Module AB069

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DIVISION OF AIR
RESOURCE MANAGEMENT

PERMIT APPLICATION

AIR CONSTRUCTION PERMIT APPLICATION TO BURN NATURAL GAS IN COGENERATION BOILER A

New Hope Power Company
Okeelanta Cogeneration Plant

Project No: 0990332-019-AC-
PSD-FL-196Q

Prepared For: New Hope Power Company
8001 U.S. Highway 27 South
South Bay, FL 33493

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

Distribution: 4 copies – FDEP
2 copies – New Hope Power Company
2 copies – Golder Associates Inc.

March 2012

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APPLICATION FOR AIR PERMIT

LONG FORM

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DIVISION OF AIR
RESOURCE MANAGEMENT

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

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

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

Air Operation Permit – Use this form to apply for:

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

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **New Hope Power Company**	
2. Site Name: **Okeelanta Cogeneration Plant**	
3. Facility Identification Number: **0990332**	
4. Facility Location... Street Address or Other Locator: **8001 U.S. Highway 27 South** City: **South Bay** County: **Palm Beach** Zip Code: **33493**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Matthew Capone, Director of Environmental Compliance**
2. Application Contact Mailing Address... Organization/Firm: **New Hope Power Company** Street Address: **8001 U.S. Highway 27 South** City: **South Bay** State: **FL** Zip Code: **33493**
3. Application Contact Telephone Numbers... Telephone: **(561) 993-1658** ext. Fax: **(561) 992-7326**
4. Application Contact E-mail Address: **Matthew_Capone@floridacrystals.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 3-15-12	3. PSD Number (if applicable):
2. Project Number(s): 0990332-019-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

With this air construction permit application, NHPC is proposing to install natural gas burners in Boiler A, which was originally authorized in Permit No. 0990332-013-AC/PSD-FL-196(L) and authorized by subsequent PSD permits through PSD-FL-196(P). Note that the heat input rate for burning natural gas will be reduced to 400 MMBtu/hr from the previously permitted 605 MMBtu/hr (Permit No. 0990005-017-AV).

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
001	Cogeneration Boiler A	A1CB	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 : **Jose Gonzalez, ~~Assistant~~ General Manager** and Vice-President
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **New Hope Power Company** Street Address: **8001 U.S. Highway 27 South** City: **South Bay** State: **FL** Zip Code: **33493**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(561) 993-1600** ext. Fax: **(561) 992-7326**
4.	Owner/Authorized Representative E-mail Address: **Jose_Gonzalez@floridacrystals.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] 3-12-12 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: **David A. Buff** Registration Number: **19011**
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. **21145** Fax: **(352) 336-6603**
4.	Professional Engineer E-mail Address: **dbuff@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.* David A. Buff 3/14/12 Signature Date (seal)

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

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **524.90** North (km) **2940.10**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **26°35'00"** Longitude (DD/MM/SS) **80°45'00"**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Matthew Capone, Director of Environmental Compliance**
2. Facility Contact Mailing Address... Organization/Firm: **New Hope Power Company** Street Address: **8001 U.S. Highway 27 South** City: **South Bay** State: **FL** Zip Code: **33493**
3. Facility Contact Telephone Numbers: Telephone: **(561) 993-1658** ext. Fax: **(561) 992-7326**
4. Facility Contact E-mail Address: **Matthew_Capone@floridacrystals.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:	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
Particulate Matter Total – PM	**A**	**N**
Particulate Matter – PM10	**A**	**N**
Particulate Matter – PM2.5	**A**	**N**
Sulfur Dioxide – SO2	**A**	**N**
Nitrogen Oxides – NOx	**A**	**N**
Carbon Monoxide – CO	**A**	**N**
Volatile Organic Compounds – VOC	**A**	**N**
Hydrogen Chloride – H106	**A**	**N**
Mercury Compounds – H114	**B**	**N**
Total Hazardous Air Pollutants – HAPs	**A**	**N**
Greenhouse Gases (GHGs)	**A**	**N**
Carbon Dioxide Equivalent (CO2e)	**A**	**N**

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

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

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

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

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

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☐ Attached, Document ID:__________ ☒ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☒ Attached, Document ID: Part B
3.	Rule Applicability Analysis: ☒ Attached, Document ID: Part B
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:__________
   ☒ Not Applicable (not an Acid Rain source)

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

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

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

Additional Requirements Comment

ATTACHMENT NHPC-FI-C1

FACILITY PLOT PLAN

LEGEND

Existing Approved Site Boundary

Source Locations

Current Boiler and ESP Buildings

PROPERTY BOUNDARY

REFERENCE

LABINS, 2004
Projection: Transverse Mercator Datum: NAD 27 Coordinate System: UTM Zone 17

110 0 110
Meters

PROJECT

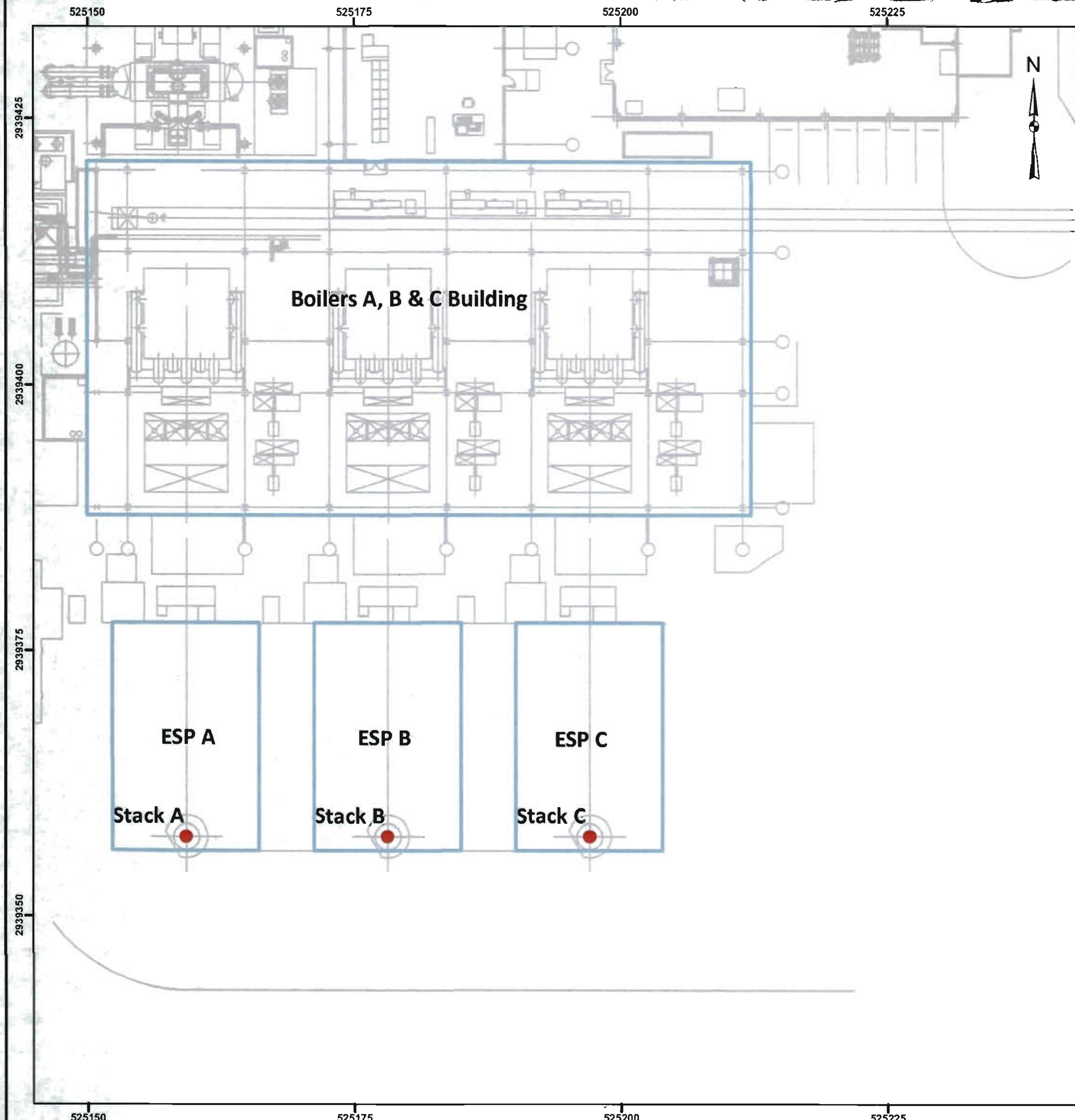
NHPC Boilers A, B, C

TITLE

NHPC EXISTING CERTIFIED SITE BOUNDARY

Golder Associates
Gainesville, Florida

PROJECT No. 073-87725			SCALE AS SHOWN	REV. 0
DESIGN	AB	14 Nov. 2008	**Attachment NHPC-FI-C1a**	
GIS	AB	14 Nov. 2008		
CHECK	PG	14 Nov. 2008		
REVIEW	DB	14 Nov. 2008		



LEGEND

● Source Locations

▭ Current Boiler and ESP Buildings

SITE BOUNDARY

REFERENCE

LABINS, 2004
Projection: Transverse Mercator Datum: NAD 27 Coordinate System: UTM Zone 17

10 0 10 Meters

PROJECT

NHPC Boilers A, B, C

TITLE

PLOT PLAN OF NHPC

Golder Associates
Gainesville, Florida

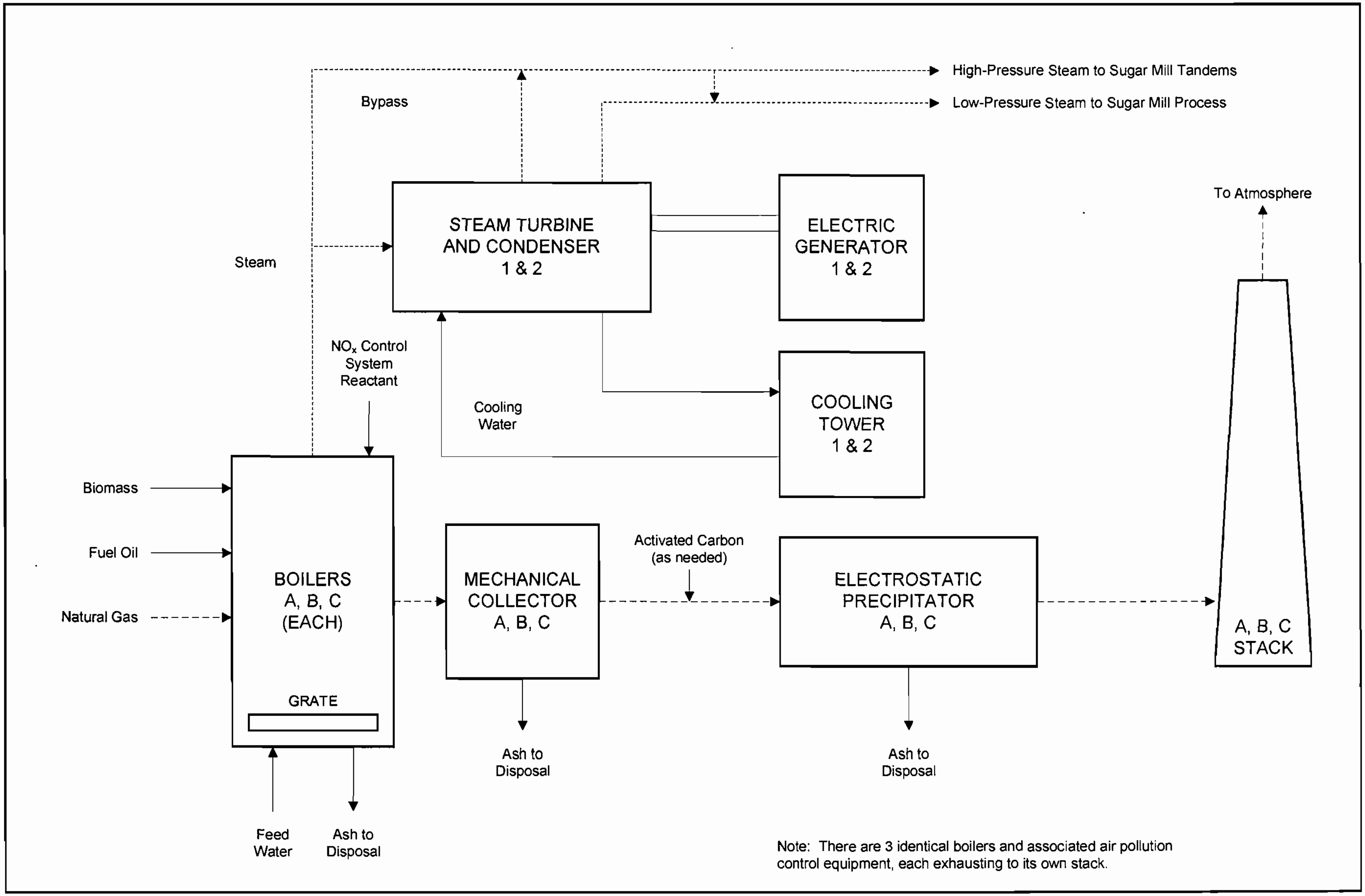
PROJECT No. 073-87725			
DESIGN	AB	14 Nov. 2008	
GIS	AB	14 Nov. 2008	
CHECK	PG	14 Nov. 2008	
REVIEW	DB	14 Nov. 2008	

SCALE AS SHOWN REV. 0

Attachment NHPC-FI-C1b

ATTACHMENT NHPC-FI-C2

PROCESS FLOW DIAGRAM



Attachment NHPC-FI-C2
Simplified Flow Diagram
New Hope Power Company, Okeelanta Cogeneration Facility
South Bay, FL

Process Flow Legend
Solid/Liquid ———▶
Steam ··········▶
Gas - - - - - -▶

Golder Associates

ATTACHMENT NHPC-FI-C3

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

ATTACHMENT NHPC-FI-C3

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

The New Hope Power Company (NHPC) takes reasonable precautions to prevent emissions of unconfined particulate matter at the cogeneration facility. These consist of the following:

- Enclosing conveyors and conveyor transfer points to preclude particulate emissions (except those directly associated with the stack/reclaimers, for which enclosure is operationally infeasible).
- Application of water sprays or chemical wetting agents and stabilizers to storage piles, handling equipment, unenclosed transfer points, etc., during dry periods as necessary to all facilities to maintain an opacity in compliance with the permit requirements.
- Enclosing the fly ash handling system including the transfer points and storage bin. The ash is wetted in the ash conditioner to minimize fugitive dust prior to it being discharged into the disposal bin.
- The mercury control system reactant storage silos are maintained at a negative pressure while operating with the exhaust vented to a filter control system. (Note: this system is currently inactive.)

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:
   Cogeneration Boiler A

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

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

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

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
   This boiler is a hybrid suspension grate unit fired by biomass (bagasse/wood) as the primary fuel. Distillate oil and natural gas are fired during startup and shutdown when necessary to ensure good combustion, to supplement biomass fuel, and during times when the biomass supply is interrupted.

Emissions Unit Control Equipment/Method: Control 1 of 4

1. Control Equipment/Method Description: **Electrostatic Precipitator – High Efficiency**	
2. Control Device or Method Code: **010**	

Emissions Unit Control Equipment/Method: Control 2 of 4

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

Emissions Unit Control Equipment/Method: Control 3 of 4

1. Control Equipment/Method Description: **Activated Carbon Injection System (currently inactive)**	
2. Control Device or Method Code: **048**	

Emissions Unit Control Equipment/Method: Control 4 of 4

1. Control Equipment/Method Description: **Multiple Cyclone without Fly Ash Reinjection**	
2. Control Device or Method Code: **076**	

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: **506,100 lb/hr steam**	
3. Maximum Heat Input Rate: **760** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **7** days/week **52** weeks/year **8,760** hours/year	
6. Operating Capacity/Schedule Comment: **Maximum production rate based on Permit No. 0990005-017-AV. Maximum heat input rate based on burning biomass. The maximum heat input rate from distillate oil is 490 MMBtu/hr. The maximum heat input rate from natural gas is 400 MMBtu/hr. Boiler operating pressure and temperature: 1,500 psig, 975°F. See Attachment NHPC-EU1-B6.**	

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: **Boiler A**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **199** feet	7. Exit Diameter: **10.0** feet
8. Exit Temperature: **332**°F	9. Actual Volumetric Flow Rate: **310,155** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: **10** feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Stack parameters based on 2012 compliance test data.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 4

1. Segment Description (Process/Fuel Type): **Electric Utility Boiler – Bagasse**		
2. Source Classification Code (SCC): **1-01-011-01**	3. SCC Units: **Tons burned (all solid fuels)**	
4. Maximum Hourly Rate: **105.56**	5. Maximum Annual Rate: **924,667**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash: **1.0**	9. Million Btu per SCC Unit: **7.2**
10. Segment Comment: **Based on 760 MMBtu/hr and 8,760 hr/yr. See Attachment NHPC-EU1-B6.**		

Segment Description and Rate: Segment 2 of 4

1. Segment Description (Process/Fuel Type): **Electric Utility Boiler – Wood-fired Boiler**		
2. Source Classification Code (SCC): **1-01-009-03**	3. SCC Units: **Tons burned (all solid fuels)**	
4. Maximum Hourly Rate: **89.41**	5. Maximum Annual Rate: **783,247**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.3**	8. Maximum % Ash: **9.0**	9. Million Btu per SCC Unit: **8.5**
10. Segment Comment: **Based on 760 MMBtu/hr and 8,760 hr/yr. See Attachment NHPC-EU1-B6.**		

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

Segment Description and Rate: Segment 3 of 4

1. Segment Description (Process/Fuel Type): **Electric Utility Boiler – Distillate Oil – Grades 1 and 2 Oil**		
2. Source Classification Code (SCC): **1-01-005-01**	3. SCC Units: **Thousand gallons burned**	
4. Maximum Hourly Rate: **3.551**	5. Maximum Annual Rate: **11,309**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **138**
10. Segment Comment: **Based on 490 MMBtu/hr heat input and heating value of 138,000 Btu/gal for No. 2 fuel oil. Maximum annual rate based on permit condition (Permit No. 0990005-017-AV), which limits oil firing to less than 25% of total heat input. See Attachment NHPC-EU1-B6.**		

Segment Description and Rate: Segment 4 of 4

1. Segment Description (Process/Fuel Type): **Electric Utility Boiler – Natural Gas**		
2. Source Classification Code (SCC): **1-01-006-01**	3. SCC Units: **Million standard cubic feet burned**	
4. Maximum Hourly Rate: **0.3891**	5. Maximum Annual Rate: **1,518**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,028**
10. Segment Comment: **Maximum hourly rate based on 400 MMBtu/hr. Maximum annual rate based on gas firing to be less than 25% of total heat input. See Attachment NHPC-EU1-B6.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	076	010	EL
PM10	076	010	EL
PM2.5	076	010	NS
SO2			EL
NOx	107		EL
CO			EL
VOC			EL
Mercury Compounds (H114)	048		EL
Hydrochloric Acid (H106)			NS
Total HAPs			NS
Lead (Pb)	076	010	NS
Fluoride (F)			NS
Sulfuric Acid Mist (SAM)			NS
Non-biogenic GHGs			NS
Non-biogenic CO2e			NS

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **19.8** lb/hour **86.55** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.026 lb/MMBtu** Reference: **Permit No. 0990332-017-AC/PSD-FL-196P**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **23.27** tons/year	8.b. Baseline 24-month Period: From: **01/2002** To: **12/2003**
9.a. Projected Actual Emissions (if required): **23.78** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years
10. Calculation of Emissions: **0.026 lb/MMBtu x 760 MMBtu/hr = 19.8 lb/hr** **19.8 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 86.55 TPY** **See Attachment NHPC-EU1-F1.10.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Based on biomass firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.026 lb/MMBtu**	4. Equivalent Allowable Emissions: **19.8** lb/hour **86.55** tons/year
5. Method of Compliance: **Annual stack testing using EPA Method 5.**	
6. Allowable Emissions Comment (Description of Operating Method): **Basis for allowable emissions code: BACT. Based on biomass firing.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.03 lb/MMBtu**	4. Equivalent Allowable Emissions: **22.8** lb/hour **99.86** tons/year
5. Method of Compliance: **Annual stack testing using EPA Method 5.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.405(2)(b), F.A.C., and 40 CFR 60.42a.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. 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: **19.8** lb/hour **86.55** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.026 lb/MMBtu (100% of PM)** Reference: **Permit No. 0990332-017-AC/PSD-FL-196P**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **23.27** tons/year	8.b. Baseline 24-month Period: From: **01/2002** To: **12/2003**
9.a. Projected Actual Emissions (if required): **23.78** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

0.026 lb/MMBtu x 760 MMBtu/hr = 19.8 lb/hr

19.8 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 86.55 TPY

See Attachment NHPC-EU1-F1.10.

11. Potential, Fugitive, and Actual Emissions Comment:

Based on biomass firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

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

1. Pollutant Emitted: **PM2.5**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **4.04** lb/hour **15.56** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0074 lb/MMBtu** Reference: **Based on AP-42, Table 1.4-2**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): **3.71** tons/year	8.b. Baseline 24-month Period: From: **01/2002** To: **12/2003**
9.a. Projected Actual Emissions (if required): **6.70** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

$7.6\ lb/10^6\ scf\ /\ 1,028\ MMBtu/10^6\ scf = 0.0074\ lb/MMBtu$

Hourly Emissions:
Natural gas: 0.0074 lb/MMBtu x 400 MMBtu/hr = 2.96 lb/hr
Remainder biomass: 0.00416 lb/MMBtu x 260 MMBtu/hr = 1.08 lb/hr
Total: 2.96 lb/hr + 1.08 lb/hr = 4.04 lb/hr

Annual Emissions:
Biomass: 0.00416 lb/MMBtu x 4,706,856 MMBtu/yr x 1 ton/2,000 lb = 9.79 TPY
Natural gas: 0.0074 lb/MMBtu x 1,560,595 MMBtu/yr x 1 ton/2,000 lb = 5.77 TPY
Total: 9.79 TPY + 5.77 TPY = 15.56 TPY

See Attachment NHPC-EU1-F1.10.

11. Potential, Fugitive, and Actual Emissions Comment:

Emission factor represents natural gas firing only. Potential hourly emissions based on combination of natural gas and biomass firing. Potential annual emissions based on gas firing to be less than 25% of total heat input.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **228.0** lb/hour **199.7** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.06 lb/MMBtu (12-month rolling average)** Reference: **Permit No. 0990332-017-AC/PSD-FL-196P**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **92.93** tons/year	8.b. Baseline 24-month Period: From: **01/2002** To: **12/2003**
9.a. Projected Actual Emissions (if required): **106.82** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

3-hour maximum: 0.30 lb/MMBtu x 760 MMBtu/hr = 228 lb/hr

24-hr rolling CEMS average: 0.20 lb/MMBtu x 760 MMBtu/hr = 152 lb/hr

30-day rolling CEMS average: 0.10 lb/MMBtu x 760 MMBtu/hr = 76.0 lb/hr

12-month rolling CEMS average: 0.06 lb/MMBtu x 760 MMBtu/hr = 45.6 lb/hr

Annual: 0.06 lb/MMBtu x 760 MMBtu/hr x 8,760 hr/yr x 1 ton/2,000 lb = 199.7 TPY

See Attachment NHPC-EU1-F1.10.

11. Potential, Fugitive, and Actual Emissions Comment:

Based on biomass firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 6

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.20 lb/MMBtu (24-hour rolling average)**	4. Equivalent Allowable Emissions: **152.0** lb/hour tons/year
5. Method of Compliance: **Continuous SO_2 monitor.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 2 of 6

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.10 lb/MMBtu (30-day rolling average)**	4. Equivalent Allowable Emissions: **76.0** lb/hour tons/year
5. Method of Compliance: **Continuous SO_2 monitor.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions = 0.10 lb/MMBtu, 30-day average. Based on biomass firing.**	

Allowable Emissions Allowable Emissions 3 of 6

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.06 lb/MMBtu (12-month rolling average)**	4. Equivalent Allowable Emissions: lb/hour **199.7** tons/year
5. Method of Compliance: **Continuous SO_2 monitor.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on biomass firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS (CONTINUED)

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 6

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05 percent sulfur**	4. Equivalent Allowable Emissions: lb/hour **39.01** tons/year
5. Method of Compliance: **Fuel analysis and limiting fuel oil burning to 24.9 percent.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on No. 2 fuel oil firing and BACT.**	

Allowable Emissions Allowable Emissions 5 of 6

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.2 lb/MMBtu**	4. Equivalent Allowable Emissions: **912** lb/hour tons/year
5. Method of Compliance: **Continuous SO_2 monitor.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.405(2)(c), F.A.C., and 40 CFR 60.43a(d)(2). Limit is for solid fuels. Based on biomass firing at 760 MMBtu/hr.**	

Allowable Emissions Allowable Emissions 6 of 6

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.2 lb/MMBtu**	4. Equivalent Allowable Emissions: **98** lb/hour tons/year
5. Method of Compliance: **Continuous SO_2 monitor.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.405(2)(c), F.A.C., and 40 CFR 60.43a(d)(2). Limit is for liquid or gaseous fuels. Based on No. 2 fuel oil firing at 490 MMBtu/hr.**	

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: **152.0** lb/hour **499.3** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.15 lb/MMBtu (30-day rolling average)** - Reference: **Permit No. 0990005-017-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **299.23** tons/year	8.b. Baseline 24-month Period: From: **01/2003** To: **12/2004**
9.a. Projected Actual Emissions (if required): **305.79** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

3-hour maximum: 0.20 lb/MMBtu x 760 MMBtu/hr = 152.0 lb/hr

30-day rolling average: 0.15 lb/MMBtu x 760 MMBtu/hr = 114.0 lb/hr

Annual: 0.15 lb/MMBtu x 760 MMBtu/hr x 8,760 hr/yr x 1 ton/2,000 lb = 499.3 TPY

See Attachment NHPC-EU1-F1.10.

11. Potential, Fugitive, and Actual Emissions Comment:

Based on biomass firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 4

1. Basis for Allowable Emissions Code: **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: **114.0** lb/hour **499.3** tons/year
5. Method of Compliance: **Continuous NO_x monitor.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on biomass firing as 30-day rolling average.**	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.60 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: **456** lb/hour tons/year
5. Method of Compliance: **Continuous NO_x monitor.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.405(2)(d), F.A.C., and 40 CFR 60.44a. Based on solid fuel firing at 760 MMBtu/hr.**	

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: **0.3 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: **147** lb/hour tons/year
5. Method of Compliance: **Continuous NO_x monitor.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.405(2)(d), F.A.C., and 40 CFR 60.44a. Based on liquid fuel firing at 490 MMBtu/hr.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 4 of 4

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.2 lb/MMBtu**	4. Equivalent Allowable Emissions: **80** lb/hour tons/year
5. Method of Compliance: **Continuous NO_x monitor.**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-296.405(2)(d), F.A.C., and 40 CFR 60.44a. Based on gas firing at 400 MMBtu/hr.**	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1,462.5** lb/hour **1,165.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **6.5 lb/MMBtu (1-hr max)** Reference: **CEM data**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **689.08** tons/year	8.b. Baseline 24-month Period: From: **01/2007** To: **12/2008**
9.a. Projected Actual Emissions (if required): **733.06** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

Cold start-up: 225 MMBtu/hr x 6.5 lb/MMBtu = 1,462.5 lb/hr

30-day rolling average: 0.50 lb/MMBtu x 760 MMBtu/hr = 380.0 lb/hr

12-month rolling average: 0.35 lb/MMBtu x 760 MMBtu/hr = 266.0 lb/hr

Annual: 0.35 lb/MMBtu x 760 MMBtu/hr x 8,760 hr/yr x 1 ton/2,000 lb = 1,165.1 TPY

See Attachment NHPC-EU1-F1.10 for calculations.

11. Potential, Fugitive, and Actual Emissions Comment:

Maximum emissions occur under cold-start-up conditions. Based on biomass firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.50 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: **380.0** lb/hour tons/year
5. Method of Compliance: **Continuous CO monitor.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.35 lb/MMBtu, 12-month rolling average**	4. Equivalent Allowable Emissions: lb/hour **1,165.1** tons/year
5. Method of Compliance: **Continuous CO monitor.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on biomass firing.**	

Allowable Emissions Allowable Emissions ____ of ____

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

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: **38.0** lb/hour **166.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.05 lb/MMBtu** Reference: **Permit No. 0990005-017-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **15.24** tons/year	8.b. Baseline 24-month Period: From: **01/2002** To: **12/2003**
9.a. Projected Actual Emissions (if required): **15.53** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years
10. Calculation of Emissions: **0.05 lb/MMBtu x 760 MMBtu/hr = 38.0 lb/hr** **38.0 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 166.4 TPY** **See Attachment NHPC-EU1-F1.10.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Based on biomass firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05 lb/MMBtu**	4. Equivalent Allowable Emissions: **38.0** lb/hour **166.4** tons/year
5. Method of Compliance: **Annual stack test using EPA Method 25A/18.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on biomass firing at 760 MMBtu/hr.**	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. 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: **0.064** lb/hour **0.28** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **8.40×10^{-5} lb/MMBtu** Reference: **Stack test data (highest 3-run average)**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **5.11×10^{-2}** tons/year	8.b. Baseline 24-month Period: From: **01/2002** To: **12/2003**
9.a. Projected Actual Emissions (if required): **5.20×10^{-2}** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly: **8.40×10^{-5} lb/MMBtu x 760 MMBtu/hr = 0.064 lb/hr**

Annual: **0.064 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 0.28 TPY**

See Attachment NHPC-EU1-F1.10.

11. Potential, Fugitive, and Actual Emissions Comment:
Based on biomass firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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 – H114**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.0041** lb/hour **0.018** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **5.4×10^{-6} lb/MMBtu** Reference: **Permit No. 0990005-017-AV**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): **1.48×10^{-3}** tons/year	8.b. Baseline 24-month Period: From: **01/2002** To: **12/2003**
9.a. Projected Actual Emissions (if required): **1.53×10^{-3}** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years
10. Calculation of Emissions: **Hourly: 5.4×10^{-6} lb/MMBtu x 760 MMBtu/hr = 0.0041 lb/hr** **Annual: 0.0041 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 0.018 TPY** **See Attachment NHPC-EU1-F1.10.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Based on biomass firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

<u>Allowable Emissions</u> Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **$5.4x10^{-6}$ lb/MMBtu**	4. Equivalent Allowable Emissions: **0.0041** lb/hour **0.018** tons/year
5. Method of Compliance: **Stack test using EPA Method 101A, 29, or 30B, conducted annually.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on biomass firing.**	

<u>Allowable Emissions</u> Allowable Emissions ____ of ____

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

<u>Allowable Emissions</u> Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **F**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.532** lb/hour **2.33** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **$7x10^{-4}$ lb/MMBtu** Reference: **Stack test data (highest 3-run average)**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): **0.64** tons/year	8.b. Baseline 24-month Period: From: **01/2002** To: **12/2003**
9.a. Projected Actual Emissions (if required): **0.65** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years
10. Calculation of Emissions: **Hourly: $7x10^{-4}$ lb/MMBtu x 760 MMBtu/hr = 0.532 lb/hr** **Annual: 0.532 lb/hr x 8,760 hr/yr x 1 ton/2,000 lb = 2.33 TPY** **See Attachment NHPC-EU1-F1.10.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Based on biomass firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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: **13.68** lb/hour **11.98** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **6% of SO_2 emissions** Reference: **Permit No. 0990332-017-AC/PSD-FL-196P**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **5.58** tons/year	8.b. Baseline 24-month Period: From: **01/2002** To: **12/2003**
9.a. Projected Actual Emissions (if required): **6.41** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years
10. Calculation of Emissions: **See Attachment NHPC-EU1-F1.10.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Based on biomass firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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: **Non-biogenic GHGs**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **79,900** lb/hour **127,424** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **163.06 lb/MMBtu** Reference: **See comment**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **4,915** tons/year	8.b. Baseline 24-month Period: From: **01/2009** To: **12/2010**
9.a. Projected Actual Emissions (if required): **66,678** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years
10. Calculation of Emissions: **See Attachment NHPC-EU1-F1.10.**	
11. Potential, Fugitive, and Actual Emissions Comment: **EPA's mandatory Reporting Rule, Tables C-1 and C-2. Potential hourly emissions based on No. 2 fuel oil. Biogenic CO_2 emissions from biomass are excluded per EPA biogenic deferral dated July 1, 2011. Potential annual emissions based on permit condition limiting fuel oil firing to less than 25% of the total heat input.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Non-biogenic CO2e**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **80,165** lb/hour **137,901** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **163.06 lb/MMBtu** Reference: **See comment**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **13,039** tons/year	8.b. Baseline 24-month Period: From: **01/2009** To: **12/2010**
9.a. Projected Actual Emissions (if required): **75,626** tons/year	9.b. Projected Monitoring Period: ☒ 5 years ☐ 10 years
10. Calculation of Emissions: **See Attachment NHPC-EU1-F1.10.**	
11. Potential, Fugitive, and Actual Emissions Comment: **EPA's mandatory Reporting Rule, Tables C-1 and C-2. Potential hourly emissions based on No. 2 fuel oil. Biogenic CO_2 emissions from biomass are excluded per EPA biogenic deferral dated July 1, 2011. Potential annual emissions based on permit condition limiting fuel oil firing to less than 25% of the total heat input.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **Continuous opacity monitor, or EPA Method 9.**	
5. Visible Emissions Comment: **40 CFR 60, Subpart Da, and Permit No. 0990332-016-AC/PSD-FL-196(P).**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 5

1. Parameter Code: VE	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Durag Model Number: D-R290	Serial Number: 31019
5. Installation Date: October 1, 1995	6. Performance Specification Test Date:
7. Continuous Monitor Comment: 40 CFR 60, Subpart Da.	

Continuous Monitoring System: Continuous Monitor 2 of 5

1. Parameter Code: EM	2. Pollutant(s): NOx
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Thermo Environmental Instruments Model Number: 42I	Serial Number: 42D-52618-292
5. Installation Date: October 1, 1995	6. Performance Specification Test Date:
7. Continuous Monitor Comment: 40 CFR 60, Subpart Da.	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor 3 of 5

1. Parameter Code: **EM**	2. Pollutant(s): **SO2**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **Thermo Environmental Instruments** Model Number: **43I**	Serial Number: **43B-51400-292**
5. Installation Date: **October 1, 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor 4 of 5

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **Thermo Environmental Instruments** Model Number: **48I**	Serial Number: **48-45334-273**
5. Installation Date: **October 1, 1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor 5 of 5

1. Parameter Code: O2	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Yokogawa Model Number: ZA8C	Serial Number: JJ113MA345
5. Installation Date: October 1, 1995	6. Performance Specification Test Date:
7. Continuous Monitor Comment: 40 CFR 60, Subpart Da.	

Continuous Monitoring System: Continuous Monitor ____ of ____

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

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

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

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: NHPC-EU1-I3 ☐ Previously Submitted, Date ____

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

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

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

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

EMISSIONS UNIT INFORMATION
Section [1]
Cogeneration Boiler A

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

ATTACHMENT NHPC-EU1-B6

OPERATING CAPACITY/SCHEDULE COMMENT

Attachment NHPC-EU1-B6a. Maximum Hourly Heat Input and Fuel Usage Rates, Boiler A
New Hope Power Company Cogeneration Facility

Fuel	Heat Input to Boiler	Heat Transfer Efficiency %	Heat Output to Steam	Fuel Firing Rate	
	Maximum Short-Term				
	(MMBtu/hr)		(MMBtu/hr)		
Biomass					
- Bagasse	760	68	516.8	105.56	tons/hr, dry [a]
- Wood	760	68	516.8	89.41	tons/hr, dry [b]
No. 2 Fuel Oil	490	85	416.5	3,551	gal/hr
Natural Gas	400	85	340.0	389,105	scf/hr
Max Fuel Oil + Bagasse					
Bagasse	147.5	68	100.3	20.49	tons/hr, dry [a]
No. 2 Fuel Oil	490.0	85	416.5	3,551	gal/hr
Natural Gas	0.0	85	0.0	0	scf/hr
Total	**637.5**		**516.8**		
Max Fuel Oil + Wood					
Wood	147.5	68	100.3	17.35	tons/hr, dry [b]
No. 2 Fuel Oil	490.0	85	416.5	3,551	gal/hr
Natural Gas	0.0	85	0.0	0	scf/hr
Total	**637.5**		**516.8**		
Max Natural Gas + Bagasse					
Bagasse	260	68	176.8	36.11	tons/hr, dry [a]
No. 2 Fuel Oil	0	85	0.0	0	gal/hr
Natural Gas	400	85	340.0	389,105	scf/hr
Total	**660**		**516.8**		
Max Natural Gas + Wood					
Wood	260	68	176.8	30.59	tons/hr, dry [a]
No. 2 Fuel Oil	0	85	0.0	0	gal/hr
Natural Gas	400	85	340.0	389,105	scf/hr
Total	**660**		**516.8**		

[a] Based on bagasse firing.

[b] Based on wood firing.

Notes:

Total steam production required = 506,100 lb/hr @ 1500 psig, 975°F.

Fuels may be burned in combination, not to exceed total heat outputs.

Based on fuel heating values as follows:

Bagasse, dry - 3,600 Btu/lb
Wood, dry - 4,250 Btu/lb
No. 2 Fuel Oil - 138,000 Btu/gal
Natural gas - 1,028 Btu/scf

Attachment NHPC-EU1-B6b. Maximum Annual Heat Input and Fuel Usage Rates, Boiler A
New Hope Power Company Cogeneration Facility

Fuel	Heat Input to Boiler (MMBtu/yr)	Heat Transfer Efficiency %	Heat Output to Steam (MMBtu/yr)	Annual Fuel Firing Rate [a]	
Normal Operations (100% Bagasse)					
Bagasse	6,657,600	68	4,527,168	924,667	tons/yr, dry
No. 2 Fuel Oil	0	85	0	0	gal/yr
Natural gas	0	85	0	0	MMscf/yr
Total	6,657,600		4,527,168		
Normal Operations (100% Wood)					
Wood	6,657,600	68	4,527,168	783,247	tons/yr, dry
No. 2 Fuel Oil	0	85	0	0	gal/yr
Natural gas	0	85	0	0	MMscf/yr
Total	6,657,600		4,527,168		
24.9% Oil Firing					
Biomass	4,706,856	68	3,200,662	653,730	tons/yr, dry [b]
No. 2 Fuel Oil	1,560,595	85	1,326,506	11,308,662	gal/yr
Natural gas	0	85	0	0	MMscf/yr
Total	6,267,451		4,527,168		
24.9% Natural Gas Firing					
Biomass	4,706,856	68	3,200,662	653,730	tons/yr, dry [b]
No. 2 Fuel Oil	0	85	0	0	gal/yr
Natural gas	1,560,595	85	1,326,506	1,518	MMscf/yr
Total	6,267,451		4,527,168		

[a] Based on 8,760 hr/yr operation.

[b] Based on heat content for bagasse.

Notes:

Total steam production required = 506,100 lb/hr @ 1500 psig, 975°F.

Fuels may be burned in combination, not to exceed total heat outputs.

Based on fuel heating values as follows:

Bagasse, dry - 3,600 Btu/lb
Wood, dry - 4,250 Btu/lb
No. 2 Fuel Oil - 138,000 Btu/gal
Natural gas- 1,028 Btu/scf

ATTACHMENT NHPC-EU1-F1.10

EMISSIONS CALCULATIONS

Attachment NHPC-EU1-F1.10a. Maximum Short-Term Emissions for Boiler A
New Hope Power Company Cogeneration Facility

Regulated Pollutant	Biomass				No. 2 Fuel Oil				Natural Gas				Max Fuel Oil, [b] Remainder Biomass Hourly Emissions (lb/hr)	Max Natural Gas, [c] Remainder Biomass Hourly Emissions (lb/hr)	Highest Hourly Emissions (lb/hr)
	Emission Factor (lb/MMBtu)	Ref	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)			
Particulate (PM)	0.026	1	760	19.8	0.026	1	490	12.7	0.0074	2	400	2.96	16.58	9.72	19.8
Particulate (PM_{10})	0.026	3	760	19.8	0.026	3	490	12.7	0.0074	2	400	2.96	16.58	9.72	19.8
Particulate ($PM_{2.5}$)	0.00416	4	760	3.16	0.0031	5	490	1.53	0.0074	2	400	2.96	2.14	4.04	4.04
Sulfur Dioxide (SO_2)															
- 3-hr Average	0.30	6	760	228	--		--	--	--		--	--	44.3	78.0	228.0
- 24-hr Rolling CEMS Average	0.20	1	--	152.0	0.20	1	490	98.0	0.0006	2	400	0.23	127.5	52.2	152.0
Carbon Monoxide															
- 1-hr Average (cold-startup) [a]	6.5	6	225	1,462.5	1.0	6	490	490	--		--	--	958.7	--	1,462.5
- 30 day rolling average	0.5	1	760	380.0	0.5	1	490	245	0.082	7	400	32.68	318.8	162.7	380.0
Nitrogen Oxides (NO_x)															
- 3 hr Average	0.20	6	760	152.0	--		--	--	--		--	--	29.5	29.5	152.0
- 30 day Rolling Average	0.15	1	760	114.0	0.15	1	490	73.5	0.15	1	400	60.0	95.6	99.0	114.0
Volatile Organic Compounds (VOC)	0.05	1	760	38.0	0.05	1	490	24.50	0.0054	2	400	2.16	31.9	15.2	38.0
Lead (Pb)	8.40E-05	8	760	0.0638	9.00E-06	9	490	4.41E-03	4.86E-07	2	400	1.95E-04	0.0168	0.0220	0.064
Mercury (Hg)	5.4E-06	1	760	4.10E-03	3.00E-06	9	490	1.47E-03	2.53E-07	10	400	1.01E-04	0.0023	0.0015	0.0041
Fluorides (F)	7.0E-04	8	760	0.532	2.70E-04	9	490	1.32E-01	--		--	--	0.236	0.1820	0.532
Sulfuric Acid Mist (SAM)	6% of SO_2	1	--	13.68	6% of SO_2	1	490	5.88	6% of SO_2	1	400	0.0140	7.650	3.134	13.68
Greenhouse Gases (GHGs):															
Biogenic Carbon Dioxide (CO_2) [d]	260.52	11	760	197,995	--		--	--	--		--	--	38,427	67,735	197,995
Non-Biogenic CO_2	--		--	--	163.05	11	490	79,896	116.89	11	400	46,756	79,896	46,756	79,896
Methane (CH_4)	0.0705	11	760	53.62	0.0066	11	490	3.24	0.0022	11	400	0.882	13.65	19.22	53.62
Nitrous Oxide (N_2O)	0.0093	11	760	7.04	0.00132	11	490	0.65	0.00022	11	400	0.088	2.01	2.50	7.04
Non-Biogenic GHG	0.0798	11	760	60.65	163.06	11	490	79,900	116.89	11	400	46,757	79,900	46,777	79,900
Non Biogenic (CO_2e)		12		3,307		12		80,165		12		46,801			80,165

Note:

[a] Under cold startup conditions, each boiler is limited to 150,000 lb/hr of steam. Heat input rate is based on this limited steam rate.

[b] Based on 490 MMBu/hr of fuel oil and 147.5 MMBtu/hr of biomass.

[c] Based on 400 MMBtu/hr of Natural gas and 260 MMBtu/hr of biomass

[d] Based on emission factor for bagasse which results in worst case emissions.

References:

1. Based on Permit No. 0990332-017-AC/PSD-FL-196(P).
2. AP-42, Table 1.4-2.
3. Based on Permit No. 0990332-017-AC/PSD-FL-196(P), Specific Condition No. 16(e). PM_{10} emissions assumed to be 100 percent of PM.
4. AP-42, Table 1.6-5, for wood/bark fired boilers. $PM_{2.5}$ emission factor is 16 percent of PM.
5. AP-42 Table 1.3-6, PM emissions from uncontrolled distillate oil firing. $PM_{2.5}$ emission factor is 12 percent of PM.
6. Based on CEMS data.
7. AP-42, Table 1.4-1, controlled gas combustion in low-NO_x burners.
8. Based on stack testing performed on Cogeneration Boiler A, Cogeneration Boiler B (EU 002), and Cogeneration Boiler C (EU 003) between 1999 and 2002. Highest 3-run average used.
9. AP-42, Table 1.3-10 for distillate oil firing.
10. AP-42, Table 1.4-4.
11. Based on Greenhouse Gas Reporting Rule (40 CFR 98 Subpart C - General Stationary Fuel Combustion Sources). Emission factors are as follows:

Fuel	Emission Factors (kg/MMBtu)		
	CO_2	CH_4	N_2O
Distillate Oil	73.96	0.003	0.0006
Bagasse	118.2	0.032	0.0042
Natural Gas	53.02	0.001	0.0001

12. GHG = sum of emission rates of CO_2, CH_4, and N_2O on a mass basis. CO_2e = sum of emission rates of CO_2, CH4, and N_2O using global warming potentials (GWP). GWP: CO_2 = 1, CH_4 = 21, and N_2O = 310. GHG = $CO_2 + CH_4 + N_2O$, $CO_2e = CO_2 + 21*CH_4 + 310*N_2O$

Attachment NHPC-EU1-F1.10b. Maximum Annual Emissions for Boiler A
New Hope Power Company Cogeneration Facility

Regulated Pollutant	Biomass Emission Factor (lb/MMBtu)	Biomass Ref	Biomass Activity Factor (MMBtu/yr)	Biomass Annual Emissions (TPY)	Alternate Fuel Emission Factor (lb/MMBtu)	Alternate Fuel Ref	Alternate Fuel Activity Factor (MMBtu/yr)	Alternate Fuel Annual Emissions (TPY)	Total Annual Emissions (TPY)
100% Biomass									
Particulate Matter (PM)	0.026	1	6,657,600	86.55	--	--	--	--	86.55
Particulate Matter (PM_{10})	0.026	1	6,657,600	86.55	--	--	--	--	86.55
Particulate Matter ($PM_{2.5}$)	0.00416	1	6,657,600	13.85	--	--	--	--	13.85
Sulfur dioxide [a] (SO_2)	0.06	2	6,657,600	199.73	--	--	--	--	199.7
Nitrogen oxides [b] (NOx)	0.15	1	6,657,600	499.32	--	--	--	--	499.3
Carbon monoxide [a] (CO)	0.35	2	6,657,600	1165.08	--	--	--	--	1,165.1
Volatile Organic Compounds (VOC)	0.05	1	6,657,600	166.44	--	--	--	--	166.4
Lead (Pb)	8.40E-05	1	6,657,600	0.280	--	--	--	--	0.280
Mercury (Hg)	5.40E-06	1	6,657,600	0.0180	--	--	--	--	0.018
Fluorides (F)	7.0E-04	1	6,657,600	2.330	--	--	--	--	2.33
Sulfuric Acid Mist (SAM)	6% of SO_2	1	--	11.98	--	--	--	--	11.98
75.1% Biomass / 24.9% Fuel Oil									
Particulate Matter (PM)	0.026	1	4,706,856	61.19	0.026	1	1,560,595	20.29	81.48
Particulate Matter (PM_{10})	0.026	1	4,706,856	61.19	0.026	1	1,560,595	20.29	81.48
Particulate Matter ($PM_{2.5}$)	0.00416	1	4,706,856	9.79	0.0031	1	1,560,595	2.43	12.22
Sulfur dioxide [a] (SO_2)	0.06	2	4,706,856	141.21	0.05	2	1,560,595	39.01	180.22
Nitrogen oxides [b] (NOx)	0.15	1	4,706,856	353.01	0.15	1	1,560,595	117.04	470.06
Carbon monoxide [a] (CO)	0.35	2	4,706,856	823.70	0.35	2	1,560,595	273.10	1,097
Volatile Organic Compounds (VOC)	0.05	1	4,706,856	117.67	0.050	1	1,560,595	39.01	156.69
Lead (Pb)	8.40E-05	1	4,706,856	0.198	9.0E-06	1	1,560,595	7.02E-03	0.205
Mercury (Hg)	5.4E-06	1	4,706,856	0.0127	3.0E-06	1	1,560,595	2.34E-03	0.015
Fluorides (F)	7.0E-04	1	4,706,856	1.65	2.70E-04	1	1,560,595	0.211	1.86
Sulfuric Acid Mist (SAM)	6% of SO_2	1	--	8.47	6% of SO2	1	1,560,595	2.34	10.81
75.1% Biomass / 24.9% Natural Gas									
Particulate Matter (PM)	0.026	1	4,706,856	61.19	0.0074	1	1,560,595	5.77	66.96
Particulate Matter (PM_{10})	0.026	1	4,706,856	61.19	0.0074	1	1,560,595	5.77	66.96
Particulate Matter ($PM_{2.5}$)	0.00416	1	4,706,856	9.79	0.0074	1	1,560,595	5.77	15.56
Sulfur dioxide [a] (SO_2)	0.06	2	4,706,856	141.21	0.00058	1	1,560,595	0.46	141.66
Nitrogen oxides [b] (NOx)	0.15	2	4,706,856	353.01	0.15	2	1,560,595	117.04	470.06
Carbon monoxide [a] (CO)	0.35	1	4,706,856	823.70	0.082	1	1,560,595	63.75	887
Volatile Organic Compounds (VOC)	0.05	1	4,706,856	117.67	0.0054	1	1,560,595	4.21	121.88
Lead (Pb)	8.40E-05	1	4,706,856	0.198	4.86E-07	1	1,560,595	3.80E-04	0.20
Mercury (Hg)	5.4E-06	1	4,706,856	0.0127	2.53E-07	1	1,560,595	1.97E-04	0.013
Fluorides (F)	7.0E-04	1	4,706,856	1.65	--		--	--	1.65
Sulfuric Acid Mist (SAM)	6% of SO_2	1	--	8.47	6% of SO_2	1	1,560,595	0.03	8.50

Maximum Annual Emissions	
Particulate Matter (PM)	86.55
Particulate Matter (PM_{10})	86.55
Particulate Matter ($PM_{2.5}$)	15.56
Sulfur dioxide [a] (SO_2)	199.73
Nitrogen oxides [b] (NOx)	499.32
Carbon monoxide [a] (CO)	1,165.1
Volatile Organic Compounds (VOC)	166.44
Lead (Pb)	0.28
Mercury (Hg)	0.018
Fluorides (F)	2.33
Sulfuric Acid Mist (SAM)	11.98

[a] Based on 12-month rolling average.
[b] Based on 30-day rolling average.

References:
1. Refer to Attachment NHPC-EU1-F1.10a.
2. Based on Permit No. 0990332-017-AC/PSD-FL-196(P).

Attachment NHPC-EU1-F1.10c. Maximum Annual Greenhouse Gas Emissions for Boiler A
New Hope Power Company Cogeneration Facility

	Biomass				Alternate Fuel				
Regulated Pollutant	Emission Factor (lb/MMBtu)	Ref	Activity Factor (MMBtu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Ref	Activity Factor (MMBtu/yr)	Annual Emissions (TPY)	Total Annual Emissions (TPY)
100% Bagasse									
Biogenic Carbon Dioxide (CO_2)	260.52	1	6,657,600	867,219	--	--	--	--	867,219
Non-Biogenic CO_2	--	--	--	--	--	--	--	--	--
Methane (CH_4)	0.0705	1	6,657,600	234.84	--	--	--	--	234.84
Nitrous Oxide (N_2O)	0.0093	1	6,657,600	30.82	--	--	--	--	30.82
Non-Biogenic GHG	0.0798	1	6,657,600	265.66	--	--	--	--	266
Non Biogenic (CO_2e)	--	2	--	14,487	--	--	--	--	14,487
100% Wood/Wood Waste									
Biogenic Carbon Dioxide (CO_2)	206.79	1	6,657,600	688,374	--	--	--	--	688,374
Non-Biogenic CO_2	--	--	--	--	--	--	--	--	--
Methane (CH_4)	0.0705	1	6,657,600	234.84	--	--	--	--	234.84
Nitrous Oxide (N_2O)	0.0093	1	6,657,600	30.82	--	--	--	--	30.82
Non-Biogenic GHG	0.0798	1	6,657,600	265.66	--	--	--	--	266
Non Biogenic (CO_2e)	--	2	--	14,487	--	--	--	--	14,487
75.1% Bagasse / 24.9% Fuel Oil									
Biogenic Carbon Dioxide (CO_2)	260.52	1	4,706,856	613,115	--	--	--	--	613,115
Non-Biogenic CO_2	--	--	--	--	163.05	6	1,560,595	127,230	127,230
Methane (CH_4)	0.0705	1	4,706,856	166.03	0.0066	6	1,560,595	5.16	171.19
Nitrous Oxide (N_2O)	0.0093	1	4,706,856	21.79	0.00132	6	1,560,595	1.03	22.82
Non-Biogenic GHG	0.0798	1	4,706,856	187.82	163.06	6	1,560,595	127,237	127,424
Non Biogenic (CO_2e)	--	2	--	10,242	--	7	--	127,659	137,901
75.1% Wood / 24.9% Fuel Oil									
Biogenic Carbon Dioxide (CO_2)	206.79	1	4,706,856	486,673	--		--	--	486,673
Non-Biogenic CO_2	--	--	--	--	163.05	6	1,560,595	127,230	127,230
Methane (CH_4)	0.0705	1	4,706,856	166.03	0.0066	6	1,560,595	5.16	171.19
Nitrous Oxide (N_2O)	0.0093	1	4,706,856	21.79	0.00132	6	1,560,595	1.03	22.82
Non-Biogenic GHG	0.0798	1	4,706,856	187.82	163.06	6	1,560,595	127,237	127,424
Non Biogenic (CO_2e)	--	2	--	10,242	--	7	--	127,659	137,901
75.1% Bagasse / 24.9% Natural Gas									
Biogenic Carbon Dioxide (CO_2)	260.52	1	4,706,856	613,115	--		--	--	613,115
Non-Biogenic CO_2	--	--	--	--	116.89	6	1,560,595	91,208	91,208
Methane (CH_4)	0.0705	1	4,706,856	166.03	0.0022	6	1,560,595	1.72	167.75
Nitrous Oxide (N_2O)	0.0093	1	4,706,856	21.79	0.00022	6	1,560,595	0.17	21.96
Non-Biogenic GHG	0.0798	1	4,706,856	187.82	116.89	6	1,560,595	91,210	91,398
Non Biogenic (CO_2e)	--	2	--	10,242	--	7	--	91,298	101,540
75.1% Wood / 24.9% Natural Gas									
Biogenic Carbon Dioxide (CO_2)	206.79	1	4,706,856	486,673	--		--	--	486,673
Non-Biogenic CO_2	--	--	--	--	116.89	6	1,560,595	91,208	91,208
Methane (CH_4)	0.0705	1	4,706,856	166.03	0.0022	6	1,560,595	1.72	167.75
Nitrous Oxide (N_2O)	0.0093	1	4,706,856	21.79	0.00022	6	1,560,595	0.17	21.96
Non-Biogenic GHG	0.0798	1	4,706,856	187.82	116.89	6	1,560,595	91,210	91,398
Non Biogenic (CO_2e)	--	2	--	10,242	--	7	--	91,208	101,450
								Maximum Annual Emissions	
								Biogenic Carbon Dioxide (CO_2)	867,219
								Non-Biogenic CO_2	127,230
								Methane (CH_4)	234.84
								Nitrous Oxide (N_2O)	30.82
								Non-Biogenic GHG	127,424
								Non Biogenic (CO_2e)	137,901

References:

1. Based on Greenhouse Gas Reporting Rule (40 CFR 98 Subpart C - General Stationary Fuel Combustion Sources). Emission factors are as follows:

	Emission Factors (kg/MMBtu)		
Fuel	CO_2	CH_4	N_2O
Distillate Oil	73.96	0.003	0.0006
Wood and Wood Waste	93.8	0.032	0.0042
Bagasse	118.2	0.032	0.0042
Natural Gas	53.02	0.001	0.0001

2. GHG = sum of emission rates of CO_2, CH_4, and N_2O on a mass basis. CO_2e = sum of emission rates of CO_2, CH_4, and N_2O using global warming potentials (GWP). GWP: CO_2 = 1, CH_4 = 21, and N_2O = 310. GHG = $CO_2 + CH_4 + N_2O$, $CO_2e = CO_2 + 21{*}CH_4 + 310{*}N_2O$

ATTACHMENT NHPC-EU1-I2

FUEL ANALYSIS OR SPECIFICATION

ATTACHMENT NHPC-EU1-I2

DESIGN FUEL SPECIFICATIONS[a] FOR THE NEW HOPE POWER COMPANY COGENERATION FACILITY

Parameter	Bagasse	Wood Waste	No. 2 Fuel Oil	Natural Gas
Specific Gravity			0.865	
Heating Value (Btu/lb)	3,600	4,250	19,175	
Heating Value (Btu/gal)			138,000	
Heating Value (Btu/scf)				1,028
Ultimate Analysis (dry basis percentage):				
Carbon	48.93	49.58	87.01	
Hydrogen	6.14	5.87	12.47	
Nitrogen	0.25	0.40	0.02	
Oxygen	43.84	40.90	0.00	
Sulfur	0.03	0.07	0.05	
Ash/Inorganic	1.0	9.0	0.00	
Moisture	52	37	–	

[a] Represents average fuel characteristics.

Sources: New Hope Power Partnership, 2002; Combustion Engineering, 1981.

ATTACHMENT NHPC-EU1-I3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

ATTACHMENT NHPC-EU1-I3
DETAILED DESCRIPTION OF CONTROL EQUIPMENT

The cogeneration facility utilizes several emission control techniques to reduce emissions. A selective non-catalytic reduction (SNCR) system is used to reduce NO_x emissions. Further, the cogeneration boilers minimize CO and VOC through proper furnace design and good combustion practices, including: control of combustion air and combustion temperature; distribution of fuel on the combustion grate; and controls over the furnace loads and transient conditions. Particulate emissions are controlled by an ESP. Multiple cyclones were installed during the 2000 calendar year to improve control of particulate emissions. Mercury emissions are controlled through a carbon injection system and the ESP system. (Note: the carbon injection system is currently inactive.)

Electrostatic Precipitator

The ESPs for the New Hope Power Company facility are manufactured by Flakt, Inc. Design specifications for the ESP (one per boiler) are provided below:

Chambers: 1
Collecting Plate: 12.30 ft L x 39.37 ft H
Fields/Chamber: 3
Specific Collection Area: 200 ft^2/1,000 acfm (minimum)
Gas Velocity: < 4 ft/s
Pressure Drop: less than 2.8 inches H_2O
Operating Temperature: 350°F
Ash Handling: Trough hopper with screw conveyor
Particulate removal efficiency: > 99.2%

NO_x Control System

The NO_x control system design employs a urea injection system manufactured by Nalco-Fueltech for NO_x control. The technology is a selective non-catalytic reduction process, which reduces NO_x emissions through chemical reaction with urea. In the process, urea is injected into the flue gas stream and reacts with nitrogen oxides to form nitrogen and water vapor.

The NO_x control system includes the following major components:

- Carrier air compressors
- Urea tank
- Urea/air flow controls
- Control panel

- Injection manifolds and injectors
- Valves and instrumentation

A single urea storage tank system is installed to supply urea to all three boilers. Urea for injection into the boilers is drawn from the tank. Two injection zones are used to provide injection at full and part load conditions. Each zone has six injectors. Zone switching valves will direct the urea/carrier mixture to the appropriate injection zone.

Specifications for the urea injection system to meet the NO_x emission rate of 0.15 lb/MMBtu when firing biomass or No. 2 fuel oil are provided below (on a per boiler basis):

Urea injection rate: 65 gal/hr (max)
Ammonia Slip (biomass, No. 2 fuel oil, natural gas): 25 ppm (max)

Mercury Control System

The mercury control system, manufactured by ABB Environmental Systems and Chemco, Inc., is stored on-site. In the case where the system must be connected to the boilers, it will function as follows. A volumetric feeder with integral supply hopper will meter activated carbon for injection at a point in the ductwork between the ESP and the ID fan. This will promote turbulent mixing and provide adequate residence time. A blower system will then transport the carbon to the injection point. The ESP will effectively capture the activated carbon particles along with the boiler fly ash (which also contains some carbon). The system is designed to inject up to 13 lb/hr of carbon into the flue gases of each boiler. (Note: the carbon injection system is currently inactive.)

Dust Control System

The cyclone dust collectors are supplied by Barron Industries, Model 460 Tube Base III 9K15 2023 AU. These are mechanical cyclone dust collectors which remove larger size particulate matter prior to the ESP. There are 460 cyclone tubes in all.

PART B

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1.0 INTRODUCTION

New Hope Power Company (NHPC) operates a 140-megawatt (MW) net electric cogeneration facility located adjacent to the Okeelanta Corporation sugar mill, approximately 6 miles south of South Bay in Palm Beach County, Florida. The facility has three essentially identical cogeneration boilers (Cogeneration Boilers A, B, and C) that combust primarily biomass (bagasse and wood) to generate steam and electricity. The cogeneration facility generates steam to produce electrical energy year-round, but also supplies the adjacent sugar mill with process steam during the sugar cane grinding season, approximately October through March. The facility also supplies the Okeelanta sugar refinery with process steam year-round.

Cogeneration Boiler A currently burns biomass (bagasse and wood) and No. 2 fuel oil to generate steam. NHPC is requesting authorization to install four (4) natural gas burners in Cogeneration Boiler A [Emissions Unit Identification Number (EUID) 001]. Each burner will have a rating of 100 million British thermal units per hour (MMBtu/hr), for a total natural gas firing capability of 400 MMBtu/hr. This will match the existing natural gas burning capability of Boilers B and C.

Cogeneration Boiler A was previously permitted to burn natural gas (Permit Nos. 0990332-013-AC/PSD-FL-196L through 0990332-017-AC/PSD-FL-196P); however, natural gas burners were never installed in Cogeneration Boiler A. Natural gas will be burned as a secondary fuel, similar to the manner in which No. 2 fuel oil is currently burned. Biomass (bagasse and wood) will remain the primary fuel. Natural gas will be used as a supplemental fuel to biomass, for flame and load stabilization, as well as during periods of startup, shutdown, and malfunction. Additionally, natural gas may be fired alone at certain times up to the full natural gas firing capability.

The price of fossil fuels, including No. 2 fuel oil, is on the rise and constantly subject to market changes. The cost of burning procured wood is also on the rise. To remain competitive, NHPC needs the ability to switch between the most cost-effective fuels available. NHPC is planning the firing of natural gas in Cogeneration Boiler A prior to the start of the 2012-2013 sugar cane crop season, beginning approximately in October 2012. Cogeneration Boiler A will have an outage prior to the beginning of the crop season when the burners must be installed. Therefore, NHPC requests that an air construction permit for the installation of the burners be issued as soon as possible.

The NHPC facility is an existing major source under the prevention of significant deterioration (PSD) new source review (NSR) regulations. NHPC has performed a PSD applicability analysis for the proposed project using the "baseline actual-to-projected actual" emission comparison allowed under Rule 62-212.400(2)(a)1 of the Florida Administrative Code (F.A.C.). Based on this comparison, all emissions increases due to the project are less than the PSD significant emission rates (SERs), as shown in Table 4-8 in Section 4.0. Therefore, the project will not trigger PSD NSR under federal and state air regulations.

A more detailed description of the proposed project is presented in Section 2.0. Preconstruction review requirements are discussed in Section 3.0, and air emission estimates and PSD applicability are presented in Section 4.0.

2.0 PROJECT DESCRIPTION

2.1 Existing Operations

Cogeneration Boiler A at the NHPC facility is currently limited to burning biomass (bagasse and wood/wood waste) as its primary fuel, with natural gas and No. 2 (distillate) fuel oil as auxiliary fuels. Distillate fuel oil with a maximum sulfur content of 0.05 percent by weight can be fired at startup and shutdown, as well as when necessary to ensure good combustion, to supplement biomass fuel, and for periods when the biomass fuel supply is interrupted. Natural gas burners were never installed in Cogeneration Boiler A, and so natural gas has never been burned in the boiler. The firing of all fossil fuels is limited to 25 percent of the total heat input to Boiler A during any calendar quarter.

Boiler A is currently permitted for the following operation:

Fuel	Maximum Heat Input Rate (MMBtu/hr)
100-Percent Biomass (bagasse or wood/wood waste) [1]	760
100-Percent Natural Gas	605 [2]
100-Percent No. 2 (Distillate) Fuel Oil	490

[1] Authorized wood is clean construction and demolition wood debris, yard trash, land clearing debris, and other cellulose and vegetative matter. No more than 30 percent by weight of yard waste (yard trash), as defined as municipal solid waste in 40 CFR 60.51a, may be combusted on a calendar quarter basis.

[2] Natural gas burners have never been installed in Boiler A.

Cogeneration Boiler A is a spreader-stoker steam boiler manufactured by Combustion Engineering and designed to produce approximately 506,100 pounds per hour (lb/hr) of steam at 1,500 pounds per square inch gauge (psig) and 975 degrees Fahrenheit (°F). Pollution control equipment includes a selective non-catalytic reduction (SNCR) system to reduce nitrogen oxide (NO_x) emissions, and mechanical dust collectors and an electrostatic precipitator (ESP) to reduce particulate matter (PM) emissions. Good operating practices and efficient combustion of clean, low-sulfur fuels minimizes emissions of carbon monoxide (CO), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOCs). Continuous emissions monitoring systems (CEMS) are required to measure emissions of SO_2, NO_x, and CO. The emission limitations to which Boiler A is subject are as follows:

- PM – 0.026 pound per million British thermal units (lb/MMBtu) and 19.8 lb/hr
- SO_2 – 0.20 lb/MMBtu (24-hour rolling CEMS average), 0.10 lb/MMBtu (30-day rolling CEMS average), 0.06 lb/MMBtu (12-month rolling CEMS average), and 152.0 lb/hr (24-hour rolling average)
- NO_x – 0.15 lb/MMBtu and 114.0 lb/hr (30-day rolling CEMS average)

- CO – 0.50 lb/MMBtu (30-day rolling CEMS average), 0.35 lb/MMBtu (12-month rolling CEMS average), and 380.0 lb/hr (30-day rolling average)
- VOC – 0.05 lb/MMBtu and 38.0 lb/hr
- Mercury (Hg) – 5.4×10^{-6} lb/MMBtu

2.2 Proposed Operations

NHPC is requesting authorization to install natural gas burners in Boiler A in order to burn natural gas as an auxiliary fuel to be fired at startup and shutdown, as well as when necessary to ensure good combustion, to supplement biomass fuel, and for periods when the biomass fuel supply is interrupted. Natural gas only may also be fired for base load steam generation. The price of fossil fuels, including distillate oil, as well as wood fuel, is on the rise and subject to market changes. To remain competitive, NHPC needs the ability to switch between the most cost-effective fuels available.

The facility intends to purchase four (4) natural gas burners for Boiler A, which will be installed in each of the four corners of the boiler. Each burner will have a maximum design heat input rate of 100 MMBtu/hr, which will result in maximum heat input rate to the boiler due to natural gas of 400 MMBtu/hr. As already required by its existing permit (Permit No. 0990032-017-AC/PSD-FL-192P), natural gas will not be burned for more than 25 percent of the heat input to the boiler during any calendar quarter.

The addition of the natural gas burners will result in a physical change to Boiler A. NHPC is planning on installing the natural gas burners prior to the beginning of the 2012 sugar cane crop season, which will begin in October 2012. The boiler will be shut down at some point prior to the 2012 sugar cane crop season (most likely during the summer), and this would be the only available time for the natural gas burners to be installed prior to the 2012-2013 crop season.

The installation of the burners will include the following:

- Burner elements, including tilting air nozzles and gas injectors
- Natural gas pilots
- Flame scanners for main burners
- Main and pilot piping module assembly
- Burner gas shutoff and vent valves
- Flexible gas hoses to burners
- Burner management system
- Interconnecting piping, tubing, conduit, and wiring

The natural gas burners will be installed at the location of the existing overfire air nozzles located in each corner of the boiler. Two of the five nozzles in each corner will be replaced with the natural gas burners.

The installation of natural gas burners will not result in an increase in steam production from Boiler A, and therefore will have no effect on any other emission units at the NHPC facility.

3.0 AIR QUALITY REVIEW REQUIREMENTS

3.1 PSD Review Requirements

The NHPC facility is located in an area of Florida that is in attainment with the national ambient air quality standards (NAAQS) for all regulated pollutants. Therefore, the proposed project is being evaluated under the PSD provisions of the NSR permitting program. A PSD review is used to determine whether significant air quality deterioration will result from a new major facility or a major modification at an existing facility. The NHPC facility is an existing major stationary source because the potential emissions of at least one PSD-regulated pollutant exceed 100 tons per year (TPY) (for example, potential NO_x emissions currently exceed 100 TPY). Therefore, PSD review is required for any pollutant for which the net increase in emissions due to the modification is greater than the PSD SER.

Federal PSD requirements are contained in Title 40, Part 52.21 of the Code of Federal Regulations (40 CFR 52.21), Prevention of Significant Deterioration of Air Quality. The Florida Department of Environmental Protection (FDEP) has adopted PSD regulations that are equivalent to the federal PSD regulations (Rule 62-212.400, F.A.C.). For an existing major stationary source for which a modification is proposed, the modification is subject to PSD review if it causes two types of emissions increases – a significant emissions increase and a significant net emissions increase. In the first step, emissions increases from the project itself are computed and compared to the PSD SERs. The relevant PSD SERs are listed in Table 3-1. If the increases are less than the SERs, then no further analysis is necessary and PSD permitting is not required. If the increases for the project itself exceed the SERs, then the second step involves additional analysis to determine if there will be a significant net emissions increase.

The determination of whether a significant emissions increase will occur is based on a comparison of "baseline actual emissions" to "projected actual emissions" for all emissions units affected by the proposed project. "Baseline actual emissions" and "projected actual emissions" are defined in Rules 62-210.200(36) and (244), F.A.C. "Baseline actual emissions" for an existing emissions unit, other than an electric utility steam generating unit, is the average rate, in TPY, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period, selected by the owner/operator, within the 10-year period immediately preceding the date a complete permit application is received by FDEP. The average rate includes fugitive emissions to the extent quantifiable and emissions associated with startups and shutdowns. The average rate must be adjusted downward to exclude:

- Any non-compliant emissions that occurred while the emissions units were operating above an emissions limitation that was legally enforceable during the consecutive 24-month period.
- Any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had such major stationary source been required to comply with such limitation during the consecutive 24-month period.

For projects involving multiple emissions units, only one consecutive 24-month period can be used for all the emissions units being modified. However, a different 24-month period can be used for each PSD pollutant.

Rule 62-210.370, F.A.C., establishes the methodology for computing baseline actual emissions and net emissions increases. In general, this rule sets forth a hierarchy of emission estimating methods, of which the most accurate method is to be used. CEMS are generally recognized as the most accurate method, followed by mass balance calculations, followed by emission factors. If stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid tests conducted during at least a 5-year period encompassing the period over which the emissions are computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

"Projected actual emissions" is the maximum annual rate, in TPY, at which an existing emissions unit is projected to emit a regulated air pollutant in any one of the 5 years following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's potential to emit that regulated air pollutant, and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the facility.

In determining the projected actual emissions, the source must consider all relevant information, including historical operating data, the company's own representations, the company's expected business activity, the company's filings with the state or federal regulatory authorities, and compliance plans or orders. Fugitive emissions, to the extent quantifiable, and emissions associated with startups and shutdowns must be considered.

The projected actual emissions shall exclude that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions, and that are also unrelated to the particular project, including any increased utilization due to demand growth (this is referred to as the "demand growth exclusion"). The preamble to the U.S. Environmental Protection Agency's (EPA's) final PSD rule revisions, promulgated on December 31, 2002, states:

> *That is, under today's new provisions for non-routine physical or operational changes to existing emissions units, rather than basing a unit's post-change emissions on its PTE, you may project an annual rate, in TPY, that reflects the maximum annual emissions rate that will occur during any one of the 5 years immediately after the physical or operational change. ...This projection of the unit's annual emissions rate following the change is defined as the "projected actual emissions", and will be based on your maximum annual rate in tons per year at which you are projected to emit a regulated NSR pollutant, less any amount of emissions that could have been accommodated during the selected 24 month baseline period and is not related to the change. Accordingly, you will calculate*

> *the unit's projected actual emissions as the product of: (1) The hourly emissions rate, which is based on the operational capabilities following the change(s), taking into account legally enforceable restrictions that could affect the hourly emissions rate following the change(s); and (2) the projected level of utilization, which is based on both the emissions unit's historical annual utilization rate and available information regarding the emissions units' likely post-change capacity utilization. …From the initial calculation, you may then make the appropriate adjustment to subtract out any portion of the emissions increase that could have been accommodated during the unit's 24-month baseline period and is unrelated to the change. [Federal Register, Vol. 67, pg. 80196]*
>
> *Consequently, under today's new rules, when a projected increase in equipment utilization is in response to a factor such as the growth in market demand, you may subtract the emission increases from the unit's projected actual emissions if: (1) The unit could have achieved the necessary level of utilization during the consecutive 24-month period you selected to establish the baseline actual emission; and (2) the increase is not related to the physical or operational change(s) made to the unit. [Federal Register, Vol. 67, pg. 80203]*

Further explanation was provided in the preamble to EPA's proposed PSD rule revisions on September 14, 2006:

> *That is, the source can emit up to its current maximum capacity without triggering major NSR under the actual-to-projected-actual test, as long as the increase is unrelated to the change. [Federal Register, Vol. 71, pg. 54237]*
>
> *Post-change emissions are generally projected using the emissions unit's maximum annual rate, in tons per year, at which it is expected to emit a regulated NSR pollutant within 5 years following a change, less any amount of emissions that the unit could have accommodated during the selected 24-month baseline period and that are unrelated to the change. This final "projected actual" value, in tons per year, is the value you compare to the "baseline actual emissions" to determine…whether the proposed project will result in a "significant" emissions increase, as defined in the first step of the calculation. [Federal Register, Vol. 71, pg. 54238]*

If the project results in a significant emissions increase for any PSD pollutant, then all contemporaneous increases or decreases in emissions of that pollutant that have occurred at the facility in the last 5 years must also be considered to determine if a significant net emissions increase has occurred.

A PSD applicability analysis was conducted to demonstrate that the proposed NHPC project would not trigger PSD review. The analysis is presented in Section 4.0.

3.2 EPA PSD Review Requirements for Greenhouse Gas Emissions

On December 15, 2009, EPA issued an endangerment finding related to greenhouse gases (GHGs) declaring that the combination of six GHGs [carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)] endangers both the public health and welfare of current and future generations.[1] Specifically, EPA found that the combined emissions of these GHGs from new motor vehicles endanger the public health and welfare, which allows the federal regulation of GHGs from new motor vehicles. EPA finalized such regulations on April 1, 2010, in a joint rulemaking with the National Highway Traffic Safety Administration (NHTSA) [the "Light-Duty Vehicle Rule" (LDV Rule)], making the collection of six GHGs "subject to regulation" under the Clean Air Act (CAA).[2]

On April 2, 2010, EPA finalized its reconsideration of the memorandum issued by previous EPA Administrator Stephen Johnson titled, "EPA's Interpretation of Regulations that Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Permit Program,"[3] also known as the "PSD Interpretive Memo". In the reconsideration, EPA decided to continue to interpret the term "subject to regulation" to include each pollutant subject to either a provision in the CAA or regulation adopted by EPA under the CAA that requires actual control of emissions of that pollutant.[4] As a result of this interpretation, GHGs became subject to CAA permitting requirements under the NSR program (specifically, the PSD portion of the NSR program) on January 2, 2011, which was the date the first control requirements in the LDV Rule took effect for GHGs.

In an attempt to reduce the permitting burden associated with triggering NSR and Title V for GHGs, EPA finalized the PSD Tailoring Rule on June 3, 2010, to limit applicability of CAA requirements to large stationary sources of GHG emissions.[5] In the final rule, EPA creates multiple steps to implement the PSD Tailoring Rule. The first (Step 1), which began January 2, 2011 (when the LDV Rule took effect) and ended on June 30, 2011, applies to "anyway sources" and "anyway modifications" that would be subject to PSD "anyway", based on emissions of pollutants other than GHGs.

Step 2 of the PSD Tailoring Rule began July 1, 2011, and requires that GHG emissions associated with each project be evaluated for PSD applicability regardless of the level of criteria pollutant emission rate increases. Therefore, the NHPC facility must analyze GHG emissions under Step 2 of the PSD Tailoring Rule. In both Step 1 and Step 2 of the Tailoring Rule, PSD permitting for GHGs is triggered if both the following occur due to a proposed modification at an existing major PSD source:

- GHG emission increases are 75,000 TPY of carbon dioxide equivalents (CO_2e) or more
- Total mass-based GHG emission increases are greater than zero

[1] 74 Federal Register (FR) 66496 (December 15, 2009).
[2] 75 FR 25324 (May 7, 2010).
[3] Memorandum issued December 18, 2008 and noticed at 73 FR 80300 (December 31, 2008).
[4] 75 FR 17004 (April 2, 2010).
[5] 75 FR 31514 (June 3, 2010).

On July 20, 2011, the EPA deferred reporting of CO_2 emissions from bioenergy and other biogenic sources under the PSD program for 3 years.[6]

A PSD applicability analysis was conducted for the proposed NHPC project to demonstrate that the proposed project would not trigger PSD review under the PSD Tailoring Rule. The analysis is presented in Section 4.0.

3.3 NSPS and NESHAPs Applicability

3.3.1 NSPS Subpart Da

Cogeneration Boiler A is currently subject to New Source Performance Standards (NSPS), Subpart Da (40 CFR 60, Subpart Da), Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. Boiler A will continue to be subject to these regulations after this project. However, Subpart Da contains provisions that are triggered if an affected source undergoes a "modification" after certain dates. A modification under NSPS is any physical change or change in the method of operation that results in an increase in actual emissions on a lb/hr basis for any pollutant regulated under the specific NSPS. Subpart Da regulates SO_2, NO_x, and PM emissions.

The installation of the natural gas burners represents a physical change to Boiler A. However, the change will not cause an increase in emissions of any NSPS-regulated pollutant on a lb/hr basis. Natural gas has lower emission factors for all three regulated pollutants compared to No. 2 distillate oil or biomass. In order to determine hourly mass emission rates of NSPS pollutants for Boiler A prior to the proposed change, the permitted heat input and emission factors for the fuel types currently burned were used. To determine hourly mass emission rates of NSPS pollutants for the boiler after the proposed change, the maximum heat input rate and emission factors for all fuel types, including natural gas, were utilized. As shown in Table 3-2, the burning of natural gas will not result in increases in hourly emissions of SO_2, NO_x, or PM.

Reconstruction under NSPS is any modification where the cost is greater than 50 percent of the cost of constructing a new emissions unit. The proposed modifications to Boiler A are estimated at $1.7 million. The cost of constructing an entirely new boiler of the same type and design is estimated at $50 million. Therefore, the cost of the proposed modifications are less than 50 percent of the cost of replacing Boiler A, and the project will not constitute "reconstruction."

Based on the above analysis of emissions to the atmosphere and costs of the proposed project, Boiler A will not be subject to new or additional regulations under NSPS Subpart Da due to the proposed project, and will continue to remain subject to the current limitations in NSPS Subpart Da.

[6] 76 FR 43490 (July 20, 2011).

3.3.2 NSPS Subpart Ea

Cogeneration Boiler A is currently subject to NSPS Subpart Ea (40 CFR 60, Subpart Ea), Standards of Performance for Municipal Waste Combustors for Which Construction is Commenced After December 20, 1989 and on or Before September 20, 1994. Cogeneration Boiler A will continue to be subject to these regulations after this project. The applicability of Subpart Ea to Boiler A will not be affected by the proposed natural gas burning project.

4.0 AIR EMISSIONS

4.1 Baseline Actual Emissions

The methodology used to determine baseline actual emissions for Cogeneration Boiler A and the results of the determination are presented in this section. Based on Florida's PSD rules, the baseline actual emissions may be based on any consecutive 24-month period out of the last 10 years prior to submitting a complete application. Since complete data are not yet available for 2011, the baseline actual emissions were calculated based on a consecutive 24-month period out of the previous nine (9) years (2002 through 2010). Actual emissions for each of these years were determined based on operating data, available stack test data, and emission factors. For each pollutant, the consecutive 2-year period with the highest average annual (TPY) emissions was selected as the baseline actual emissions for Boiler A. The 2-year baseline periods used for each pollutant are as follows:

Pollutant	2-Year Average Baseline
Sulfur Dioxide – SO_2	2002 to 2003
Nitrogen Oxides – NO_x	2003 to 2004
Carbon Monoxide – CO	2007 to 2008
Particulate Matter – PM	2002 to 2003
Particulate Matter under 10 microns in diameter – PM_{10}	2002 to 2003
Particulate Matter under 2.5 microns in diameter – $PM_{2.5}$	2002 to 2003
Volatile Organic Compounds – VOCs	2002 to 2003
Sulfuric Acid Mist – SAM	2002 to 2003
Lead – Pb	2002 to 2003
Mercury – Hg	2002 to 2003
Fluorides – F	2002 to 2003
Greenhouse Gases – GHGs*	2009 to 2010
CO_2e*	2009 to 2010

* Excludes biogenic CO_2.

The baseline actual emissions for Boiler A may differ from the annual emissions shown in the Annual Operating Reports (AORs) submitted to FDEP by NHPC, as described below.

The emission factors used for determining the baseline actual emissions are shown in Table 4-1. The Florida rules require that if stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid tests conducted during at least a 5-year period encompassing the period over which the emissions are computed, provided all stack tests used represent the same operational and physical configuration of the unit. To determine the operational and physical configuration of Boiler A for each year during the past 10 years, the permitting files were researched. It was concluded that Boiler A has had the same operational/physical configuration throughout the years for which stack tests are used to determine the baseline emissions (2002 through 2010). Stack test data for Boiler A used to determine baseline actual emissions are presented in Table 4-2. Stack test data are available for Boiler A for PM, VOC, and Hg.

The resulting baseline actual emissions for each pollutant for each year, based on the revised emission factors, are presented in Tables 4-3 through 4-5. The highest 2-year average for each pollutant represents the baseline actual emissions (see Table 4-6). The following sections describe in more detail the development of the baseline actual emission factors for each PSD pollutant. Emission factor references are provided in Appendix A.

4.1.1 Sulfur Dioxide – SO_2

Distillate Fuel Oil and Biomass – Baseline actual SO_2 emissions were calculated from annual average CEMS data from Boiler A, on a lb/MMBtu basis (see Tables 4-1 and 4-2).

Total Emissions – Using the fuel heat contents and fuel burning rates in Boiler A for each year, and the emission factors described above, the annual SO_2 emissions were calculated (see Table 4-4). The 2-year annual average SO_2 emissions were then calculated (see Table 4-5), and the highest 2-year average was selected as the baseline actual emissions (see Table 4-6).

4.1.2 Nitrogen Oxides – NO_x

Distillate Fuel Oil and Biomass – Baseline actual NO_x emissions were calculated from annual average CEMS data from Boiler A, on a lb/MMBtu basis (see Tables 4-1 and 4-2).

Total Emissions – Using the fuel heat contents and fuel burning rates in Boiler A for each year, and the emission factors described above, the annual NO_x emissions were calculated (see Table 4-4). The 2-year annual average NO_x emissions were then calculated (see Table 4-5), and the highest 2-year average was selected as the baseline actual emissions (see Table 4-6).

4.1.3 Carbon Monoxide – CO

Distillate Fuel Oil and Biomass – Baseline actual CO emissions were calculated from annual average CEMS data from Boiler A, on a lb/MMBtu basis (see Tables 4-1 and 4-2). Note that in two years, the reported CO CEMS data exceeded the CO emission limit of 0.35 lb/MMBtu based on a 12-month rolling average. Therefore, for these two years, the CEMS data were corrected to 0.35 lb/MMBtu for use in calculating baseline emissions.

Total Emissions – Using the fuel heat contents and fuel burning rates in Boiler A for each year and the emission factors described above, the annual CO emissions were calculated (see Table 4-4). The 2-year annual average CO emissions were then calculated (see Table 4-5), and the highest 2-year average was selected as the baseline actual emissions (see Table 4-6).

4.1.4 Particulate Matter – PM/PM_{10}/$PM_{2.5}$

Distillate Oil – Baseline actual PM emissions were calculated using an emission factor of 2 pounds per thousand gallons (lb/10^3 gal) from AP-42, Table 1.3-1. This emission factor was divided by the heat content of distillate oil of 138,000 British thermal units per gallon (Btu/gal), resulting in an emission factor of 0.0145 lb/MMBtu (see Table 4-1).

Biomass – Baseline actual PM emissions were calculated based on annual PM compliance test data (see Table 4-2). The compliance test averages, in lb/MMBtu, were determined for each year. The Florida rules require that if stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid tests conducted during at least a 5-year period encompassing the period over which the emissions are computed, provided all stack tests used represent the same operational and physical configuration of the unit. To determine the average emission factor for 2002, the stack test results from 2002 through 2010 were averaged (see Tables 4-1 and 4-2). This 9-year average was used as the emission factor for every year.

PM_{10} emission factors were assumed to be 100 percent of PM emissions, based on the requirement of Permit No. 0990332-017-AC/PSD-FL-196(P), Specific Condition No. 16(e). $PM_{2.5}$ emission factors were based on 16 percent of PM emissions from AP-42, Table 1.1-6, for ESP control (see Table 4-1).

Total Emissions – Using the fuel heat contents and fuel burning rates in Boiler A for each year, and the emission factors described above, the annual PM/PM_{10}/$PM_{2.5}$ emissions were calculated (see Table 4-4). The 2-year annual average PM/PM_{10}/$PM_{2.5}$ emissions were then calculated (see Table 4-5), and the highest 2-year averages were selected as the baseline actual emissions (see Table 4-6).

4.1.5 Volatile Organic Compounds – VOC

Distillate Oil – Baseline actual VOC emissions were calculated using an emission factor of 0.2 lb/10^3 gal from AP-42, Table 1.3-3. This emission factor was divided by the heat content of distillate oil of 138,000 Btu/gal, resulting in an emission factor of 0.0014 lb/MMBtu (see Table 4-1).

Biomass – Baseline actual VOC emissions were calculated based on annual VOC compliance test data (see Table 4-2). The compliance test averages, in lb/MMBtu, were determined for each year. The Florida rules require that if stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid tests conducted during at least a 5-year period encompassing the period over which the emissions are computed, provided all stack tests used represent the same operational and physical configuration of the unit. To determine the average emission factor for 2002, the stack test results from 2002 through 2010 were averaged (see Tables 4-1 and 4-2). This 9-year average was used as the emission factor for every year.

Total Emissions – Using the fuel heat contents and fuel burning rates in Boiler A for each year and the emission factors described above, the annual VOC emissions were calculated (see Table 4-4). The 2-year annual average VOC emissions were then calculated (see Table 4-5), and the highest 2-year averages were selected as the baseline actual emissions (see Table 4-6).

4.1.6 Sulfuric Acid Mist – SAM

Distillate Oil – Baseline actual SAM emissions were calculated from an emission factor of 6 percent of SO_2 emissions, based on Permit No. 0990005-017-AV (see Table 4-1).

Biomass – Baseline actual SAM emissions were calculated using an emission factor of 6 percent of SO_2 emissions from Permit No. 0990005-017-AV (see Table 4-1).

Total Emissions – Using the fuel heat contents and fuel burning rates in Boiler A for each year and the emission factors described above, the annual SAM emissions were calculated (see Table 4-4). The 2-year annual average SAM emissions were then calculated (see Table 4-5), and the highest 2-year average was selected as the baseline actual emissions (see Table 4-6).

4.1.7 Lead – Pb

Distillate Oil – Baseline actual Pb emissions were calculated from an emission factor of 9×10^{-6} lb/MMBtu from AP-42, Table 1.3-10 (see Table 4-1).

Biomass – Baseline actual Pb emissions were calculated from an emission factor of 2.48×10^{-5} lb/MMBtu from a series of stack tests performed on Boilers A, B, and C between 1999 and 2002 (see Table 4-1 and Appendix A).

Total Emissions – Using the fuel heat contents and fuel burning rates in Boiler A for each year and the emission factors described above, the annual Pb emissions were calculated (see Table 4-4). The 2-year annual average Pb emissions were then calculated (see Table 4-5), and the highest 2-year average was selected as the baseline actual emissions (see Table 4-6).

4.1.8 Mercury – Hg

Distillate Oil – Baseline actual Hg emissions were calculated from an emission factor of 3×10^{-6} lb/MMBtu from AP-42, Table 1.3-10 (see Table 4-1).

Biomass – Baseline actual Hg emissions were calculated based on annual Hg compliance test data (see Table 4-2). The compliance test averages, in lb/MMBtu, were determined for each year. The Florida rules require that if stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid tests conducted during at least a 5-year period encompassing the period over which the emissions are computed, provided all stack tests used represent the same operational and physical configuration of the unit. To determine the average emission factor for 2002, the stack test results from 2002 through 2010 were averaged (see Tables 4-1 and 4-2). This 9-year average was used as the emission factor for every year.

Total Emissions – Using the fuel heat contents and fuel burning rates in Boiler A for each year and the emission factors described above, the annual Hg emissions were calculated (see Table 4-4). The 2-year annual average Hg emissions were then calculated (see Table 4-5), and the highest 2-year average was selected as the baseline actual emissions (see Table 4-6).

4.1.9 Fluorides – F

Distillate Oil – No emission factors exist for fluoride emissions from distillate oil firing.

Biomass – Baseline actual F emissions were calculated from an emission factor of 0.00031 lb/MMBtu from a series of stack tests performed on Boilers A, B, and C between 1999 and 2002 (see Table 4-1 and Appendix A).

Total Emissions – Using the fuel heat contents and fuel burning rates in Boiler A for each year and the emission factors described above, the annual F emissions were calculated (see Table 4-4). The 2-year annual average F emissions were then calculated (see Table 4-5), and the highest 2-year average was selected as the baseline actual emissions (see Table 4-6).

4.1.10 Greenhouse Gases

Baseline actual GHG emissions for distillate oil and biomass combustion were calculated from emission factors published in the mandatory GHG reporting rule (40 CFR 98, Subpart C, Tables C-1 and C-2). These emission factors are as follows:

	Emission Factors (kg/MMBtu)		
Fuel	**CO_2**	**CH_4**	**N_2O**
Distillate Oil	73.96	0.003	0.0006
Wood and Wood Waste (Wood and Wood Residuals Category)	93.8	0.032	0.0042
Bagasse (Agricultural Byproducts Category)	118.17	0.0032	0.0042

The emission factors in kilograms per MMBtu (kg/MMBtu) were multiplied by a conversion factor of 2.20462 pounds per kilogram (lb/kg) to obtain factors in terms of lb/MMBtu (see Table 4-1).

Using the fuel heat contents and fuel burning rates for Boiler A for each year, and the emission factors described above, the annual GHG emissions were calculated (see Table 4-4). Both biogenic and non-biogenic CO_2 emissions were determined. The 2-year annual average GHG emissions were then calculated (see Table 4-5), and the highest 2-year average was selected as the baseline actual emissions (see Table 4-6).

4.2 Projected Actual Emissions

"Projected actual emissions" for Cogeneration Boiler A were developed based on the past operation of the boiler. The emission factors used to calculate the projected actual emissions due to natural gas combustion were as follows:

- SO_2 – 0.6 pound per million cubic feet (lb/10^6 ft^3) from AP-42, Table 1.4-2
- NO_x – 0.15 lb/MMBtu from Permit No. 0990332-017-AC/PSD-FL-196(P)
- CO – 84 lb/10^6 ft^3 from AP-42, Table 1.4-1, controlled gas combustion in low-NO_x burners
- PM – 7.6 lb/10^6 ft^3 from AP-42, Table 1.4-2
- PM_{10} – 100 percent of PM from AP-42, Table 1.4-2
- $PM_{2.5}$ – 100 percent of PM from AP-42, Table 1.4-2
- VOC – 5.5 lb/10^6 ft^3 from AP-42, Table 1.4-2
- SAM – Similar factor as fuel oil (approximately 6 percent of SO_2 emissions)
- Pb – 0.0005 lb/10^6 ft^3 from AP-42, Table 1.4-2
- Hg – 0.00026 lb/10^6 ft^3 from AP-42, Table 1.4-4
- F – No emission factor exists for fluoride emissions from natural gas combustion
- GHGs – from the mandatory GHG reporting rule (40 CFR 98, Tables C-1 and C-2)
  - CO_2 – 53.02 kg/MMBtu
  - CH_4 – 0.001 kg/MMBtu
  - N_2O – 0.0001 kg/MMBtu

A heating value for natural gas of 1,028 Btu/ft^3 was used to convert the emission factors to lb/MMBtu.

The projected activity factor is based on the historical maximum annual heat input to Boiler A from each fuel, as well as the historical maximum total heat input over the last 9 years (see Table 4-3):

- Distillate Oil – 68,089 MMBtu/yr (occurred in 2009)
- Wood/Wood Waste – 1,983,620 MMBtu/yr (occurred in 2003)
- Bagasse – 2,399,976 MMBtu/yr (occurred in 2007)
- Total – 4,188,924 MMBtu/yr (occurred in 2003)

The projected activity factor for natural gas was based on 24.9 percent of the historical highest total heat input rate to Boiler A. Under the current operating permit, total fossil fuel usage is limited to less than 25 percent heat input on a calendar quarter basis. The new natural gas burners, rated for 400 MMBtu/hr, could potentially supply this amount of heat input. The resulting natural gas activity factor was:

4,188,924 MMBtu/yr x 0.249 = 1,043,042 MMBtu/yr

In determining the actual projected emissions, the emission factors were ranked on a lb/MMBtu basis, and the heat input was then maximized for the worst-case pollutant, with the total annual heat input equal to the maximum annual heat input rate to Boiler A over the last 9 years (see Table 4-7).

4.3 Effects on Other Emissions Units

The proposed project will only add natural gas to the fuel burning capabilities of Boiler A. Natural gas, when burned, will merely replace the heat input that would have been provided by No. 2 fuel oil or wood/bagasse, and will therefore not have an effect on any other emissions units at the NHPC facility.

4.4 PSD Review

The net increases in emissions due to the proposed natural gas burning project for Boiler A are summarized in Table 4-8. The net increases in emissions were calculated by subtracting the baseline actual emissions (see Table 4-6) from the projected actual emissions (see Table 4-7), which represents the actual increases in emissions due to the project.

An additional calculation was performed to determine what additional increases in emissions, which have not been accounted for in this application, could occur without resulting in a PSD significant increase in emissions. This calculation does not attempt to determine the additional emissions that could be emitted in the future due to demand growth, but rather what additional emissions increases could occur due to the project without triggering PSD review.

As shown, no emission increases exceed the PSD significant emissions rate. Therefore, PSD review does not apply to the proposed project.

TABLES

Table 3-1: PSD Significant Emission Rates and *de Minimis* Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration[a] ($\mu g/m^3$)
Sulfur Dioxide (SO_2)	NAAQS, NSPS	40	13, 24-hour
Total Particulate Matter (PM)	NSPS	25	10, 24-hour
Particulate Matter <10 microns (PM_{10})	NAAQS	15	10, 24-hour
Fine Particulate Matter ($PM_{2.5}$)	NAAQS	10; or 40 SO_2 or NO_x	2.3, 24-hour[c]
Nitrogen Oxides (NO_X)	NAAQS, NSPS	40	14, annual
Carbon Monoxide (CO)	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (VOC)	NAAQS, NSPS	40	100 TPY[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist (SAM)	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Mercury	NESHAP	0.1	0.25, 24-hour
MWC Organics	NSPS	3.5×10^{-6}	NM
MWC Metals	NSPS	15	NM
MWC Acid Gases	NSPS	40	NM
MSW Landfill Gases	NSPS	50	NM
Greenhouse Gases- Mass Basis, and	--	0, and	NM
- CO_2e Basis	--	75,000	NM

[a] Short-term concentrations are not to be exceeded.

[b] No *de minimis* concentration; an increase in VOC or NO_x emissions of 100 TPY or more will require monitoring analysis for ozone.

[c] Proposed (Option 3 of three significant monitoring concentrations proposed), Federal Register, September 21, 2007.

Note: Ambient monitoring requirements for any pollutant may be exempted if the impact of the increase in emissions is below the *de minimis* monitoring concentrations.

CO_2e= Carbon dioxide equivalents

MSW = municipal solid waste

MWC = municipal waste combustor

NAAQS = National Ambient Air Quality Standards

NESHAP = National Emission Standards for Hazardous Air Pollutants

NM = no ambient measurement method established, therefore no *de minimis* concentration has been established.

NSPS = New Source Performance Standards

Source: 40 CFR 52.21

Table 3-2: Change in Hourly Emission Rates of NSPS-Regulated Pollutants, Cogeneration Boiler A

Pollutant / Fuel	Emissions before the Change: Emission Factor (lb/MMBtu) [a]	Emissions before the Change: Activity Factor (MMBtu/hr) [b]	Emissions before the Change: Hourly Emissions (lb/hr) [c]	Emissions after the Change: Emission Factor (lb/MMBtu) [a]	Emissions after the Change: Activity Factor (MMBtu/hr) [b]	Emissions after the Change: Hourly Emissions (lb/hr) [c]	Change in Hourly Emissions (lb/hr)
Sulfur Dioxide - SO_2							
-- *Distillate Oil*	0.051	490	25.0	0.051	490	25.0	
-- *Biomass*	0.051	760	38.8	0.051	760	38.8	
-- *Natural Gas*	--	--	--	0.0006	400	0.2	
-- *Distillate Oil / Biomass*	--	490 / 270	38.8	--	490 / 270	38.8	
-- *Natural Gas / Biomass*	--	--	--	--	400 / 360	18.6	
-- Worst-Case Emissions			**38.8**			**38.8**	**0.0**
Nitrogen Oxides - NO_x							
-- *Distillate Oil*	0.146	490	71.5	0.146	490	71.5	
-- *Biomass*	0.146	760	111.0	0.146	760	111.0	
-- *Natural Gas* [d]	--	--	--	0.146	400	58.4	
-- *Distillate Oil / Biomass*	--	490 / 270	111.0	--	490 / 270	111.0	
-- *Natural Gas / Biomass*	--	--	--	--	400 / 360	111.0	
-- Worst-Case Emissions			**111.0**			**111.0**	**0.0**
Particulate Matter Total - PM							
-- *Distillate Oil*	0.0239	490	11.7	0.024	490	11.7	
-- *Biomass*	0.0207	270	5.6	0.0207	760	15.7	
-- *Natural Gas*	--	--	--	0.0074	400	3.0	
-- *Distillate Oil / Biomass*	--	490 / 270	17.3	--	490 / 270	17.3	
-- *Natural Gas / Biomass*	--	--	--	--	400 / 360	10.4	
-- Worst-Case Emissions			**17.3**			**17.3**	**0.0**

[a] See Table 4-1 for emission factors for distillate oil and bagasse combustion. See Table 4-7 for emission factors for natural gas.

[b] Activity factor based on maximum permitted/proposed heat input rates when each fuel (760 MMBtu/hr for biomass or a combination of biomass and fossil fuels, 490 MMBtu/hr for distillate oil, and 400 MMBtu/hr for natural gas).

[c] Hourly emissions based on which emission firing scenario generated the highest emissions (biomass alone or biomass in combination with fossil fuels).

[d] NO_x emissions from natural gas combustion will be controlled by the SNCR system to the level of other fuels.

Table 4-1: Emission Factors Used to Determine Baseline Actual Annual Emissions (2002 - 2010), Cogeneration Boiler A

Source Description	Operating Hours	Sulfur Content (%)	Annual Process / Production Rate	Heat Input Rate (MMBtu)	Pollutant Emission Factors (lb/MMBtu)														
					SO_2 [A]	NO_x [A]	CO [A]	PM	PM_{10} [B]	$PM_{2.5}$	VOC	SAM [B]	Lead	Mercury	Fluorides [C]	Biogenic CO_2 [D]	Non-Biogenic CO_2 [D]	CH_4 [D]	N_2O [D]
Boiler A (EU 001)																			
2002 Actual Emission Factors																			
- *Distillate Oil*	6,845	0.05	245.53 $x10^3$ gal	33,883	0.051	0.145	0.242	0.0239 [E]	0.0239	0.0029 [F]	0.0014 [G]	0.0031	9.00E-06 [H]	3.00E-06 [H]	--	--	163.05	0.0066	0.0013
- *Wood / Wood Waste*			217,130 tons wood	1,845,605	0.051	0.145	0.242	0.0111 [I]	0.0111	0.0018 [J]	0.0074 [I]	0.0031	2.48E-05 [C]	6.94E-07 [I]	0.00031	206.79	--	0.0705	0.0093
- *Bagasse*			306,370 tons bagasse	2,205,864	0.051	0.145	0.242	0.0111 [I]	0.0111	0.0018 [J]	0.0074 [I]	0.0031	2.48E-05 [C]	6.94E-07 [I]	0.00031	260.52	--	0.0705	0.0093
2003 Actual Emission Factors																			
- *Distillate Oil*	7,430	0.05	242 $x10^3$ gal	33,396	0.039	0.144	0.221	0.0239 [E]	0.0239	0.0029 [F]	0.0014 [G]	0.0023	9.00E-06 [H]	3.00E-06 [H]	--	--	163.05	0.0066	0.0013
- *Wood / Wood Waste*			233,367 tons wood	1,983,620	0.039	0.144	0.221	0.0111 [I]	0.0111	0.0018 [J]	0.0074 [I]	0.0023	2.48E-05 [C]	6.94E-07 [I]	0.00031	206.79	--	0.0705	0.0093
- *Bagasse*			301,654 tons bagasse	2,171,909	0.039	0.144	0.221	0.0111 [I]	0.0111	0.0018 [J]	0.0074 [I]	0.0023	2.48E-05 [C]	6.94E-07 [I]	0.00031	260.52	--	0.0705	0.0093
2004 Actual Emission Factors																			
- *Distillate Oil*	7,659	0.05	184.5 $x10^3$ gal	25,461	0.035	0.146	0.260	0.0239 [E]	0.0239	0.0029 [F]	0.0014 [G]	0.0021	9.00E-06 [H]	3.00E-06 [H]	--	--	163.05	0.0066	0.0013
- *Wood / Wood Waste*			198,279 tons wood	1,685,372	0.035	0.146	0.260	0.0111 [I]	0.0111	0.0018 [J]	0.0074 [I]	0.0021	2.48E-05 [C]	6.94E-07 [I]	0.00031	206.79	--	0.0705	0.0093
- *Bagasse*			327,185 tons bagasse	2,355,732	0.035	0.146	0.260	0.0111 [I]	0.0111	0.0018 [J]	0.0074 [I]	0.0021	2.48E-05 [C]	6.94E-07 [I]	0.00031	260.52	--	0.0705	0.0093
2005 Actual Emission Factors																			
- *Distillate Oil*	7,238	0.05	226.6 $x10^3$ gal	31,271	0.032	0.144	0.222	0.0239 [E]	0.0239	0.0029 [F]	0.0014 [G]	0.0019	9.00E-06 [H]	3.00E-06 [H]	--	--	163.05	0.0066	0.0013
- *Wood / Wood Waste*			219,266 tons wood	1,863,761	0.032	0.144	0.222	0.0111 [I]	0.0111	0.0018 [J]	0.0074 [I]	0.0019	2.48E-05 [C]	6.94E-07 [I]	0.00031	206.79	--	0.0705	0.0093
- *Bagasse*			265,678 tons bagasse	1,912,882	0.032	0.144	0.222	0.0111 [I]	0.0111	0.0018 [J]	0.0074 [I]	0.0019	2.48E-05 [C]	6.94E-07 [I]	0.00031	260.52	--	0.0705	0.0093
2006 Actual Emission Factors																			
- *Distillate Oil*	7,283	0.05	93.02 $x10^3$ gal	12,837	0.028	0.146	0.290	0.0239 [E]	0.0239	0.0029 [F]	0.0014 [G]	0.0017	9.00E-06 [H]	3.00E-06 [H]	--	--	163.05	0.0066	0.0013
- *Wood / Wood Waste*			219,191 tons wood	1,863,124	0.028	0.146	0.290	0.0111 [I]	0.0111	0.0018 [J]	0.0074 [I]	0.0017	2.48E-05 [C]	6.94E-07 [I]	0.00031	206.79	--	0.0705	0.0093
- *Bagasse*			264,394 tons bagasse	1,903,637	0.028	0.146	0.290	0.0111 [I]	0.0111	0.0018 [J]	0.0074 [I]	0.0017	2.48E-05 [C]	6.94E-07 [I]	0.00031	260.52	--	0.0705	0.0093
2007 Actual Emission Factors																			
- *Distillate Oil*	7,724	0.05	154.745 $x10^3$ gal	21,355	0.035	0.144	0.350	0.0239 [E]	0.0239	0.0029 [F]	0.0014 [G]	0.0021	9.00E-06 [H]	3.00E-06 [H]	--	--	163.05	0.0066	0.0013
- *Wood / Wood Waste*			195,158 tons wood	1,658,843	0.035	0.144	0.350	0.0111 [I]	0.0111	0.0018 [J]	0.0074 [I]	0.0021	2.48E-05 [C]	6.94E-07 [I]	0.00031	206.79	--	0.0705	0.0093
- *Bagasse*			333,330 tons bagasse	2,399,976	0.035	0.144	0.350	0.0111 [I]	0.0111	0.0018 [J]	0.0074 [I]	0.0021	2.48E-05 [C]	6.94E-07 [I]	0.00031	260.52	--	0.0705	0.0093
2008 Actual Emission Factors																			
- *Distillate Oil*	7,581	0.02	276.9 $x10^3$ gal	38,212	0.042	0.144	0.350	0.0239 [E]	0.0239	0.0029 [F]	0.0014 [G]	0.0025	9.00E-06 [H]	3.00E-06 [H]	--	--	163.05	0.0066	0.0013
- *Wood / Wood Waste*			179,167 tons wood	1,522,920	0.042	0.144	0.350	0.0111 [I]	0.0111	0.0018 [J]	0.0074 [I]	0.0025	2.48E-05 [C]	6.94E-07 [I]	0.00031	206.79	--	0.0705	0.0093
- *Bagasse*			310,260 tons bagasse	2,233,872	0.042	0.144	0.350	0.0111 [I]	0.0111	0.0018 [J]	0.0074 [I]	0.0025	2.48E-05 [C]	6.94E-07 [I]	0.00031	260.52	--	0.0705	0.0093
2009 Actual Emission Factors																			
- *Distillate Oil*	7,015	0.02	493.4 $x10^3$ gal	68,089	0.038	0.141	0.299	0.0239 [E]	0.0239	0.0029 [F]	0.0014 [G]	0.0023	9.00E-06 [H]	3.00E-06 [H]	--	--	163.05	0.0066	0.0013
- *Wood / Wood Waste*			197,025 tons wood	1,674,713	0.038	0.141	0.299	0.0111 [I]	0.0111	0.0018 [J]	0.0074 [I]	0.0023	2.48E-05 [C]	6.94E-07 [I]	0.00031	206.79	--	0.0705	0.0093
- *Bagasse*			291,510 tons bagasse	2,098,872	0.038	0.141	0.299	0.0111 [I]	0.0111	0.0018 [J]	0.0074 [I]	0.0023	2.48E-05 [C]	6.94E-07 [I]	0.00031	260.52	--	0.0705	0.0093
2010 Actual Emission Factors																			
- *Distillate Oil*	6,290	0.01	353.438 $x10^3$ gal	48,774	0.034	0.139	0.311	0.0239 [E]	0.0239	0.0029 [F]	0.0014 [G]	0.0020	9.00E-06 [H]	3.00E-06 [H]	--	--	163.05	0.0066	0.0013
- *Wood / Wood Waste*			185,180 tons wood	1,574,030	0.034	0.139	0.311	0.0111 [I]	0.0111	0.0018 [J]	0.0074 [I]	0.0020	2.48E-05 [C]	6.94E-07 [I]	0.00031	206.79	--	0.0705	0.0093
- *Bagasse*			311,637 tons bagasse	2,243,786	0.034	0.139	0.311	0.0111 [I]	0.0111	0.0018 [J]	0.0074 [I]	0.0020	2.48E-05 [C]	6.94E-07 [I]	0.00031	260.52	--	0.0705	0.0093

[A] Based on annual average CEMS value (see Table 4-2).

[B] Based on expected emissions from Permit No. 0990332-017-AC/PSD-FL-196(P), Specific Condition Nos. 16(c) and 16(e). SAM emissions assumed to be 6 percent of SO_2. PM_{10} emissions assumed to be 100 percent of PM.

[C] Based on stack testing performed on Cogeneration Boiler A, Cogeneration Boiler B (EU 002), and Cogeneration Boiler C (EU 003) between 1999 and 2002.

[D] Based on Greenhouse Gas Reporting Rule (40 CFR 98 Subpart C - General Stationary Fuel Combustion Sources). Emission factors and fuel heat content are as follows:

Fuel	Emission Factors (kg/MMBtu)		
	CO_2	CH_4	N_2O
Distillate Oil	73.96	0.003	0.0006
Wood and Wood Waste	93.8	0.032	0.0042
Bagasse	118.17	0.032	0.0042

[E] AP-42 Table 1.3-1, PM emissions from uncontrolled No. 2 fuel oil firing. PM emission factor is 3.3 lb/10^3 gal (filterable plus condensible PM). Emission factor is divided by the heat content of 138,000 Btu/gal.

[F] AP-42 Table 1.3-6, PM emissions from uncontrolled distillate oil firing. $PM_{2.5}$ emission factor is 12 percent of PM.

[G] AP-42 Table 1.3-3, non-methane total organic compounds from distillate oil firing in industrial boilers. VOC emission factor is 0.2 lb/10^3 gal. Emission factor is divided by the heat content of 138,000 Btu/gal.

[H] AP-42, Table 1.3-10 for distillate oil firing.

[I] Based on stack testing (see Table 4-2).

[J] AP-42, Table 1.6-5, for wood/bark fired boilers with multiple cyclone control of spreader stoker boilers without flyash reinjection. $PM_{2.5}$ emission factor is 16 percent of PM.

Table 4-2: Cogeneration Boiler A Stack Tests and Emissions Data

Test Date	Heat Input Rate (MMBtu/hr)	PM Emission Rate [a]		VOC Emission Rate [a]		Hg Emission Rate [a]		CEMS Emission Rates (lb/MMBtu) [a]		
		lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	lb/MMBtu	SO_2	NO_x	CO
2/13/2002	766.6	5.91	0.0077	5.57	0.0073	1.25E-03	1.64E-06	0.051	0.145	0.242
1/22/2003	745.4	6.64	0.0089	1.93	0.0026	5.63E-04	7.55E-07	0.039	0.144	0.221
2/16/2004	627.1	4.28	0.0068	3.54	0.0057	3.92E-04	6.23E-07	0.035	0.146	0.260
2/24/2005	665.8	10.81	0.0162	0.95	0.0014	1.77E-04	2.66E-07	0.032	0.144	0.222
2/14/2006	681.3	4.82	0.0071	8.91	0.0131	2.72E-04	3.99E-07	0.028	0.146	0.290
2/15/2007	595.0	7.59	0.0128	4.94	0.0083	6.60E-04	1.11E-06	0.035	0.144	0.350 [b]
2/8/2008	654.3	8.47	0.0129	4.94	0.0075	7.63E-04	1.17E-06	0.042	0.144	0.350 [b]
3/18/2009	572.9	11.80	0.0207	11.66	0.0206	1.00E-04	1.77E-07	0.038	0.141	0.299
2/18/2010	591.1	4.20	0.0071	0.09	0.0002	6.31E-05	1.07E-07	0.034	0.139	0.311
Minimum:	**572.9**	**4.20**	**0.0068**	**0.09**	**0.0002**	**6.31E-05**	**1.07E-07**	**0.028**	**0.139**	**0.221**
Average:	**655.5**	**7.17**	**0.0111**	**4.73**	**0.0074**	**4.72E-04**	**6.94E-07**	**0.037**	**0.144**	**0.283**
Maximum:	**766.6**	**11.80**	**0.0207**	**11.66**	**0.0206**	**1.25E-03**	**1.64E-06**	**0.051**	**0.146**	**0.350**

[a] Maximum permitted emission rates are as follows (Permit No. 0990005-017-AV):

PM = 0.026 lb/MMBtu and 19.8 lb/hr
VOC = 0.05 lb/MMBtu and 38.0 lb/hr
Hg = 5.4×10^{-6} lb/MMBtu
SO_2 = 0.06 lb/MMBtu (12-month rolling CEMS average)
NO_x = 0.15 lb/MMBtu (30-day rolling CEMS average)
CO = 0.35 lb/MMBtu (12-month rolling CEMS average)

[b] Annual average CO CEMS value reduced to the permit limit of 0.35 lb/MMBtu as a 12-month rolling average.

Table 4-3: Annual Operating and Fuel Usage Data, Cogeneration Boiler A

Year	Operating Hours	Fuel Usage Rates				Heat Input (MMBtu/yr) [a]				Heat Input (%)		
		Distillate Oil (10^3 gal/yr)	Oil Sulfur (%)	Wood / Wood Waste (TPY)	Bagasse (TPY)	Distillate Oil	Wood / Wood Waste	Bagasse	Total	Distillate Oil	Wood / Wood Waste	Bagasse
2002	6,845	245.53	0.05	217,130	306,370	33,883	1,845,605	2,205,864	4,085,352	0.83	45.18	53.99
2003	7,430	242.00	0.05	233,367	301,654	33,396	1,983,620	2,171,909	4,188,924	0.80	47.35	51.85
2004	7,659	184.50	0.05	198,279	327,185	25,461	1,685,372	2,355,732	4,066,565	0.63	41.44	57.93
2005	7,238	226.60	0.05	219,266	265,678	31,271	1,863,761	1,912,882	3,807,913	0.82	48.94	50.23
2006	7,283	93.02	0.05	219,191	264,394	12,837	1,863,124	1,903,637	3,779,597	0.34	49.29	50.37
2007	7,724	154.75	0.05	195,158	333,330	21,355	1,658,843	2,399,976	4,080,174	0.52	40.66	58.82
2008	7,581	276.90	0.02	179,167	310,260	38,212	1,522,920	2,233,872	3,795,004	1.01	40.13	58.86
2009	7,015	493.40	0.02	197,025	291,510	68,089	1,674,713	2,098,872	3,841,674	1.77	43.59	54.63
2010	6,290	353.44	0.01	185,180	311,637	48,774	1,574,030	2,243,786	3,866,591	1.26	40.71	58.03
Minimum:	**6,290**	**93.02**	**0.01**	**179,167**	**264,394**	**12,837**	**1,522,920**	**1,903,637**	**3,779,597**	**0.34**	**40.13**	**50.23**
Average:	**7,229**	**252.24**	**0.04**	**204,863**	**301,335**	**34,809**	**1,741,332**	**2,169,614**	**3,945,755**	**0.89**	**44.14**	**54.97**
Maximum:	**7,724**	**493.40**	**0.05**	**233,367**	**333,330**	**68,089**	**1,983,620**	**2,399,976**	**4,188,924**	**1.77**	**49.29**	**58.86**

[a] Based on heat content of 138,000 Btu/gal for distillate oil, 4,250 Btu/lb for wood/wood waste, and 3,600 Btu/lb for bagasse.

Table 4-4: Baseline Actual Annual (2002 – 2010) Emissions, Cogeneration Boiler A

Source	Pollutant Emission Rate (TPY)																
Description	SO_2	NO_x	CO	PM	PM_{10}	$PM_{2.5}$	VOC	SAM	Lead	Mercury	Fluorides	Biogenic CO_2	Non-Biogenic CO_2	CH_4	N_2O	GHG*	CO_2e*
2002 Actual Emissions																	
- Distillate Oil	0.86	2.46	4.10	0.405	0.405	0.049	0.025	0.052	1.52E-04	5.08E-05	--	--	2,762	0.112	0.022	2,763	2,772
- Wood / Wood Waste	47.06	133.81	223.32	10.29	10.29	1.65	6.84	2.82	2.29E-02	6.41E-04	0.29	190,829	--	65.10	8.54	74	4,016
- Bagasse	56.25	159.93	266.91	12.30	12.30	1.97	8.18	3.37	2.74E-02	7.66E-04	0.34	287,336	--	77.81	10.21	88	4,800
- Total	**104.18**	**296.19**	**494.33**	**22.99**	**22.99**	**3.66**	**15.04**	**6.25**	**5.04E-02**	**1.46E-03**	**0.63**	**478,165**	**2,762**	**143.02**	**18.78**	**2,924**	**11,588**
2003 Actual Emissions																	
- Distillate Oil	0.65	2.40	3.69	0.399	0.399	0.048	0.024	0.039	1.50E-04	5.01E-05	--	--	2,723	0.110	0.022	2,723	2,732
- Wood / Wood Waste	38.68	142.82	219.19	11.06	11.06	1.77	7.35	2.32	2.46E-02	6.89E-04	0.31	205,100	--	69.97	9.18	79	4,316
- Bagasse	42.35	156.38	240.00	12.11	12.11	1.94	8.05	2.54	2.69E-02	7.54E-04	0.34	282,913	--	76.61	10.06	87	4,726
- Total	**81.68**	**301.60**	**462.88**	**23.56**	**23.56**	**3.75**	**15.43**	**4.90**	**5.17E-02**	**1.49E-03**	**0.65**	**488,012**	**2,723**	**146.69**	**19.26**	**2,889**	**11,774**
2004 Actual Emissions																	
- Distillate Oil	0.45	1.86	3.31	0.304	0.304	0.037	0.018	0.027	1.15E-04	3.82E-05	--	--	2,076	0.084	0.017	2,076	2,083
- Wood / Wood Waste	29.49	123.03	219.10	9.39	9.39	1.50	6.25	1.77	2.09E-02	5.85E-04	0.26	174,262	--	59.45	7.80	67	3,667
- Bagasse	41.23	171.97	306.25	13.13	13.13	2.10	8.73	2.47	2.92E-02	8.18E-04	0.37	306,858	--	83.10	10.91	94	5,126
- Total	**71.16**	**296.86**	**528.65**	**22.83**	**22.83**	**3.64**	**15.00**	**4.27**	**5.03E-02**	**1.44E-03**	**0.63**	**481,119**	**2,076**	**142.63**	**18.73**	**2,237**	**10,876**
2005 Actual Emissions																	
- Distillate Oil	0.50	2.25	3.47	0.374	0.374	0.045	0.023	0.030	1.41E-04	4.69E-05	--	--	2,549	0.103	0.021	2,550	2,558
- Wood / Wood Waste	29.82	134.19	206.88	10.39	10.39	1.66	6.91	1.79	2.31E-02	6.47E-04	0.29	192,707	--	65.74	8.63	74	4,055
- Bagasse	30.61	137.73	212.33	10.66	10.66	1.71	7.09	1.84	2.37E-02	6.64E-04	0.30	249,172	--	67.47	8.86	76	4,162
- Total	**60.93**	**274.17**	**422.68**	**21.42**	**21.42**	**3.41**	**14.02**	**3.66**	**4.70E-02**	**1.36E-03**	**0.59**	**441,879**	**2,549**	**133.32**	**17.51**	**2,700**	**10,776**
2006 Actual Emissions																	
- Distillate Oil	0.18	0.94	1.86	0.153	0.153	0.018	0.009	0.011	5.78E-05	1.93E-05	--	--	1,047	0.042	0.008	1,047	1,050
- Wood / Wood Waste	26.08	136.01	270.15	10.38	10.38	1.66	6.91	1.57	2.31E-02	6.47E-04	0.29	192,641	--	65.72	8.63	74	4,054
- Bagasse	26.65	138.97	276.03	10.61	10.61	1.70	7.06	1.60	2.36E-02	6.61E-04	0.30	247,968	--	67.15	8.81	76	4,142
- Total	**52.91**	**275.91**	**548.04**	**21.15**	**21.15**	**3.38**	**13.97**	**3.17**	**4.68E-02**	**1.33E-03**	**0.59**	**440,608**	**1,047**	**132.91**	**17.45**	**1,197**	**9,246**
2007 Actual Emissions																	
- Distillate Oil	0.37	1.54	3.74	0.255	0.255	0.031	0.015	0.022	9.61E-05	3.20E-05	--	--	1,741	0.071	0.014	1,741	1,747
- Wood / Wood Waste	29.03	119.44	290.30	9.25	9.25	1.48	6.15	1.74	2.06E-02	5.76E-04	0.26	171,519	--	58.51	7.68	66	3,610
- Bagasse	42.00	172.80	420.00	13.38	13.38	2.14	8.90	2.52	2.98E-02	8.33E-04	0.37	312,621	--	84.66	11.11	96	5,222
- Total	**71.40**	**293.77**	**714.03**	**22.88**	**22.88**	**3.65**	**15.06**	**4.28**	**5.05E-02**	**1.44E-03**	**0.63**	**484,140**	**1,741**	**143.24**	**18.81**	**1,903**	**10,579**
2008 Actual Emissions																	
- Distillate Oil	0.80	2.75	6.69	0.457	0.457	0.055	0.028	0.048	1.72E-04	5.73E-05	--	--	3,115	0.126	0.025	3,115	3,126
- Wood / Wood Waste	31.98	109.65	266.51	8.49	8.49	1.36	5.65	1.92	1.89E-02	5.29E-04	0.24	157,465	--	53.72	7.05	61	3,314
- Bagasse	46.91	160.84	390.93	12.45	12.45	1.99	8.28	2.81	2.77E-02	7.76E-04	0.35	290,984	--	78.80	10.34	89	4,861
- Total	**79.70**	**273.24**	**664.13**	**21.40**	**21.40**	**3.41**	**13.95**	**4.78**	**4.68E-02**	**1.36E-03**	**0.59**	**448,449**	**3,115**	**132.64**	**17.42**	**3,265**	**11,300**
2009 Actual Emissions																	
- Distillate Oil	1.29	4.80	10.18	0.814	0.814	0.098	0.049	0.078	3.06E-04	1.02E-04	--	--	5,551	0.225	0.045	5,551	5,570
- Wood / Wood Waste	31.82	118.07	250.37	9.33	9.33	1.49	6.21	1.91	2.08E-02	5.82E-04	0.26	173,160	--	59.07	7.75	67	3,644
- Bagasse	39.88	147.97	313.78	11.70	11.70	1.87	7.78	2.39	2.60E-02	7.29E-04	0.33	273,399	--	74.04	9.72	84	4,567
- Total	**72.99**	**270.84**	**574.33**	**21.85**	**21.85**	**3.46**	**14.04**	**4.38**	**4.71E-02**	**1.41E-03**	**0.59**	**446,559**	**5,551**	**133.33**	**17.52**	**5,702**	**13,781**
2010 Actual Emissions																	
- Wood / Wood Waste	0.83	3.39	7.58	0.583	0.583	0.070	0.035	0.050	2.19E-04	7.32E-05	--	--	3,976	0.161	0.032	3,977	3,990
- Bagasse	26.76	109.40	244.76	8.77	8.77	1.40	5.83	1.61	1.95E-02	5.47E-04	0.25	162,749	--	55.52	7.29	63	3,425
- Total	38.14	155.94	348.91	12.51	12.51	2.00	8.32	2.29	2.78E-02	7.79E-04	0.35	292,276	--	79.15	10.39	90	4,882
- Total	**65.73**	**268.73**	**601.25**	**21.86**	**21.86**	**3.47**	**14.19**	**3.94**	**4.76E-02**	**1.40E-03**	**0.60**	**455,025**	**3,976**	**134.83**	**17.71**	**4,129**	**12,297**

* Biogenic CO_2 emissions are excluded per EPA PSD Tailoring Rule.

Table 4-5: Summary of Baseline 2-Year Average Actual Annual Emissions, Cogeneration Boiler A

Source	Pollutant Emission Rate (TPY)																
Description	SO_2	NO_x	CO	PM	PM_{10}	$PM_{2.5}$	VOC	SAM	Lead	Mercury	Fluorides	Biogenic CO_2	Non-Biogenic CO_2	CH_4	N_2O	GHG*	CO_2e*
2002 - 2003 Average Emissions																	
- Distillate Oil	0.76	2.43	3.90	0.402	0.402	0.048	0.024	0.045	1.51E-04	5.05E-05	--	--	2,743	0.111	0.022	2,743	2,752
- Wood / Wood Waste	42.87	138.31	221.25	10.67	10.67	1.71	7.10	2.57	2.38E-02	6.65E-04	0.30	197,965	--	67.54	8.86	76	4,166
- Bagasse	49.30	158.15	253.45	12.20	12.20	1.95	8.11	2.96	2.72E-02	7.60E-04	0.34	285,124	--	77.21	10.13	87	4,763
- Total	**92.93**	**298.90**	**478.60**	**23.27**	**23.27**	**3.71**	**15.24**	**5.58**	**5.11E-02**	**1.48E-03**	**0.64**	**483,089**	**2,743**	**144.86**	**19.02**	**2,906**	**11,681**
2003 - 2004 Average Emissions																	
- Distillate Oil	0.55	2.13	3.50	0.352	0.352	0.042	0.021	0.033	1.32E-04	4.41E-05	--	--	2,399	0.097	0.019	2,399	2,407
- Wood / Wood Waste	34.09	132.93	219.14	10.23	10.23	1.64	6.80	2.05	2.28E-02	6.37E-04	0.29	189,681	--	64.71	8.49	73	3,992
- Bagasse	41.79	164.17	273.12	12.62	12.62	2.02	8.39	2.51	2.81E-02	7.86E-04	0.35	294,885	--	79.85	10.48	90	4,926
- Total	**76.42**	**299.23**	**495.76**	**23.20**	**23.20**	**3.70**	**15.21**	**4.59**	**5.10E-02**	**1.47E-03**	**0.64**	**484,566**	**2,399**	**144.66**	**18.99**	**2,563**	**11,325**
2004 - 2005 Average Emissions																	
- Distillate Oil	0.47	2.06	3.39	0.339	0.339	0.041	0.021	0.028	1.28E-04	4.25E-05	--	--	2,313	0.094	0.019	2,313	2,320
- Wood / Wood Waste	29.66	128.61	212.99	9.89	9.89	1.58	6.58	1.78	2.20E-02	6.16E-04	0.28	183,484	--	62.60	8.22	71	3,861
- Bagasse	35.92	154.85	259.29	11.90	11.90	1.90	7.91	2.15	2.65E-02	7.41E-04	0.33	278,015	--	75.29	9.88	85	4,644
- Total	**66.05**	**285.51**	**475.67**	**22.13**	**22.13**	**3.53**	**14.51**	**3.96**	**4.86E-02**	**1.40E-03**	**0.61**	**461,499**	**2,313**	**137.98**	**18.12**	**2,469**	**10,826**
2005 - 2006 Average Emissions																	
- Distillate Oil	0.34	1.59	2.67	0.264	0.264	0.032	0.016	0.020	9.92E-05	3.31E-05	--	--	1,798	0.073	0.015	1,798	1,804
- Wood / Wood Waste	27.95	135.10	238.52	10.39	10.39	1.66	6.91	1.68	2.31E-02	6.47E-04	0.29	192,674	--	65.73	8.63	74	4,055
- Bagasse	28.63	138.35	244.18	10.64	10.64	1.70	7.07	1.72	2.37E-02	6.63E-04	0.30	248,570	--	67.31	8.83	76	4,152
- Total	**56.92**	**275.04**	**485.36**	**21.29**	**21.29**	**3.40**	**14.00**	**3.42**	**4.69E-02**	**1.34E-03**	**0.59**	**441,244**	**1,798**	**133.12**	**17.48**	**1,949**	**10,011**
2006 - 2007 Average Emissions																	
- Distillate Oil	0.28	1.24	2.80	0.204	0.204	0.025	0.012	0.017	7.69E-05	2.56E-05	--	--	1,394	0.057	0.011	1,394	1,398
- Wood / Wood Waste	27.56	127.72	280.23	9.82	9.82	1.57	6.53	1.65	2.19E-02	6.11E-04	0.27	182,080	--	62.12	8.15	70	3,832
- Bagasse	34.33	155.88	348.01	11.99	11.99	1.92	7.98	2.06	2.67E-02	7.47E-04	0.34	280,294	--	75.90	9.96	86	4,682
- Total	**62.16**	**284.84**	**631.04**	**22.01**	**22.01**	**3.51**	**14.52**	**3.73**	**4.86E-02**	**1.38E-03**	**0.61**	**462,374**	**1,394**	**138.08**	**18.13**	**1,550**	**9,913**
2007 - 2008 Average Emissions																	
- Distillate Oil	0.59	2.14	5.21	0.356	0.356	0.043	0.022	0.035	1.34E-04	4.47E-05	--	--	2,428	0.098	0.020	2,428	2,436
- Wood / Wood Waste	30.51	114.54	278.40	8.87	8.87	1.42	5.90	1.83	1.97E-02	5.52E-04	0.25	164,492	--	56.12	7.37	63	3,462
- Bagasse	44.46	166.82	405.46	12.91	12.91	2.07	8.59	2.67	2.87E-02	8.04E-04	0.36	301,802	--	81.73	10.73	92	5,042
- Total	**75.55**	**283.51**	**689.08**	**22.14**	**22.14**	**3.53**	**14.51**	**4.53**	**4.86E-02**	**1.40E-03**	**0.61**	**466,294**	**2,428**	**137.94**	**18.11**	**2,584**	**10,940**
2008 - 2009 Average Emissions																	
- Distillate Oil	1.05	3.78	8.43	0.635	0.635	0.076	0.039	0.063	2.39E-04	7.97E-05	--	--	4,333	0.176	0.035	4,333	4,348
- Wood / Wood Waste	31.90	113.86	258.44	8.91	8.91	1.43	5.93	1.91	1.98E-02	5.55E-04	0.25	165,312	--	56.40	7.40	64	3,479
- Bagasse	43.39	154.40	352.35	12.08	12.08	1.93	8.03	2.60	2.69E-02	7.52E-04	0.34	282,192	--	76.42	10.03	86	4,714
- Total	**76.34**	**272.04**	**619.23**	**21.62**	**21.62**	**3.43**	**14.00**	**4.58**	**4.70E-02**	**1.39E-03**	**0.59**	**447,504**	**4,333**	**132.99**	**17.47**	**4,484**	**12,541**
2009 - 2010 Average Emissions																	
- Distillate Oil	1.06	4.10	8.88	0.699	0.699	0.084	0.042	0.064	2.63E-04	8.76E-05	--	--	4,764	0.193	0.039	4,764	4,780
- Wood / Wood Waste	29.29	113.73	247.57	9.05	9.05	1.45	6.02	1.76	2.02E-02	5.64E-04	0.25	167,955	--	57.30	7.52	65	3,535
- Bagasse	39.01	151.96	331.35	12.10	12.10	1.94	8.05	2.34	2.69E-02	7.54E-04	0.34	282,837	--	76.59	10.05	87	4,725
- Total	**69.36**	**269.78**	**587.79**	**21.86**	**21.86**	**3.47**	**14.11**	**4.16**	**4.74E-02**	**1.41E-03**	**0.59**	**450,792**	**4,764**	**134.08**	**17.61**	**4,915**	**13,039**
Highest Consecutive	**'02 - '03**	**'03 - '04**	**'07 - '08**	**'02 - '03**	**'02 - '03**	**'02 - '03**	**'02 - '03**	**'02 - '03**	**'02 - '03**	**'02 - '03**	**'02 - '03**	**'03 - '04**	**'09 - '10**	**'02 - '03**	**'02 - '03**	**'09 - '10**	**'09 - '10**
2-Year Average	**92.93**	**299.23**	**689.08**	**23.27**	**23.27**	**3.71**	**15.24**	**5.58**	**0.05**	**0.00**	**0.64**	**484,566**	**4,764**	**144.86**	**19.02**	**4,915**	**13,039**

* Biogenic CO_2 emissions are excluded per EPA PSD Tailoring Rule.

Table 4-6: Summary of Baseline Actual Annual Emissions, Cogeneration Boiler A

Source Description	Year 1 Activity Factor	Year 1 Emission Factor	Year 1 Emissions (TPY)	Year 2 Activity Factor	Year 2 Emission Factor	Year 2 Emissions (TPY)	2-Year Average (TPY)
SO_2		**2002**			**2003**		**'02 - '03**
- Distillate Oil	33,883 MMBtu	0.051 lb/MMBtu	0.86	33,396 MMBtu	0.039 lb/MMBtu	0.65	0.76
- Wood / Wood Waste	1,845,605 MMBtu	0.051 lb/MMBtu	47.06	1,983,620 MMBtu	0.039 lb/MMBtu	38.68	42.87
- Bagasse	2,205,864 MMBtu	0.051 lb/MMBtu	56.25	2,171,909 MMBtu	0.039 lb/MMBtu	42.35	49.30
- Total	**4,085,352**		**104.18**	**4,188,924**		**81.68**	**92.93**
NO_x		**2003**			**2004**		**'03 - '04**
- Distillate Oil	33,396 MMBtu	0.144 lb/MMBtu	2.40	25,461 MMBtu	0.146 lb/MMBtu	1.86	2.13
- Wood / Wood Waste	1,983,620 MMBtu	0.144 lb/MMBtu	142.82	1,685,372 MMBtu	0.146 lb/MMBtu	123.03	132.93
- Bagasse	2,171,909 MMBtu	0.144 lb/MMBtu	156.38	2,355,732 MMBtu	0.146 lb/MMBtu	171.97	164.17
- Total			**301.60**			**296.86**	**299.23**
CO		**2007**			**2008**		**'07 - '08**
- Distillate Oil	21,355 MMBtu	0.350 lb/MMBtu	3.74	38,212 MMBtu	0.350 lb/MMBtu	6.69	5.21
- Wood / Wood Waste	1,658,843 MMBtu	0.350 lb/MMBtu	290.30	1,522,920 MMBtu	0.350 lb/MMBtu	266.51	278.40
- Bagasse	2,399,976 MMBtu	0.350 lb/MMBtu	420.00	2,233,872 MMBtu	0.350 lb/MMBtu	390.93	405.46
- Total			**714.03**			**664.13**	**689.08**
PM		**2002**			**2003**		**'02 - '03**
- Distillate Oil	33,883 MMBtu	0.0239 lb/MMBtu	0.41	33,396 MMBtu	0.0239 lb/MMBtu	0.40	0.40
- Wood / Wood Waste	1,845,605 MMBtu	0.0111 lb/MMBtu	10.29	1,983,620 MMBtu	0.0111 lb/MMBtu	11.06	10.67
- Bagasse	2,205,864 MMBtu	0.0111 lb/MMBtu	12.30	2,171,909 MMBtu	0.0111 lb/MMBtu	12.11	12.20
- Total			**22.99**			**23.56**	**23.27**
PM_{10}		**2002**			**2003**		**'02 - '03**
- Distillate Oil	33,883 MMBtu	0.0239 lb/MMBtu	0.41	33,396 MMBtu	0.0239 lb/MMBtu	0.40	0.40
- Wood / Wood Waste	1,845,605 MMBtu	0.0111 lb/MMBtu	10.29	1,983,620 MMBtu	0.0111 lb/MMBtu	11.06	10.67
- Bagasse	2,205,864 MMBtu	0.0111 lb/MMBtu	12.30	2,171,909 MMBtu	0.0111 lb/MMBtu	12.11	12.20
- Total			**22.99**			**23.56**	**23.27**
$PM_{2.5}$		**2002**			**2003**		**'02 - '03**
- Distillate Oil	33,883 MMBtu	0.0029 lb/MMBtu	0.05	33,396 MMBtu	0.0029 lb/MMBtu	0.05	0.05
- Wood / Wood Waste	1,845,605 MMBtu	0.0018 lb/MMBtu	1.65	1,983,620 MMBtu	0.0018 lb/MMBtu	1.77	1.71
- Bagasse	2,205,864 MMBtu	0.0018 lb/MMBtu	1.97	2,171,909 MMBtu	0.0018 lb/MMBtu	1.94	1.95
- Total			**3.66**			**3.75**	**3.71**
VOC		**2002**			**2003**		**'02 - '03**
- Distillate Oil	33,883 MMBtu	0.0014 lb/MMBtu	0.02	33,396 MMBtu	0.0014 lb/MMBtu	0.02	0.02
- Wood / Wood Waste	1,845,605 MMBtu	0.0074 lb/MMBtu	6.84	1,983,620 MMBtu	0.0074 lb/MMBtu	7.35	7.10
- Bagasse	2,205,864 MMBtu	0.0074 lb/MMBtu	8.18	2,171,909 MMBtu	0.0074 lb/MMBtu	8.05	8.11
- Total			**15.04**			**15.43**	**15.24**
SAM		**2002**			**2003**		**'02 - '03**
- Distillate Oil	33,883 MMBtu	0.0031 lb/MMBtu	0.05	33,396 MMBtu	0.0023 lb/MMBtu	0.04	0.05
- Wood / Wood Waste	1,845,605 MMBtu	0.0031 lb/MMBtu	2.82	1,983,620 MMBtu	0.0023 lb/MMBtu	2.32	2.57
- Bagasse	2,205,864 MMBtu	0.0031 lb/MMBtu	3.37	2,171,909 MMBtu	0.0023 lb/MMBtu	2.54	2.96
- Total			**6.25**			**4.90**	**5.58**
Lead		**2002**			**2003**		**'02 - '03**
- Distillate Oil	33,883 MMBtu	9.00E-06 lb/MMBtu	1.52E-04	33,396 MMBtu	9.00E-06 lb/MMBtu	1.50E-04	1.51E-04
- Wood / Wood Waste	1,845,605 MMBtu	2.48E-05 lb/MMBtu	2.29E-02	1,983,620 MMBtu	2.48E-05 lb/MMBtu	2.46E-02	2.38E-02
- Bagasse	2,205,864 MMBtu	2.48E-05 lb/MMBtu	2.74E-02	2,171,909 MMBtu	2.48E-05 lb/MMBtu	2.69E-02	2.72E-02
- Total			**5.04E-02**			**5.17E-02**	**5.11E-02**
Mercury		**2002**			**2003**		**'02 - '03**
- Distillate Oil	33,883 MMBtu	3.00E-06 lb/MMBtu	5.08E-05	33,396 MMBtu	3.00E-06 lb/MMBtu	5.01E-05	5.05E-05
- Wood / Wood Waste	1,845,605 MMBtu	6.94E-07 lb/MMBtu	6.41E-04	1,983,620 MMBtu	6.94E-07 lb/MMBtu	6.89E-04	6.65E-04
- Bagasse	2,205,864 MMBtu	6.94E-07 lb/MMBtu	7.66E-04	2,171,909 MMBtu	6.94E-07 lb/MMBtu	7.54E-04	7.60E-04
- Total			**1.46E-03**			**1.49E-03**	**1.48E-03**
Fluorides		**2002**			**2003**		**'02 - '03**
- Wood / Wood Waste	1,845,605 MMBtu	0.00031 lb/MMBtu	0.29	1,983,620 MMBtu	0.00031 lb/MMBtu	0.31	0.30
- Bagasse	2,205,864 MMBtu	0.00031 lb/MMBtu	0.34	2,171,909 MMBtu	0.00031 lb/MMBtu	0.34	0.34
- Total			**0.63**			**0.65**	**0.64**
GHG		**2009**			**2010**		**'09 - '10**
- Distillate Oil							
- Biogenic CO_2	68,089 MMBtu	-- lb/MMBtu	--	48,774 MMBtu	-- lb/MMBtu	--	--
- Non-Biogenic CO_2	68,089 MMBtu	163.05 lb/MMBtu	5,551	48,774 MMBtu	163.05 lb/MMBtu	3,976	4,764
- CH_4	68,089 MMBtu	0.0066 lb/MMBtu	0.23	48,774 MMBtu	0.0066 lb/MMBtu	0.16	0.19
- N_2O	68,089 MMBtu	0.0013 lb/MMBtu	0.045	48,774 MMBtu	0.0013 lb/MMBtu	0.032	0.039
- Wood / Wood Waste							
- Biogenic CO_2	1,674,713 MMBtu	206.79 lb/MMBtu	173,160	1,574,030 MMBtu	206.79 lb/MMBtu	162,749	167,955
- Non-Biogenic CO_2	1,674,713 MMBtu	-- lb/MMBtu	--	1,574,030 MMBtu	-- lb/MMBtu	--	--
- CH_4	1,674,713 MMBtu	0.0705 lb/MMBtu	59.07	1,574,030 MMBtu	0.0705 lb/MMBtu	55.52	57.30
- N_2O	1,674,713 MMBtu	0.0093 lb/MMBtu	7.75	1,574,030 MMBtu	0.0093 lb/MMBtu	7.29	7.52
- Bagasse							
- Biogenic CO_2	2,098,872 MMBtu	260.52 lb/MMBtu	273,399	2,243,786 MMBtu	260.52 lb/MMBtu	292,276	282,837
- Non-Biogenic CO_2	2,098,872 MMBtu	-- lb/MMBtu	--	2,243,786 MMBtu	-- lb/MMBtu	--	--
- CH_4	2,098,872 MMBtu	0.0705 lb/MMBtu	74.04	2,243,786 MMBtu	0.0705 lb/MMBtu	79.15	76.59
- N_2O	2,098,872 MMBtu	0.0093 lb/MMBtu	9.72	2,243,786 MMBtu	0.0093 lb/MMBtu	10.39	10.05
- Total (Excluding Biogenic CO_2)			**5,702**			**4,129**	**4,915**
CO_2e		**2009**			**2010**		**'09 - '10**
- Distillate Oil							
- Biogenic CO_2	-- tons CO_2	1 lb CO_2e/lb	--	-- tons CO_2	1 lb CO_2e/lb	--	--
- Non-Biogenic CO_2	5,551 tons CO_2	1 lb CO_2e/lb	5,551	3,976 tons CO_2	1 lb CO_2e/lb	3,976	4,764
- CH_4	0.23 tons CH_4	21 lb CO_2e/lb	4.73	0.16 tons CH_4	21 lb CO_2e/lb	3.39	4.06
- N_2O	0.045 tons N_2O	310 lb CO_2e/lb	13.96	0.032 tons N_2O	310 lb CO_2e/lb	10.00	11.98
- Wood / Wood Waste							
- Biogenic CO_2	173,160 tons CO_2	1 lb CO_2e/lb	173,160	162,749 tons CO_2	1 lb CO_2e/lb	162,749	167,955
- Non-Biogenic CO_2	-- tons CO_2	1 lb CO_2e/lb	--	-- tons CO_2	1 lb CO_2e/lb	--	--
- CH_4	59.07 tons CH_4	21 lb CO_2e/lb	1,240.55	55.52 tons CH_4	21 lb CO_2e/lb	1,165.97	1,203.26
- N_2O	7.753 tons N_2O	310 lb CO_2e/lb	2,403.56	7.287 tons N_2O	310 lb CO_2e/lb	2,259.06	2,331.31
- Bagasse							
- Biogenic CO_2	273,399 tons CO_2	1 lb CO_2e/lb	273,399	292,276 tons CO_2	1 lb CO_2e/lb	292,276	282,837
- Non-Biogenic CO_2	-- tons CO_2	1 lb CO_2e/lb	--	-- tons CO_2	1 lb CO_2e/lb	--	--
- CH_4	74.04 tons CH_4	21 lb CO_2e/lb	1,554.74	79.15 tons CH_4	21 lb CO_2e/lb	1,662.09	1,608.42
- N_2O	9.717 tons N_2O	310 lb CO_2e/lb	3,012.32	10.388 tons N_2O	310 lb CO_2e/lb	3,220.30	3,116.31
- Total (Excluding Biogenic CO_2)			**13,781**			**12,297**	**13,039**

Table 4-7: Projected Actual Annual Emissions, Cogeneration Boiler A

Pollutant	Emission Factor (lb/MMBtu)	Ref	Activity Factor [a] Heat Input Rate (MMBtu/yr)	Activity Factor [a] Fuel Usage	Maximum Annual Emissions (TPY)
Sulfur Dioxide - SO_2					
- *Distillate Oil*	0.0510	1	0	0 x 10^3 gal/yr	0
- *Wood / Wood Waste*	0.0510	1	1,788,948	210,465 tons wood/yr	45.62
- *Bagasse*	0.0510	1	2,399,976	333,330 tons bagasse/yr	61.20
- *Natural Gas*	0.0006	2	0	0 x 10^6 ft^3/yr	0
		Total:	4,188,924		106.82
Nitrogen Oxides - NO_x					
- *Distillate Oil*	0.1460	1	0	0.00 x 10^3 gal/yr	0.00
- *Wood / Wood Waste*	0.1460	1	745,906	87,754 tons wood/yr	54.45
- *Bagasse*	0.1460	1	2,399,976	333,330 tons bagasse/yr	175.20
- *Natural Gas*	0.1460	3	1,043,042	1,014.632 x 10^6 ft^3/yr	76.14
		Total:	4,188,924		305.79
Carbon Monoxide - CO					
- *Distillate Oil*	0.35	1	0	0 x 10^3 gal/yr	0
- *Wood / Wood Waste*	0.35	1	1,788,948	210,465 tons wood/yr	313.07
- *Bagasse*	0.35	1	2,399,976	333,330 tons bagasse/yr	420.00
- *Natural Gas*	0.0817	4	0	0 x 10^6 ft^3/yr	0
		Total:	4,188,924		733.06
Particulate Matter Total - PM					
- *Distillate Oil*	0.0239	5	68,089	493.40 x 10^3 gal/yr	0.81
- *Wood / Wood Waste*	0.0111	6	1,720,859	202,454 tons wood/yr	9.59
- *Bagasse*	0.0111	6	2,399,976	333,330 tons bagasse/yr	13.38
- *Natural Gas*	0.0074	2	0	0 x 10^6 ft^3/yr	0
		Total:	4,188,924		23.78
Particulate Matter - PM_{10}					
- *Distillate Oil*	0.0239	7	68,089	493.40 x 10^3 gal/yr	0.81
- *Wood / Wood Waste*	0.0111	7	1,720,859	202,454 tons wood/yr	9.59
- *Bagasse*	0.0111	7	2,399,976	333,330 tons bagasse/yr	13.38
- *Natural Gas*	0.0074	2	0	0.000 x 10^6 ft^3/yr	0.00
		Total:	4,188,924		23.78
Particulate Matter - $PM_{2.5}$					
- *Distillate Oil*	0.0029	8	68,089	493.40 x 10^3 gal/yr	0.10
- *Wood / Wood Waste*	0.0018	9	677,817	79,743 tons wood/yr	0.60
- *Bagasse*	0.0018	9	2,399,976	333,330 tons bagasse/yr	2.14
- *Natural Gas*	0.0074	2	1,043,042	1,014.632 x 10^6 ft^3/yr	3.86
		Total:	4,188,924		6.70
Volatile Organic Compounds - VOC					
- *Distillate Oil*	0.0014	10	0	0 x 10^3 gal/yr	0
- *Wood / Wood Waste*	0.0074	6	1,788,948	210,465 tons wood/yr	6.63
- *Bagasse*	0.0074	6	2,399,976	333,330 tons bagasse/yr	8.90
- *Natural Gas*	0.0054	2	0	0 x 10^6 ft^3/yr	0
		Total:	4,188,924		15.53
Sulfuric Acid Mist - SAM					
- *Distillate Oil*	0.0031	7	68,089	493.40 x 10^3 gal/yr	0.10
- *Wood / Wood Waste*	0.0031	7	1,720,859	202,454 tons wood/yr	2.63
- *Bagasse*	0.0031	7	2,399,976	333,330 tons bagasse/yr	3.67
- *Natural Gas*	3.50E-05	7	0	0 x 10^6 ft^3/yr	0
			4,188,924		6.41
Lead - Pb					
- *Distillate Oil*	9.00E-06	11	0	0 x 10^3 gal/yr	0
- *Wood / Wood Waste*	2.48E-05	12	1,788,948	210,465 tons wood/yr	2.22E-02
- *Bagasse*	2.48E-05	12	2,399,976	333,330 tons bagasse/yr	2.98E-02
- *Natural Gas*	4.86E-07	2	0	0 x 10^6 ft^3/yr	0
		Total:	4,188,924		5.20E-02
Mercury - Hg					
- *Distillate Oil*	3.00E-06	11	68,089	493.40 x 10^3 gal/yr	1.02E-04
- *Wood / Wood Waste*	6.94E-07	6	1,720,859	202,454 tons wood/yr	5.98E-04
- *Bagasse*	6.94E-07	6	2,399,976	333,330 tons bagasse/yr	8.33E-04
- *Natural Gas*	2.53E-07	13	0	0 x 10^6 ft^3/yr	0
		Total:	4,188,924		1.53E-03
Fluorides - F					
- *Distillate Oil*	--	--	--	-- --	--
- *Wood / Wood Waste*	0.00031	12	1,788,948	210,465 tons wood/yr	0.28
- *Bagasse*	0.00031	12	2,399,976	333,330 tons bagasse/yr	0.37
- *Natural Gas*	--	--	--	-- --	--
		Total:	4,188,924		0.65

Table 4-7: Projected Actual Annual Emissions, Cogeneration Boiler A

Pollutant	Emission Factor (lb/MMBtu)	Ref	Activity Factor [a] Heat Input Rate (MMBtu/yr)	Activity Factor [a] Fuel Usage	Maximum Annual Emissions (TPY)
Greenhouse Gases - GHGs					
- Distillate Oil					
- Biogenic CO_2	--	--	--	-- --	--
- Non-Biogenic CO_2	163.05	14	68,089	493.40 x 10^3 gal/yr	5,551
- CH_4	0.0066	14	0	0 x 10^3 gal/yr	0
- N_2O	0.0013	14	0	0 x 10^3 gal/yr	0
- Wood / Wood Waste					
- Biogenic CO_2	206.79	14	677,817	79,743 tons wood/yr	70,084
- Non-Biogenic CO_2	--	--	--	-- --	--
- CH_4	0.0705	14	1,788,948	210,465 tons wood/yr	63.10
- N_2O	0.0093	14	1,788,948	210,465 tons wood/yr	8.28
- Bagasse					
- Biogenic CO_2	260.52	14	2,399,976	333,330 tons bagasse/yr	312,621
- Non-Biogenic CO_2	--	--	--	-- --	--
- CH_4	0.0705	14	2,399,976	333,330 tons bagasse/yr	84.66
- N_2O	0.0093	14	2,399,976	333,330 tons bagasse/yr	11.11
- Natural Gas					
- Biogenic CO_2	--	--	--	-- --	--
- Non-Biogenic CO_2	116.89	14	1,043,042	1,014.632 x 10^6 ft^3/yr	60,960
- CH_4	0.0022	14	0	0 x 10^6 ft^3/yr	0
- N_2O	0.00022	14	0	0 x 10^6 ft^3/yr	0
				Total (Excluding Biogenic CO_2):	**66,678**
CO_2 Equivalents - CO_2e					
- Distillate Oil					
- Biogenic CO_2	--	15	--	-- --	--
- Non-Biogenic CO_2	163.05	15	68,089	493.40 x 10^3 gal/yr	5,551
- CH_4	0.1389	15	0	0 x 10^3 gal/yr	0
- N_2O	0.4101	15	0	0 x 10^3 gal/yr	0
- Wood / Wood Waste					
- Biogenic CO_2	206.79	15	677,817	79,743 tons wood/yr	70,084
- Non-Biogenic CO_2	--	15	--	-- --	--
- CH_4	1.4815	15	1,788,948	210,465 tons wood/yr	1,325.17
- N_2O	2.8704	15	1,788,948	210,465 tons wood/yr	2,567.51
- Bagasse					
- Biogenic CO_2	260.52	15	2,399,976	333,330 tons bagasse/yr	312,621
- Non-Biogenic CO_2	--	15	--	-- --	--
- CH_4	1.4815	15	2,399,976	333,330 tons bagasse/yr	1,777.79
- N_2O	2.8704	15	2,399,976	333,330 tons bagasse/yr	3,444.46
- Natural Gas					
- Biogenic CO_2	--	15	--	-- --	--
- Non-Biogenic CO_2	116.89	15	1,043,042	1,014.632 x 10^6 ft^3/yr	60,960
- CH_4	0.0463	15	0	0 x 10^6 ft^3/yr	0
- N_2O	0.0683	15	0	0 x 10^6 ft^3/yr	0
				Total (Excluding Biogenic CO_2):	**75,626**

Footnotes:

[a] Activity factor based on the highest annual heat input rate to the boiler over the last 9 years (4,188,924 MMBtu; see Table 4-3). Fuel usage rate determined based on which fuel would result in the worst case emissions (on a lb/MMBtu basis). Heat input rate for each determined by the highest annual heat input rate over the last 9 years (see Table 4-3). Natural gas usage rate based on 24.9-percent of the highest annual heat input rate to the boiler over the last 9 years (0.249 * 4,188,924 MMBtu = 1,043,042 MMBtu).

References:

1. Highest annual average CEMS value (see Table 4-2).
2. AP-42, Table 1.4-2.
3. Based on assumption that existing NOx control system will maintain NOx emissions below the permitted rate of 0.15 lb/MMBtu (Permit No. 0990332-017-AC/PSD-FL-192P).
4. AP-42, Table 1.4-1, controlled gas combustion in low-NO_x burners.
5. AP-42 Table 1.3-1, PM emissions from uncontrolled No. 2 fuel oil firing. PM emission factor is 2 lb/10^3 gal. Emission factor is divided by the heat content of 138,000 Btu/gal.
6. Based on stack testing (see Table 4-2).
7. Based on expected emissions from Permit No. 0990332-017-AC/PSD-FL-196(P), Specific Condition Nos. 16(c) and 16(e). SAM emissions assumed to be 6 percent of SO_2. PM_{10} emissions assumed to be 100 percent of PM.
8. AP-42 Table 1.3-6, PM emissions from uncontrolled distillate oil firing. $PM_{2.5}$ emission factor is 12 percent of PM.
9. AP-42, Table 1.6-5, for wood/bark fired boilers with multiple cyclone control of spreader stoker boilers without flyash reinjection. $PM_{2.5}$ emission factor is 16 percent of PM.
10. AP-42 Table 1.3-3, non-methane total organic compounds from distillate oil firing in industrial boilers.
11. AP-42, Table 1.3-10 for distillate oil firing.
12. Based on stack testing performed on Cogeneration Boiler A, Cogeneration Boiler B (EU 002), and Cogeneration Boiler C (EU 003) between 1999 and 2002.
13. AP-42, Table 1.4-4.
14. Based on Greenhouse Gas Reporting Rule (40 CFR 98 Subpart C - General Stationary Fuel Combustion Sources). Emission factors and fuel heat content are as follows:

Fuel	Emission Factors (kg/MMBtu) CO_2	CH_4	N_2O
Distillate Oil	73.96	0.003	0.0006
Wood and Wood Waste	93.8	0.032	0.0042
Bagasse	118.17	0.032	0.0042
Natural Gas	53.02	0.001	0.0001

15. Based on emission factors for CO_2, CH_4, and N_2O using global warming potentials (GWP). GWP: CO_2 = 1, CH_4 = 21, and N_2O = 310. $CO_2e = CO_2 + 21*CH_4 + 310*N_2O$.

Table 4-8: PSD Applicability Analysis, Cogeneration Boiler A

	Pollutant Emission Rate (TPY)												
Emissions Category	SO_2	NO_x	CO	PM	PM_{10}	$PM_{2.5}$	VOC	SAM	Lead	Mercury	Fluorides	GHG [f]	CO_2e [f]
PROJECTED ACTUAL Emissions [a]													
- Distillate Oil	0	0	0	0.81	0.81	0.10	0	0.10	0	1.02E-04	--	5,551	5,551
- Wood / Wood Waste	45.62	54.45	313.07	9.59	9.59	0.60	6.63	2.63	2.22E-02	5.98E-04	0.28	71	3,893
- Bagasse	61.20	175.20	420.00	13.38	13.38	2.14	8.90	3.67	2.98E-02	8.33E-04	0.37	96	5,222
- Natural Gas	0	76.14	0	0	0	3.86	0	0	0	0	--	60,960	60,960
- Total	**106.82**	**305.79**	**733.06**	**23.78**	**23.78**	**6.70**	**15.53**	**6.41**	**5.20E-02**	**1.53E-03**	**0.65**	**66,678**	**75,626**
BASELINE ACTUAL Emissions [b]													
- Distillate Oil	0.76	2.13	5.21	0.40	0.40	0.05	0.02	0.05	1.51E-04	5.05E-05	--	4,764	4,780
- Wood / Wood Waste	42.87	132.93	278.40	10.67	10.67	1.71	7.10	2.57	2.38E-02	6.65E-04	0.30	65	3,535
- Bagasse	49.30	164.17	405.46	12.20	12.20	1.95	8.11	2.96	2.72E-02	7.60E-04	0.34	87	4,725
- Total	**92.93**	**299.23**	**689.08**	**23.27**	**23.27**	**3.71**	**15.24**	**5.58**	**5.11E-02**	**1.48E-03**	**0.64**	**4,915**	**13,039**
Actual Increase Due to Project [c]	**13.89**	**6.56**	**43.98**	**0.51**	**0.51**	**2.99**	**0.29**	**0.83**	**9.09E-04**	**5.77E-05**	**0.01**	**61,763**	**62,587**
Additional Increase Under PSD Threshold [d]	**25.11**	**32.44**	**55.02**	**24.39**	**14.39**	**6.91**	**38.71**	**6.07**	**5.89E-01**	**9.49E-02**	**2.89**	**-61,762**	**11,413**
Total Increase To Not Trigger PSD Review [e]	**39.00**	**39.00**	**99.00**	**24.90**	**14.90**	**9.90**	**39.00**	**6.90**	**0.59**	**0.095**	**2.90**	**1**	**74,000**
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	10	40	7	0.6	0.1	3	0	75,000
PSD REVIEW TRIGGERED?	No	No	No	No	No	No	No	No	No	No	No	No	

[a] See Table 4-7 for derivation of projected actual emissions.

[b] See Tables 4-5 and 4-6 for derivation of Baseline Actual Emissions.

[c] Projected actual emissions minus baseline actual emissions.

[d] Represents additional increase in emissions not accounted for in the application that would not result in a PSD signficant increase.

[e] Projected actual emissions plus additional increase under PSD threshold minus baseline actual emissions.

[f] GHG = sum of emission rates of CO_2, CH_4, and N_2O on a mass basis. CO_2e = sum of emission rates of CO_2, CH_4, and N_2O using global warming potentials (GWP). PSD applicability analysis excludes biogenic CO_2 emissions per the EPA PSD tailoring rule.

GWP: CO_2 = 1, CH_4 = 21, and N_2O = 310. GHG = $CO_2 + CH_4 + N_2O$, $CO_2e = CO_2 + 21{*}CH_4 + 310{*}N_2O$.

APPENDIX A

REFERENCES FOR EMISSION FACTORS

in Btu/lb, Btu/gal, or Btu/scf, as appropriate.

(F) The total quantity of each type of fossil fuel combusted during the reporting year, in lb, gallons, or scf, as appropriate.

(G) Annual biogenic CO_2 mass emissions, in metric tons.

(x) When ASTM methods D7459–08 and D6866–08 are used to determine the biogenic portion of the annual CO_2 emissions from MSW combustion, report:

(A) The results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO_2 emissions from MSW combustion is 30 percent, report 0.30).

(B) Annual combined biomass and fossil fuel CO_2 emissions from MSW combustion, in metric tons of CO_2e.

(C) The quantities V_{ff}, V_{total}, and V_{MSW} from § 98.33(e)(4)(ii), if CEMS are used to measure CO_2 emissions.

(D) The annual volume of biogenic CO_2 emissions from MSW combustion, in metric tons.

(xi) When ASTM methods D7459–08 and D6866–08 are used to determine the biogenic portion of the annual CO_2 emissions from a unit that co-fires biogenic (other than MSW) and non-biogenic fuels, you shall report the results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO_2 emissions is 30 percent, report 0.30).

(3) Within 30 days of receipt of a written request from the Administrator, you shall submit explanations of the following:

(i) An explanation of how company records are used to quantify fuel consumption, if the Tier 1 or Tier 2 Calculation Methodology is used to calculate CO_2 emissions.

(ii) An explanation of how company records are used to quantify fuel consumption, if solid fuel is combusted and the Tier 3 Calculation Methodology is used to calculate CO_2 emissions.

(iii) An explanation of how sorbent usage is quantified.

(iv) An explanation of how company records are used to quantify fossil fuel consumption in units that uses CEMS to quantify CO_2 emissions and combusts both fossil fuel and biomass.

(v) An explanation of how company records are used to measure steam production, when it is used to calculate CO_2 mass emissions under § 98.33(a)(2)(iii) or to quantify solid fuel usage under § 98.33(c)(3).

(4) Within 30 days of receipt of a written request from the Administrator, you shall submit the verification data and information described in paragraphs (e)(2)(iii), (e)(2)(v), and (e)(2)(vii) of this section.

§ 98.37 Records that must be retained.

In addition to the requirements of § 98.3(g), you must retain the applicable records specified in §§ 98.34(f) and (g), 98.35(b), and 98.36(e).

§ 98.38 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

TABLE C–1 TO SUBPART C OF PART 98—DEFAULT CO_2 EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL

Fuel type	Default high heat value	Default CO_2 emission factor
Coal and coke	mmBtu/short ton	kg CO_2/mmBtu
Anthracite	25.09	103.54
Bituminous	24.93	93.40
Subbituminous	17.25	97.02
Lignite	14.21	96.36
Coke	24.80	102.04
Mixed (Commercial sector)	21.39	95.26
Mixed (Industrial coking)	26.28	93.65
Mixed (Industrial sector)	22.35	93.91
Mixed (Electric Power sector)	19.73	94.38
Natural gas	mmBtu/scf	kg CO_2/mmBtu
Pipeline (Weighted U.S. Average)	1.028×10^{-3}	53.02
Petroleum products	mmBtu/gallon	kg CO_2/mmBtu
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Residual Fuel Oil No. 5	0.140	72.93
Residual Fuel Oil No. 6	0.150	75.10
Still Gas	0.143	66.72
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.096	62.64
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.83
Other Oil (>401 deg F)	0.139	76.22
Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.129	70.97

TABLE C–1 TO SUBPART C OF PART 98—DEFAULT CO_2 EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL—Continued

Fuel type	Default high heat value	Default CO_2 emission factor
Petroleum Coke	0.143	102.41
Special Naphtha	0.125	72.34
Unfinished Oils	0.139	74.49
Heavy Gas Oils	0.148	74.92
Lubricants	0.144	74.27
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22
Asphalt and Road Oil	0.158	75.36
Crude Oil	0.138	74.49
Fossil fuel-derived fuels (solid)	mmBtu/short ton	kg CO_2/mmBtu
Municipal Solid Waste [1]	9.95	90.7
Tires	26.87	85.97
Fossil fuel-derived fuels (gaseous)	mmBtu/scf	kg CO_2/mmBtu
Blast Furnace Gas	0.092×10^{-3}	274.32
Coke Oven Gas	0.599×10^{-3}	46.85
Biomass fuels—solid	mmBtu/short ton	kg CO_2/mmBtu
Wood and Wood Residuals	15.38	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	25.83	105.51
Biomass fuels—gaseous	mmBtu/scf	kg CO_2/mmBtu
Biogas (Captured methane)	0.841×10^{-3}	52.07
Biomass Fuels—Liquid	mmBtu/gallon	kg CO_2/mmBtu
Ethanol (100%)	0.084	68.44
Biodiesel (100%)	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

[1] Allowed only for units that do not generate steam and use Tier 1.

TABLE C–2 TO SUBPART C OF PART 98—DEFAULT CH_4 AND N_2O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C–1)	1.1×10^{-2}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum (All fuel types in Table C–1)	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels—Solid (All fuel types in Table C–1)	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels—Liquid (All fuel types in Table C–1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1g of CH_4/MMBtu.

[1] Allowed only for units that do not generate steam and use Tier 1.

TABLE C–2 TO SUBPART C—DEFAULT CH_4 AND N_2O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C–1)	1.1×10^{-2}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}

TABLE C–2 TO SUBPART C—DEFAULT CH_4 AND N_2O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL—Continued

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
Petroleum (All fuel types in Table C–1)	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels—Solid (All fuel types in Table C–1)	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels—Liquid (All fuel types in Table C–1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1 g of CH_4/MMBtu.

Subpart D—Electricity Generation

§ 98.40 Definition of the source category.

(a) The electricity generation source category comprises electricity generating units that are subject to the requirements of the Acid Rain Program and any other electricity generating units that are required to monitor and report to EPA CO_2 emissions year-round according to 40 CFR part 75.

(b) This source category does not include portable equipment, emergency equipment, or emergency generators, as defined in § 98.6.

§ 98.41 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains one or more electricity generating units and the facility meets the requirements of § 98.2(a)(1).

§ 98.42 GHGs to report.

(a) For each electricity generating unit that is subject to the requirements of the Acid Rain Program or is otherwise required to monitor and report to EPA CO_2 emissions year-round according to 40 CFR part 75, you must report under this subpart the annual mass emissions of CO_2, N_2O, and CH_4 by following the requirements of this subpart.

(b) For each electricity generating unit that is not subject to the Acid Rain Program or otherwise required to monitor and report to EPA CO_2 emissions year-round according to 40 CFR part 75, you must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O by following the requirements of subpart C.

(c) For each stationary fuel combustion unit that does not generate electricity, you must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O by following the requirements of subpart C of this part.

§ 98.43 Calculating GHG emissions.

Continue to monitor and report CO_2 mass emissions as required under § 75.13 or section 2.3 of apppendix G to 40 CFR part 75, and § 75.64. Calculate CO_2, CH_4, and N_2O emissions as follows:

(a) Convert the cumulative annual CO_2 mass emissions reported in the fourth quarter electronic data report required under § 75.64 from units of short tons to metric tons. To convert tons to metric tons, divide by 1.1023.

(b) Calculate and report annual CH_4 and N_2O mass emissions under this subpart by following the applicable method specified in § 98.33(c).

§ 98.44 Monitoring and QA/QC requirements.

Follow the applicable quality assurance procedures for CO_2 emissions in appendices B, D, and G to 40 CFR part 75.

§ 98.45 Procedures for estimating missing data.

Follow the applicable missing data substitution procedures in 40 CFR part 75 for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

§ 98.46 Data reporting requirements.

The annual report shall comply with the data reporting requirements specified in § 98.36(b) and, if applicable, § 98.36(c)(2) or (c)(3).

§ 98.47 Records that must be retained.

You shall comply with the recordkeeping requirements of §§ 98.3(g) and 98.37.

§ 98.48 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Subpart E—Adipic Acid Production

§ 98.50 Definition of source category.

The adipic acid production source category consists of all adipic acid production facilities that use oxidation to produce adipic acid.

§ 98.51 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an adipic acid production process and the facility meets the requirements of either § 98.2(a)(1) or (2).

§ 98.52 GHGs to report.

(a) You must report N_2O process emissions at the facility level.

(b) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit following the requirements of subpart C.

§ 98.53 Calculating GHG emissions.

(a) You must determine annual N_2O emissions from adipic acid production according to paragraphs (a)(1) or (a)(2) of this section.

(1) Use a site-specific emission factor and production data according to paragraphs (b) through (h) of this section.

(2) Request Administrator approval for an alternative method of determining N_2O emissions according to paragraphs (a)(2)(i) and (a)(2)(ii) of this section.

(i) You must submit the request within 45 days following promulgation of this subpart or within the first 30 days of each subsequent reporting year.

(ii) If the Administrator does not approve your requested alternative method within 150 days of the end of the reporting year, you must determine the N_2O emissions factor for the current reporting period using the procedures specified in paragraphs (b) through (h) of this section.

(b) You must conduct an annual performance test according to

Table 1.3-1. CRITERIA POLLUTANT EMISSION FACTORS FOR FUEL OIL COMBUSTION[a]

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[e]		Filterable PM[f]	
	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING
Boilers > 100 Million Btu/hr										
No. 6 oil fired, normal firing (1-01-004-01), (1-02-004-01), (1-03-004-01)	157S	A	5.7S	C	47	A	5	A	9.19(S)+3.22	A
No. 6 oil fired, normal firing, low NO_x burner (1-01-004-01), (1-02-004-01)	157S	A	5.7S	C	40	B	5	A	9.19(S)+3.22	A
No. 6 oil fired, tangential firing, (1-01-004-04)	157S	A	5.7S	C	32	A	5	A	9.19(S)+3.22	A
No. 6 oil fired, tangential firing, low NO_x burner (1-01-004-04)	157S	A	5.7S	C	26	E	5	A	9.19(S)+3.22	A
No. 5 oil fired, normal firing (1-01-004-05), (1-02-004-04)	157S	A	5.7S	C	47	B	5	A	10	B
No. 5 oil fired, tangential firing (1-01-004-06)	157S	A	5.7S	C	32	B	5	A	10	B
No. 4 oil fired, normal firing (1-01-005-04), (1-02-005-04)	150S	A	5.7S	C	47	B	5	A	7	B
No. 4 oil fired, tangential firing (1-01-005-05)	150S	A	5.7S	C	32	B	5	A	7	B
No. 2 oil fired (1-01-005-01), (1-02-005-01), (1-03-005-01)	142S[h]	A	5.7S	C	24	D	5	A	2	A
No.2 oil fired, LNB/FGR, (1-01-005-01), (1-02-005-01), (1-03-005-01)	142S[h]	A	5.7S	A	10	D	5	A	2	A

Table 1.3-1. (cont.)

Firing Configuration (SCC)[a]	SO_2[b] Emission Factor ($lb/10^3$ gal)	SO_2[b] EMISSION FACTOR RATING	SO_3[c] Emission Factor ($lb/10^3$ gal)	SO_3[c] EMISSION FACTOR RATING	NO_x[d] Emission Factor ($lb/10^3$ gal)	NO_x[d] EMISSION FACTOR RATING	CO[e] Emission Factor ($lb/10^3$ gal)	CO[e] EMISSION FACTOR RATING	Filterable PM[f] Emission Factor ($lb/10^3$ gal)	Filterable PM[f] EMISSION FACTOR RATING
Boilers < 100 Million Btu/hr										
No. 6 oil fired (1-02-004-02/03) (1-03-004-02/03)	157S	A	2S	A	55	A	5	A	9.19(S)+3.22[i]	B
No. 5 oil fired (1-03-004-04)	157S	A	2S	A	55	A	5	A	10[i]	A
No. 4 oil fired (1-03-005-04)	150S	A	2S	A	20	A	5	A	7	B
Distillate oil fired (1-02-005-02/03) (1-03-005-02/03)	142S	A	2S	A	20	A	5	A	2	A
Residential furnace (A2104004/A2104011)	142S	A	2S	A	18	A	5	A	0.4[g]	B

a To convert from lb/103 gal to kg/103 L, multiply by 0.120. SCC = Source Classification Code.
b References 1-2,6-9,14,56-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.
c References 1-2,6-8,16,57-60. S indicates that the weight % of sulfur in the oil should be multiplied by the value given. For example, if the fuel is 1% sulfur, then S = 1.
d References 6-7,15,19,22,56-62. Expressed as NO2. Test results indicate that at least 95% by weight of NOx is NO for all boiler types except residential furnaces, where about 75% is NO. For utility vertical fired boilers use 105 lb/103 gal at full load and normal (>15%) excess air. Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are related to fuel nitrogen content, estimated by the following empirical relationship: lb NO2 /103 gal = 20.54 + 104.39(N), where N is the weight % of nitrogen in the oil. For example, if the fuel is 1% nitrogen, then N = 1.
e References 6-8,14,17-19,56-61. CO emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained.
f References 6-8,10,13-15,56-60,62-63. Filterable PM is that particulate collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. Particulate emission factors for residual oil combustion are, on average, a function of fuel oil sulfur content where S is the weight % of sulfur in oil. For example, if fuel oil is 1% sulfur, then S = 1.
g Based on data from new burner designs. Pre-1970's burner designs may emit filterable PM as high as 3.0 1b/103 gal.
h The SO2 emission factor for both no. 2 oil fired and for no. 2 oil fired with LNB/FGR, is 142S, not 157S. Errata dated April 28, 2000. Section corrected May 2010.
i The PM factors for No.6 and No. 5 fuel were reversed. Errata dated April 28, 2000. Section corrected May 2010.

Table 1.3-2. CONDENSABLE PARTICULATE MATTER EMISSION FACTORS FOR OIL COMBUSTION[a]

Firing Configuration[b] (SCC)	Controls	CPM - TOT[c, d]		CPM - IOR[c, d]		CPM - ORG[c, d]	
		Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING	Emission Factor (lb/10^3 gal)	EMISSION FACTOR RATING
No. 2 oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	All controls, or uncontrolled	1.3[d, e]	D	65% of CPM-TOT emission factor[c]	D	35% of CPM-TOT emission factor[c]	D
No. 6 oil fired (1-01-004-01/04, 1-02-004-01, 1-03-004-01)	All controls, or uncontrolled	1.5[f]	D	85% of CPM-TOT emission factor[d]	E	15% of CPM-TOT emission factor[d]	E

[a] All condensable PM is assumed to be less than 1.0 micron in diameter.
[b] No data are available for numbers 3, 4, and 5 oil. For number 3 oil, use the factors provided for number 2 oil. For numbers 4 and 5 oil, use the factors provided for number 6 oil.
[c] CPM-TOT = total condensable particulate matter.
CPM-IOR = inorganic condensable particulate matter.
CPM-ORG = organic condensable particulate matter.
[d] To convert to lb/MMBtu of No. 2 oil, divide by 140 MMBtu/10^3 gal. To convert to lb/MMBtu of No. 6 oil, divide by 150 MMBtu/10^3 gal.
[e] References: 76-78.
[f] References: 79-82.

Table 1.3-3. EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), METHANE, AND NONMETHANE TOC (NMTOC) FROM UNCONTROLLED FUEL OIL COMBUSTION[a]

EMISSION FACTOR RATING: A

Firing Configuration (SCC)	TOC[b] Emission Factor ($lb/10^3$ gal)	Methane[b] Emission Factor ($lb/10^3$ gal)	NMTOC[b] Emission Factor ($lb/10^3$ gal)
Utility boilers			
No. 6 oil fired, normal firing (1-01-004-01)	1.04	0.28	0.76
No. 6 oil fired, tangential firing (1-01-004-04)	1.04	0.28	0.76
No. 5 oil fired, normal firing (1-01-004-05)	1.04	0.28	0.76
No. 5 oil fired, tangential firing (1-01-004-06)	1.04	0.28	0.76
No. 4 oil fired, normal firing (1-01-005-04)	1.04	0.28	0.76
No. 4 oil fired, tangential firing (1-01-005-05)	1.04	0.28	0.76
Industrial boilers			
No. 6 oil fired (1-02-004-01/02/03)	1.28	1.00	0.28
No. 5 oil fired (1-02-004-04)	1.28	1.00	0.28
Distillate oil fired (1-02-005-01/02/03)	0.252	0.052	0.2
No. 4 oil fired (1-02-005-04)	0.252	0.052	0.2
Commercial/institutional/residential combustors			
No. 6 oil fired (1-03-004-01/02/03)	1.605	0.475	1.13
No. 5 oil fired (1-03-004-04)	1.605	0.475	1.13
Distillate oil fired (1-03-005-01/02/03)	0.556	0.216	0.34
No. 4 oil fired (1-03-005-04)	0.556	0.216	0.34
Residential furnace (A2104004/A2104011)	2.493	1.78	0.713

a To convert from lb/103 gal to kg/103 L, multiply by 0.12. SCC = Source Classification Code.

b References 29-32. Volatile organic compound emissions can increase by several orders of magnitude if the boiler is improperly operated or is not well maintained.

Table 1.3-6. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR UNCONTROLLED INDUSTRIAL BOILERS FIRING DISTILLATE OIL[a]

EMISSION FACTOR RATING: E

Particle Size[b] (μm)	Cumulative Mass % Stated Size	Cumulative Emission Factor ($lb/10^3$ gal)
15	68	1.33
10	50	1.00
6	30	0.58
2.5	12	0.25
1.25	9	0.17
1.00	8	0.17
0.625	2	0.04
TOTAL	100	2.00

[a] Reference 26. Source Classification Codes 1-02-005-01/02/03. To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.12.
[b] Expressed as aerodynamic equivalent diameter.

Table 1.3-7. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS UNCONTROLLED COMMERCIAL BOILERS BURNING RESIDUAL OR DISTILLATE OIL[a]

EMISSION FACTOR RATING: D

Particle Size[b] (μm)	Cumulative Mass % Stated Size		Cumulative Emission Factor[c] ($lb/10^3$ gal)	
	Residual Oil	Distillate Oil	Residual Oil	Distillate Oil
15	78	60	6.50A	1.17
10	62	55	5.17A	1.08
6	44	49	3.67A	1.00
2.5	23	42	1.92A	0.83
1.25	16	38	1.33A	0.75
1.00	14	37	1.17A	0.75
0.625	13	35	1.08A	0.67
TOTAL	100	100	8.34A	2.00

[a] Reference 26. Source Classification Codes: 1-03-004-01/02/03/04 and 1-03-005-01/02/03/04. To convert from $lb/10^3$ gal to $kg/10^3$ L, multiply by 0.12.
[b] Expressed as aerodynamic equivalent diameter.
[c] Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content where S is the weight % of sulfur in the fuel. For example, if the fuel is 1.0% sulfur, then S = 1.
No. 6 oil: A = 1.12(S) + 0.37 No. 4 oil: A = 0.84
No. 5 oil: A = 1.2 No. 2 oil: A = 0.24

Table 1.3-10. EMISSION FACTORS FOR TRACE ELEMENTS FROM DISTILLATE FUEL OIL COMBUSTION SOURCES[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Emission Factor (lb/10^{12} Btu)										
	As	Be	Cd	Cr	Cu	Pb	Hg	Mn	Ni	Se	Zn
Distillate oil fired (1-01-005-01, 1-02-005-01, 1-03-005-01)	4	3	3	3	6	9	3	6	3	15	4

[a] Data are for distillate oil fired boilers, SCC codes 1-01-005-01, 1-02-005-01, and 1-03-005-01. References 29-32, 40-44 and 83. To convert from lb/10^{12} Btu to pg/J, multiply by 0.43.

Table 1.6-5. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR WOOD/BARK-FIRED BOILERS[a]

EMISSION FACTOR RATING: E

Particle Size[b] (μm)	Cumulative Mass % ≤ Stated Size				
		Controlled			
	Uncontrolled[c]	Multiple Cyclone[d]	Multiple Cyclone[e]	Scrubber[f]	Dry Electrostatic Granular Filter (DEGF)
15	94	96	35	98	77
10	90	91	32	98	74
6	86	80	27	98	69
2.5	76	54	16	98	65
1.25	69	30	8	96	61
1.00	67	24	6	95	58
0.625	ND	16	3	ND	51
Total	100	100	100	100	100

[a] Reference 89.
[b] Expressed as aerodynamic equivalent diameter.
[c] From data on underfeed stokers. May also be used as size distribution for wood-fired boilers.
[d] From data on spreader stokers with flyash reinjection.
[e] From data on spreader stokers without flyash reinjection.
[f] From data on Dutch ovens. Assumed control efficiency is 94%.

Table A-1: Historical Stack Test Data, New Hope Power Company

Test Date	Unit	Fuel Type	Lead (lb/MMBtu)	Fluorides (lb/MMBtu)
01/99-02/99	Unit A	Wood	3.00E-05	9.38E-05
	Unit B	Wood	8.40E-05	5.07E-05
	Unit C	Wood	4.00E-04 [a]	1.13E-04 [a]
01/99-02/99	Unit A	Bagasse	2.00E-05	7.06E-05
	Unit B	Bagasse	7.30E-06	4.07E-05
	Unit C	Bagasse	6.30E-06	3.04E-05
12/99-01/00	Unit A	Wood	1.19E-05	1.50E-04
	Unit B	Wood	7.97E-06	1.60E-04
	Unit C	Wood	1.75E-05	3.10E-04
12/99-01/00	Unit A	Bagasse	3.41E-06	3.70E-04
	Unit B	Bagasse	6.68E-06	4.40E-04
	Unit C	Bagasse	9.77E-06	3.90E-04
01/3/01-01/23/01	Unit A	Wood	7.49E-05	7.00E-04
	Unit B	Wood	1.97E-05	6.00E-04
	Unit C	Wood	3.91E-05	6.00E-04
01/3/01-01/23/01	Unit A	Bagasse	3.81E-05	6.00E-04
	Unit B	Bagasse	4.76E-05	4.00E-04
	Unit C	Bagasse	1.63E-05	3.00E-04
02/12/02-02/14/02	Unit A	Biomass [b]	2.08E-05	--
	Unit B	Biomass [b]	1.41E-05	--
	Unit C	Biomass [b]	2.09E-05	--
Average			2.48E-05	3.12E-04

Sources: Air Consulting and Engineering, Inc., 2008; Golder, 2008.

[a] Results may not be representative due to high PM emissions.

[b] Biomass firing consisted of approximately 50% wood and 50% bagasse.

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