Joe

Module AB174

Permit Application

TITLE V AIR OPERATION PERMIT REVISION APPLICATION

New Hope Power Company
Okeelanta Cogeneration Plant

Project No. 0990005-034-AV

Prepared For: New Hope Power Company
21250 U.S. Highway 27 South
South Bay, FL 33493 USA

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

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

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APPLICATION FOR AIR PERMIT

LONG FORM

Department of Environmental Protection

RECEIVED MAY 06 2013 DIVISION OF AIR RESOURCE MANAGEMENT

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

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

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

Air Operation Permit – Use this form to apply for:

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

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **New Hope Power Company**	
2. Site Name: **Okeelanta Cogeneration Plant**	
3. Facility Identification Number: ~~0990332~~ 0990005	
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: 5-6-13	3. PSD Number (if applicable):
2. Project Number(s): 0990005-034-AV	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☐ Air construction permit.

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

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

Air Operation Permit

☐ Initial Title V air operation permit.

☒ Title V air operation permit revision.

☐ Title V air operation permit renewal.

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

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

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

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

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

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

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

Application Comment

This Title V revision application is to incorporate Construction Permit Nos. 0990332-019-AC and 0990332-020-AC into the current Title V Air Operating Permit No. 0990005-033-AV. Permit No. 0990332-019-AC authorized the installation of natural gas burners in Boiler A with a firing capability of 400 MMBtu/hour. Permit No. 0990332-020-AC removed the requirement to maintain an activated carbon injection (ACI) system on-site except in the event two or more boilers failed their annual mercury compliance test.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
001	Cogeneration Boiler A		N/A
002	Cogeneration Boiler B		N/A
003	Cogeneration Boiler C		N/A

Application Processing Fee

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

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. Owner/Authorized Representative Name :
2. Owner/Authorized Representative Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Owner/Authorized Representative Telephone Numbers... Telephone: ( ) ext. Fax: ( )
4. Owner/Authorized Representative E-mail Address:
5. Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.* Signature Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:
   Jose Gonzalez, Vice President of Industrial Operations

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: **New Hope Power Company**
   Street Address: **8001 U.S. Highway 27 South**
   City: **South Bay** State: **FL** Zip Code: **33493**

4. Application Responsible Official Telephone Numbers...
   Telephone: **(561) 993-1600** ext. Fax: **(561) 992-7326**

5. Application Responsible Official E-mail Address: **Jose_Gonzalez@floridacrystals.com**

6. Application Responsible Official Certification:

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

Signature: [signature] Date: 5-3-13

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **Philip Cobb** Registration Number: **72386**
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. **21144** Fax: **(352) 336-6603**
4.	Professional Engineer E-mail Address: **pcobb@golder.com**
5.	Professional Engineer Statement: *I, the undersigned, hereby certify, except as particularly noted herein*, that:* *(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and* *(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.* *(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.* *(4) If the purpose of this application is to obtain an air construction permit (check here ☐, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.* *(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☒, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.* Signature 5/2/13 Date (seal)

* Attach any exception to certification statement.

**Board of Professional Engineers Certificate of Authorization #00001670.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **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:__________ ☒ Previously Submitted, Date: 03/14/2012	
2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID:__________ ☒ Previously Submitted, Date: 03/14/2012	
3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID:__________ ☒ Previously Submitted, Date: 03/14/2012	

Additional Requirements for Air Construction Permit Applications

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

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications

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

Additional Requirements for Title V Air Operation Permit Applications

1. List of Insignificant Activities: (Required for initial/renewal applications only)
   ☐ Attached, Document ID:__________ ☒ 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: NHPC-FI-CV3
   Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.

4. List of Equipment/Activities Regulated under Title VI: (If applicable, required for initial/renewal applications only)
   ☐ Attached, Document ID:__________
   ☐ Equipment/Activities Onsite but Not Required to be Individually Listed
   ☒ Not Applicable

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

6. Requested Changes to Current Title V Air Operation Permit:
   ☒ Attached, Document ID: NHPC-FI-CV6 ☐ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Facilities Subject to Acid Rain, CAIR, or Hg Budget Program

1.	Acid Rain Program Forms: Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)): ☐ Attached, Document ID:__________ ☐ 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-CV3

COMPLIANCE REPORT AND PLAN

ATTACHMENT NHPC-FI-CV3
COMPLIANCE REPORT

New Hope Power Company (NHPC) certifies that the Okeelanta Cogeneration Plant located in South Bay, Palm Beach County, Florida, as of the date of this application, is in compliance with each applicable requirement addressed in this Title V air operation permit revision application.

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

Compliance statements for this facility will be submitted on an annual basis to Florida Department of Environmental Protection (FDEP), on or before March 1 of each year.

5-3-13

Signature, Responsible Official | Date

ATTACHMENT NHPC-FI-CV6

REQUESTED CHANGES TO CURRENT TITLE V AIR OPERATION PERMIT

ATTACHMENT NHPC-FI-CV6

REQUESTED CHANGES TO CURRENT TITLE V AIR OPERATION PERMIT

Changes to Fuel Management Plan

Section 4, Appendix FM of the current Title V Air Operation Permit contains a fuel management plan for the NHPC facility. Page FM-4 of the appendix contains procedures for obtaining composite samples. These procedures are listed below:

- Throughout the sample collection, compositing and delivery to the laboratories, a chain of custody will be used to document sample collection through analysis.
- Thoroughly mix all of the individual grab samples and pour the entire composite sample over a clean plastic sheet.
- Break sample pieces larger than 3 inches into smaller sizes.
- Make a pie shape with the entire composite sample and subdivide into four equal parts.
- Separate one of the quarter samples as the first subset. If a duplicate sample is to be obtained for analysis, separate a second quarter of the sample as the second subset.
- <u>Do not grind the sample subset in a mill as this may contaminate the sample with metals</u>.
- If the quarter sample is too large, subdivide it further as described above.
- Transfer each sample subset into a clean plastic sealable bag. Document and label each sample appropriately.
- At least one sample subset of the composite sample will be retained temporarily on site for use as a control sample to verify the lab results, if necessary.

Additionally, the following statement appears on page FM-5:

> The composite samples will be processed by a third party vendor and/or laboratory for required analytical results. It is noted that the National Council for Air and Stream Improvement (NCASI) has identified <u>grinding of biomass samples as a possible point of sample contamination due to the metals contained in the grinding equipment used in labs. As a result, the lab may not grind the sample</u>, but instead may cut the samples to appropriate size prior to digestion and analysis.

The wording underlined above has recently come to the forefront of discussions between FDEP and NHPC as a result of fuel analyses that seemed to indicate that the levels of metals in the fuel used by NHPC were above their respective emission limits. Although the fuel sample pieces must be broken into sizes smaller than 3 inches, large sample pieces may still result in a grab sample that is not representative of the overall fuel mix. At the suggestion of FDEP, NHPC is requesting that the requirement to not grind the sample in a mill be changed to allow, as an option, grinding in a mill or resizing using other suitable methods in order to ensure uniform size distribution. NHPC believes that that risk of metals contaminating the fuel samples by grinding or another form of subdividing the sample subset is less than the risk of a non-representative sample resulting from large wood pieces in the sample. Also, NHPC is developing sample handling and preparation protocols with the laboratories to ensure metals contamination does not occur or is minimized.

Therefore, NHPC suggests that the language in Appendix FM be changed to allow grinding the samples or use of other procedures to ensure a uniform distribution of wood particles. This will provide for a sample of more uniform size, which is more well mixed, and therefore more representative of the actual fuel mix being used at the facility. It is also noted that the final Boiler MACT rule recently issued (January 31, 2013) requires biomass samples to be ground in a mill. EPA has therefore concluded that metals contamination due to grinding is not an issue.

The following is the suggested wording for the Title V permit:

- Throughout the sample collection, compositing and delivery to the laboratories, a chain of custody will be used to document sample collection through analysis.
- Thoroughly mix all of the individual grab samples and pour the entire composite sample over a clean plastic sheet.
- Break sample pieces larger than 3 inches into smaller sizes.
- Make a pie shape with the entire composite sample and subdivide into four equal parts.
- Separate one of the quarter samples as the first subset. If a duplicate sample is to be obtained for analysis, separate a second quarter of the sample as the second subset.
- ~~Do not grind the sample subset in a mill as this may contaminate the sample with metals.~~ The sample subset may be ground in a mill or resized using other suitable laboratory methods in order to ensure a uniform size distribution. If a grinding mill is used, care should be taken to avoid metals contamination from the mill (use of a ceramic mill, proper cleaning and sharpening of mill prior to grinding, etc.).
- If the quarter sample is too large, subdivide it further as described above.
- Transfer each sample subset into a clean plastic sealable bag. Document and label each sample appropriately.
- At least one sample subset of the composite sample will be retained temporarily on site for use as a control sample to verify the lab results, if necessary.

Additionally, the following text is suggested:

> The composite samples will be processed by a third party vendor and/or laboratory for required analytical results. It is noted that the National Council for Air and Stream Improvement (NCASI) has identified grinding of biomass samples as a possible point of sample contamination due to the metals contained in the grinding equipment used in labs. ~~As a result, the lab may not grind the sample, but instead may cut the samples to appropriate size prior to digestion and analysis.~~ Therefore, care must be taken to avoid or minimize metals contamination during the grinding process, including use of a non-metal grinding mill (ceramic, etc.) and proper cleaning and maintenance in order to ensure optimal performance of the mill, or use of other resizing methods.

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: **Zurn** Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
    Boiler A is a hybrid suspension grate unit fired by biomass (bagasse/wood) as the primary fuel. Distillate oil and/or natural gas is 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 INFORMATION
Section [1]
Cogeneration Boiler A

Emissions Unit Control Equipment/Method: Control 1 of 3

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

Emissions Unit Control Equipment/Method: Control 2 of 3

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 3

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

Emissions Unit Control Equipment/Method: Control _____ of _____

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

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate: **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 **52** weeks/year	 **7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Maximum production rate based on Permit No. 0990005-033-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, B, and C**		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** 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: 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. 0990005-033-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. Natural gas will be burned 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 to the full natural gas firing capacity.**		

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)			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. 0990332-020-AC/PSD-FL-196Q**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.026 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** Reference: **Permit No. 0990332-020-AC/PSD-FL-196Q**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.026 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: **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. 0990332-020-AC/PSD-FL-196Q**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

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 SO2 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 SO2 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 SO2 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 SO2 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 SO2 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. 0990332-020-AC/PSD-FL-196Q**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **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 NOx 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 NOx 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 NOx 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 (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 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 NOx 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 and Permit No. 0990332-020-AC/PSD-FL-196Q**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

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.

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

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. 0990332-020-AC/PSD-FL-196Q**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

0.05 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: **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: **$5.4x10^{-6}$ lb/MMBtu** Reference: **Permit No. 0990332-020-AC/PSD-FL-196Q**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly: $5.4x10^{-6}$ 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.

Allowable Emissions Allowable Emissions 1 of 1

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

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. 0990332-020-AC/PSD-FL-196Q.**	

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: **CO2**	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:	

EMISSIONS UNIT INFORMATION
Section [1]
Cogeneration Boiler A

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-EU1-I1** ☐ Previously Submitted, Date ______

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **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: ______ ☒ Previously Submitted, Date **05/10/2012**

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: **NHPC-EU1-I4** ☐ Previously Submitted, Date ______
☐ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: ______ ☒ Previously Submitted, Date **05/10/2012**
☐ Not Applicable

6. Compliance Demonstration Reports/Records:
☐ Attached, Document ID: ______
Test Date(s)/Pollutant(s) Tested: ______
☒ Previously Submitted, Date: **January 2012**
Test Date(s)/Pollutant(s) Tested: **01/19/2012 – PM, VOC, Hg**
☐ To be Submitted, Date (if known): ______
Test Date(s)/Pollutant(s) Tested: ______
☐ Not Applicable
Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

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

Additional Requirements for Title V Air Operation Permit Applications

1.	Identification of Applicable Requirements: ☒ Attached, Document ID: NHPC-EU1-IV1
2.	Compliance Assurance Monitoring: ☐ Attached, Document ID: ____________ ☒ Not Applicable
3.	Alternative Methods of Operation: ☒ Attached, Document ID: NHPC-EU1-IV3 ☐ 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, Boilers A, B, and C
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

All values are based on a single boiler.

Attachment NHPC-EU1-B6b. Maximum Annual Heat Input and Fuel Usage Rates, Boilers A, B, and C
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

All values are based on a single boiler.

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ATTACHMENT NHPC-EU1-F1.10

EMISSIONS CALCULATIONS

Attachment NHPC-EU1-F1.10a. Maximum Short-Term Emissions for Boilers A, B and C
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
Sulfur Dioxide (SO_2)															
- 3-hr Average	0.30	4	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	4	225	1,462.5	1.0	4	490	490	--		--	--	958.7	--	1,462.5
- 30 day rolling average	0.5	1	760	380.0	0.5	1	490	245	0.082	5	400	32.68	318.8	162.7	380.0
Nitrogen Oxides (NO_x)															
- 3 hr Average	0.20	4	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	6	760	0.0638	9.00E-06	7	490	4.41E-03	4.86E-07	2	400	1.95E-04	0.0168	0.0220	0.064

All values are based on a single boiler.

Notes:

[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 Based on CEMS data.

5 AP-42, Table 1.4-1, controlled gas combustion in low-NO_x burners.

6 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.

7 AP-42, Table 1.3-10 for distillate oil firing.

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Attachment NHPC-EU1-F1.10b. Maximum Annual Emissions for Boilers A, B and C
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
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
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
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
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
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
								Maximum Annual Emissions	
								Particulate Matter (PM)	86.55
								Particulate Matter (PM_{10})	86.55
								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

All values are based on a single boiler.

Notes:
[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).

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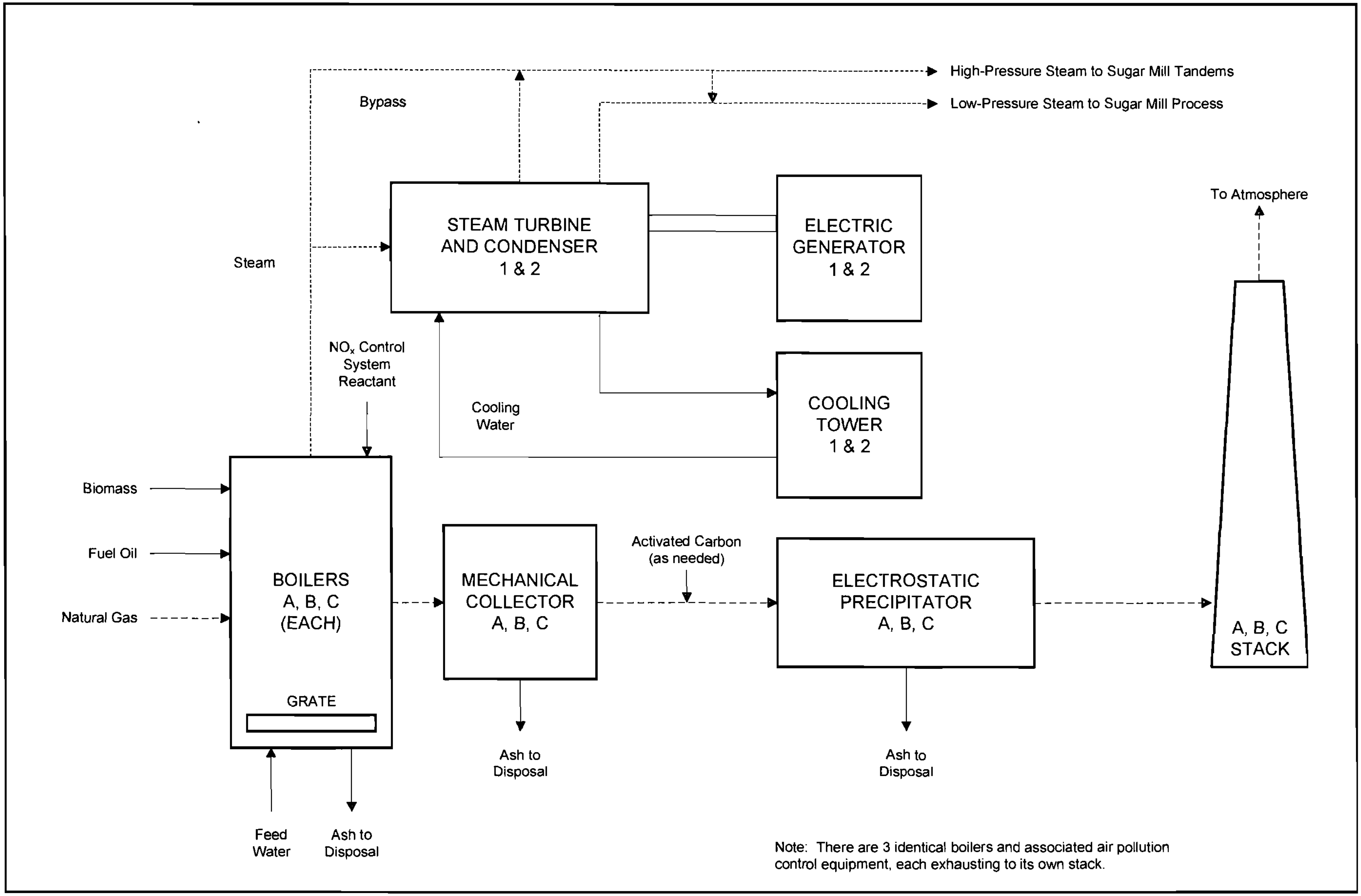
ATTACHMENT NHPC-EU1-I1

PROCESS FLOW DIAGRAM



Attachment NHPC-EU1-I1
Simplified Flow Diagram
New Hope Power Company, Okeelanta Cogeneration Facility
South Bay, FL

Process Flow Legend
Solid/Liquid
Steam
Gas

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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-I4

PROCEDURES FOR STARTUP AND SHUTDOWN

ATTACHMENT NHPC-EU1-I4

PROCEDURES FOR STARTUP AND SHUTDOWN NHPC COGENERATION BOILERS

During startup and shutdown of the boiler, excess emissions for more than 2 hours in a 24-hour period are possible. Pursuant to Rule 62-210.700(1), F.A.C., the following procedures and precautions are taken to minimize the magnitude and duration of excess emissions during startup and shutdown.

Startup Procedures

1. Check to ensure all the boiler doors/registers are closed.
2. The CEM system is started, propane supply to the gun is opened and compressed air is admitted to atomizing system.
3. The start switch is turned on to activate the startup sequence. Once oil firing is established, minimum fire (10%) is maintained for 30 minutes on and 30 minutes off for approximately 2 hours.
4. Continuous firing is established and steam pressure increased to about 150 psig. Firing continues on low fire until operating pressure (350 psig) is available on the line (about 5 hours after initial firing). Atomization is changed to steam.
5. Once consistent steam flow to user(s), e.g., turboalternator, is established, boiler controls are placed in automatic.

Shutdown Procedures

1. Control is turned off and the fuel pump is shut off.
2. The atomizing steam valve is closed. The FD fan is shut off.
3. After about 3 hours, the drum level is set at maximum level.

ATTACHMENT NHPC-EU1-IV1

IDENTIFICATION OF APPLICABLE REQUIREMENTS

Florida Department of Environmental Protection

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

Rick Scott
Governor

Jennifer Carroll
Lt. Governor

Herschel T. Vinyard Jr.
Secretary

PERMITTEE

New Hope Power Company (NHPC)
Okeelanta Cogeneration Plant
8001 U.S. Highway 27 South
South Bay, Florida 33493

Authorized Representative:
Mr. Jose Gonzalez, General Manager & Vice President

Air Permit No. 0990332-019-AC
Permit Expires: December 31, 2013
SIC No. 4911
Cogeneration Boiler A
Installation of Natural Gas Burners
Palm Beach County

PROJECT

The Okeelanta Cogeneration Plant is located off U.S. Highway 27 South approximately six miles south of South Bay in Palm Beach County, Florida. The UTM coordinates of the facility are Zone 17, 524.9 kilometers (km) East and 2940.1 km North. The project is the installation four natural gas burners in Cogeneration Boiler A. Each natural gas burner will have a rating of 100 million British thermal units per hour.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of: Chapter 403 of the Florida Statutes (F.S.) and Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.). The permittee is authorized to conduct the proposed work in accordance with the conditions of this permit. This project is subject to the general preconstruction review requirements in Rule 62-212.300, F.A.C.

Upon issuance of this final permit, any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida
Electronic Signature

CERTIFICATE OF SERVICE

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

Mr. Jose Gonzalez, NHPC: Jose_Gonzalez@floridacrystals.com
Mr. Micah Leis, NHPC: Micah_Leis@floridacrystals.com
Mr. Ricardo Lima, Okeelanta Corporation: Ricardo_Lima@floridacrystals.com
Mr. David Buff, P.E., Golder Associates: dbuff@golder.com
Mr. Lennon Anderson, DEP SED: Lennon.Anderson@dep.state.fl.us
Ms. Cindy Mulkey, DEP Siting Office: cindy.mulkey@dep.state.fl.us
Ms. Heather Ceron, EPA Region 4: ceron.heather@epa.gov
Ms. Lynn Scearce, DEP PC Reading File: lynn.scearce@dep.state.fl.us
Ms. Barbara Friday, DEP Reading File: barbara.friday@dep.state.fl.us

Clerk Stamp

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

FACILITY DESCRIPTION

The facility consists of two adjacent plants. The Okeelanta Corporation operates a sugar mill and a sugar refinery (ARMS Facility I.D. No. 0990005) including packaging and transshipment activities. New Hope Power Company (the permittee) operates a 140 megawatts cogeneration plant (DEP File No. 0990332) that provides process steam for the sugar mill/refinery and generates electricity for sale to the power grid. The cogeneration plant, sugar mill, and sugar refinery are all considered a single facility for purposes of the Prevention of Significant Deterioration (PSD) and Title V regulatory programs. The facility is located off U.S. Highway 27 South, approximately six miles south of South Bay in Palm Beach County, Florida. The UTM coordinates of the facility are Zone 17, 524.9 kilometers (km) East and 2940.1 km North.

PROJECT DESCRIPTION

The following emission unit (EU) is affected by this permitting action.

EU ID No.	Emission Unit Description
001	Cogeneration Boiler A (760 MMBtu/hour)

Cogeneration Boiler A currently burns biomass (bagasse and wood) as its primary fuel and No. 2 fuel oil (maximum sulfur content of 0.05 percent by weight) as a supplemental fuel to generate steam. The permittee requests authorization to install four natural gas burners in Cogeneration Boiler A. The natural gas burners will be installed in each of the four corners of the boiler. Each natural gas burner will have a rating of 100 million Btu per hour (MMBtu/hour) for a total natural gas firing capability of 400 MMBtu/hour.

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, the natural gas burners were never installed in the boiler. Once the burners are installed, natural gas will be burned as a supplemental fuel, similar to the manner in which No. 2 fuel oil is currently burned. Biomass will remain the primary fuel. Natural gas will be used as 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. As already required by an existing permit (Permit No. 0990032-017-AC/PSD-FL-192P), fossil fuels will not be burned for more than 25 percent of the heat input to the boiler during any calendar quarter.

The permittee plans to install the natural gas burners prior to the beginning of the 2012 sugar cane crop season, which will begin in approximately October 2012. The following equipment will be installed:

- 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; and
- Interconnecting piping, tubing, conduit, and wiring.

FACILITY REGULATORY CLASSIFICATION

- The facility is a major source of hazardous air pollutants (HAP).
- The facility does **not** operate units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400, F.A.C. for the PSD of Air Quality.

- The facility operates units that are subject to the New Source Performance Standards (NSPS) in Part 60, Title 40 of the Code of Federal Regulations (CFR) and the National Emissions Standards for Hazardous Air Pollutants (NESHAP) in Part 60, Title 40 of the CFR.

PREVIOUS APPLICABLE REQUIREMENTS

The conditions of this permit supplement all previously issued air construction and operation permits for this emission unit. Unless otherwise specified, these conditions are in addition to all other applicable permit conditions and regulations. [Rule 62-4.070, F.A.C.]

1. Permitting Authority: The permitting authority for this project is the Office of Permitting and Compliance in the Division of Air Resource Management of the Department of Environmental Protection (Department). The Office of Permitting and Compliance mailing address is 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. All documents related to applications for permits to operate an emissions unit shall be submitted to the Air Resource Section of the Department's South District Office at: 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33902-2549. The telephone number is 239/344-5651 and the fax number is 850/412-0590. Copies shall be sent to each agency identified under Compliance Authority.
2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resource Section of the Department's South District Office at: 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33902-2549. The telephone number is 239/344-5651 and the fax number is 850/412-0590. Copies of all such documents shall also be submitted to the Air Pollution Control Section of the Palm Beach County Health Department at P.O. Box 29, West Palm Beach, Florida 33402-0029 (Telephone No. 561/837-5900 and Facsimile No. 561/837-5295).
3. Appendices: The following Appendix is included in Section 4 of this permit:
   - Appendix A: Citation Formats and Glossary of Common Terms;
   - Appendix B: General Conditions: and
   - Appendix C: Common Conditions.
4. Applicable Regulations, Forms and Application Procedures: Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S.; and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296 and 62-297, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.
5. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]
6. Modifications: The permittee shall notify the Compliance Authority upon commencement of construction. No new emissions unit shall be constructed and no existing emissions unit shall be modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]
7. Source Obligation:

   (a) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

   (b) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

[Rule 62-212.400(12), F.A.C.]

8. Application for Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V air operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V air operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the appropriate Permitting Authority with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220 and Chapter 62-213, F.A.C.]

9. Actual Emissions Reporting: This permit is based on an analysis that compared baseline actual emissions with projected actual emissions and avoided the requirements of subsection 62-212.400(4) through (12), F.A.C. for several pollutants. Therefore, pursuant to Rule 62-212.300(1)(e), F.A.C., the permittee is subject to the following monitoring, reporting and recordkeeping provisions.

   a. The permittee shall monitor the emissions of any PSD pollutant that the Department identifies could increase as a result of the construction or modification and that is emitted by any emissions unit that could be affected; and, using the most reliable information available, calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change. Emissions shall be computed in accordance with the provisions in Rule 62-210.370, F.A.C., which are provided in Appendix C of this permit.

   b. The permittee shall report to the Department within 60 days after the end of each calendar year during the 5-year period setting out the unit's annual emissions during the calendar year that preceded submission of the report. The report shall contain the following:

      1) The name, address and telephone number of the owner or operator of the major stationary source;

      2) The annual emissions calculations pursuant to the provisions of 62-210.370, F.A.C., which are provided in Appendix C of this permit;

      3) If the emissions differ from the preconstruction projection, an explanation as to why there is a difference; and

      4) Any other information that the owner or operator wishes to include in the report.

   c. The information required to be documented and maintained pursuant to subparagraphs 62-212.300(1)(e)1 and 2, F.A.C., shall be submitted to the Department, which shall make it available for review to the general public.

   For this project, the permit requires the annual reporting of actual NO_X, CO and SO_2 emissions for the following units: Cogeneration Boiler A (EU 001).

   [Application 0990332-019-AC; and Rules 62-212.300(1)(e) and 62-210.370, F.A.C.]

This section of the permit addresses the following emission unit.

EU ID No. 001	Cogeneration Boiler A
Description: This unit is a biomass-fired spreader stoker steam boiler manufactured by Zurn and designed to produce approximately 506,100 pounds per hour of steam at 1500 pounds per square inch, gage (psig) and 975 degrees Fahrenheit (°F). *Fuels and Capacity*: The primary fuel is biomass (760 MMBtu/hour), which includes bagasse from the adjacent sugar mill and clean wood material delivered to the plant by area subcontractors. The auxiliary fuels are natural gas (400 MMBtu/hour) as a result of this permitting action and very low sulfur distillate oil (490 MMBtu/hour). *Controls*: Pollution control equipment includes low nitrogen oxide (NO_X) burners for gas firing, a selective non-catalytic reduction system to reduce NO_X emissions, mechanical dust collectors and an electrostatic precipitator to reduce particulate matter (PM) emissions, and an activated carbon injection system to reduce potential mercury emissions. Good combustion practices and the efficient combustion of clean, low sulfur fuels minimize emissions of carbon monoxide (CO), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC). *Stack Parameters*: Exhaust gases exit a 10 feet diameter stack that is at least 199 feet tall and with a volumetric flow rate of approximately 319,000 actual cubic feet per minute (acfm) at 352 °F.	

CONSTRUCTION DETAILS

1. New Construction: This minor permit modification authorizes the addition of four 100 MMBtu/hour low NO_X natural gas burners to Cogeneration Boiler A for a total natural gas firing capacity of 400 MMBtu/hour. The natural gas burners will be installed in each of the four corners of the boiler. This will match the existing natural gas burning capability of Cogeneration Boilers B and C (EU 002 and 003). The natural gas burners will be installed at the location of the existing overfire air ports. Two of the five port nozzles in each corner will be replaced with the natural gas burners. Within 10 days of establishing commercial operation utilizing the natural gas burners, the permittee shall notify the Compliance Authority. The notification shall include the date of commercial startup and identify any substantial changes in the final equipment that differ from the application. [Design; Rule 62-4.070(3), F.A.C.]

OPERATIONAL RESTRICTIONS

2. Permitted Capacity: The maximum heat input rate to Boiler A shall not exceed 400 MMBtu/hour when burning 100 percent natural gas. [Application; Rules 62-212.400 and 62-4.070(3), F.A.C.]
3. Auxiliary Fuel: Boiler A is authorized to fire pipeline quality natural gas as a startup and auxiliary fuel. [Application; Rules 62-212.400 and 62-4.070(3), F.A.C.]
4. Fossil Fuel Limitation: The firing of fossil fuels shall be less than 25 percent of the total heat input to Boiler A during any calendar quarter. [Application; Rules 62-212.400 and 62-4.070(3), F.A.C.]
5. Fuel Records: The permittee install a natural gas flow meter on Boiler A to determine the fuel consumption rate. [Application; Rules 62-212.400 and 62-4.070(3), F.A.C.]

APPLICABLE NSPS

6. NSPS Subpart Da: Boiler A is subject to the requirements of NSPS 40 CFR 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units. This standard has emission limits for PM, SO_2 and NO_X applicable to Boiler A when firing natural gas. [NSPS 40 CFR 60, Subpart Da]

EMISSION LIMITS

7. PM Emission Limits: The NSPS Subpart Da PM limit is 0.03 lb/MMBtu of heat input for all fuels. Compliance is shown by a three run stack test average. Meeting the previously set PM BACT emission limit of 0.026 lb/MMBtu by a three run stack test average ensures compliance with the NSPS Subpart Da emission limit. [NSPS 40 CFR 60, Subpart Da and PSD-FL-196L]

8. SO_2 Emission Limits: The NSPS Subpart Da SO_2 limit is 0.20 lb SO_2/MMBtu of heat input for liquid and gaseous fuels not derived from solid fuel. Compliance is by a continuous emission monitoring system (CEMS) on a 30-day rolling average basis. Meeting the previously set SO_2 BACT emission limit of 0.20 lb/MMBtu on a 24-hour rolling average basis ensures compliance with the NSPS Subpart Da emission limit. [NSPS 40 CFR 60, Subpart Da and PSD-FL-196L]

9. NO_X Emission Limits: The NSPS Subpart Da NO_X limit is 0.20 lb/MMBtu of heat input for gaseous fuels not derived from coal. Compliance is by a CEMS on a 30-boiler operating day rolling average basis. Meeting the previously set NO_X BACT emission limit of 0.15 lb/MMBtu on a 30-boiler operating day rolling average basis ensures compliance with the NSPS Subpart Da emission limit. [NSPS 40 CFR 60, Subpart Da and PSD-FL-196L]

MONITORING AND REPORTING

10. Monitoring while Firing Natural Gas: Monitoring while firing natural gas to show that PSD significant emission rates (SER) were not exceeded as a result of this project shall be performed in accordance with the procedures given in **Specific Conditions 29.d and 29.e** of permit PSD-FL-196L. [Application; Rules 62-212.400 and 62-4.070(3), F.A.C]

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

Rick Scott
Governor

Jennifer Carroll
Lt. Governor

Herschel T. Vinyard Jr.
Secretary

PERMITTEE

New Hope Power Company
Okeelanta Cogeneration Plant
8001 U.S. Highway 27 South
South Bay, Florida 33493

Authorized Representative:
Mr. Jose Gonzalez, General Manager & Vice President

Air Permit No. 0990332-020-AC
PSD-FL-196Q
SIC No. 4911
Cogeneration Boilers A, B and C
Modification of ACI Requirement
Palm Beach County, Florida

PROJECT

The Okeelanta Cogeneration Plant is located off U.S. Highway 27 South approximately six miles south of South Bay in Palm Beach County, Florida. The UTM coordinates of the facility are Zone 17, 524.9 kilometers (km) East and 2940.1 km North. The project involves the modification of the requirement to install activated carbon injection (ACI) systems on Cogeneration Boilers A, B and C. Since the existing facility has been constructed, no expiration date is provided in this minor modification to the existing PSD permit.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of: Chapter 403 of the Florida Statutes (F.S.) and Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.). The permittee is authorized to conduct the proposed work in accordance with the conditions of this permit. The original project was subject to preconstruction review in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality; however, this minor modification is only subject to the general preconstruction review requirements in Rule 62-212.300, F.A.C.

Upon issuance of this final permit, any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida
(Electronic Signature)

FINAL PERMIT

CERTIFICATE OF SERVICE

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

Mr. Jose Gonzalez, NHPC: Jose_Gonzalez@floridacrystals.com
Mr. Micah Leis, NHPC: Micah_Leis@floridacrystals.com
Mr. David Buff, P.E., Golder Associates: dbuff@golder.com
Mr. Lennon Anderson, DEP SED: Lennon.Anderson@dep.state.fl.us
Ms. Cindy Mulkey, DEP Siting Office: cindy.mulkey@dep.state.fl.us
Ms. Heather Ceron, EPA Region 4: ceron.heather@epa.gov
Ms. Lynn Scearce, DEP OPC Reading File: lynn.scearce@dep.state.fl.us
Ms. Barbara Friday, DEP OPC Reading File: barbara.friday@dep.state.fl.us

Clerk Stamp

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

FACILITY DESRIPTION

The facility consists of two adjacent plants. The Okeelanta Corporation operates a sugar mill and a sugar refinery (ARMS No. 0990005) including packaging and transshipment activities. The permittee, New Hope Power Company (NHPC) operates a 140-megawatt cogeneration plant (ARMS No. 0990332) that provides process steam for the sugar mill/refinery and generates electricity for sale to the power grid. The cogeneration plant, sugar mill and sugar refinery are all considered a single facility for purposes of the Prevention of Significant Deterioration (PSD) and Title V regulatory programs. The facility is located off U.S. Highway 27 South, approximately six miles south of South Bay in Palm Beach County, Florida. The UTM coordinates of the facility are Zone 17, 524.9 kilometers (km) East and 2940.1 km North.

PROJECT DESCRIPTION

The following emission units are affected by this permitting action.

EU No.	Emission Unit Description
001	Cogeneration Boiler A
002	Cogeneration Boiler B
003	Cogeneration Boiler C

Project No. 0990332-020-AC (PSD-FL-196Q): Currently each cogeneration boiler at the NHPC has a mercury (Hg) emission limit of 5.4×10^{-6} pounds per million British thermal units (lb/MMBtu) of heat input as listed in Specific Condition 16 of Section III of Air Construction Permit No. 0990332-017-AC (PSD-FL-196P). In addition, if two or more cogeneration boilers exceed the annual mercury emission limit, activated carbon injection (ACI) systems must be installed on all three units and a mercury testing protocol must be submitted to the Department that is designed to establish an effective carbon injection rate to control Hg emissions and meet the emission standard. Since no boiler has failed the annual mercury compliance test, this revision modifies the permit to remove the ACI systems while stipulating that the systems must be re-installed, if necessary.

FACILITY REGULATORY CLASSIFICATION

- The facility is a major source of hazardous air pollutants (HAP).
- The facility does **not** operate units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400, F.A.C. for the PSD of Air Quality.
- The facility operates units that are subject to the New Source Performance Standards (NSPS) in Part 60, Title 40 of the Code of Federal Regulations (CFR) and the National Emissions Standards for Hazardous Air Pollutants (NESHAP) in Part 60, Title 40 of the CFR.

PREVIOUS APPLICABLE REQUIREMENTS

The conditions of this permit supplement all previously issued air construction and operation permits for these emission units. Unless otherwise specified, these conditions are in addition to all other applicable permit conditions and regulations. [Rule 62-4.070, F.A.C.]

1. Permitting Authority: The permitting authority for this project is the Office of Permitting and Compliance in the Division of Air Resource Management of the Department of Environmental Protection (Department). The Office of Permitting and Compliance mailing address is 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. All documents related to applications for permits to operate an emissions unit shall be submitted to the Air Resource Section of the Department's South District Office at: 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33902-2549. The telephone number is 239/344-5651 and the fax number is 850/412-0590. Copies shall be sent to each agency identified under Compliance Authority.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resource Section of the Department's South District Office at: 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33902-2549. The telephone number is 239/344-5651 and the fax number is 850/412-0590. Copies of all such documents shall also be submitted to the Air Pollution Control Section of the Palm Beach County Health Department at P.O. Box 29, West Palm Beach, Florida 33402-0029 (Telephone No. 561/837-5900 and Facsimile No. 561/837-5295).

3. Appendices: The following Appendix is included in Section 4 of this permit:
   - Appendix A: Citation Formats and Glossary of Common Terms;
   - Appendix B: General Conditions: and
   - Appendix C: Common Conditions.

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

5. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

6. Modifications: The permittee shall notify the Compliance Authority upon commencement of construction. No new emissions unit shall be constructed and no existing emissions unit shall be modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

7. Source Obligation:

   (a) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

   (b) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

[Rule 62-212.400(12), F.A.C.]

8. Application for Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V air operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V air operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the appropriate Permitting Authority with copies to the Compliance Authority. *{Permitting Note: The application to revise the Title V permit for the changes to the ACI system may be coordinated with the project to install gas burners on Cogeneration Boiler A.}* [Rules 62-4.030, 62-4.050, 62-4.220 and Chapter 62-213, F.A.C.]

This section of the permit addresses the following emissions units.

EU ID No. 001, 002 and 003	Cogeneration Boilers A, B, and C
Description: Each boiler is a biomass-fired spreader stoker steam boiler manufactured by Zurn and designed to produce approximately 506,100 pounds per hour of steam at 1500 pounds per square inch, gage (psig) and 975degrees Fahrenheit (°F). *Fuels and Capacity*: The primary fuel is biomass at a heat input rate of 760 million British thermal units per hour (MMBtu/hr). The biomass includes bagasse from the adjacent sugar mill and clean wood material delivered to the plant by area subcontractors. Auxiliary fuels include natural gas and very low sulfur distillate oil. *Controls*: Pollution control equipment includes low-NOx burners for gas firing, a selective non-catalytic reduction system to reduce nitrogen oxides emissions, and mechanical dust collectors and an electrostatic precipitator to reduce particulate matter emissions. Good operating practices and the efficient combustion of clean, low-sulfur fuels minimizes emissions of carbon monoxide, sulfuric acid mist, sulfur dioxide, and volatile organic compounds. *Stack Parameters*: Exhaust gases exit a 10 feet diameter stack that is at least 199 feet tall and with a volumetric flow rate of approximately 319,000 acfm at 352° F.	

CONSTRUCTION DETAILS

1. New Construction: The existing cogeneration plant includes a nominal 75 MW steam turbine electrical generator and a mechanical draft cooling tower. This PSD modification authorizes the addition of a nominal 65 MW steam turbine electrical generator and the addition of a 2-cell mechanical draft cooling tower. Within 10 days of establishing commercial operation of the new steam turbine electrical generator, the permittee shall notify the Bureau of Air Regulation and Compliance Authorities. The notification shall include the date of commercial startup and identify any substantial changes in the final equipment that differ from the application. [Design; Rule 62-4.070(3), F.A.C.] *{Permitting Note: Upon completion of the additional steam turbine-generator project, the cogeneration plant will have a nominal generating capacity of 140 MW. Therefore, the project subjects the facility to the power plant site certification requirements of the Department. Any subsequent modifications must also be made in accordance with appropriate site certification requirements. Project No. 0990332-020-AC represents a minor modification to the original PSD air construction permit and no new construction is authorized.}*

2. Boiler Design: The cogeneration boilers shall consist of spreader stoker units designed to fire biomass as the primary fuel with pipeline natural gas and distillate oil as auxiliary fuels. Natural gas and distillate oil are fired at startup and shutdown, when necessary to ensure good combustion, to supplement biomass fuel, and for periods when the biomass fuel supply is interrupted. No other fuels are authorized. *{Permitting Note: Each boiler was originally designed to fire low sulfur coal as an emergency backup fuel, but no transfer, crushing, or storage systems were ever installed. The permittee shall obtain a permit modification before firing any other fuel (including coal) not specifically authorized by this permit.}*

3. Stack: Each boiler shall have an individual stack that is at least 199 feet tall. The permanent stack sampling facilities for each stack must comply with Rule 62-297.345, F.A.C.

4. Process Monitors: Each boiler shall be equipped with instruments to measure the fuel feed rate, heat input, steam production, steam pressure, and steam temperature. Appendix E identifies minimum requirements for monitoring equipment.

5. Control Equipment: Each boiler shall be equipped with:
    - Low-NOx natural gas burners rated for no more than 0.15 pounds of NOx per MMBtu of heat input. Four burners are installed with one in each corner of the boiler. The maximum heat input rate from all

four burners is 400 MMBtu per hour. {Permitting note: For Boilers B and C, four 100 MMBtu/hour gas burners have been installed. Permit No. 0990332-019-AC authorizes construction to add four 100 MMBtu/hour burners to Boiler A.}

- Mechanical dust collectors consisting of four, large diameter, multi-tube modules with airfoil vanes or equivalent equipment. The mechanical dust collectors shall be installed and maintained as pre-control devices prior to each electrostatic precipitator and designed for a removal efficiency of at least 85% of the particulate matter greater than 10 microns in size (assuming a specific gravity of 2.00).
- An electrostatic precipitator (ESP) designed for at least 98 percent removal of particulate matter.
- A selective non-catalytic reduction (SNCR) system designed for at least 40 percent removal of NOx.

6. Continuous Monitors: For each cogeneration boiler, the permittee shall install, calibrate, maintain, and operate continuous emissions monitoring systems (CEMS) and continuous opacity monitoring systems (COMS) to measure and record emissions of carbon monoxide (CO), nitrogen oxides (NOx), opacity, oxygen (O_2), and sulfur dioxide (SO_2) in a manner sufficient to demonstrate compliance with the standards of this permit. The opacity monitor shall be placed in the ductwork between the electrostatic precipitator and the stack or in the stack. Appendix E identifies minimum requirements for monitoring systems.

7. Good Combustion Practices: An oxygen meter shall be installed for each unit to continuously monitor a representative sample of the flue gas. The oxygen monitor shall be used with automatic feedback or manual controls to continuously optimize air/fuel ratio parameters. Depending on the fuel quality and existing combustion conditions, the operator shall provide sufficient excess air to ensure good combustion within the boiler. The application to revise the Title V operation permit shall identify "good combustion practices" for the cogeneration boilers to minimize pollutant emissions during startup, operation, and shutdown. The document "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls" shall be used as a guide. Good combustion controls shall also include the following:

   - Maintain improved combustion controls to provide efficient tuning of air/fuel control instrumentation.
   - Maintain rotary pocket-style wood feeders with efficient air seal to minimize intrusion of ambient air.
   - Maintain effective water level controls in bottom ash system to prevent intrusion of ambient air.
   - Mix biomass fuel to provide a consistent fuel blend.
   - Maintain the flue gas oxygen content to provide efficient combustion for the existing conditions.
   - When necessary to enhance poor combustion, reduce the biomass feed rate below the maximum rate.
   - When necessary to enhance poor combustion, co-fire natural gas or distillate oil.

8. O&M Plans: The application to revise the Title V operation permit shall include an operation and maintenance plan consisting of at least the following items.

   a. For the cogeneration boilers, electrostatic precipitators (ESP), selective non-catalytic reduction (SNCR) systems, and silo fabric filters, identify: the capacities, design efficiencies, pollutant emission rates, general operational description of equipment, key design and operating parameters, expected operating range of each key parameter, monitoring of key parameters, frequency of monitoring (instantaneous, continual, or continuous), and actions taken to return key parameters to within the expected operating ranges. The plan shall also specify good operating practices to promote efficient boiler combustion, startup and shutdown procedures for the boilers and control systems to minimize emissions, and precautions to prevent fugitive particulate matter emissions. *{Permitting Note: Operation outside of the specified operating range for any monitored parameter would not be a violation by itself. However, continued operation outside of a specified operating range without corrective action may be considered circumvention of the air pollution control equipment or methods.}*

   b. For the selective non-catalytic reduction (SNCR) systems identify an alternate NOx emissions control plan based on previous monitoring data that shall be implemented in case the NOx monitoring system is down. The plan shall identify the minimum urea injection rate that has demonstrated continuous compliance with the NOx emissions standard at various load conditions.

9. Materials Handling Controls: For the fly ash handling and mercury control system reactant storage systems (if required to be installed by condition 16.g. below):

   a. The particulate matter filter control system for the storage silos shall be designed to achieve an outlet dust loading of no greater than 0.01 grains per actual cubic feet of exhaust.

   b. The fly ash handling system (including transfer points and storage bin) shall be enclosed. The ash shall be wetted in the ash conditioner to minimize fugitive dust prior to discharging to the disposal bin.

OPERATIONAL RESTRICTIONS

10. Permitted Capacity: The cogeneration boilers shall be constructed and operated in accordance with the capabilities and specifications described in the application. The maximum heat input rate to each cogeneration boiler shall not exceed 760 MMBtu/hr when burning 100 percent biomass, 400 MMBtu/hr when burning 100 percent natural gas, and 490 MMBtu/hr when burning 100 percent very low sulfur distillate oil. The steam production of each boiler shall not exceed an average of 506,100 pounds per hour at 1,500 psig and 975°F. The operating hours of the cogeneration boilers are not restricted (8760 hours per year).

11. Primary Fuel: The primary fuel for the plant shall be biomass, which shall consist of bagasse and authorized wood material. Bagasse is the fibrous vegetative residue remaining after the sugarcane milling process. Authorized wood material is clean construction and demolition wood debris, yard trash, land clearing debris, and other clean cellulose and vegetative matter. Each cogeneration boiler shall combust no more than 30% by weight yard waste (yard trash) on a calendar quarter basis that is defined as a municipal solid waste (MSW) in 40 CFR 60.51a. The biomass fuel used at the cogeneration plant shall not contain hazardous substances, hazardous wastes, biomedical wastes, or garbage. The fuel used at the cogeneration plant shall not contain special wastes, except wood, lumber, trees, tree remains, bagasse, cane tops and leaves, and other clean vegetative and cellulose matter. The permittee shall perform a daily visual inspection of any wood material or similar vegetative matter that has been delivered to the plant for use as fuel. Any shipment observed to contain prohibited materials shall not be used as fuel, unless such materials can be readily segregated and removed from the wood material and vegetative matter.

    The permittee shall design and implement a management and testing program for the wood material and other materials delivered to the plant for fuel. The program shall be designed to keep painted and chemically treated wood, household garbage, toxic or hazardous non-biomass and non-combustible waste material, from being burned at this plant. The program shall provide for the routine inspection and/or testing of the fuel at the originating wood yard sites as well as at the cogeneration site, to ensure that the quantities of painted or chemically treated wood in the fuel are minimized. Based on the analysis of a composite sample, wood material containing more than 70.7 ppm arsenic or 83.3 ppm chromium or 62.8 ppm copper shall not be burned. Fuel scheduled for burning shall be inspected daily. At a minimum, the fuel management program shall include the following sampling and analyses:

    a. At least twice each month, the permittee shall have separate analyses conducted on an as-fired wood sample and an as-fired bagasse sample for the following: heating value (modified ASTM D3286, Btu/lb, dry), carbon content (modified ASTM D5373, percent by weight, dry), sulfur content (modified ASTM D4239 Method C, percent by weight, dry), and moisture content (modified ASTM D3173, percent by weight). In addition the wood sample shall be analyzed for copper, chromium, and arsenic in accordance with Methods 3050/6010 (EPA Method SW-846) and reported in ppm by weight, dry. Samples shall be taken at least two weeks apart.

    b. At least once each month, the permittee shall have an analysis conducted on a composite sample of fly ash and bottom ash for arsenic, copper, and chromium in accordance with the procedures described in

EPA Method SW-846, *Test Methods for Evaluating Solid Waste, Physical/Chemical Methods* (40 CFR 261, Appendix III). The analytical results from ash testing shall be used in conjunction with those from the as-fired wood samples to evaluate the effectiveness of the fuel management program in removing chemically treated wood from the biomass fuel. The permittee shall dispose of all ash generated on site in accordance with the applicable state and federal regulations.

c. Analytical results of the as-fired biomass fuels and ash sampling shall be summarized and provided in the quarterly report to the Compliance Authority.

The ash and fuel management program shall become part of the Title V operation permit.

12. Auxiliary Fuel: The cogeneration boilers shall fire only distillate oil and pipeline natural gas as auxiliary fuels. Distillate oil shall be new No. 2 oil with a maximum sulfur content of 0.05 percent sulfur by weight as determined by the appropriate test method listed in 40 CFR 60.17. "New" oil is oil that has been refined from crude oil and that has not been used in any manner that may contaminate it. Each boiler may startup solely on pipeline natural gas or distillate oil.

13. Fossil Fuel Limitation: The firing of fossil fuels (distillate oil and natural gas) shall be less than 25 percent of the total heat input to each cogeneration boiler during any calendar quarter.

14. Fuel Records: The permittee shall maintain a daily log of the amounts and types of fuels used. The amount, heating value, and sulfur content of each fuel oil delivery shall be kept in a log for at least five years. For each calendar month, the actual monthly SO_2 emissions and the 12-month rolling total SO_2 emissions shall be determined and kept in a log.

15. Permanent Shutdown: Sugar mill boiler Nos. 4, 5, 6, 10, 11, 12, 14, and 15 shall remain permanently shutdown and rendered incapable of operation. *{Permitting Note: Okeelanta Corporation's Boiler No. 16 may operate in accordance with modified Permit No. PSD-FL-169(A).}* [Rule 62-212.400, F.A.C.]

EMISSIONS LIMITING STANDARDS

16. Emissions Standards: Based on the maximum permitted heat input to each cogeneration boiler, stack emissions shall not exceed the standards specified in the following table:

Pollutant	Averaging Period	Emissions Standards per Boiler[i]	
		lb/MMBtu	lb/hr
Carbon Monoxide (CO)[a]	30-day rolling CEMS avg.	0.50	380.0
	12-month rolling CEMS avg.	0.35	
Nitrogen Oxides (NO_X)[b]	30-day rolling CEMS avg.	0.15	114.0
Sulfur Dioxide (SO_2)[c]	24-hour rolling CEMS avg.	0.20	152.0
	30-day rolling CEMS avg.	0.10	
	12-month rolling CEMS avg.	0.06	
Stack Opacity[d]	6-minute block COMS avg. (Alternative: EPA Method 9)	≤ 20% opacity, except for one 6-minute block per hour that is ≤ 27% opacity	
Particulate Matter (PM/PM10)[e]	3-run test avg.	0.026	19.8
Volatile Organic Compounds (VOC)[f]	3-run test avg.	0.05	38.0
Mercury[g]	3-run test avg.	5.4×10^{-06}	NA
Lead and Fluorides[h]	The BACT determination for lead and fluoride emissions is the use of fuels containing low levels of these compounds (bagasse, wood, distillate oil, and natural gas) and prospective removal with the fly ash by the mechanical dust collectors and electrostatic precipitators.		

a. Compliance shall be determined by data collected from the required CO CEMS in terms of "lb/MMBtu of heat input". The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler operating days and be consistent with the NOx monitoring requirements below. Compliance with the 12-month standard shall be based on the rolling average for each consecutive 12-month period.

b. Compliance shall be determined by data collected from the required NO_X CEMS in terms of "lb/MMBtu of heat input". The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler operating days and the requirements of 40 CFR 60.13, 60.44a, 60.46a, 60.47a, 60.48a, and 60.49a. A boiler-operating day is any day in which any authorized fuel is fired.

c. Compliance with the SO_2 standards shall be determined by data collected from the required SO_2 CEMS in terms of "lb/MMBtu of heat input". The 24-hour average shall be determined by calculating the arithmetic average of all valid hourly emission rates for 24 successive boiler-operating hours. The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler-operating days and the requirements of 40 CFR 60.13, 60.43a, 60.46a, 60.47a, 60.48a, and 60.49a. Compliance with the 12-month standard shall be based on the rolling average for each consecutive 12-month period. Valid SO_2 hourly averages shall not be excluded from any compliance average. *{Permitting Note: Potential emissions of sulfuric acid mist are minimized by the effective control of SO_2 emissions with the firing of low sulfur fuels. For reporting purposes, sulfuric acid mist emissions shall be estimated as 6% of the total measured SO_2 emissions.}*

d. Continuous compliance with the opacity standard shall be determined by data collected from the required COMS in terms of "percent opacity" based on 6-minute block averages. Alternatively, compliance may also be determined by conducting EPA Method 9 observations.

e. Compliance with the particulate matter standards shall be determined by the average of three test runs conducted in accordance with EPA Method 5. For purposes of reporting PM_{10} emissions, it shall be assumed that all particulate matter emitted is PM_{10}.

f. Compliance with the VOC standards shall be determined by the average of three test runs conducted in accordance with EPA Method 25A based on propane. In addition, the permittee may choose to conduct EPA Method 18 concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. Otherwise, all emissions measured by EPA Method 25A shall be considered "volatile organic compounds".

g. Compliance with the mercury standards shall be determined by the average of three test runs conducted in accordance with EPA Method 101A or 29. Emissions in excess of this standard shall be a violation of the permit. In addition, if two or more cogeneration boilers exceed the annual mercury emission limit, the permittee shall install and operate a carbon injection system (or equivalent) for all three units within 30 days of the stack test report due date. The minimum carbon injection rate shall be at least 7 pounds per hour. Within 60 days of the stack test report due date, the permittee shall submit to the permitting and compliance authorities a mercury testing protocol designed to establish an effective carbon injection rate to control mercury emissions. Within 60 days of receiving approval for the mercury testing protocol by the permitting authority, the permittee shall begin the approved testing program. At a minimum, the permittee shall submit a full engineering report summarizing the uncontrolled emissions, controlled emissions, fuels, operating capacities, and recommending a minimum activated carbon injection rate to control mercury emissions.

h. The particulate matter standard is also a surrogate standard for lead emissions. *{Permitting Note: For reporting purposes, average lead emissions are expected to be 2.6×10^{-05} lb/MMBtu and average fluoride emissions are expected to be 1.9×10^{-04} lb/MMBtu when firing bagasse/wood.}*

i. Each boiler shall comply with the standards when firing any combination of authorized fuels. The "lb/hour" rates are based on the highest emission standard shown for that pollutant. Required compliance tests shall be performed in accordance with the requirements of Condition No. 19. The cogeneration boilers are also subject to the new source performance standards (NSPS Subpart Da) for new electric utility steam generating units. These requirements include the general provisions of Subpart A in 40 CFR 60, as well as the following source-specific applicable requirements: 60.40a (Applicability and Designation of Affected Facility); 60.41a (Definitions); 60.42a (Standards for Particulate Matter); 60.43a (Standard for Sulfur Dioxide); 60.44a (Standard for Nitrogen Oxides); 60.46a (Compliance Provisions); 60.47a (Emissions Monitoring); 60.48a (Compliance Determination Procedures and Methods); and 60.49a (Reporting Requirements). The cogeneration boilers are also subject to Rule 62-296.405(2), F.A.C. (Fossil Fuel Steam Generators with more than 250 MMBtu per Hour of Heat Input), Rule 62-296.410, F.A.C. (Carbonaceous Fuel Burning Equipment), and Rule 62-296.570, F.A.C. (Reasonably Available Control Technology Requirements for Major VOC and NOx Facilities).

{Permitting Note: Appendix D identifies the final BACT determinations for the cogeneration boilers.}

17. Material Handling: The following conditions apply to the biomass, ash, and activated carbon handling facilities.

    a. All conveyors and conveyor transfer points shall be enclosed to preclude PM emissions (except those directly associated with the stacker/reclaimer, for which enclosure is operationally infeasible).

    b. Water sprays, chemical wetting agents, and/or stabilizers shall be applied to storage piles, handling equipment, unenclosed transfer points, etc. during dry periods and as necessary to prevent visible emissions. When adding, moving or removing material from the storage pile, visible emissions of no more than 20% opacity are allowed.

    c. In the event that an ACI system is required to meet the permitted mercury emission limit, the mercury control system reactant storage silo(s) shall be maintained at a negative pressure while operating with the exhaust vented to a filter control system. Visible emissions from any storage silo shall not exceed 5 percent opacity based on a 6-minute block average. A visible emissions test (EPA Method 9) shall be performed at least annually for each silo that is loaded with carbon during the federal fiscal year.

STARTUP, SHUTDOWN, AND MALFUNCTION

18. Startup, Shutdown, and Malfunction Requirements: The permittee shall comply with the following requirements regarding periods of startup, shutdown, and malfunction for each cogeneration boiler.

    a. *Definitions*

        1) Excess emissions are emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions that occur during startup, shutdown, or malfunction. [Rule 62-210.200(106), F.A.C.]

        2) Startup is the commencement of operation of a boiler which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which may result in excess emissions. Periods of startup for each boiler shall end once steam generation reaches 150,000 pounds per hour. A cold startup is a startup after the boiler has been shutdown for 24 hours or more. A warm startup is a startup after the boiler has been shutdown for less than 24 hours.

        3) Shutdown is the cessation of the operation of a boiler for any purpose after steam generation drops below 150,000 pounds per hour.

        4) Malfunction is any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(160), F.A.C.]

b. *Prohibition*: Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. Emissions data recorded during such preventable periods shall be included in the compliance averages. [Rule 62-210.700(4), F.A.C.]

c. *Monitoring Data Exclusion*: Each continuous monitoring system shall operate and record data during all periods of operation (including startup, shutdown, and malfunction) except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Provided the operators implement best operational practices to minimize the amount and duration of emissions, the following conditions apply. Pursuant to Rules 62-210.700(1) and (5), F.A.C., these conditions consider the variations in operation of the cogeneration boilers.

1) Natural gas or distillate oil shall be fired during startup prior to energizing the electrostatic precipitator (ESP). Once the operating temperature recommended by the ESP manufacturer is maintained (approximately 340° F to 350 ° F), it shall be placed on line and the boiler shall comply with the opacity standard specified in Condition No. 16. The ESP shall be on line and functioning properly before firing any biomass. The opacity limit does not apply when the ESP is off line due to warm startup, cold startup, or shutdown. No more than twenty 6-minute block averages of opacity monitoring data shall be excluded in a 24-hour period due to documented malfunctions.

2) Hourly CO and NOx emission rate values collected during startup, shutdown, or documented malfunction may be excluded from the 30-day and/or 12-month compliance averages. No more than six hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a cold startup. No more than three hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a warm startup. No more than two hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a malfunction. No more than two hourly emission rate values (CO or NOx) shall be excluded in a 24-hour period due to a shutdown. For each cogeneration boiler, no more than 183 hourly emission rate values shall be excluded during any calendar quarter.

3) All valid hourly SO_2 emission rate values shall be included in all of the compliance averages. [40 CFR 60.46a and 60.49a]

4) To "document" a malfunction, the operator shall notify the Compliance Authority within one working day of the malfunction by phone, facsimile, or electronic mail. The notification shall include the date and time of malfunction, a description of the malfunction and probable cause, steps to taken to minimize emissions, and actions taken to correct the problem. [Rules 62-210.700(6) and 62-4.130, F.A.C.]

d. *Reporting*: In conjunction with the annual operating report, the permittee shall identify the number of startups, the number of shutdowns, and the number of malfunctions that occurred during the year for each boiler. For each boiler's CO and NOx monitors, the report shall identify the annual hours of emission data excluded from the compliance determination due to each type of incident (startups; shutdowns; and documented malfunctions).

[Rule 62-210.700, F.A.C.; Rule 62-4.070(3), F.A.C.; 40 CFR 60.8; and 40 CFR 60.46a]

COMPLIANCE METHODS AND REPORTING

19. Stack Test Requirements

a. *Initial Tests*: Initial tests were initially required for emissions of mercury, particulate matter, and volatile organic compounds. The Department may require these initial tests to be repeated if major physical or operational changes are made that affect main components such as the boiler, fuels, and/or pollution control equipment.

b. *Annual Tests*: At least once during each federal fiscal year, the permittee shall conduct compliance tests for emissions of mercury, particulate matter, and volatile organic compounds.

c. *Renewal Tests*: Within the 12-month period prior to submitting an application to renew the Title V air operation permit, the permittee shall conduct compliance tests for emissions of, mercury, particulate matter, and volatile organic compounds. Tests shall be conducted at five-year intervals.

d. *Test Procedures*: The emission compliance tests shall be conducted in accordance with the provisions of Chapter 62-297, F.A.C., 40 CFR 60.46a (NSPS Subpart Da), and as summarized in Appendix C of this permit. The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. The biomass fuel feed for each test run shall consist of at least 45% wood materials by weight. Testing of emissions shall be conducted with each cogeneration boiler operating at permitted capacity, which is defined as a heat input rate between 684 and 760 MMBtu/hour and firing 100% biomass. If it is impracticable to test at permitted capacity, a cogeneration boiler may be tested at less than the maximum permitted capacity; in this case, subsequent operation is limited to 110 percent of the test rate until a new test is conducted. Within three days of completing a test below permitted capacity, the permittee shall provide written notification of the restricted operational capacity to the Compliance Authority. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(7)(a)9, F.A.C. and 40 CFR 60.7, 60.8]

e. *Test Methods*: Compliance with the emission limits specified in this permit shall be demonstrated using EPA Methods, as contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources), or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

EPA Method	Description
1	Selection of sample site and velocity traverses
2	Stack gas flow rate when converting concentrations to or from mass emission limits
3A	Gas analysis when needed for calculation of molecular weight or percent O2
4	Moisture content when converting stack velocity to dry volumetric flow rate for use in converting concentrations in dry gases to or from mass emission limits
5	Particulate matter emissions
6 or 6C	Sulfur dioxide emissions
7 or 7E	Nitrogen oxide emissions
9	Visible emissions determination of opacity *{Permitting Note: Although each unit is required to monitor opacity with a COMS, visible observations may also be used to demonstrate compliance.}*
10	Carbon monoxide emissions
12	Inorganic lead emissions
19	Calculation of sulfur dioxide and nitrogen oxide emission rates
25A	Volatile organic compounds emissions *{Permitting Note: EPA Method 18 may be conducted concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. Otherwise, all emissions measured by EPA Method 25A shall be considered "volatile organic compounds".*
29	Multiple metals emissions
101A	Particulate and gaseous mercury emissions

No other methods may be used to demonstrate compliance unless prior written approval is received from the Department. Other applicable testing requirements are included in Appendix C of the permit. The permittee shall use CEMS and COMS data to demonstrate compliance with the emissions standards for CO, NOx, opacity, and SO_2. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

20. Continuous Monitor Requirements: The permittee shall demonstrate compliance with the emissions standards for CO, NOx, opacity, and SO_2 based on data collected from the continuous emissions monitoring systems (CEMS) and continuous opacity monitoring systems (COMS) required for each cogeneration boiler. Appendix E specifies the minimum requirements for monitoring equipment.

21. Quarterly Reports: For each cogeneration boiler, the permittee shall submit a quarterly report for each required continuous emissions and opacity monitoring system in accordance with the requirements specified in Appendix E of this permit. The permittee shall also submit a quarterly summary of the fuel analyses, fuel usage, and equipment malfunctions. For each malfunction, the report shall identify the cause (if known), and corrective actions taken. The quarterly reports and summaries shall be submitted to the Compliance Authority no later than 30 days following each calendar quarter.

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

NESHAP REQUIRMENTS

23. Subpart DDDDD Applicability: The cogeneration boilers are subject to the applicable provisions for existing units of NESHAP Subpart DDDDD in 40 CFR 63 for Industrial, Commercial, and Institutional Boilers and Process Heaters for major sources of HAP.

    {Permitting Note: On January 9, 2012, the U.S. District Court for the District of Columbia vacated EPA's stay of the final Subpart DDDDD provisions (dated March 21, 2011). Currently, the cogeneration boilers will have to meet the applicable requirements of the March 21st version by March 21 2014, which specifies emissions limits for PM, hydrogen chloride (HCl), mercury (Hg), CO and dioxin/furans (D/F). However, the EPA is reconsidering the requirements in Subpart DDDDD, and it is currently finalizing a revised (proposed) version of Subpart DDDDD (dated December 23rd, 2011). If the requirements in Subpart DDDDD are revised and issued as final rules as a result of the reconsideration process, the biomass boilers will have to meet these revised requirements, which may specify emission limits for PM, HCl, Hg, and CO with dioxin/furan emissions controlled by work practice standards. For the December 21, 2011 proposed (reconsidered) NESHAP, it is likely that the boilers must come into compliance with the emission limits for PM, HCl, Hg and CO three years after the date of publication of the final reconsideration of the rule.}

    [NESHAP 40 CFR 63, Subpart DDDDD]

ATTACHMENT NHPC-EU1-IV3

ALTERNATIVE METHODS OF OPERATION
COGENERATION BOILERS A (EU-002), B (EU-003) AND C (EU-003)

The cogeneration boilers are permitted to burn biomass as a primary fuel, and fire distillate oil or natural gas as auxiliary fuels.

III. EMISSIONS UNIT INFORMATION

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

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

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

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

EMISSIONS UNIT INFORMATION
Section [2]
Cogeneration Boiler B

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 B

3. Emissions Unit Identification Number: **002**

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

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

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: **Zurn** Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
    Boiler B has a hybrid suspension grate unit fired by biomass (bagasse/wood) as the primary fuel. Distillate oil and/or natural gas is 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 3

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

Emissions Unit Control Equipment/Method: Control 2 of 3

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 3

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

Emissions Unit Control Equipment/Method: Control ____ of ____

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

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-EU1-I1 ☐ Previously Submitted, Date ______

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: 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: ______ ☒ Previously Submitted, Date 05/10/2012

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: NHPC-EU1-I4 ☐ Previously Submitted, Date ______
☐ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: ______ ☒ Previously Submitted, Date 05/10/2012
☐ Not Applicable

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

☒ Previously Submitted, Date: March 2013
Test Date(s)/Pollutant(s) Tested: 03/01/2013 – PM, VOC, Hg

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

☐ Not Applicable

Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

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

Additional Requirements for Title V Air Operation Permit Applications

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

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

   ☒ 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 C

3. Emissions Unit Identification Number: **003**

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

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

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: **Zurn** Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
   Boiler C has a hybrid suspension grate unit fired by biomass (bagasse/wood) as the primary fuel. Distillate oil and/or natural gas is 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 3

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

Emissions Unit Control Equipment/Method: Control 2 of 3

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 3

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

Emissions Unit Control Equipment/Method: Control ____ of ____

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

EMISSIONS UNIT INFORMATION
Section [3]
Cogeneration Boiler C

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-EU1-I1 ☐ Previously Submitted, Date ______

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: 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: ______ ☒ Previously Submitted, Date 05/10/2012

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: NHPC-EU1-I4 ☐ Previously Submitted, Date ______
☐ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: ______ ☒ Previously Submitted, Date 05/10/2012
☐ Not Applicable

6. Compliance Demonstration Reports/Records:
☐ Attached, Document ID: ______
Test Date(s)/Pollutant(s) Tested: ______
☒ Previously Submitted, Date: March 2013
Test Date(s)/Pollutant(s) Tested: 02/28/2013 – PM, VOC, Hg
☐ To be Submitted, Date (if known): ______
Test Date(s)/Pollutant(s) Tested: ______
☐ Not Applicable
Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

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

Additional Requirements for Title V Air Operation Permit Applications

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

Additional Requirements Comment

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

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