each boiler.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 6

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Bituminous Coal; Coal and coal treated with a latex binder**		
2. Source Classification Code (SCC): **1-01-002-18**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **221.12**	5. Maximum Annual Rate: **1,937,011**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **8**	8. Maximum % Ash: **18**	9. Million Btu per SCC Unit: **25**
10. Segment Comment: **Total for both boilers based on 2,764 MMBtu/hr heat input rate for each boiler.**		

Segment Description and Rate: Segment 2 of 6

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 Burned**	
4. Maximum Hourly Rate: **212.62**	5. Maximum Annual Rate: **1,862,511**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **8**	8. Maximum % Ash: **18**	9. Million Btu per SCC Unit: **26**
10. Segment Comment: **Total for both boilers based on 2,764 MMBtu/hr heat input rate for each boiler.**		

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

Segment Description and Rate: Segment 3 of 6

1. Segment Description (Process/Fuel Type): **External Combustion Boilers; Electric Generation; Landfill gas**		
2. Source Classification Code (SCC): **1-01-006-01**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **0.012**	5. Maximum Annual Rate: **102.50**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,000**
10. Segment Comment: **195 cf/min x 60 min/hr = 0.0117 x 10^6 cf/hr** **0.0117 x 10^6 cf/hr x 8,760 hr/yr = 102.5 x 10^6 cf/yr** **Represents total landfill gas to both boilers.**		

Segment Description and Rate: Segment 4 of 6

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 Burned**	
4. Maximum Hourly Rate: **0.62**	5. Maximum Annual Rate: **2,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2 gr/100 scf**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,022**
10. Segment Comment: **Rates are total for both boilers.**		

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

Segment Description and Rate: Segment 5 of 6

1. Segment Description (Process/Fuel Type): **External Combustion Boiler; Electric Generation; Distillate Fuel Oil - Grades 1 or 2 Oil**		
2. Source Classification Code (SCC): **1-01-005-01**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **4.52**	5. Maximum Annual Rate: **3,432.8**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **140**
10. Segment Comment: **Rates are total for both boilers.**		

Segment Description and Rate: Segment 6 of 6

1. Segment Description (Process/Fuel Type): **External Combustion Boiler; Electric Generation; Wood/Bark Waste**		
2. Source Classification Code (SCC): **1-01-009-02**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: **175,200**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **16**
10. Segment Comment: **Rates are total for both boilers.** **Maximum daily rate = 240 tons/day/boiler.**		

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
NOx	107		EL
CO			EL
SO2	041	013	EL
VOC			EL
PM	018		EL
PM10	018		EL
Mercury (H114)	013	018	EL
PB	018		EL
SAM	041	013	EL
HF (H107)	013		EL
HAPs			NS
HCl (H106)	013		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: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **156.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.22 lb/MMBtu** Reference: **Section 1.6 of AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Potential annual = 7,680 MMBtu/day x day/24 hr x 0.22 lb/MMBtu x (1 – 49.3/100) x 8,760 hr/yr x ton/2,000 lb = 156.4 TPY** **See Table 7 of Part II.**	
11. Potential, Fugitive, and Actual Emissions Comment: **The above emissions are for wood chip firing only.**	

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: **0.09 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: **498** lb/hour **2,180** tons/year
5. Method of Compliance: **Compliance with the NOx emission limit will be demonstrated using CEMs.**	
6. Allowable Emissions Comment (Description of Operating Method): **Represents total of both boilers.**	

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: **0.6 lb/MMBtu**	4. Equivalent Allowable Emissions: **3,317** lb/hour **14,528** tons/year
5. Method of Compliance: **Compliance with the NOx emission limit will be demonstrated using CEMs.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on 40 CFR 60, Subpart Da. Represents total of both boilers.**	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **3,600 TPY**	4. Equivalent Allowable Emissions: lb/hour **3,600** tons/year
5. Method of Compliance: **Compliance with the NOx emission limit will be demonstrated using CEMs.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable to NGS Boiler Nos. 1, 2, and 3 (EU003) combined, 12-month rolling average.**	

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: lb/hour **76.8** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.60 lb/MMBtu** Reference: **Section 1.6 of AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Potential annual = 7,680 MMBtu/day x day/24 hr x 0.6 lb/MMBtu x (1 – 90.9/100) x 8,760 hr/yr x ton/2,000 lb = 76.8 TPY** **See Table 7 of Part II.**	
11. Potential, Fugitive, and Actual Emissions Comment: **The above emissions are for wood chip firing only.**	

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: **350 lb/hr, 24-hr block, each boiler**	4. Equivalent Allowable Emissions: **700** lb/hour **3,066** tons/year
5. Method of Compliance: **Compliance with the CO emission limit will be demonstrated using CEMs.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-003-AC/PSD-FL-265.** **Represents total of both boilers.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **10.5** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.025 lb/MMBtu** Reference: **Section 1.6 of AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Potential annual = 7,680 MMBtu/day x day/24 hr x 0.025 lb/MMBtu x (1 – 70/100) x 8,760 hr/yr x ton/2,000 lb = 10.5 TPY** **See Table 7 of Part II.**	
11. Potential, Fugitive, and Actual Emissions Comment: **The above emissions are for wood chip firing only.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.20 lb/MMBtu, 24-hr block average**	4. Equivalent Allowable Emissions: **1,106** lb/hour **4,843** tons/year
5. Method of Compliance: **Compliance with the SO_2 emission limit will be demonstrated using CEMs.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-003-AC/PSD-FL-265.** **Represents total of both boilers.**	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.15 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: **829** lb/hour **3,632** tons/year
5. Method of Compliance: **Compliance with the SO_2 emission limit will be demonstrated using CEMs.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-003-AC/PSD-FL-265.** **Represents total of both boilers.**	

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: **0.6 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: **3,317** lb/hour **12,284** tons/year
5. Method of Compliance: **Compliance with the SO_2 emission limit will be demonstrated using CEMs.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on 40 CFR 60, Subpart Da.** **Represents total of both boilers.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 4 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **12,284 TPY**	4. Equivalent Allowable Emissions: lb/hour **12,284** tons/year
5. Method of Compliance: **Compliance with the SO_2 emission limit will be demonstrated using CEMs.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable to NGS Units 1, 2, and 3 combined, 12-month rolling average.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **23.8** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.017 lb/MMBtu** Reference: **Section 1.6 of AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Potential annual = 7,680 MMBtu/day x day/24 hr x 0.017 lb/MMBtu x 8,760 hr/yr x ton/2,000 lb = 23.8 TPY

See Table 7 of Part II.

11. Potential, Fugitive, and Actual Emissions Comment:

The above emissions are for wood chip firing only.

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: **14 lb/hr, 3-hour average, each boiler**	4. Equivalent Allowable Emissions: **28** lb/hour **123** tons/year
5. Method of Compliance: **Testing once in every five years using EPA Method 18, 25, or 25A. Compliance with CO limits based on CEMS data can be used as surrogate.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-003-AC/PSD-FL-265.** **Represents total of both boilers.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **2.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.237 lb/MMBtu** Reference: **Section 1.6 of AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Potential annual = 7,680 MMBtu/day x day/24 hr x 0.237 lb/MMBtu x (1 – 99.4/100) x 8,760 hr/yr x ton/2,000 lb = 2.1 TPY

See Table 7 of Part II.

11. Potential, Fugitive, and Actual Emissions Comment:

The above emissions are for wood chip firing only.

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: **0.011 lb/MMBtu, 3-hour average**	4. Equivalent Allowable Emissions: **61** lb/hour **266** tons/year
5. Method of Compliance: **Annual compliance tests using EPA Methods 5, 5B, 8, 17, or 29 while firing petroleum coke.**	
6. Allowable Emissions Comment (Description of Operating Method): **If petroleum coke has been fired for less than 100 hours during previous quarter or less than 400 hours during the previous federal fiscal year, the testing may be performed while firing coal.** **Represents total of both boilers. Permit No. 0310045-003-AC/PSD-FL-265.**	

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: **881 TPY**	4. Equivalent Allowable Emissions: lb/hour **881** tons/year
5. Method of Compliance: **Annual compliance tests using EPA Methods 5, 5B, 8, 17, or 29 while firing petroleum coke.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable to NGS Units 1, 2, and 3 combined, 12-month rolling average.** **Permit No. 0310045-003-AC/PSD-FL-265.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. 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: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **2.0** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.217 lb/MMBtu** Reference: **Section 1.6 of AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Potential annual = 7,680 MMBtu/day x day/24 hr x 0.217 lb/MMBtu x (1 – 99.4/100) x 8,760 hr/yr x ton/2,000 lb = 2.0 TPY

See Table 7 of Part II.

11. Potential, Fugitive, and Actual Emissions Comment:

The above emissions are for wood chip firing only.

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: **0.011 lb/MMBtu, 3-hour average**	4. Equivalent Allowable Emissions: **61** lb/hour **266** tons/year
5. Method of Compliance: **Annual compliance tests using EPA Methods 5, 5B, 8, 17, or 29 while firing petroleum coke.**	
6. Allowable Emissions Comment (Description of Operating Method): **If petroleum coke has been fired for less than 100 hours during previous quarter or less than 400 hours during the previous federal fiscal year, the testing may be performed while firing coal.** **Represents total of both boilers. Permit No. 0310045-003-AC/PSD-FL-265.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. 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: **Mercury**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.06** lb/hour **0.26** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.03 lb/hour (6-hour average), each boiler** Reference: **Permit No. 0310045-003-AC/PSD-FL-265**	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:

Each unit:

Annual mercury emissions rate: 0.03 lb/hr x 8,760 hr/yr x ton/2,000 lb = 0.13 ton/yr

Note: Emissions calculated based on emission limit. Uncontrolled emission factors for coal and biomass are equivalent on a lb/MMBtu basis (see Tables 1.1-18 and 1.6-4 of AP-42).

11. Potential, Fugitive, and Actual Emissions Comment:

Emissions are based on a 6-hour average and represent total for both boilers. Above emissions reflect existing emission limits for the units. Mercury emissions from biomass firing are expected to be almost zero.

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: **0.03 lb/hr, 6-hour average, each boiler**	4. Equivalent Allowable Emissions: **0.06** lb/hour **0.26** tons/year
5. Method of Compliance: **Initial testing using EPA Methods 29, 101, or 101A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-003-AC/PSD-FL-265.** **Equivalent emissions represent total of both boilers.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. 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: **Pb**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.14** lb/hour **0.62** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.07 lb/hour (3-hour average), each boiler** Reference: **Permit No. 0310045-003-AC/PSD-FL-265**	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: **Each unit: Annual lead emissions rate: 0.07 lb/hr x 8,760 hr/yr x ton/2,000 lb = 0.31 ton/yr** **Note: Emissions calculated based on emission limits. Uncontrolled emission factor for lead is lower for biomass than coal on a lb/MMBtu basis (see Tables 1.1-18 and 1.6-4 of AP-42).**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emissions are based on a 3-hour average and represent total for both boilers. Above emissions reflect existing limits for the units. Lead emissions from biomass firing are expected to be zero.**	

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: **0.07 lb/hr, 3-hour average, each boiler**	4. Equivalent Allowable Emissions: **0.14** lb/hour **0.62** tons/year
5. Method of Compliance: **Testing once every five years at Title V permit renewal on one of the units using EPA Method 12 or 29.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-003-AC/PSD-FL-265.** **Equivalent emissions represent total of both boilers.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. 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: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **1.6** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0038 lb/MMBtu** Reference: **Section 1.6 of AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Potential annual = 7,680 MMBtu/day x day/24 hr x 0.0038 lb/MMBtu x (1 – 70/100) x 8,760 hr/yr x ton/2,000 lb = 1.6 TPY

See Table 7 of Part II.

11. Potential, Fugitive, and Actual Emissions Comment:

The above emissions are for wood chip firing only.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.1 lb/hr, 3-hour average, each boiler**	4. Equivalent Allowable Emissions: **2.2** lb/hour **9.64** tons/year
5. Method of Compliance: **Initial compliance test only using EPA Method 8. Compliance with SO_2 limits based on CEMS data can be used as a surrogate.**	
6. Allowable Emissions Comment (Description of Operating Method): **Continuous compliance is demonstrated by complying with the SO_2 limits based on CEMS data as surrogate.** **Permit No. 0310045-003-AC/PSD-FL-265.** **Equivalent emissions represent total of both boilers.**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. 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: **Hydrogen Fluoride**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.86** lb/hour **3.76** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.43 lb/hour (3-hour average), each boiler** Reference: **Permit No. 0310045-003-AC/PSD-FL-265**	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:

Each unit: Annual HF emissions rate: 0.43 lb/hr x 8,760 hr/yr x ton/2,000 lb = 1.88 tons/yr

Note: Emissions calculated based on emission limits. Uncontrolled emission factor for coal is expected to be much higher than for wood since there is no fluoride emission factor in AP-42 for biomass.

11. Potential, Fugitive, and Actual Emissions Comment:

Emissions are based on a 3-hour average and represent total for both boilers. Above emissions reflect existing limits for the units. HF emissions from biomass firing are expected to be almost zero.

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: **0.43 lb/hr, 3-hour average, each boiler**	4. Equivalent Allowable Emissions: **0.86** lb/hour **3.76** tons/year
5. Method of Compliance: ***Initial compliance test only using EPA Method 13A or 13B.***	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 0310045-003-AC/PSD-FL-265.** **Represents total of both boilers.**	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **COMS**	
5. Visible Emissions Comment: **Rule 62-212.400, F.A.C; and Permit No. 0310045-03-AC/PSD-FL-265.**	

Visible Emissions Limitation: Visible Emissions Limitation 2 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: **60** min/hour	
4. Method of Compliance: **COMS**	
5. Visible Emissions Comment: **40 CFR 60 Subpart Da.**	

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: **VE**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **KVB/MIP** Model Number: **LM3086EPA3**	Serial Number: **See Comment**
5. Installation Date: **7/14/2002 (Boiler No. 1)** **4/1/2002 (Boiler No. 2)**	6. Performance Specification Test Date: **10/14/2002 (Boiler No. 1)** **7/1/2002 (Boiler No. 2)**
7. Continuous Monitor Comment: **Serial Number: NGS CFB Boiler No. 1: 730216** **Serial Number: NGS CFB Boiler No. 2: 730217**	

Continuous Monitoring System: Continuous Monitor 2 of 6

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **Thermo Scientific** Model Number: **48ITLE-ACPCB**	Serial Number: **See Comment**
5. Installation Date: **11/1/2009**	6. Performance Specification Test Date: **1/21/2010 (Boiler No. 1)** **1/7/2010 (Boiler No. 2)**
7. Continuous Monitor Comment: **Serial Number: NGS CFB Boiler No. 1: 0819830961** **Serial Number: NGS CFB Boiler No. 2: 0819830960**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor 3 of 6

1. Parameter Code: **EM**	2. Pollutant(s): **NOx**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **42i**	Serial Number: **See Comment**
5. Installation Date: **11/1/2009**	6. Performance Specification Test Date: **1/21/2010 (Boiler No. 1)** **1/7/2010 (Boiler No. 2)**
7. Continuous Monitor Comment: **Serial Number: NGS CFB Boiler No. 1: 0809828969** **Serial Number: NGS CFB Boiler No. 2: CM08030131**	

Continuous Monitoring System: Continuous Monitor 4 of 6

1. Parameter Code: **EM**	2. Pollutant(s): **SO2**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **43i**	Serial Number: **See Comment**
5. Installation Date: **11/1/2009**	6. Performance Specification Test Date: **1/21/2010 (Boiler No. 1)** **1/7/2010 (Boiler No. 2)**
7. Continuous Monitor Comment: **Serial Number: NGS CFB Boiler No. 1: CM08030142** **Serial Number: NGS CFB Boiler No. 2: CM08030140**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor 5 of 6

1. Parameter Code: **CO2**	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **410i**	Serial Number: **See Comment**
5. Installation Date: **11/1/2009**	6. Performance Specification Test Date: **1/21/2010 (Boiler No. 1)** **1/7/2010 (Boiler No. 2)**
7. Continuous Monitor Comment: **Serial Number: NGS CFB Boiler No. 1: 0800226818** **Serial Number: NGS CFB Boiler No. 2: 0800226813**	

Continuous Monitoring System: Continuous Monitor 6 of 6

1. Parameter Code: **EM**	2. Pollutant(s): **Mercury**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **Thermo Scientific** Model Number: **80I-ADFNCB**	Serial Number: **See Comment**
5. Installation Date: **September 12, 2008**	6. Performance Specification Test Date: **See Comment**
7. Continuous Monitor Comment: **Serial Number = NGS CFB Boiler No. 1: 0809128431** **Serial Number = NGS CFB Boiler No. 2: 0805028186** **Test Date: NGS CFB Boiler No. 1: June 23, 2009** **Test Date: NGS CFB Boiler No. 2: March 24, 2009** **Required per Permit No. 0310045-022-AC/PSD-FL-265E. JEA is requesting in this application that this requirement be deleted.**	

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: **JEA-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: ______ ☐ 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 **July 2008**

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: ______ ☒ Previously Submitted, Date **July 2008**
☐ Not Applicable (construction application)

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

6. Compliance Demonstration Reports/Records:
☐ Attached, Document ID: ______
Test Date(s)/Pollutant(s) Tested: ______

☐ Previously Submitted, Date: ______
Test Date(s)/Pollutant(s) Tested: ______

☐ To be Submitted, Date (if known): ______
Test Date(s)/Pollutant(s) Tested: ______

☒ Not Applicable
Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute:
☐ Attached, Document ID: ______ ☒ Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

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

Additional Requirements for Title V Air Operation Permit Applications

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

Additional Requirements Comment

PART II

PART II

EXECUTIVE SUMMARY

JEA is seeking authorization from the Florida Department of Environmental Protection (FDEP) for the following:

A. Burn up to a maximum of 240 tons per day (TPD) of biomass (i.e., wood chips from tree trimmings and similar plant materials) in each of Northside Generating Station (NGS) Boiler Nos. 1 and 2 (EU IDs 027 and 026).

B. Remove the voluntary requirements for the continuous emission monitoring systems (CEMS) installed to measure mercury emissions from NGS Boiler Nos. 1 and 2.

C. Clarify that St. Johns River Power Park (SJRPP) Units 1 and 2 flue gas desulfurization (FGD) systems may use one scrubber tower while operating at low loads.

A. 240 TPD Biomass Firing for NGS Boiler Nos. 1 and 2

In October 2011, FDEP authorized JEA to burn up to a maximum of 33.3 TPD of biomass in each of NGS Boiler Nos. 1 and 2 (FDEP Project No. 0310045-032-AC authorized on October 10, 2011), which amounts to 1 percent of the heat input potential for both boilers. FDEP also determined that the biomass-burning project would cause miniscule changes in emissions compared to the small and allowable day-to-day variations in the coal and petcoke and blend ratios, and therefore exempted the project from requiring an air construction (AC) permit.

In January 2012, JEA submitted an AC permit application (Project No. 0310045-034- AC) requesting a maximum of 300 TPD of biomass-firing per boiler, where JEA demonstrated that the proposed biomass-firing was projected to decrease emissions of greenhouse gases (GHGs), and of all criteria pollutants except nitrogen oxides (NO_x) and volatile organic compounds (VOC), which were projected to increase. JEA also demonstrated that based on the current actual-to-projected actual emissions test, the use of a maximum of 300 TPD of biomass per boiler would not result in an increase of NO_x or VOC above the Prevention of Significant Deterioration (PSD) significant emission rates. In May 2012, JEA withdrew the 300 TPD biomass-firing request (letter to FDEP dated May 11), and wanted to submit a new AC permit application with a revised quantity of biomass-firing. In this AC permit application, JEA is requesting firing a maximum of 240 TPD of biomass per boiler. Since the revised biomass-firing quantity is less, the conclusions presented in the 300 TPD biomass-firing application are still the same. Only the NO_x and VOC emissions are projected to increase; however, the increase will be below the respective PSD significant emission rates. There are no other changes to Boiler Nos. 1 and 2 as a result of this project.

B. Removal of Mercury CEMS for NGS Boiler Nos. 1 and 2

JEA voluntarily installed and began operating mercury CEMS on NGS Boiler Nos. 1 and 2 in 2009. The operation and the quality assurance/quality control (QA/QC) program for the CEMS has been difficult, expensive, and manpower-intensive, and the mercury levels for Boiler Nos. 1 and 2 are at or below the detection levels of these monitors, resulting in limited data of little if any value. In addition, the U.S. Environmental Protection Agency (EPA) recently finalized the National Emissions Standards for Hazardous Air Pollutants (NESHAP) applicable to utility steam generating units, such as NGS Boiler Nos. 1 and 2, and as part of that rulemaking established new requirements for monitoring mercury emissions that are currently scheduled to become applicable in 2015. JEA requests that the mercury CEMS be removed from the operating permit, recognizing that the newly promulgated NESHAP requirements may apply to these units in the future.

C. Low-Load One Scrubber Tower Operation for SJRPP Units 1 and 2

SJRPP Units 1 and 2 are equipped with FGD systems that include three scrubber towers per unit. When operating at full load, two of the three scrubber towers are operated to meet the sulfur dioxide (SO_2) emissions limits established as Best Available Control Technology (BACT) and incorporated into the Title V Permit, with a third tower available as a backup. SJRPP requested and received authorization from FDEP to evaluate the SO_2 emissions using one scrubber tower while operating at low loads. Based on JEA's evaluation, the SO_2 emission limits are achievable with one scrubber tower when operating at low load. As a result, JEA requests that the permit clarify that at low load operations, one scrubber tower may be used.

INTRODUCTION

The NGS and SJRPP facilities are adjacent and located at 4377 Heckscher Drive, Jacksonville, Duval County, Florida. Both facilities are covered under one Title V Permit (Permit No. 0310045-030-AV).

Golder Associates Inc. (Golder) was contracted to prepare the necessary air permit application seeking authorization for the above mentioned minor modification projects. This minor source AC permit application package consists of the appropriate application form [DEP Form 62-210.900(1)], a technical description of the projects, and rule applicability for the projects.

A. 240 TPD Biomass Firing for NGS Boiler Nos. 1 and 2

The maximum heat input rate for NGS Boiler Nos. 1 and 2 is 2,764 million British thermal units per hour (MMBtu/hr) for each boiler. JEA is proposing to burn a maximum of 240 TPD of biomass in each boiler, which is the maximum potential amount of biomass that can be handled with existing equipment. Heat input from biomass was estimated from Section 1.6 of AP-42, Wood Residue Combustion in Boilers, that provides a range of heating values – from about 4,500 British thermal units per pound (Btu/lb) of fuel on a wet, as-fired basis to about 8,000 Btu/lb for dry wood. Using a conservative high estimate of 8,000 Btu/lb, the proposed wood chip firing will have the potential to replace a total of 3,840 MMBtu/day per boiler or 2,803,200 MMBtu per year of current actual heat input for both boilers. The project does not include any physical changes to the boiler units.

NO_x emissions from the NGS Boiler Nos. 1 and 2 are currently controlled by a selective non-catalytic reduction (SNCR) system installed on each boiler. Particulate matter (PM) emissions from the units are controlled by fabric filters, and SO_2 emissions are controlled by limestone injection and a spray dryer absorber system. There will be no change to the existing control equipment as a result of the proposed project and no new emission control technology will be added.

B. Removal of Mercury CEMS for NGS Boiler Nos. 1 and 2

JEA requests FDEP to remove the conditions referencing the voluntary CEMS for mercury on NGS Boiler Nos. 1 and 2. In the original approval for the repowering of NGS Boiler Nos. 1 and 2 (circulating fluidized bed type) with air pollution control equipment, a BACT determination was made for mercury emissions along with an initial compliance test on Unit 2 using EPA Methods 29, 101, or 101A (Condition 40 of AC Permit No. 0310045-003-AC/PSD-FL-265). Subsequently, JEA voluntarily installed mercury CEMS, and this was reflected in Condition G.24 of current Title V Permit No. 0310045-030-AV as shown below:

> Hg Continuous Emissions Monitoring Systems Operation. The permittee has voluntarily agreed to install and operate Hg CEMS on Units 1 and 2. The Hg CEMS were installed and operational in 2009, and shall be operated in accordance with the quality assurance/quality control (QA/QC) plan submitted by JEA and approved by the Department. The attached **Appendix Hg CEMS - Quality Assurance Plan** is a part of this permit. Any future revisions to the QA/QC plan that are approved by the Department will also be part of the permit. This

requirement will stay in effect until such time that the state or EPA passes a regulatory requirement for mercury detailing the Hg CEMS operational protocol, at which time that rule will become the preferred protocol. The annual relative accuracy test required by the QA/QC plan can be performed by the permittee under the normal mode of operation. For JEA, the normal mode of operation is firing a fuel blend which is typically 15% coal and 85% petroleum coke. Every reasonable effort should be made by the permittee for the Hg CEMS to be operating during the time periods when the SDA is off-line. If the Hg CEMS is not operating during a time period when the SDA is taken off-line, the best estimate of Hg emissions shall be provided to the Department and EQD based on the requirements of Rule 62-210.370, F.A.C. [Rules 62-4.070(3) and 62-210.370, F.A.C.; and 0310045-022-AC/PSD-FL-265E, specific condition 50.(b).]

This condition confirms the voluntary nature of the mercury CEMS. Moreover, this condition reflects the updates from Permit No. 0310045-022-AC/PSD-FL-265E recognizing the continued difficulty in the operation and QA/QC program for this equipment. The CEMS are first generation, expensive to maintain, and manpower-intensive, and the mercury levels for Boiler Nos. 1 and 2 are at or below the detection levels of these monitors, resulting in limited data of little if any value. In addition, EPA recently finalized the NESHAP applicable to utility steam generating units, such as NGS Boiler Nos. 1 and 2, and as part of that rulemaking established new requirements for monitoring mercury emissions that are currently scheduled to become applicable in 2015. As a result, JEA requests that the mercury CEMS be deleted from the permit. The following are the affected conditions in the current Title V permit:

- Delete reference to "mercury (Hg)" in line 3 of Condition G.24
- Delete paragraph titled "Hg Continuous Emission Monitoring Systems Operation" of Condition G.24
- Delete paragraph titled "Continuous Emissions Monitoring Systems Reporting" of Condition G.24
- Delete Appendix Hg CEMS – Quality Assurance Plan

C. Low-Load One Scrubber Tower Operation for SJRPP Units 1 and 2

SJRPP Units 1 and 2 are equipped with FGD systems that include three scrubber towers per unit. When operating at full load, two of the three scrubber towers have typically been used in the past to meet the SO_2 emissions limits established as BACT and incorporated into the Title V Permit. A third tower has been maintained for use as a backup during maintenance of the other towers. Since SJRPP Units 1 and 2 started operations in the early 1980s, the units had been operated at baseload conditions. Recently, due to the lower price of natural gas, these two units have begun operating at lower loads, down to 50 percent load. SJRPP requested and received authorization from FDEP to evaluate the SO_2 emissions using one scrubber tower while operating at low loads to confirm that the SO_2 emission limit would be met.

As explained in JEA's submittal earlier this year, there are a number of benefits if a single tower is used when the units are operating at half load, including reduced water usage, reduced wastewater discharge, reduced undesirable internal process foaming (resulting in reduced operational and maintenance issues), reduced outage maintenance costs to remove solidified foam buildup, reduced solids removal costs, savings in auxiliary equipment and slurry preparation costs, and reduced wastewater treatment costs. These reductions result in benefits to JEA's customers and the environment. The results of JEA's evaluation demonstrate that when operating at low loads, the SO_2 emission limit will be met when a single scrubber tower is used.

When the Department authorized a week's testing to compile representative rates during low load operations and single tower usage, the Department mentioned that it may be necessary to provide reasonable assurances that actual emissions would not increase. The Department characterized the use of a single scrubber tower instead of two scrubber towers as a change in the established method of operation, even though the original and current permits do not specifically require operation of two towers, nor do they prohibit the unit from operating with only one tower. While JEA does not agree with the Department's statements that the use of a single scrubber represents a change in the method of operation, the data compiled during the testing period demonstrates that emissions are actually lower when using a single tower.

The evaluation consisted of operating at high loads with two scrubber towers in operation during early morning (around 5 a.m.) till around 10 p.m. or midnight. From around 10 p.m. to midnight, until about 4 a.m., the unit was operated at low loads with only one scrubber tower in operation. A summary of the hourly CEMs and operating data observed during the evaluation is presented in Table 9. This table presents the SO_2 emission rates in pounds per million British thermal units (lb/MMBtu) and pounds per hour (lb/hr); the percent SO_2 removal; and the operating load, for the average, maximum, minimum, and standard deviation of the observed data for two-tower operation and one-tower operation. In addition, the table shows the upper and lower confidence interval based on the technique specified in Title 40, Part 60 of the Code of Federal Regulations (40 CFR 60), Appendix C – Determination of Emission Rate Change. This technique uses the "Student's *t*-test" to determine the 95 percent confidence level of emission data and determine if an emission change has occurred. If the upper and lower confidence intervals of two data sets overlap in value then there is no statistical difference. The results of the evaluation provide the following conclusions:

- The operating load for the one tower operation was statistically significantly lower than the two tower operation and was about 50 percent that of the two tower operation.
- The SO_2 emissions in lb/MMBtu during one tower operation are statistically significantly lower than two tower operation.
- There is no statistical difference in percent SO_2 removal observed during the evaluation.

As a result, JEA requests FDEP add a permitting note to clarify and confirm that a single tower may be used when the unit is operating at low loads.

RULE APPLICABILITY

Under Federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a pre-construction permit issued. EPA has approved Florida's State Implementation Plan (SIP), which contains PSD regulations. The applicable PSD rules in Florida are found in Rule 62- 212.400, Florida Administrative Code (F.A.C.).

A "major facility" is defined as any of 28 named source categories that have the potential to emit 100 tons per year (TPY) or more, or any other stationary facility that has the potential to emit 250 TPY or more, of any pollutant regulated under the CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. Once a new source is determined to be a "major facility" for a particular pollutant, any pollutant emitted in amounts greater than the PSD significant emission rates is subject to PSD review. For an existing source for which a modification is proposed, the modification is subject to PSD review if the increase in emissions due to the modification is greater than the PSD significant emission rates. PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 52.21, Prevention of Significant Deterioration of Air Quality. The State of Florida has adopted rules to implement the federal PSD requirements and EPA has approved these as part of Florida's SIP. (Rule 62-212.400, F.A.C.). Major facilities and major modifications are required to undergo the following analyses related to PSD for each pollutant emitted in significant amounts:

- Control technology review
- Source impact analysis
- Air quality analysis (monitoring)
- Source information
- Additional impact analyses

The NGS is part of the JEA NGS/SJRPP/Separations Technology (ST) facility complex, which is a major facility under FDEP rules. Based on Rule 62-210.200(205), F.A.C., modification is defined as any physical change in, change in the method of operation of, or addition to a facility that would result in an increase in the actual emissions of any pollutant subject to new source review regulation under the CAA. Because there is a change in the method of operation with the addition of biomass as a fuel for normal operation, the project is a potential modification as defined in the FDEP rules in Rule 62-210.200 and under the PSD rules in Rule 62-212.400, F.A.C. PSD review would be required for the projects if there were a significant increase in emissions.

A. 240 TPD Biomass Firing for NGS Boiler Nos. 1 and 2

NGS Boiler Nos. 1 and 2 are baseload electric generating units firing natural gas, No. 2 fuel oil, coal, petroleum coke, and landfill gas. Future use of these primary fuels will not change. Since each boiler is rated at 2,764 MMBtu/hr of heat input and the proposed biomass fuel will have the potential to provide only 7,680 MMBtu/day heat input for both boilers, the primary heat input will be achieved by firing the currently permitted fuels. The daily heat input of 7,680 MMBtu/day achieved by biomass is only 5.8 percent of the daily heat input potential of 132,672 MMBtu/day for both boilers. Thus, only 5.8 percent of heat input obtained from firing currently permitted fuels will be replaced by firing biomass (while operating at full load). To evaluate any potential increases in emissions, a comparison was made between projected actual annual emissions resulting from 480 TPD of wood chip firing and the baseline actual annual emissions.

The baseline or current actual emissions are the emissions over a consecutive 24-month period within the 5 years immediately preceding the date that a complete application is submitted. The use of different consecutive 24-month periods for each pollutant is allowed. For an existing facility for which a modification is proposed, the modification is subject to PSD review if the increase in emissions due to the modification is greater than the PSD significant emission rates for any applicable pollutant.

Table 1 presents the actual annual heat inputs for Boiler Nos. 1 and 2 resulting from different fuels reported in the Annual Operating Reports (AORs) for the period 2007 through 2011, as well as the actual operating hours for each unit. The table also presents individual fuel heat inputs as a percent of total heat input.

Table 2 summarizes the annual emissions for Boiler Nos. 1 and 2 reported in the AORs for each calendar year in the period 2007 through 2011. The carbon dioxide (CO_2) emission rates in Table 2 were obtained from EPA's Acid Rain database.

The actual emissions reported in AORs are presented as a function of heat input (lb/MMBtu) in Table 3. Emissions factors are presented for each individual boiler and also as an average rate for both Boiler Nos. 1 and 2.

Since emissions of nitrous oxide (N_2O) and methane (CH_4) were not reported in the AORs, they were calculated based on the actual annual heat input and emission factors from 40 CFR 98, Subpart C. These emissions are summarized in Table 4, which also shows the CO_2 equivalent (CO_2e) rates for these pollutants.

NO_x emissions from Boiler Nos. 1 and 2 are currently controlled by a SNCR system. PM emissions from the units are controlled by fabric filters, and SO_2 emissions are controlled by limestone injection and a spray dryer absorber system. The actual control efficiency of these controls is estimated in Table 5 by comparing the current actual emission factors to the uncontrolled emission factors from EPA's AP-42. For SO_2, since the uncontrolled emission factor was not readily available, a typical control efficiency of 70 percent was assumed. Sulfuric acid mist (SAM) emissions are also expected to be controlled at an efficiency similar to SO_2. For VOC, since the calculation indicated no decrease in actual emission factor, a control efficiency of 0 percent was assumed.

Table 6 presents the average emissions for each consecutive 2-year period based on the calendar year emissions in Table 3. The annual average emissions for each consecutive 2-year period are consistent with the definition of baseline actual emissions for fossil fuel-fired steam electric generating units.

Table 7 presents the future projected actual emissions due to wood chip firing. The potential annual heat input is based on maximum wood chip usage of 480 TPD for 365 days per year and using a heating value of 8,000 Btu/lb for dry wood. Using the highest heat input provides a conservative estimate of emissions. Emission factors used are from Section 1.6 of AP-42. PM emission factors include condensable PM assuming all condensable PM are in 2.5 micron ($PM_{2.5}$) size category. There are no emission factors available in AP-42 for SAM. The SAM emission rate was calculated assuming 10 percent of the SO_2 emissions will be oxidized into sulfur trioxide (SO_3), which will then convert to SAM through chemical reaction in the atmosphere. GHG emission factors for wood chip firing were obtained from Table C-2, Subpart C, 40 CFR 98. Initially the uncontrolled emission rates were calculated. The actual control efficiencies estimated in Table 5 were applied to the uncontrolled emission rates to estimate the future projected actual emission rates. Emission control efficiencies for VOC, SAM, and GHGs were assumed to be zero.

The PSD applicability analysis is presented in Table 8. The baseline emissions used are the maximum 2-year average emissions for each pollutant in Table 6. The actual emission factors in lb/MMBtu were obtained from Table 3. The actual emission factors for N_2O and CH_4 in CO_2e lb/MMBtu were estimated from the baseline emissions and maximum 2-year period average heat input. The actual emission factors are applied to the maximum heat input due to wood chip firing to calculate current actual emissions that will be replaced by emissions when co-firing wood chips. The projected actual emissions are emissions due to co-firing wood chips at the maximum heat input representative of 240 tons/day/unit. The baseline actual emissions were subtracted from the projected actual emissions with wood chip firing and the difference was compared to the PSD significant emission rates for each pollutant.

There is a minor amount of fugitive emissions that can result from transporting the wood chips within the JEA plant site, and storage/handling. Appendix A contains two tables that provide estimates of fugitive emissions. Table A-1 provides estimates of wood delivery and unloading. Wood chips will be stored in a small area (<1 acre) adjacent to an existing hopper. Table A-2 provides handling and loading of wood chips into the existing hopper on the conveyor. Wood typically has high moisture content, low silt content, and will be preprocessed to a size that can be accommodated by the CFB boilers. The size of the wood and moisture will result in low fugitive emissions compared to coal. No change in emissions will occur within the existing coal/pet coke handling systems. Reasonable precautions as contained in Condition FW5 of the Title V permit will be followed to minimize fugitive emissions from this minor source.

As shown in Table 8, there will be a decrease in all pollutants except PM, NO_x and VOC. However, the increase in NO_x and VOC will be much lower than 40 TPY, which is the PSD significant emission rate for both pollutants. The emission increases calculated for NO_x and VOC are an artifact of using emission factors. An increase in emissions is not expected from coal/petcoke firing since biomass is co-fired in small amounts (< 10%) and combustion controls will limit increases in emissions. Table 8 also shows that the GHG emissions from the use of biomass is reduced; however, until July 21, 2014, biogenic CO_2 emissions are not included pursuant to 40 CFR 52.21(b)(49)(ii)(a). Therefore, PSD review is not triggered for GHGs as a result of this project. As a result, the proposed project is not subject to PSD for criteria pollutants or GHGs. A state minor source AC permit application for criteria pollutants is applicable to the project.

B. Removal of Mercury CEMS for NGS Boiler Nos. 1 and 2

There will be no effect on emissions as a result of removal of the voluntary CEMS, and a PSD applicability analysis is not required.

C. Low-Load One Scrubber Tower Operation for SJRPP Units 1 and 2

JEA believes that operation of one scrubber tower is currently allowed under its permit. However, as shown in Table 9, SO_2 emissions in lb/MMBtu are statistically significantly lower during one tower operation than during two tower operation, and there is no statistically significant difference between the SO_2 removal efficiencies for two-tower or one-tower operation.

TABLES

Table 1. NGS Boiler Nos. 1 and 2 Annual Heat Inputs, 2007 - 2011

Year	Heat Input from Bituminous Coal (MMBtu/yr)			Heat Input from Distillate Oil (MMBtu/yr)			Heat Input from Natural Gas (MMBtu/yr)			Heat Input from Coke (MMBtu/yr)			Total Actual Heat Input (MMBtu/yr)			Actual Operating Hours (hr/yr)	
	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2
2011	1,118,800	1,181,125	2,299,925	0	0	0	194,292	311,484	505,776	8,213,975	8,213,975	16,427,950	9,527,067	9,706,584	19,233,651	5,263	5,937
2010	1,644,874	1,722,358	3,367,232	0	0	0	34,304	24,720	59,024	15,357,748	16,661,805	32,019,553	17,036,926	18,408,883	35,445,809	6,816	7,177
2009	1,349,691	1,498,508	2,848,199	0	0	0	14,602	35,666	50,268	14,351,596	14,564,536	28,916,132	15,715,889	16,098,710	31,814,599	6,227	6,332
2008	1,698,226	1,488,040	3,186,266	0	0	0	70,283	46,200	116,483	17,798,191	15,357,664	33,155,855	19,566,700	16,891,904	36,458,604	7,940	6,885
2007	2,981,916	2,729,706	5,711,622	0	0	0	49,162	99,274	148,436	16,854,068	16,156,248	33,010,316	19,885,146	18,985,228	38,870,374	7,765	7,374

Individual Fuel Heat Input as a Percent of Total Heat Input

Year	Heat Input from Bituminous Coal (MMBtu/yr)			Heat Input from Distillate Oil (MMBtu/yr)			Heat Input from Natural Gas (MMBtu/yr)			Heat Input from Coke (MMBtu/yr)		
	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total	Boiler 1	Boiler 2	Total
2011	5.8%	6.1%	12.0%	0	0	0	1.0%	1.6%	2.6%	42.7%	42.7%	85.4%
2010	4.6%	4.9%	9.5%	0	0	0	0.1%	0.1%	0.2%	43.3%	47.0%	90.3%
2009	4.2%	4.7%	9.0%	0	0	0	0.0%	0.1%	0.2%	45.1%	45.8%	90.9%
2008	4.7%	4.1%	8.7%	0	0	0	0.2%	0.1%	0.3%	48.8%	42.1%	90.9%
2007	7.7%	7.0%	14.7%	0	0	0	0.1%	0.3%	0.4%	43.4%	41.6%	84.9%

Two-Year Average Heat Input (MMBtu)

Years	MMBTU
2011-2010	27,339,730
2010-2009	33,630,204
2009-2008	34,136,601
2008-2007	37,664,489

Note: All values are based on annual operating reports for the period 2007 - 2011.

Table 2. Annual Emissions Reported in 2007-2011 Annual Operating Reports

Year	Pollutant	Boiler No. 1 (tons)	Boiler No. 2 (tons)	Total (tons)
2011	NO_x	267.4	354.6	622.0
	CO	467.6	164.5	632.1
	SO_2	952.7	1,077.1	2,029.8
	VOC	13.1	13.5	26.7
	PM	15.9	16.8	32.6
	PM_{10}	15.3	15.9	31.2
	SAM [a]	--	--	310.8
	CO_2	1,302,275.0	1,438,295.4	2,740,570.4
2010	NO_x	704.0	902.7	1,606.7
	CO	302.2	200.3	502.5
	SO_2	1,584.2	1,607.5	3,191.7
	VOC	21.2	22.1	43.3
	PM	21.7	16.2	38.0
	PM_{10}	22.1	20.0	42.1
	SAM [a]	--	--	488.7
	CO_2	2,090,362.3	2,125,872.5	4,216,234.8
2009	NO_x	810.0	804.1	1,614.1
	CO	119.9	150.5	270.4
	SO_2	1,397.1	1,387.9	2,785.0
	VOC	19.6	20.0	39.6
	PM	18.7	29.0	47.7
	PM_{10}	17.5	27.0	44.5
	SAM [a]	--	--	426.5
	CO_2	1,922,135.5	1,948,776.2	3,870,911.7
2008	NO_x	818.7	701.2	1,519.9
	CO	203.4	125.0	328.4
	SO_2	1,565.0	1,565.0	3,130.0
	VOC	24.6	21.2	45.9
	PM	26.4	33.5	59.8
	PM_{10}	18.9	22.9	41.8
	SAM [a]	--	--	479.3
	CO_2	2,278,188.9	1,828,111.5	4,106,300.4
2007	NO_x	724.6	719.3	1,443.9
	CO	256.8	329.5	586.3
	SO_2	1,510.5	1,411.7	2,922.2
	VOC	24.7	23.0	47.8
	PM	10.3	37.6	47.9
	PM_{10}	10.1	28.0	38.1
	SAM [a]	--	--	447.5
	CO_2	2,295,968.3	2,100,239.5	4,396,207.8

Source: Annual Operating Report (AOR) for JEA NGS&SJRPP, 2007 - 2011.

Table 3. Actual Emissions as a Function of Heat Input, 2007 - 2011

BOILER 1

Year	Actual Annual Heat Input (MMBtu/yr) [a]	Boiler 1 Actual Emissions (TPY) [b]								Emissions per Unit Heat Input [c] (lb/MMBtu)							
		NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2	NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2
2011	9,527,067	267.4	467.6	13.1	952.7	15.9	15.3	145.9	1,302,275.0	0.0561	0.0982	0.0028	0.2000	0.0033	0.0032	0.0306	273.4
2010	17,036,926	704.0	302.2	21.2	1,584.2	21.7	22.1	242.6	2,090,362.3	0.0826	0.0355	0.0025	0.1860	0.0025	0.0026	0.0285	245.4
2009	15,715,889	810.0	119.9	19.6	1,397.1	18.7	17.5	213.9	1,922,135.5	0.1031	0.0153	0.0025	0.1778	0.0024	0.0022	0.0272	244.6
2008	19,566,700	818.7	203.4	24.6	1,565.0	26.4	18.9	239.6	2,278,188.9	0.0837	0.0208	0.0025	0.1600	0.0027	0.0019	0.0245	232.9
2007	19,885,146	724.6	256.8	24.7	1,510.5	10.3	10.1	231.3	2,295,968.3	0.0729	0.0258	0.0025	0.1519	0.0010	0.0010	0.0233	230.9

BOILER 2

Year	Actual Annual Heat Input (MMBtu/yr) [a]	Boiler 2 Actual Emissions (TPY) [b]								Emissions per Unit Heat Input [c] (lb/MMBtu)							
		NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2	NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2
2011	9,706,584	354.6	164.5	13.5	1,077.1	16.8	15.9	164.9	1,438,295.4	0.0731	0.0339	0.0028	0.2219	0.0035	0.0033	0.0340	296.4
2010	18,408,883	902.7	200.3	22.1	1,607.5	16.2	20.0	246.1	2,125,872.5	0.0981	0.0218	0.0024	0.1746	0.0018	0.0022	0.0267	231.0
2009	16,098,710	804.1	150.5	20.0	1,387.9	29.0	27.0	212.5	1,948,776.2	0.0999	0.0187	0.0025	0.1724	0.0036	0.0034	0.0264	242.1
2008	16,891,904	701.2	125.0	21.2	1,565.0	33.5	22.9	239.6	1,828,111.5	0.0830	0.0148	0.0025	0.1853	0.0040	0.0027	0.0284	216.4
2007	18,985,228	719.3	329.5	23.0	1,411.7	37.6	28.0	216.2	2,100,239.5	0.0758	0.0347	0.0024	0.1487	0.0040	0.0029	0.0228	221.2

BOILERS 1 & 2

Year	Actual Annual Heat Input (MMBtu/yr) [a]	Boilers 1 & 2 Total Actual Emissions (TPY) [b]								Emissions per Unit Heat Input [c] (lb/MMBtu)							
		NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2	NO_X	CO	VOC	SO_2	PM	PM_{10}	SAM	CO_2
2011	19,233,651	622.0	632.1	26.7	2,029.8	32.6	31.2	310.8	2,740,570.4	0.0647	0.0657	0.0028	0.2111	0.0034	0.0032	0.0323	285.0
2010	35,445,809	1,606.7	502.5	43.3	3,191.7	38.0	42.1	488.7	4,216,234.8	0.0907	0.0284	0.0024	0.1801	0.0021	0.0024	0.0276	237.9
2009	31,814,599	1,614.1	270.4	39.6	2,785.0	47.7	44.5	426.5	3,870,911.7	0.1015	0.0170	0.0025	0.1751	0.0030	0.0028	0.0268	243.3
2008	36,458,604	1,519.9	328.4	45.9	3,130.0	59.8	41.8	479.3	4,106,300.4	0.0834	0.0180	0.0025	0.1717	0.0033	0.0023	0.0263	225.3
2007	38,870,374	1,443.9	586.3	47.8	2,922.2	47.9	38.1	447.5	4,396,207.8	0.0743	0.0302	0.0025	0.1504	0.0025	0.0020	0.0230	226.2
									Average	0.0961	0.0470	0.0025	0.1610	0.0029	0.0026	0.0247	225.7283
									for Period:	2009-10	2010-11	2007-08	2007-08	2007-08	2009-10	2007-08	2007-08

[a] Based on AOR data; see Table 1.
[b] Based on AOR data; see Table 2.
[c] Total actual emissions divided by total heat input.

Table 4. Estimated Actual Annual Emissions of N_2O and CH_4 for the Period 2007 - 2011
NGS Boiler Nos. 1 and 2

Unit	Actual Annual Heat Input [a] (MMBtu/yr)	N_2O Emissions: Emission Factor [b] (lb/MMBtu)	N_2O Annual Emissions (lb/yr)	N_2O Annual Emissions (TPY)	N_2O CO_2e [c] Rate (TPY)	CH_4 Emissions: Emission Factor [b] (lb/MMBtu)	CH_4 Annual Emissions (lb/yr)	CH_4 Annual Emissions (TPY)	CH_4 CO_2e [c] Rate (TPY)
Bituminous Coal									
2011	2,299,925	3.53E-03	8,110.5	4.1	1,257.1	2.4E-02	55,759.4	27.9	585.5
2010	3,367,232	3.53E-03	11,874.2	5.9	1,840.5	2.4E-02	81,635.2	40.8	857.2
2009	2,848,199	3.53E-03	10,043.9	5.0	1,556.8	2.4E-02	69,051.7	34.5	725.0
2008	3,186,266	3.53E-03	11,236.0	5.6	1,741.6	2.4E-02	77,247.8	38.6	811.1
2007	5,711,622	3.53E-03	20,141.5	10.1	3,121.9	2.4E-02	138,472.6	69.2	1,454.0
Natural Gas-Firing									
2011	505,776	2.20E-04	111.5	0.056	17.3	2.2E-03	1,114.7	0.557	11.7
2010	59,024	2.20E-04	13.0	0.007	2.0	2.2E-03	130.1	0.065	1.4
2009	50,268	2.20E-04	11.1	0.006	1.7	2.2E-03	110.8	0.055	1.2
2008	116,483	2.20E-04	25.7	0.013	4.0	2.2E-03	256.7	0.128	2.7
2007	148,436	2.20E-04	32.7	0.016	5.1	2.2E-03	327.2	0.164	3.4
Coke									
2011	16,427,950	3.53E-03	57,931.5	29.0	8,979.4	2.4E-02	398,279.2	199.1	4,181.9
2010	32,019,553	3.53E-03	112,913.8	56.5	17,501.6	2.4E-02	776,282.0	388.1	8,151.0
2009	28,916,132	3.53E-03	101,969.8	51.0	15,805.3	2.4E-02	701,042.7	350.5	7,360.9
2008	33,155,855	3.53E-03	116,920.8	58.5	18,122.7	2.4E-02	803,830.6	401.9	8,440.2
2007	33,010,316	3.53E-03	116,407.6	58.2	18,043.2	2.4E-02	800,302.1	400.2	8,403.2
Total									
2011	--	--	--	33.1	10,253.8	--	--	227.6	4,779.1
2010	--	--	--	62.4	19,344.1	--	--	429.0	9,009.5
2009	--	--	--	56.0	17,363.8	--	--	385.1	8,087.2
2008	--	--	--	64.1	19,868.3	--	--	440.7	9,254.0
2007	--	--	--	68.3	21,170.2	--	--	469.6	9,860.6

[a] Based on AOR data; see Table 1.
[b] Table C-2, Subpart C, 40 CFR 98. Emission factors in kg/MMBtu were converted to lb/MMBtu by multiplying by 2.204.
[c] N_2O and CH_4 are multiplied by a factor of 310 and 21, respectively, to determine CO_2 equivalence.

Table 5. Current Actual Pollution Control Efficiency

Pollutant	Uncontrolled Emission Factor [a] (lb/ton)	Fuel Heat Content [b] (MMBtu/ton)	Uncontrolled Emission Factor (lb/MMBtu)	Current Actual Emission Factors [c] (lb/MMBtu)	Actual Control Efficiency (%)
NO_x	5	25	0.200	0.0961	52.0
CO	18	25	0.720	0.05	93.5
SO_2	--	25	--	0.16	70.0 [d]
VOC	0.06	25	0.0024	0.0025	None
PM	13.2	25	0.528	0.0029	99.5
PM_{10}	13.2	25	0.528	0.0026	99.5
$PM_{2.5}$	13.2	25	0.528	0.0026	99.5

[a] Based on Tables 1.1-3, 1.1-4, 1.1-19 of Section 1.1, AP-42.
[b] Based on heat content of bituminous coal, 25 MMBtu/ton.
[c] Based on current actual emission rates in lb/MMBtu during for Boilers 1 and 2.
[d] Based on Table 1.1-1 of AP-42, typical control efficiency for spray drying 70 to 90%.

Table 6. Annual Average Emissions for Boilers 1 & 2 for Each Consecutive Two-Year Period, 2007-2011

	Annual Emissions for Boiler Nos. 1 & 2					Two-Year Average Emissions			
Pollutant	2011	2010	2009	2008	2007	2011-2010 (tons)	2010-2009 (tons)	2009-2008 (tons)	2008-2007 (tons)
NO_x	622.0	1,606.7	1,614.1	1,519.9	1,443.9	1,114.4	1,610.4	1,567.0	1,481.9
CO	632.1	502.5	270.4	328.4	586.3	567.3	386.5	299.4	457.3
SO_2	2,029.8	3,191.7	2,785.0	3,130.0	2,922.2	2,610.8	2,988.4	2,957.5	3,026.1
VOC	26.7	43.3	39.6	45.9	47.8	35.0	41.4	42.7	46.8
PM	32.6	38.0	47.7	59.8	47.9	35.3	42.8	53.8	53.8
PM_{10}	31.2	42.1	44.5	41.8	38.1	36.7	43.3	43.2	40.0
$PM_{2.5}$ [a]	31.2	42.1	44.5	41.8	38.1	36.7	43.3	43.2	40.0
SAM [b]	310.8	488.7	426.5	479.3	447.5	399.8	457.6	452.9	463.4
CO_2	2,740,570.4	4,216,234.8	3,870,911.7	4,106,300.4	4,396,207.8	3,478,402.6	4,043,573.3	3,988,606.0	4,251,254.1
N_2O [c] (CO_2e)	10,253.8	19,344.1	17,363.8	19,868.3	21,170.2	14,799.0	18,354.0	18,616.1	20,519.2
CH_4 [c] (CO_2e)	4,779.1	9,009.5	8,087.2	9,254.0	9,860.6	6,894.3	8,548.3	8,670.6	9,557.3

[a] Assuming equal to PM_{10} emissions.

[b] Not reported in AORs - based on assuming 10% of SO_2 converts to SO_3, all of which converts to SAM.

[c] Calculated based on actual annual heat input - see Table 3.

Source: Annual Operating Report (AOR) for 2007 - 2011; EPA's Acid Rain database.

Table 7. Projected Actual Emissions for NGS Boiler Nos. 1 and 2 due to Wood Chip Firing

Pollutant	Proposed Biomass Usage [a] (tons/day)	Biomass Heating Value [b] (Btu/lb)	Daily Heat Input from Biomass (MMBtu/day)	Annual Heat Input from Biomass [c] (MMBtu/yr)	Emission Factor [d] (lb/MMBtu)	Uncontrolled Annual Emissions (TPY)	Estimated Control Efficiency [e] (%)	Annual Emissions (TPY)
NO_x	480.0	8,000.0	7,680.0	2,803,200	0.22	308.4	52.0	148.1
CO	480.0	8,000.0	7,680.0	2,803,200	0.60	841.0	93.5	54.9
SO_2	480.0	8,000.0	7,680.0	2,803,200	0.025	35.0	70.0	10.5
VOC	480.0	8,000.0	7,680.0	2,803,200	0.017	23.8	0.0	23.8
PM	480.0	8,000.0	7,680.0	2,803,200	0.237	332.2	99.5	1.8
PM_{10}	480.0	8,000.0	7,680.0	2,803,200	0.217	304.1	99.5	1.7
$PM_{2.5}$	480.0	8,000.0	7,680.0	2,803,200	0.137	192.0	99.5	1.0
SAM	480.0	8,000.0	7,680.0	2,803,200	0.0038	5.4	70.0	1.6
GHGs [f]								
CO_2	480.0	8,000.0	7,680.0	2,803,200	206.7	289,760.1	0.0	289,760.1
N_2O	480.0	8,000.0	7,680.0	2,803,200	9.26E-03	13.0	0.0	13.0
CH_4	480.0	8,000.0	7,680.0	2,803,200	7.05E-02	98.9	0.0	98.8

[a] Proposed daily wood chip usage.

[b] Heating value based on Section 1.6 of AP-42. Dry wood heating value of 8,000 Btu/lb used as a conservative (high) value.

[c] Based on 365 days per year operation.

[d] Tables 1.6-1, 1.6-2, and 1.6-3, Section 1.6, AP-42. SAM emission factor based on assumption that 10% of the SO_2 is further oxidized to SO_3, which is then converted to SAM (98/80).

[e] Current actual control efficiency calculated in Table 5. Based on Table 1.1-1 of AP-42, typical SO_2 control efficiency for spray drying is 70 to 90%. SAM is also expected to be controlled at a similar efficiency as SO_2.

[f] GHG emission factors are based on Tables C-1 and C-2, Subpart 98, 40 CFR 60.

Table 8. PSD Applicability, Wood Chip Firing, NGS Boiler Nos. 1 and 2

Pollutant	Baseline Actual Emissions[a] (TPY)	Baseline 2-Year Period	Current Actual Emission Factors (lb/MMBtu)	Heat Input to be Replaced by Wood Chips[b] (MMBtu/yr)	Emissions for Heat Input Potential of Wood Chips[c] (TPY)	Wood Chip Firing Projected Emissions [d] (TPY)	Projected Actual Emissions (TPY)	Increase/Decrease in Emissions (Projected – Baseline Actual) (TPY)		PSD Significant Emission Rates (TPY)
NO_x	1,610	2010 - 2009	0.0961	2,803,200.0	134.6	148.1	1,624	13.5	(1)	40
CO	567	2011 - 2010	0.05	2,803,200.0	65.9	54.9	556	-11.0		100
SO_2	3,026	2008 - 2007	0.16	2,803,200.0	225.7	10.5	2,811	-215.2		40
VOC	47	2008 - 2007	0.0025	2,803,200.0	3.5	23.8	67	20.3	(1)	40
PM	54	2008 - 2007	0.0029	2,803,200.0	4.0	6.5	56	2.5		25
PM_{10}	43	2010 - 2009	0.0026	2,803,200.0	3.6	2.6	42	-1.0		15
$PM_{2.5}$	43	2010 - 2009	0.0026	2,803,200.0	3.6	1.2	41	-2.5		10
SAM[e]	463	2008 - 2007	0.0247	2,803,200.0	34.6	1.6	430	-33.0		7
GHGs										
CO_2	4,251,254	2008 - 2007	225.7	2,803,200.0	316,380.8	289,760.1	4,224,633			
N_2O (CO_2e)	20,519	2008 - 2007	1.1	2,803,200.0	1,527.2	4,022.0	23,014			
CH_4 (CO_2e)	9,557	2008 - 2007	0.5	2,803,200.0	711.3	2,075.9	10,922			
Total GHGs (CO_2e)	4,281,330.6				318,619.3	295,858.0	4,258,569.3	-22,761.3		75,000[f]

(1) These emissions represent calculated emission increase due to an artifact of using emission factors. Since biomass is co-fired with coal and pet coke in small amounts (<10%), actual emissions for these combustion related pollutants are not expected to increase from existing coal/pet coke firing due to combustion controls inherent in the system.

[a] Based on AOR data for the period 2006 - 2010; see Table 6.

[b] See Table 7 for maximum heat input potential for wood chips.

[c] Emissions from coal/pet coke firing that is replaced by the heat input potential of maximum annual wood chip usage.

[d] Projected annual emissions for annual wood chip usage; see Table 7. See Tables A-1 and A-2 for fugitive emissions. PM esitmated at 4.67 TPY, PM_{10} at 0.94 TPY and $PM_{2.5}$ at 0.11 TPY.

[e] SAM emissions data are not available (NA) in the AORs for 2005 - 2009.

[f] Prior to July 21, 2014 biogenic CO_2 GHG emissions are not included in the calculation pursuant to 40 CFR 52.21 (b)(49)(ii)(a). Therefore, biogenic CO_2 emissions can be excluded from the projected actual emission calculation.

APPENDIX A

TABLE A-1
EMISSION CALCULATIONS FOR WOOD DELIVERY

Paved Roads (on-property roads, Heckscher Drive):

$E = k\ (sL/2)^{0.65}\ (W/3)^{1.5} - C$	PM	PM_{10}	$PM_{2.5}$	Sources and Data:
k	0.082	0.016	0.0024	AP-42, Section 13.2.1
sL (silt loading; g/m^2)	1	1	1	Silt loading from Golder 2001 (BBTT).
W (average weight)	22.5	22.5	22.5	32.5 tons loaded 12.5 tons unloaded
C (1980s emission factor)	0.00047	0.00047	0.00036	AP-42, Section 13.2.1
Emission Factor (lb/VMT)	1.0729	0.2090	0.0311	
Amount (tons)	175,200	175,200	175,200	240 tons/day/unit; 365 days per year
Trips (20 tons)	8,760	6,738	6,738	Hauling Distance on JEA Property:
Miles	1.89	1.89	1.89	(Estimated from construction traffic analysis)
Rainfall (1-P/4/365); P - precipitatio	0.92	0.92	0.92	5000 ft linear (maximum distance to stoarge area)
Emissions (lb)	16386.83	2455.12	364.87	1.89 miles roundtrip 16,591 miles traveled
				Precip. = 115.9 # days of precipitation >/= 0.01 inch; NOAA, 2008.
Additional Control:	70%	70%	70%	Watering and sweeping as necessary.
Emissions (lb)	4916.05	736.54	109.46	
Emissions (tons)	2.46	0.37	0.05	

Unloading Fill
Batch Drop

$E = k\ (0.0032)\ (U/5)^{1.3}\ /(M/2)^{1.4}$	PM	PM_{10}	$PM_{2.5}$	Sources and Data:
k	0.74	0.35	0.053	AP-42, Section 13.2.4
U (wind speed; mph)	6.7	6.7	6.7	Jacksonville International Airport (25-year average) NOAA 2008
M (moisture; %)	15	15	15	Conservative estimate, wood typically 25% or greated.
Emission Factor (lb/ton)	0.00020632	9.76E-05	1.48E-05	
Tons	175,200	175,200	175,200	240 tons/day; 365 days per year
Emissions (lb; uncontrolled)	36.15	17.10	2.59	
Emissions (tons)	0.02	0.01	0.00	

Sources:

EPA, 2006a; AP-42, Section 13.2.1 Paved Roads.
EPA, 2006c; AP-42, Section 13.2.4 for Aggregate Handling and Storage Piles.

TABLE A-2
EMISSION CALCULATIONS FOR WOOD LOADING INTO HOPPER

		PM	PM_{10}	$PM_{2.5}$	
Unpaved Roads (Frontend Loader Travel):					
		PM	**PM_{10}**	**$PM_{2.5}$**	**Sources and Data:**
$E = k \times (s/12)^a \times (w/3)^b$; where a = 0.7 and b= 0.45, k = 4.9 for	k	4.9	1.5	0.15	AP-42, Section 13.2.2; w = average tons; s = silt content
where a = 0.9 and b= 0.45, k = 1.5 for PM_{10}	s	4.8	4.8	4.8	Silt loading from Table 13.2.2-1 Sand and Gravel
where a = 0.9 and b= 0.45, k = 0.15 for $PM_{2.5}$	w	10.00	10.00	10.00	10.00 tons of grader Caperpillar 962K Wheeled Loaded
Emission Factor (lb/VMT)		4.44	1.13	0.11	
Amount (cubic yards)		415,831	415,831	415,831	31.2 lb/ft^3 bulk density; 240 tons/day
Grading Compacting Amount per Movement (cubic yards)		3.27	3.27	3.27	Caterpillat, Model 962k, 2012.
Movements		127,187	127,187	127,187	
Distance per movement (ft/movment)		200.0	200.0	200.0	
Distance (miles traveled; VMT)		4,818	4,818	4,818	
Rainfall (365-P)/365		0.68	0.68	0.68	Precip. = 115.9 NOAA, 2008 (30-year average)
Emissions (lb)		14,583	3,717	372	lb/VMT x VMT x rainfall factor
Additional Control:		70%	70%	70%	Watering
Emissions (lb)		4,375	1,115	112	
Emissions (tons)		2.19	0.56	0.06	
Unloading Wood					
Batch Drop					
$E = k\,(0.0032)\,(U/5)^{1.3}/(M/2)^{1.4}$		**PM**	**PM_{10}**	**$PM_{2.5}$**	**Sources and Data:**
k		0.74	0.35	0.053	AP-42, Section 13.2.4
U (wind speed; mph)		6.7	6.7	6.7	Jacksonville International Airport (25-year average) NOAA, 2008
M (moisture; %)		15	15	15	Conservative assumption.
Emission Factor (lb/ton)		2.06E-04	9.76E-05	1.48E-05	
Tons (loading and unloading)		87,600	87,600	87,600	Loading into the existing biomass hopper.
Emissions (lb; uncontrolled)		18.07	8.55	1.29	
Emissions (tons)		0.0090	0.0043	0.0006	

Sources:

EPA, 2006b; AP-42, Section 13.2.2 Unpaved Roads.
EPA, 2006c; AP-42, Section 13.2.4 for Aggregate Handling and Storage Piles.

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