Dawd
Module AC01b

PSD AIR CONSTRUCTION APPLICATION FOR NEW NATURAL GAS-FIRED BOILER

New Hope Power Company
Okeelanta Cogeneration Plant

0990332-021-AC-
PSD-425

PERMIT APPLICATION

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

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

Distribution: 7 copies – FDEP
2 copies – New Hope Power Company
2 copies – Golder Associates Inc.

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Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

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

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

Air Operation Permit – Use this form to apply for:

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

To ensure accuracy, please see form instructions.

Identification of Facility

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

Application Contact

1. Application Contact Name: **Matthew Capone, Director of Environmental Compliance**
2. Application Contact Mailing Address... Organization/Firm: **New Hope Power Company** Street Address: **One North Clematis Street, Suite 200** City: **West Palm Beach** State: **FL** Zip Code: **33401**
3. Application Contact Telephone Numbers... Telephone: **(561) 366-5000** 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: 1-30-13	3. PSD Number (if applicable):
2. Project Number(s): 0990332-024-AC	4. Siting Number (if applicable): **PA-04-46A**

PSD 425

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

NHPC is submitting this air construction permit application because NHPC is proposing to add a new natural gas-fired boiler. The addition of a natural gas-fired boiler will add flexibility in using the most economical and efficient fuels and fuel mix. However, the current maximum electrical generating capacity of the facility (140 net MW) will not increase with the addition of the new boiler.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
	Natural Gas Fired Boiler D	AC1A	$7,500

Application Processing Fee

Check one: ☒ Attached - Amount: $ 7,500 ☐ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1.	Owner/Authorized Representative Name : **Jose Gonzalez, Vice President of Industrial Operations**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **New Hope Power Company** Street Address: **8001 U.S. Highway 27 South** City: **South Bay** State: **FL** Zip Code: **33493**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(561) 993-1600** ext. Fax: **(561) 992-7326**
4.	Owner/Authorized Representative E-mail Address: **Jose_Gonzalez@floridacrystals.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.* Signature: [signature] Date: 1-21-13

APPLICATION INFORMATION

Application Responsible Official Certification

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

1. Application Responsible Official Name:

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):
   - ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
   - ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
   - ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
   - ☐ The designated representative at an Acid Rain source or CAIR source.

3. Application Responsible Official Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
   Telephone: ( ) ext. Fax: ( )

5. Application Responsible Official E-mail Address:

6. Application Responsible Official Certification:

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

________________________ ________________

Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **David A. Buff** Registration Number: **19011**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **6026 NW 1st Place** City: **Gainesville** State: **FL** Zip Code: **32607**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 336-5600** ext. **21145** Fax: **(352) 336-6603**
4.	Professional Engineer E-mail Address: **dbuff@golder.com**
5.	Professional Engineer Statement: *I, the undersigned, hereby certify, except as particularly noted herein*, that:* *(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and* *(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.* *(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.* *(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.* *(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.* David A. Buff 1/29/13 Signature Date (seal)

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

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

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

Facility Contact

1. Facility Contact Name: **Matthew Capone, Director of Environmental Compliance**
2. Facility Contact Mailing Address... Organization/Firm: **New Hope Power Company** Street Address: **One North Clematis Street, Suite 200** City: **West Palm Beach** State: **FL** Zip Code: **33401**
3. Facility Contact Telephone Numbers: Telephone: **(561) 366-5000** 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**

*** Excluding biogenic CO_2.**

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

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☒ Attached, Document ID: **PSD Report**
3.	Rule Applicability Analysis: ☒ Attached, Document ID: **PSD Report**
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: **PSD Report** ☐ Not Applicable
7.	Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☐ Attached, Document ID: **PSD Report** ☐ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☐ Attached, Document ID: **PSD Report** ☐ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications

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

Additional Requirements for Title V Air Operation Permit Applications

1.	List of Insignificant Activities: (Required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☐ Not Applicable (revision application)
2.	Identification of Applicable Requirements: (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought) ☐ Attached, Document ID:__________ ☐ Not Applicable (revision application with no change in applicable requirements)
3.	Compliance Report and Plan: (Required for all initial/revision/renewal applications) ☐ Attached, Document ID:__________ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4.	List of Equipment/Activities Regulated under Title VI: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☐ Equipment/Activities Onsite but Not Required to be Individually Listed ☐ Not Applicable
5.	Verification of Risk Management Plan Submission to EPA: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☐ Not Applicable
6.	Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:__________ ☐ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

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

1.	Acid Rain Program Forms: Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)): ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________ ☒ Not Applicable (not an Acid Rain source) Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.): ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________ ☒ Not Applicable New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.): ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________ ☒ Not Applicable
2.	CAIR Part (DEP Form No. 62-210.900(1)(b)): ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________ ☒ Not Applicable (not a CAIR source)

Additional Requirements Comment

ATTACHMENT NHPC-FI-C3

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

ATTACHMENT NHPC-FI-C3

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

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

- Enclosing conveyors and conveyor transfer points to preclude particulate emissions (except those directly associated with the stack/reclaimers, for which enclosure is operationally infeasible).
- Application of water sprays or chemical wetting agents and stabilizers to storage piles, handling equipment, unenclosed transfer points, etc., during dry periods as necessary to reduce and control opacity in compliance with the permit requirements.
- Enclosing the fly ash handling system including the transfer points and storage bin. The ash is wetted in the ash conditioner to minimize fugitive dust prior to it being discharged into the disposal bin.

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:
   Natural Gas Fired Boiler – Boiler D

3. Emissions Unit Identification Number:

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

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

   ☐ Acid Rain Unit

   ☐ CAIR Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:
    This boiler will fire natural gas (primary fuel) and No. 2 Fuel Oil (backup fuel) and be capable of producing up to 440,000 lb/hr (1-hr average) of steam for use in generating electricity and process steam.

EMISSIONS UNIT INFORMATION
Section [1]
Natural Gas Fired Boiler D

Emissions Unit Control Equipment/Method: Control 1 of 2

1. Control Equipment/Method Description: **Flue Gas Recirculation**
2. Control Device or Method Code: **026**

Emissions Unit Control Equipment/Method: Control 2 of 2

1. Control Equipment/Method Description: **Ultra Low NOx Burners**
2. Control Device or Method Code: **205**

Emissions Unit Control Equipment/Method: Control ____ of ____

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

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: **440,000 lb/hr steam (1-hr)**	
3. Maximum Heat Input Rate: **589** 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: **The maximum heat input rate from natural gas or No. 2 fuel oil will be 589 MMBtu/hr (1-hr average) and 536 MMBtu/hr (24-hr average). These heat input rates correspond to steam production rates of 440,000 lb/hr (1-hr average) and 400,000 lb/hr (24-hr average). Boiler operating pressure and temperature: 1,500 psig, 905°F. See Table 2-1 of PSD Report.**	

EMISSIONS UNIT INFORMATION
Section [1]
Natural Gas Fired Boiler D

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 D**		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: **150** feet	7. Exit Diameter: **8.2** feet
8. Exit Temperature: **350**°F	9. Actual Volumetric Flow Rate: **314,379** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Stack parameters are based on estimated design parameters at the time of the application.**		

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

Segment Description and Rate: Segment 1 of 2

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: **4.331**	5. Maximum Annual Rate: **5,174**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **136**
10. Segment Comment: **Maximum hourly rate based on 589 MMBtu/hr. Maximum annual rate based on 536 MMBtu/hr, 8,760 hr/yr operation, and no more than 15-percent of the annual heat input to the boiler from fuel oil. See Table 2-1 of PSD Report.**		

Segment Description and Rate: Segment 2 of 2

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: **0.577**	5. Maximum Annual Rate: **4,599**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,020**
10. Segment Comment: **Maximum hourly rate based on 589 MMBtu/hr. Maximum annual rate based on 536 MMBtu/hr and 8,760 hr/yr operation. See Table 2-1 of PSD Report.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			NS
PM10			NS
PM2.5			NS
SO2			NS
NOx	205		EL
CO	026		EL
VOC	026		NS
Mercury Compounds (H114)			NS
Lead (Pb)			NS
Fluoride (F)			NS
Sulfuric Acid Mist (SAM)			NS
GHGs *			NS
CO2e *			NS
Total HAPs			NS
H104 - Hexane			NS

* Excluding biogenic CO_2.

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: **14.29** lb/hour **23.39** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0243 lb/MMBtu for fuel oil combustion** Reference: **AP-42**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Tables 2-2 and 2-3 of PSD Report for emissions calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Worst case emissions scenario based on 100-percent natural gas firing or 85-percent natural gas/15-percent No. 2 fuel oil firing. PM emissions include condensable and filterable particulates.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **11.39** lb/hour **21.66** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0193 lb/MMBtu for fuel oil combustion** Reference: **AP-42**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Tables 2-2 and 2-3 of PSD Report for emissions calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Worst case emissions scenario based on 100-percent natural gas firing or 85-percent natural gas/15-percent No. 2 fuel oil firing. PM10 emissions include condensable and filterable particulates.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM2.5**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **6.71** lb/hour **18.87** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0114 lb/MMBtu for fuel oil combustion** Reference: **AP-42**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Tables 2-2 and 2-3 of PSD Report for emissions calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Worst case emissions scenario based on 100-percent natural gas firing or 85-percent natural gas/15-percent No. 2 fuel oil firing. PM2.5 emissions include condensable and filterable particulates.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **30.75** lb/hour **19.54** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.052 lb/MMBtu for fuel oil combustion** Reference: **AP-42**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Tables 2-2 and 2-3 of PSD Report for emissions calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Worst case emissions scenario based on 100-percent natural gas firing or 85-percent natural gas/15-percent No. 2 fuel oil firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

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: **30.75** lb/hour **19.54** tons/year
5. Method of Compliance: **Fuel analysis and limiting fuel oil burning to less than 15 percent on an annual heat input basis.**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on No. 2 fuel oil firing.**	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **58.90** lb/hour **140.74** 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 (30-day rolling average)** Reference: **Proposed BACT limit**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Tables 2-2 and 2-3 of PSD Report for emissions calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emission factor based on proposed BACT emission limit for any fuel (natural gas or No. 2 fuel oil) burned.**	

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: **0.06 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: **32.16** lb/hour **140.74** tons/year
5. Method of Compliance: **Continuous NOx monitor**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on a 30-day rolling average**	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **94.24** lb/hour **187.65** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.08 lb/MMBtu (30-day rolling average)** Reference: **Proposed BACT limit**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Tables 2-2 and 2-3 of PSD Report for emissions calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Emission factor based on proposed BACT emission limit for any fuel (natural gas or No. 2 fuel oil) burned.**	

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: **0.08 lb/MMBtu, 30-day rolling average**	4. Equivalent Allowable Emissions: **42.88** lb/hour **187.65** tons/year
5. Method of Compliance: **Continuous CO monitor**	
6. Allowable Emissions Comment (Description of Operating Method): **Based on a 30-day rolling average**	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3.18** lb/hour **12.65** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0054 lb/MMBtu for natural gas combustion** Reference: **AP-42**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Tables 2-2 and 2-3 of PSD Report for emissions calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Worst case emissions scenario based on 100-percent natural gas firing or 85-percent natural gas/15-percent No. 2 fuel oil firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **Pb**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **5.30×10^{-3}** lb/hour **4.14×10^{-3}** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **9.0×10^{-6} lb/MMBtu for fuel oil combustion** Reference: **AP-42**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Tables 2-2 and 2-3 of PSD Report for emissions calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Worst case emissions scenario based on 100-percent natural gas firing or 85-percent natural gas/15-percent No. 2 fuel oil firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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: **Hg – H114**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.77×10^{-3}** lb/hour **1.56×10^{-3}** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **3.0×10^{-6} lb/MMBtu for fuel oil combustion** Reference: **AP-42**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

See Tables 2-2 and 2-3 of PSD Report for emissions calculations.

11. Potential, Fugitive, and Actual Emissions Comment:
Worst case emissions scenario based on 100-percent natural gas firing or 85-percent natural gas/15-percent No. 2 fuel oil firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **F**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.016** lb/hour **0.010** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2.74×10^{-5} lb/MMBtu for fuel oil combustion** Reference: **AP-42**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Tables 2-2 and 2-3 of PSD Report for emissions calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Worst case emissions scenario based on 100-percent natural gas firing or 85-percent natural gas/15-percent No. 2 fuel oil firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.37** lb/hour **0.87** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.00232 lb/MMBtu for fuel oil combustion** Reference: **AP-42**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Tables 2-2 and 2-3 of PSD Report for emissions calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Worst case emissions scenario based on 100-percent natural gas firing or 85-percent natural gas/15-percent No. 2 fuel oil firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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: **GHGs (mass basis)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **96,043** lb/hour **290,427** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **163.06 lb/MMBtu for fuel oil combustion** Reference: **40 CFR Part 98, Subpart C**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Tables 2-2 and 2-3 of PSD Report for emissions calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Worst case emissions scenario based on 100-percent natural gas firing or 85-percent natural gas/15-percent No. 2 fuel oil firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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: **GHGs (CO_2e basis)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **96,362** lb/hour **290,841** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **163.60 lb/MMBtu for fuel oil combustion** Reference: **40 CFR Part 98, Subpart C**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

See Tables 2-2 and 2-3 of PSD Report for emissions calculations.

11. Potential, Fugitive, and Actual Emissions Comment:
Worst case emissions scenario based on 100-percent natural gas firing or 85-percent natural gas/15-percent No. 2 fuel oil firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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: **HAPs**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **4.55** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See Table 2-4** Reference: **See Table 2-4 of PSD Report**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Table 2-4 of PSD Report for emissions calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Worst case emissions scenario based on 100-percent natural gas firing or 85-percent natural gas/15-percent No. 2 fuel oil firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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: **Hexane – H104**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour **4.14** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.00176 lb/MMBtu for natural gas combustion** Reference: **See Table 2-4 of PSD Report**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See Table 2-4 of PSD Report for emissions calculations.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Worst case emissions scenario based on 100-percent natural gas firing or 85-percent natural gas/15-percent No. 2 fuel oil firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 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.**	

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 2

1. Parameter Code: **EM**	2. Pollutant(s): **NOx**
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: **40 CFR 60, Subpart Da**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **O2**	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: **40 CFR 60, Subpart Da**	

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: PSD Report ☐ 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: PSD Report ☐ Previously Submitted, Date ___________

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

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

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

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

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

   ☒ Not Applicable

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

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

EMISSIONS UNIT INFORMATION
Section [1]
Natural Gas Fired Boiler D

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: PSD Report ☐ 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: PSD Report ☒ Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ____ ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

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

Additional Requirements Comment

ATTACHMENT NHPC-EU1-I2

FUEL ANALYSIS OR SPECIFICATION

ATTACHMENT NHPC-EU1-I2

DESIGN FUEL SPECIFICATIONS[a] FOR BOILER D

Parameter	No. 2 Fuel Oil	Natural Gas
Specific Gravity	0.865	
Heating Value (Btu/lb)	19,175	
Heating Value (Btu/gal)	136,000	–
Heating Value (Btu/scf)	–	1,020
Ultimate Analysis (dry basis percentage):		
Carbon	87.01	68.37
Hydrogen	12.47	21.82
Nitrogen	0.02	9.80
Oxygen	0.00	–
Sulfur (max)	0.05	–
Ash/Inorganic	0.00	–
Moisture	–	–

[a] Represents average fuel characteristics.

PSD REPORT

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List of Acronyms and Abbreviations

AAQS	ambient air quality standards
AQRV	air quality-related value
BACT	best available control technology
CAA	Clean Air Act
CAIR	clean air interstate rule
CEMS	continuous emission monitoring system
CFR	Code of Federal Regulations
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
COMS	continuous opacity monitoring system
DAS	data acquisition system
EGU	electric utility steam generating unit
ENP	Everglades National Park
EPA	U.S. Environmental Protection Agency
ESP	electrostatic precipitator
°F	degrees Fahrenheit
F.A.C.	Florida Administrative Code
FDEP	Florida Department of Environmental Protection
FPPSA	Florida Power Plant Siting Act
FR	Federal Register
ft	foot
GCP	good combustion practices
GEP	good engineering practice
GHG	greenhouse gases
HAP	hazardous air pollutant
HFC	hydrofluorocarbon
Hg	mercury
hr/yr	hours per year
km	kilometer
kW	kilowatts
lb/hr	pounds per hour
lb/MMBtu	pound per million British thermal units
lb/MW-hr	pound per megawatt hour
LDV	light-duty vehicle
MACT	maximum achievable control technology
MMBtu/hr	million British thermal units per hour
MW	megawatt
MW-hr	megawatt-hours
MW-hr/yr	megawatt-hours per year
N_2O	nitrous oxide
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGVD	national geodetic vertical datum
NHPC	New Hope Power Company
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	new source performance standards
NSR	new source review
NWR	National Wildlife Refuge

List of Acronyms and Abbreviations (continued)

O_3	ozone
Pb	lead
PFC	perfluorocarbon
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to 10 microns
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to 2.5 microns
ppb	parts per billion
ppm	parts per million
PSD	prevention of significant deterioration
SAM	sulfuric acid mist
SER	significant emission rate
SF_6	sulfur hexafluoride
SIL	significant impact level
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
TPY	tons per year
$\mu g/m^3$	micrograms per cubic meter
VOC	volatile organic compound

1.0 INTRODUCTION

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

NHPC is proposing to add a fourth boiler, "Boiler D", to the facility. Boiler D will be fired primarily with natural gas, with No. 2 fuel oil used only as a backup fuel. The new gas-fired boiler will allow NHPC the flexibility to produce steam and electricity year-round from all four boilers based on the most economical fuel or fuel mix, using bagasse, wood, No. 2 fuel oil, and/or natural gas. The current maximum electrical generating capacity of the facility (140 net MW) will not be increased with the addition of the new boiler.

Boiler D will have a maximum 1-hour average heat input rate of 589 million British thermal units per hour (MMBtu/hr) and a maximum 24-hour average heat input rate of 536 MMBtu/hr. The corresponding steam production rates are 440,000 pounds per hour (lb/hr) as a 1-hour average, and 400,000 lb/hr as a 24-hour average. The new gas-fired boiler will be permitted for 8,760 hours per year (hr/yr) operation.

The primary fuel for Boiler D will be natural gas, with very low sulfur distillate fuel oil used as backup. The distillate fuel oil will contain a maximum sulfur content of 0.05 percent. To control emissions of oxides of nitrogen (NO_x), the boiler will use ultra low-NO_x burners for firing natural gas and distillate oil. The very low sulfur content of the fuels utilized will control emissions of particulate matter (PM), sulfur dioxide (SO_2), mercury (Hg), and metals. A modern combustion system design and overfire air system will control emissions of carbon monoxide (CO) and volatile organic compounds (VOCs).

The construction of the new boiler requires an air construction permit and prevention of significant deterioration (PSD) approval. PSD approval requires the submission of air quality assessments for determining the facility's compliance with state and federal new source review (NSR) regulations. These assessments include the air quality impact analyses performed using appropriate air dispersion models. Best Available Control Technology (BACT) analyses also must be performed to evaluate the selected emission control technology.

The U.S. Environmental Protection Agency (EPA) has implemented regulations requiring a PSD review for new and modified sources with air emissions above certain threshold amounts. EPA's PSD regulations are promulgated under Title 40, Parts 52 and 51.166 of the Code of Federal Regulations (40 CFR 52 and

51.166). Florida's PSD regulations are codified in Rule 62-212.400 of the Florida Administrative Code (F.A.C.). The Florida PSD regulations incorporate the requirements of EPA's PSD regulations. The new natural gas-fired boiler will be a "major modification" of an existing major source under PSD rules.

Based on the potential emissions from Boiler D, PSD review is required for each of the following regulated pollutants:

- NO_x
- CO
- PM with an aerodynamic diameter less than or equal to 10 microns (PM_{10})
- PM with an aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$)
- Greenhouse gases (GHGs)

Palm Beach County has been designated as an attainment area for several criteria pollutants: $PM_{2.5}$, SO_2, CO, and nitrogen dioxide (NO_2). Palm Beach County is unclassifiable for PM_{10} and lead (Pb), and a maintenance area for ozone (O_3). Palm Beach County is a PSD Class II area for PM_{10}, $PM_{2.5}$, SO_2, CO, NO_2, Pb, and VOCs. Therefore, the PSD review for Boiler D will follow the regulations pertaining to these designations. For each pollutant subject to PSD review, the following analyses are required:

1. Ambient monitoring analysis, unless the net increase in emissions due to the modification causes impacts that are below specified significant impact levels (SILs)
2. Application of BACT for each new or modified emissions unit
3. Air quality impact analysis, unless the net increase in emissions due to the modification causes impacts that are below specified SILs
4. Additional impact analysis (impact on soils, vegetation, visibility, and growth), including impacts on PSD Class I areas

The new boiler will be a minor source of hazardous air pollutants (HAPs), but the NHPC facility is a major source of HAPs.

This PSD permit application addresses these requirements and is organized into six additional sections, followed by the appendices:

- A description of the project, including air emission sources and pollution control equipment, is presented in Section 2.0
- The regulatory applicability analysis for the proposed project is presented in Section 3.0
- The ambient air monitoring analysis is presented in Section 4.0
- The BACT analysis is presented in Section 5.0
- The air quality impact analysis is presented in Section 6.0
- The additional impact analysis is presented in Section 7.0

Supporting documentation is presented in the appendices.

2.0 PROJECT DESCRIPTION

NHPC operates a 140 net MW cogeneration facility located adjacent to the Okeelanta Corporation sugar mill and refinery, approximately 6 miles south of South Bay in Palm Beach County, Florida. A regional map showing the location of the site is presented in Figure 2-1.

The facility is currently operating under Final Title V Permit No. 0990005-033-AV, issued on October 11, 2012. The original construction permit for the facility was issued to Okeelanta Power L.P. on September 27, 1993 (Permit No. AC50-219413/PSD-FL-196). Construction was completed on the cogeneration facility in 1995 and it has been operating since that time.

The original construction permit has been modified several times. Permit No. 0990332-017-AC/ PSD-FL-196(P), issued on June 6, 2005, allowed the addition to the facility of a nominal 65-MW steam turbine electrical generator. This addition increased the facility capacity from 74.9 net MW, based on the existing single turbine generator, to a total of 140 net MW of steam-generated electricity. This increase in electrical generation capacity was certified under the Florida Electrical Power Plant Siting Act (FPPSA) in Case No. 04-3209EPP and Conditions of Certification (No. PA-04-46) were issued. Construction on the new electrical generator was completed in January 2007.

In 2010, Conditions of Certification (No. PA-04-46A) were issued to incorporate the requirements related to the construction and operation of an on-site ash monofill that will serve the facility. However, construction of the ash monofill has not yet commenced.

Two subsequent PSD permit amendments were issued in 2012: Permit No. 0990332-019-AC was issued on June 6, 2012, for the installation of four natural gas burners in Boiler A; and Permit No. 0990332-020-AC/ PSD-FL-196(Q) was issued on July 12, 2012, authorizing the removal of the activated carbon injection systems on Boilers A, B, and C.

2.1 Existing Operations

The NHPC site encompasses approximately 349 acres, which includes approximately 111 acres for the NHPC cogeneration facility (see Figure 2-2). A figure showing the certified site in relation to the NHPC/Okeelanta property boundaries is presented in Figure 2-3. A plot plan of the NHPC cogeneration facility is presented in Figure 2-4, showing the locations of the existing Boilers A, B, and C. Adjacent to the site are the Okeelanta sugar mill and refinery and the Transshipment facility. The area surrounding NHPC and the Okeelanta sugar mill and refinery consists of sugar cane fields. The nearest residence is approximately 3.6 miles north of the plant. The nearest community, South Bay, is approximately 6 miles north of the facility. A transmission line corridor is located to the west.

The site elevation is nominally 25 feet (ft) with respect to the national geodetic vertical datum (NGVD) of 1929, and about 16 ft above the surrounding terrain. The boiler building floor elevation is 16.5 ft. The terrain surrounding the site is flat.

The three existing steam boilers combust biomass (bagasse and wood), with small amounts of No. 2 fuel oil and natural gas, to generate steam and electricity. Each of the three existing boilers is currently permitted to produce an average of 506,100 lb/hr of steam. The cogeneration facility supplies the adjacent Okeelanta sugar mill with process steam during the sugar cane grinding season, approximately October through March, and also supplies the associated Okeelanta sugar refinery with process steam year-round. The existing configuration of the cogeneration boilers and turbine electric generators is shown in Figure 2-5.

Bagasse is supplied to the NHPC boilers from the adjacent Okeelanta sugar mill during the sugar mill grinding season. Excess bagasse is stored on-site for use as boiler fuel during the off-crop season. Wood fuel is delivered to the facility via truck and placed into the wood storage area for use as boiler fuel year-round.

Natural gas and No. 2 fuel oil are fired as secondary fuels used to supplement biomass during periods of startup and shutdown. Distillate oil is stored in one 50,000-gallon tank.

The Title V operating permit for the facility limits the maximum heat input to each of the three boilers to 760 MMBtu/hr when firing 100-percent biomass, and 490 MMBtu/hr when firing No. 2 fuel oil. Permit No. PSD-FL-196(M) limits the maximum heat input to each of the three boilers to 400 MMBtu/hr when firing natural gas.

Each of the three existing boilers has mechanical dust collectors and electrostatic precipitators (ESPs) for PM control, and a urea-based selective non-catalytic reduction (SNCR) system for NO_x control. The stacks on each boiler have a height of 199 ft.

2.2 Proposed New Natural Gas-Fired Boiler

NHPC is requesting authorization to add a natural gas-fired boiler (Boiler D) to the facility. The addition of a natural gas-fired boiler will allow NHPC the flexibility to produce steam and electricity year-round based on the most economical fuel or fuel mix, i.e., bagasse, wood, natural gas, or No. 2 fuel oil. Steam produced by the new boiler will be tied into the existing steam system, which serves two electrical generators and provides the Okeelanta sugar mill and refinery with steam. The current maximum electrical generating capacity of the facility of 140 net MW will not be increased with the addition of the new boiler.

The proposed location for the new natural gas-fired Boiler D is shown in Figures 2-6 and 2-7. Approximately 1 acre of the existing NHPC site will be used for the Boiler D power block. A flow diagram of the proposed configuration with Boiler D is shown in Figure 2-8.

Boiler D will be permitted for 8,760 hr/yr operation. The boiler will be a modern design natural gas-fired boiler. The minimum expected combustion efficiency while burning either natural gas or No. 2 fuel oil is expected to be 85 percent. The primary fuel will be natural gas, with No. 2 (distillate) fuel oil used as backup fuel. The distillate fuel oil will contain a maximum sulfur content of 0.05 percent. No. 2 fuel oil firing will be limited to 15 percent of the annual heat input during any single calendar year, and 10 percent of the annual average heat input during any 3 calendar years.

The maximum 1-hour average heat input to the boiler will be 589 MMBtu/hr, corresponding to a maximum 1-hour average steam production rate of 440,000 lb/hr. The maximum 24-hour average heat input will be 536 MMBtu/hr, corresponding to a maximum 24-hour average steam production rate of 400,000 lb/hr. Maximum heat input rates and fuel usage rates are shown in Table 2-1. The derivation of the maximum short-term and annual heat input rates for the natural gas boiler is provided in Appendix A.

2.3 Air Pollution Control Equipment

Ultra-low NO_x burners will be used to control NO_x emissions from the new natural gas-fired boiler. Ultra low-NO_x burners represent the state-of-the-art in combustion controls for NO_x emissions from natural gas-fired boilers. In addition to the burner design, the boiler will employ "good combustion practices" (GCPs). The air flow through the boiler will be controlled in order to achieve high thermal efficiency and proper excess air levels to control emissions of CO, PM, and VOCs. The GCPs for the boiler will include the following:

> <u>Good Combustion Practices</u>: An oxygen meter shall be installed at the boiler outlet 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 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 "GCPs" for the natural gas boiler 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 the flue gas oxygen content to provide efficient combustion for the existing conditions

The very low sulfur content of the fuels utilized will control emissions of PM, SO_2, Hg, and metals. The modern combustion and overfire air system will control emissions of CO and VOCs.

Emissions of GHGs, which consist of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O), will be minimized by using the lowest GHG-emitting fossil fuel, i.e., natural gas, and incorporating the most modern, energy efficiency design for the new boiler.

Additional information concerning the air pollution control equipment for Boiler D is provided in Section 5.0, Control Technology Review.

2.4 Air Emissions

The maximum short-term emissions for the proposed Boiler D are presented in Table 2-2 for each fuel. Maximum short-term emissions of NO_x and CO are dependent on averaging time. Maximum hourly emissions of CO are based on 0.16 pound per million British thermal units (lb/MMBtu) of heat input to the boiler, and for NO_x are based on 0.10 lb/MMBtu. The maximum 30-day rolling average emissions are based on the proposed BACT limits of 0.06 lb/MMBtu of heat input to the boiler for NO_x and 0.08 lb/MMBtu of heat input for CO.

Emissions of PM, PM_{10}, and $PM_{2.5}$ are based on AP-42 emission factors for uncontrolled natural gas and No. 2 fuel oil combustion. The emissions include both filterable and condensable PM. Emissions of SO_2, VOCs, sulfuric acid mist (SAM), Pb, and Hg are a function of the fuels burned. Maximum emissions for these pollutants are based on AP-42 emission factors for natural gas and No. 2 fuel oil combustion.

Emissions of GHGs are based on EPA's Mandatory GHG Reporting rule, contained in 40 CFR 98, Subpart C. The GHGs from combustion of natural gas and No. 2 fuel oil consist of CO_2, CH_4, and N_2O. CO_2 equivalent (CO_2e) emissions are obtained by multiplying each GHG by its global warming potential.

The maximum annual emissions for the new Boiler D, for two fuel combinations consisting of 100 percent natural gas, and 85 percent natural gas/15-percent No. 2 fuel oil, are presented in Table 2-3.

The new Boiler D will be subject to New Source Performance Standards (NSPS) for Electric Utility Boilers, 40 CFR 60, Subpart Da. The proposed boiler will meet all emission limits imposed by the NSPS (see Section 3.6 for further discussion).

Annual emissions of HAPs from the proposed Boiler D are shown in Table 2-4. The two potential fuel scenarios are shown to determine worst-case annual emissions. As shown, the maximum annual emissions of any single HAP are 4.1 tons per year (TPY), which is less than the major source HAP threshold of 10 TPY. Also, the maximum annual emissions of all HAPs combined are 4.55 TPY, which is less than the major source HAP threshold of 25 TPY. Therefore, the proposed Boiler D will be a minor source of HAPs.

2.5 Stack Parameters and Site Layout

Stack parameters for the natural gas boiler are presented in Table 2-5. Stack parameters are shown for 100 percent, 91 percent, 75 percent, and 50 percent load conditions, although the boiler will normally be operated at or near the maximum steam rate.

The dimensions of the boiler buildings and nearby structures at NHPC, including the proposed Boiler D building, are presented in Section 6.0. The plot plan with the new Boiler D is shown in Figure 2-7. Stack sampling facilities will be constructed on the boiler stack in accordance with Rule 62-297.310(6), F.A.C.

2.6 Monitoring

Monitoring of steam production, fuel usage rates, air pollutant emissions, and air pollution control device parameters will be performed for boiler operation. Fuel flow meters will be used to determine the heat input rate to the boiler. The heat input rate to the boiler will be determined on an hourly basis. The design efficiency for fossil fuels of 85 percent will be used to determine the amount of fossil fuel heat input used to generate the steam.

Air pollutant emission rates for NO_x and CO will be monitored using a continuous emission monitoring system (CEMS). A continuous opacity monitoring system (COMS) will not be installed on the boiler stack; instead, NHPC will utilize periodic EPA Method 9 visible emissions testing. Monitoring will comply with NSPS Subpart Da requirements.

NHPC currently maintains a data acquisition system (DAS) for the existing three boilers. The new natural gas boiler monitoring will be incorporated into the existing DAS upon startup.

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

Federal and state air regulatory requirements associated with permitting of the project are discussed below. Specific regulatory and/or permitting requirements that may be applicable to the project are described in Sections 3.1 through 3.8. The applicability of these requirements to the proposed project is described in Section 3.9.

3.1 National and State Ambient Air Quality Standards

The existing applicable National and Florida ambient air quality standards (AAQS) are presented in Table 3-1. Primary NAAQS were promulgated to protect the public health, and secondary NAAQS were promulgated to protect the public welfare, from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas in which measured air quality is in or is assumed to be in compliance with the NAAQS are referred to as attainment or unclassifiable areas, respectively. Areas of the country in violation of NAAQS are designated as nonattainment areas. New or modified sources located in or near nonattainment may be subject to more stringent air permitting requirements.

Pollutants for which AAQS have been established are referred to as criteria pollutants. These pollutants include PM_{10}, $PM_{2.5}$, SO_2, CO, NO_2, O_3, and Pb.

On October 17, 2006, the EPA finalized revised AAQS for PM [71 Federal Register (FR) 61236]. The revised PM primary and secondary AAQS included two new $PM_{2.5}$ standards: a short-term 24-hour average standard and an annual average standard. The $PM_{2.5}$ standards are based on a 3-year average of the 98th percentile of 24-hour average concentrations that must not exceed 35 micrograms per cubic meter ($\mu g/m^3$) (from population-oriented monitors). Also, the 3-year average of annual average concentrations must not exceed 15 $\mu g/m^3$ (from a single or community-oriented monitor). The form of compliance for the annual standard remains in the form of the number of expected annual average exceedances, averaged over 3 years.

On March 27, 2008, EPA promulgated revisions to the National AAQS for O_3 (73 FR 16436). The O_3 standard was modified to be 0.075 part per million (ppm) for an 8-hour average concentration; this standard is achieved when the 3-year average concentration of the 4th highest value is 0.075 ppm or less.

In addition, EPA has recently promulgated 1-hour AAQS for SO_2 and NO_2. The 1-hour SO_2 standard is 75 parts per billion (ppb), equivalent to 196 $\mu g/m^3$. The 1-hour standard is met at an ambient air quality monitoring site when the 3-year average of the annual 99th percentile of the daily maximum 1-hour average concentrations is less than or equal to 196 $\mu g/m^3$.

The national primary 1-hour ambient air quality standard for NO_2 is 100 ppb, equivalent to 189 μg/m^3. The 1-hour primary standard is met when the 3-year average of the annual 98th percentile of the daily maximum 1-hour average concentration is less than or equal to 189 μg/m^3.

The Florida Department of Environmental Protection (FDEP) has adopted all of the EPA NAAQS by reference [Rule 62-204.800(1), F.A.C.]. Based on evaluations performed by FDEP, the air quality in Palm Beach County meets the AAQS. As a result, Palm Beach County is classified as an attainment or maintenance area for all criteria pollutants (Rule 62-204.340, F.A.C.). Broward County is also an attainment or maintenance area for all criteria pollutants. Adjacent counties, such as Martin and Hendry Counties, are classified as attainment areas for all criteria pollutants.

3.2 PSD Review Requirements

3.2.1 General Requirements

Under federal and state of Florida PSD review requirements, all new major sources and major modifications to existing major sources must be reviewed and a construction permit issued prior to the commencement of construction. The NHPC facility is located in an area of Florida that is in attainment with the NAAQS for all regulated pollutants. Therefore, the proposed project is being evaluated under the PSD provisions of the NSR permitting program. The PSD review is used to determine whether significant air quality deterioration will result from a new major facility or a major modification at an existing major facility.

A "major facility" is defined as any one of 28 named source categories that has the potential to emit 100 TPY or more of any pollutant regulated under the Clean Air Act (CAA), other than GHGs. If the facility is not in one of the 28 named source categories, the major source threshold is 250 TPY for pollutants other than GHGs. For GHGs, a "major facility" is one with the potential to emit 100,000 TPY or more of CO_2e, excluding biogenic CO_2.

The NHPC facility is an existing major stationary source because it is one of the named 28 source categories (fossil fuel-fired steam electric plants of more than 250 MMBtu/hr heat input), and the potential emissions of at least one PSD-regulated pollutant exceeds 100 TPY (for example, potential NO_x emissions currently exceed 100 TPY). Therefore, PSD review is required for any pollutant for which the net increase in emissions due to the modification is greater than the PSD significant emission rate (SER). The PSD SERs are presented in Table 3-2.

For projects that trigger PSD, EPA regulations identify certain increases above an air quality baseline concentration level of SO_2, PM_{10}, $PM_{2.5}$, and NO_2 concentrations that would constitute significant deterioration. The EPA classification designations and allowable PSD increments are included in Table 3-1. The magnitude of the allowable increment depends upon the classification of the area in which a new source (or modification) is located, or where it has maximum impacts. Based on criteria established in the CAA Amendments, EPA has classified areas as Class I (international parks, national wilderness areas, and memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). There is also a Class III land use designation, which would allow for greater degradation than in either Class I or Class II areas. However, there are no areas of the country that are designated as Class III PSD areas. The state of Florida has adopted the EPA classification designations and allowable PSD increments for SO_2, PM_{10}, and NO_2 increments.

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

The determination of whether a significant emissions increase will occur is based on a comparison of "baseline actual emissions" to "projected actual emissions" for all emissions units affected by the proposed project. "Baseline actual emissions" and "projected actual emissions" are defined in Rules 62-210.200(36) and (252), F.A.C. "Baseline actual emissions" for a new emissions unit is zero. "Baseline actual emissions" for an existing electric utility steam generating unit (EGU) is the average rate, in TPY, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period, selected by the owner/operator, within the 5-year period immediately preceding the date a complete permit application is received by FDEP.

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

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

Major facilities or major modifications to an existing major facility are required to undergo the following analyses related to PSD, for each pollutant emitted in significant amounts:

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

In addition to these analyses, a new facility or major modification also must be reviewed with respect to Good Engineering Practice (GEP) stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

EPA PSD Review Requirements for Greenhouse Gas Emissions

On December 15, 2009, EPA issued an endangerment finding related to GHGs, declaring that the combination of six GHGs [CO_2, CH_4, N_2O, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)] endangers both the public health and welfare of current and future generations.[1] EPA finalized such regulations on April 1, 2010, in a joint rulemaking with the National Highway Traffic Safety Administration [the "Light-Duty Vehicle Rule" (LDV Rule)], making the emission of six GHGs "subject to regulation" under the CAA.[2]

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

In an attempt to reduce the permitting burden associated with triggering NSR and Title V for GHGs, EPA finalized the PSD "Tailoring Rule" on June 3, 2010, limited the applicability of CAA requirements to large stationary sources of GHG emissions.[5] In the final rule, EPA created multiple steps to implement the

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

PSD Tailoring Rule. The first (Step 1), which began January 2, 2011 (when the LDV Rule took effect) and ended on June 30, 2011, applies to "anyway sources" and "anyway modifications" that would be subject to PSD "anyway", based on emissions of pollutants other than GHGs.

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

- GHG emission increases are 75,000 TPY of CO_2e or more
- Total mass-based GHG emission increases are greater than zero

On July 20, 2011, the EPA deferred reporting of CO_2 emissions from bioenergy and other biogenic sources under the PSD program for 3 years.[6] Therefore, biogenic CO_2 is excluded from determining if the above thresholds are exceeded.

3.2.2 Control Technology Review

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emissions-limiting standards be met and that BACT be applied to control emissions from the source. The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility exceeds the respective SER (see Table 3-2).

BACT is defined in 40 CFR 52.21(b)(12) as:

> *An emissions limitation (including a visible emission standard) based on the maximum degree of reduction of each pollutant subject to regulation under the Act which would be emitted by any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs, determination is achievable through application of production processes and available methods, systems, and techniques) for control of such pollutant. In no event shall application of best available control technology (BACT) result in emissions of any pollutant, which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular part of a source or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice, or operation and shall provide for compliance by means, which achieve equivalent results.*

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

BACT is defined in Rule 62-210.200(40), F.A.C., as:

(a) An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case-by-case basis, taking into account:

1. Energy, environmental and economic impacts, and other costs

2. All scientific, engineering, and technical material and other information available to the Department

3. The emission limiting standards or BACT determinations of Florida and any other state determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

(b) If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.

(c) Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

(d) In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.

BACT was promulgated within the framework of the PSD requirements in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in EPA's *Guidelines for Determining Best Available Control Technology (BACT)* (EPA, 1978), in the PSD *Workshop Manual-Draft* (EPA, 1980), and in the *New Source Review Workshop Manual-Draft* (EPA, 1990). These guidelines were promulgated by the EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT analyses must be conducted on a case-by-case basis, and BACT in one area may differ than BACT in another area. According to the EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors."

BACT requirements are intended to ensure that the control systems incorporated in the design of a facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT cannot be less stringent than any applicable NSPS for a source. An evaluation of the air pollution control techniques and systems is required, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology. The cost-benefit analysis requires the documentation of the material, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

The EPA has issued a draft guidance document on the top-down approach entitled *Top-Down Best Available Control Technology Guidance Document* (EPA, 1990). EPA's BACT guidelines include a "top-down" approach to determine the "best available control technology" for application at a particular facility. These guidelines discuss the BACT as a "case-by-case" analysis to identify the most stringent emission control technologies that have been applied to the same or similar source categories, and then to select a BACT emission rate, taking into account technical feasibility and energy, environmental, and economic impacts specific to the project. The most effective control alternative not rejected from the analysis is proposed as BACT.

EPA's BACT guidelines establish a specific five-step analytical process for conducting a BACT determination. The five steps consist of:

1. Identifying the potentially applicable control technologies for the proposed process or source
2. Evaluating the technical options for feasibility taking into consideration source-specific factors
3. Comparing the remaining control technologies based on effectiveness
4. Evaluating the remaining options taking into consideration energy, environmental, and economic impacts
5. Selecting BACT based on the above analyses

EPA recommends that permitting authorities continue to use the Agency's five-step "top down" BACT process to determine BACT for GHGs as well. EPA believes that in BACT reviews for GHGs, it is important to consider options that improve the overall energy efficiency of the source or modification – through technologies, processes, and practices at the emitting unit. In general, a more energy efficient technology burns less fuel than a less energy efficient technology on a per-unit-of-output basis. Thus, considering the most energy efficient technologies in the BACT analysis helps reduce the products of combustion, which includes not only GHGs but other regulated NSR pollutants (e.g., NO_x, SO_2, $PM/PM_{10}/PM_{2.5}$, CO, etc.). Thus, EPA emphasizes that energy efficiency should be considered in BACT determinations for all regulated NSR pollutants (not just GHGs).

EPA has also issued several guidance documents for BACT determinations for GHG emissions. These include:

- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Industrial, Commercial, and Institutional Boilers, October 2010.
- Available And Emerging Technologies For Reducing Greenhouse Gas Emissions From Coal-Fired Electric Generating Units, October 2010.

3.2.3 Source Impact Analysis

A source impact analysis must be performed for a proposed major source or major modification subject to PSD review, and for each pollutant for which the increase in emissions exceeds the PSD SERs presented in Table 3-2. PSD regulations specifically allow for the use of atmospheric dispersion models in performing impact analyses, estimating baselines and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Models designated by the EPA must normally be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in EPA's publication *Guideline on Air Quality Models* (Appendix W to 40 CFR 51, Federal Register dated November 9, 2005).

To address compliance with AAQS and PSD Class II increments, a source impact analysis must be performed for those criteria pollutants where the net increase in impacts as a result of the new source or modification is above SILs, as presented in Table 3-1. The SILs are threshold levels that are used to determine the level of air impact analyses needed for the project. If the new or modified source's impacts are predicted to be less than significant, then the source's impacts, by definition, will not cause or contribute to a violation of an ambient air quality standard, and thus additional modeling with other sources is not required. However, if the source's impacts are predicted to be greater than the SILs, additional modeling with other sources is required to demonstrate compliance with AAQS and PSD increments.

Various lengths of record for meteorological data can be used for impact analysis. A 5-year period is normally used with corresponding evaluation of the predicted concentrations for comparison to AAQS or PSD increments for applicable pollutants, averaging times, and format of the standards. The meteorological data are selected based on an evaluation of measured weather data from a nearby weather station that represents weather conditions at the project site. The criteria used in this evaluation includes determining the distance of the project site to the weather station, comparing topographical and land use features between the locations, and determining availability of necessary meteorological parameters.

3.3 Air Quality Monitoring Requirements

In accordance with requirements of 40 CFR 52.21(m) and Rule 62-212.400(5)(f), any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility would potentially emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the SER (see Table 3-2).

Ambient air monitoring for a period of up to 1 year is generally appropriate to satisfy the PSD monitoring requirements. A minimum of 4 months of data is required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA, 1987a).

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that FDEP may exempt a proposed major stationary facility or major modification from the monitoring requirements, with respect to a particular pollutant, if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2. If a facility's predicted impacts are less than the *de minimis* levels, preconstruction monitoring will not be required pursuant to Rule 62-212.400(3)(e), F.A.C.

3.4 Good Engineering Practice Stack Height

The 1977 CAA Amendments require that the degree of emission limitation for control of any pollutant not be affected by a stack height that exceeds GEP or by any other dispersion technique. On July 8, 1985, the EPA promulgated final stack height regulations (EPA, 1985a). FDEP has adopted identical regulations (Rule 62-210.550, F.A.C.). GEP stack height is defined as the highest of:

1. 65 meters, or
2. A height established by applying the formula:
   $H_g = H + 1.5L$
   where: H_g = GEP stack height,
   H = Height of the structure or nearby structure, and
   L = Lesser dimension (height or projected width) of nearby structure(s); or
3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 kilometer (km).

GEP stack height is determined by comparing the height of the Project's stacks to the dimensions of nearby structures that might influence the exhaust plume based on EPA plume downwash criteria. The type of information required to determine GEP stack height is contained in Sections 2.0 and 6.0.

Although the stack height used in modeling for determining compliance with AAQS and PSD increments is not to exceed the GEP stack height, the actual stack height may be greater. If the stack height is lower than the GEP height, building downwash effects must be included in the modeling analysis.

3.5 Additional Impact Analysis

In addition to air quality impact analyses, federal and Florida PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the Project [40 CFR 52.21(o)]. These analyses are to be conducted primarily for PSD Class I areas. Impacts that result from general commercial, residential, industrial, and other secondary growth associated with the project also must be quantified and evaluated. These analyses are required for each pollutant emitted in significant amounts (Table 3-2).

An air quality related values (AQRVs) analysis is required to assess the potential risk to AQRVs in PSD Class I areas. The U.S. Department of the Interior in 1978 administratively defined AQRVs to be:

> *All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.*
>
> *Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside (Federal Register, 1978).*

AQRVs include visibility, freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent on these communities for habitat. Rare, endemic, threatened, and endangered species of the national park and bioindicators of air pollution (e.g., lichens) must also be evaluated.

3.6 Emission Standards

3.6.1 New Source Performance Standards

The NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the CAA Amendments of 1977, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated." The NSPS are contained in 40 CFR 60. The following sections describe NSPS that are potentially applicable to the proposed natural gas-fired boiler at NHPC.

3.6.1.1 Subpart Da

Federal NSPS exist for EGUs (40 CFR 60, Subpart Da). The NSPS applies to all units capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel) for which construction commenced after September 18, 1978. Subpart Da limits emissions of NO_x, SO_2, and PM from fossil fuel and wood firing.

EPA issued changes to these NSPS on February 27, 2006 (71 FR 9866) and February 16, 2012 (77 FR 9450). The revisions are applicable to new affected facilities that commence construction after February 28, 2005 and after May 3, 2011. For new units burning gaseous and/or liquid fuels, for which construction commences after May 3, 2011, the following limits apply:

- PM – Units that burn only gaseous or liquid fuels with potential SO_2 emission rates of 0.060 lb/MMBtu or less, and do not use a post-combustion technology to reduce SO_2 or PM emissions, are exempt from the PM emission limit.
- SO_2 – emissions are limited to 1.0 pound per megawatt hour (lb/MW-hr) gross energy output, or 1.2 lb/MW-hr net energy output, or 97 percent reduction, based on a 30-day rolling average.
- NO_x – emissions limited to 0.70 lb/MW-hr gross energy output, or 0.76 lb/MW-hr net energy output, based on a 30-day rolling average.
- Visible emissions – limited to 20-percent opacity (6-minute average) except up to 27-percent opacity is allowed for one 6-minute period per hour.
- NO_x + CO – as an alternative to meeting the NO_x standard above, the owner/operator may elect to meet a combined limit for NO_x plus CO emissions of 1.1 lb/MW-hr gross energy output, or 1.2 lb/MW-hr net energy output, based on a 30-day rolling average.

It is noted that for facilities which commence construction, reconstruction, or modification after May 3, 2011, the emission limits apply at all times, including during periods of startup, shutdown, and malfunction.

Subpart Da requires continuous monitoring systems in order to demonstrate compliance with the emission limits. Units that burn only gaseous or liquid fuels with potential SO_2 emission rates of 0.060 lb/MMBtu or less, and do not use a post-combustion technology to reduce SO_2 or PM emissions, are not required to install a COMS, but instead can elect to monitor opacity using EPA Method 9 or submit a site-specific monitoring plan. Also, such units are not required to install a CEMS for SO_2. A CEMS for NO_x is required, and if the unit elects to comply with the NO_x + CO combined emission limit, a CO CEMS is required.

For units demonstrating compliance with the output-based standards, a continuous *volumetric flow* rate monitor measuring the flow rate of the exhaust gases is required. In addition, a wattmeter and process steam continuous monitors are required to measure gross electrical output as well as gross process steam output.

3.6.1.2 Subpart Db

The NSPS for Industrial Boilers, 40 CFR 60, Subpart Db, is potentially applicable to the new natural gas boiler if the new boiler is not subject to Subpart Da. Subpart Db regulates Industrial-Commercial-Institutional Boilers for which construction, modification, or reconstruction commenced after June 19, 1989. It applies to boilers with a heat input capacity of greater than 100 MMBtu/hr.

Subpart Db specifies that units subject to Subpart Da are not subject to Subpart Db.

3.6.1.3 Subpart TTTT

On April 13, 2012, EPA proposed NSPS for GHG emissions for electric utility generating units, 40 CFR 60 Subpart TTTT (77 FR 22392). This proposed NSPS is potentially applicable to the new natural gas boiler. Units that are subject to this NSPS are ones that that commenced construction after April 13, 2012, and which have a base load rating of more than 73 MW or 250 MMBtu/hr heat input of fossil fuel.

The proposed CO_2 emission limit under Subpart TTTT is 1,000 lb/MW-hr on a 12-operating month annual average basis. EPA has not yet finalized this proposed rule.

3.6.2 National Emission Standards for Hazardous Air Pollutants (NESHAP)

The EPA has issued National Emission Standards for Hazardous Air Pollutants (NESHAPs) for various source categories under 40 CFR 63. These standards are referred to as maximum achievable control technology (MACT) standards because they require that maximum achievable control technology be applied to control the emissions of HAPs.

The EPA promulgated final MACT standards for EGUs on February 16, 2012 as 40 CFR 63, Subpart UUUUU (77 FR 9464). The Utility MACT rule covers only coal- and oil-fired EGUs. An oil-fired EGU is one that burns fuel oil for more than 10.0 percent of the average annual heat input during any 3 calendar years, or for more than 15.0 percent of the annual heat input during any single calendar year.

Federal regulations in 40 CFR 63, Subpart B, require that a case-by-case MACT determination be made for new major sources of HAPs if a MACT rule has not been promulgated for the source category. Under this rule, a major source is defined as one that has the potential to emit 10 TPY or more of any HAP or 25 TPY or more of any combination of HAPs.

3.6.3 Clean Air Interstate Rule

The Clean Air Interstate Rule (CAIR) was promulgated under 40 CFR 96 to reduce the emissions of precursor pollutants to O_3 and fine particulate formation and therefore, the interstate transport of O_3 and fine particulates. CAIR applies to EGUs. CAIR regulates NO_x and SO_2 emissions. At this time, the legal status of CAIR is uncertain. CAIR was challenged in the U.S. Court of Appeals, which vacated the rule, but it appears that the court's decision may be reconsidered or reviewed by the U.S. Supreme Court.

3.6.4 Transport Rule

A December 2008 court decision kept the requirements of CAIR in place temporarily but directed EPA to issue a new rule to implement CAA requirements concerning the transport of air pollution across state boundaries. On July 6, 2011, the EPA finalized the Transport Rule, which was intended to replace CAIR. The Transport Rule requires states to significantly improve air quality by reducing power plant emissions that contribute to O_3 and fine particle pollution in other states. The rule requires a total of 28 states to reduce annual SO_2 emissions, annual NO_x emissions, and/or O_3 season NO_x emissions to assist in attaining the 1997 O_3 and fine particle and 2006 fine particle NAAQS. On February 7, 2012 and June 5, 2012, EPA issued two sets of minor adjustments to the Transport Rule. Also, the court recently stayed the Transport Rule but kept CAIR in place. This court's decision is likely to be appealed to the U.S. Supreme Court.

The Transport Rule contains an exemption for a cogeneration unit that generates less than 219,000 megawatt-hours (MW-hr), gross, in any calendar year.

3.6.5 Florida Emission-Limiting Standards

Several Florida emissions-limiting standards exist for steam generating units. Fossil fuel steam generating units with greater than 250 MMBtu/hr heat input are subject to the emission limitations of Rule 62-296.405(2), F.A.C., pertaining to PM, SO_2, NO_x, and visible emissions. FDEP has adopted the EPA NSPS by reference in Rule 62-204.800(7), F.A.C. Therefore, NHPC is required to meet the same emissions, performance testing, monitoring, reporting, and record keeping requirements as those described in Subsection 3.6.1. FDEP has authority to implement NSPS requirements in Florida.

3.7 Florida Air Permitting Requirements

The FDEP regulations require any new source to obtain an air permit prior to construction. Major new sources must meet the appropriate PSD and nonattainment requirements as discussed previously. Required permits and approvals for air pollution sources include NSR for nonattainment areas, PSD, NSPS, NESHAPs, Air Construction Permit, and Air Operation Permit. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.210, 62-210.300(1), and 62-212.400, F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A.C.

3.8 Local Air Regulations

Palm Beach County regulates the air emissions and impacts from the NHPC facility pursuant to a development order that was issued by the County pursuant to the County's land development regulations. The emissions related to the new natural gas boiler will be governed by Palm Beach County in the same manner. Specifically, the County will need to authorize the new boiler by amending the County's development order for the NHPC facility.

3.9 Source Applicability

3.9.1 Area Classification

The project site is located in Palm Beach County, which has been designated by the EPA and the FDEP as an attainment or maintenance area for all criteria pollutants. Palm Beach County and surrounding counties are designated as PSD Class II areas for SO_2, PM_{10}, $PM_{2.5}$, and NO_2. The nearest Class I area to the site is the Everglades National Park (ENP), located about 92 km (57 miles) south of the NHPC facility.

3.9.2 PSD Review

3.9.2.1 Pollutant Applicability

The NHPC facility is considered to be an existing major stationary facility because the facility belongs to one of the 28 named PSD source categories, and potential emissions of certain regulated pollutants exceed 100 TPY (for example, potential SO_2 emissions currently exceed 100 TPY). Therefore, PSD review is required for any pollutant for which the increase in emissions due to the proposed modification is greater than the PSD SERs (see Table 3-2).

Presented in Table 3-3 are the future potential annual emissions from proposed Boiler D, based on the new boiler operating at the maximum 24-hour heat input rate for 8,760 hr/yr (refer to Table 2-3). The net increase in emissions due to the proposed boiler at the facility is also compared to the PSD SERs in Table 3-3. As shown, the net increase exceeds the PSD SERs for NO_x, CO, PM_{10}, $PM_{2.5}$, and GHGs. As a result, all contemporaneous increases and decreases in emissions occurring at the NHPC facility within the last 5 years must be considered for these pollutants only. These are also shown in Table 3-3. The only contemporaneous increases or decreases occurring at the facility within the last 5 years were for the addition of natural gas firing to Boiler A.

As shown, the net increase in emissions, considering the contemporaneous increases, exceeds the PSD SERs for NO_x, CO, PM_{10}, $PM_{2.5}$, and GHGs. As a result, PSD review applies for these pollutants. The BACT analysis for these pollutants other than GHGs is presented in Section 5.0. The BACT analysis for GHGs is presented in a separate report to EPA.

3.9.2.2 Source Impact Analysis

A source impact analysis was performed for PM_{10}, $PM_{2.5}$, NO_x, and CO emissions resulting from the proposed Boiler D. This analysis is presented in Section 6.0. Additional impacts upon the PSD Class I area are also addressed and presented in Section 7.0.

Based on the source impact analysis, the pollutant impacts of the proposed project are predicted to be above the EPA Class II SILs only for NO_2 for the 1-hour averaging time. Therefore, additional modeling of the impacts on the PSD Class II areas was performed for this pollutant and averaging time.

Based on the source impact analysis, the pollutant impacts of the proposed project are predicted to be below the proposed EPA Class I SILs for all pollutants and averaging times. Therefore, additional modeling analysis of the impacts on the PSD Class I area was not performed.

3.9.2.3 Ambient Monitoring Analysis

Based on the increase in emissions from the proposed modification (see Table 3-3), a pre-construction ambient monitoring analysis is required for PM_{10}, $PM_{2.5}$, NO_x, and CO, and monitoring data is required to be submitted as part of the application. However, if the net increase in impacts of a pollutant is less than the applicable *de minimis* monitoring concentration, then an exemption from submittal of pre-construction ambient monitoring data may be obtained [40 CFR 52.21(i)(8)]. In addition, if the EPA has not established an acceptable ambient monitoring method for the pollutant, monitoring is not required.

As shown in Table 3-4, based on results presented in Section 6.9, the maximum impacts due to proposed Boiler D are predicted to be below the PSD *de minimis* concentration levels for all pollutants requiring PSD review. However, NO_2 monitoring data are presented in Section 4.0 to support the NO_2 AAQS modeling analysis.

3.9.2.4 GEP Stack Height Impact Analysis

The proposed Boiler D will have a stack height of 150 ft. This stack height does not exceed the *de minimis* GEP stack height of 65 meters (213 ft), and therefore, the project will be in compliance with the GEP stack height rules.

3.9.3 Emission Standards

3.9.3.1 NSPS Subpart Da

The Subpart Da NSPS applies to all EGUs capable of combusting more than 250 MMBtu/hr heat input of fossil fuel (either alone or in combination with any other fuel). Since the new boiler will combust natural gas alone or in combination with No. 2 fuel oil at a heat input rate greater than 250 MMBtu/hr, the NSPS in 40 CFR 60 Subpart Da are applicable.

The proposed Boiler D will comply with the applicable emission limits and requirements discussed previously in Section 3.6. The estimated NO_x emissions from Boiler D are 0.39 lb/MW-hr during the crop season and 0.40 lb/MW-hr during the off-season, both well below the 0.70 lb/MW-hr NSPS. Refer to Appendix B for the derivation of emission rates in terms of lb/MW-hr gross output, for comparison to the NSPS emission limits.

3.9.3.2 Subpart Db

The NSPS for Industrial Boilers, 40 CFR 60, Subpart Db, is potentially applicable to the new natural gas boiler if the new boiler is not subject to Subpart Da. However, as discussed in Section 3.6, the new boiler will be subject to the Subpart Da NSPS. Therefore, the new boiler will not be subject to Subpart Db.

3.9.3.3 Subpart TTTT

The NSPS for EGUs, 40 CFR 60, Subpart TTTT, which regulates GHG emissions, is applicable to the new Boiler D. The proposed Boiler D will comply with the applicable emission limits and requirements discussed previously in Section 3.6. The estimated CO_2 emissions from Boiler D when firing natural gas are 825 lb/MW-hr during the crop season and 848 lb/MW-hr during the off-season, both well below the 1,000 lb/MW-hr NSPS. For No. 2 fuel oil firing, CO_2 emissions are estimated at 1,151 lb/MW-hr during the crop season, and 1,184 lb/MW-hr during the off-season. Since No. 2 fuel oil firing will be limited to 15 percent on an annual basis, the 12-month average maximum CO_2 emissions are estimated at 888 lb/MW-hr. Refer to Appendix B for the derivation of emission rates in terms of lb/MW-hr gross output, for comparison to the NSPS emission limit.

3.9.4 NESHAPs

The new natural gas-fired boiler at NHPC will burn natural gas at greater than 10 percent of the annual average heat input during any 3 calendar years, or for more than 15 percent of the annual heat input during any calendar year. The boiler will not burn fuel oil at greater than 10 percent of the annual average heat input during any 3 calendar years, or for more than 15 percent of the annual heat input during any single calendar year. Therefore, the new Boiler D will not be subject to Subpart UUUUU, which only regulates coal and oil-fired units.

In the absence of MACT regulations applicable to proposed Boiler D, 40 CFR 63, Subpart B, could require that a case-by-case MACT determination be made for the boiler. However, as demonstrated in Section 2.4, Boiler D will not itself be a major source of HAPs; therefore, case-by-case MACT does not apply.

3.9.5 Transport Rule

Under the Transport Rule, the exemption criterion for a cogeneration unit specifies that the unit must not generate more than 219,000 MW-hr in any calendar year. Although the new natural gas-fired boiler will be capable of producing up to 439,752 megawatt-hours per year (MW-hr/yr), the actual electrical generation will depend on its use. Based on historical operation of the other three boilers at NHPC, the 219,000-MW-hr/yr threshold should not be exceeded by the gas-fired boiler in any calendar year.

3.9.5.1 State of Florida Standards

The applicable state of Florida emission limits for new fossil fuel steam generators with more than 250 MMBtu/hr heat input are the same as the applicable NSPS. For the new natural gas boiler, the applicable NSPS is 40 CFR 60 Subpart Da, as described *in Subsection* 3.9.3.1. Therefore, the new natural gas boiler will comply with the Florida emission standards contained in Rule 62-296.405(2), F.A.C.

4.0 AMBIENT MONITORING ANALYSIS

4.1 Monitoring Requirements

In accordance with requirements of 40 CFR 52.21(m) and Rule 62-212.400(5)(f), F.A.C., an air quality analysis must be conducted for each criteria and non-criteria pollutant subject to regulation under the CAA before a major stationary source is constructed. Criteria pollutants are those pollutants for which AAQS have been established. Non-criteria pollutants are those pollutants that may be regulated by emission standards for which AAQS have not been established. This analysis may be performed by the use of modeling and/or by monitoring the air quality. In addition, if EPA has not established an acceptable ambient monitoring method for the pollutant, monitoring is not required.

Based on the potential emissions from NHPC Boiler D (see Table 3-3), pre-construction ambient monitoring analyses for $PM_{10}/PM_{2.5}$, NO_2, and CO may be required as part of the application. However, ambient monitoring analyses are not required if it can be demonstrated that the proposed source's maximum air quality impacts will not exceed the PSD *de minimis* concentration levels.

As presented in Section 6.10, and shown in Table 3-4, the maximum impacts due to proposed Boiler D only are predicted to be below the PSD *de minimis* concentration levels for all pollutants and averaging times.

Background concentrations for NO_2 are presented in this section to support the air impact analysis.

4.2 NO_2 Background Ambient Monitoring Data

Ambient NO_2 monitoring data from existing monitoring stations are included in this application to provide background concentrations for the AAQS modeling analysis presented in Section 6.0. Measured ambient NO_2 data from the nearest monitor are presented in Table 4-1. The nearest monitor to the NHPC site that measures NO_2 concentrations is located in Lantana (AIRS No. 12-099-1020) in Palm Beach County. This station is operated by the FDEP and measures concentrations according to EPA procedures.

As shown in Table 4-1, from 2010 through 2011, the 98th percentile 1-hour average NO_2 concentration measured at the Lantana site was 87 $\mu g/m^3$, while in 2011 it was 71 $\mu g/m^3$. This concentration is less than the 1-hour average NO_2 AAQS of 188 $\mu g/m^3$.

As shown in Table 4-1, the 2-year average of the 98th percentile of the daily maximum 1-hour NO_2 concentrations measured during 2010-2011 was 79 $\mu g/m^3$. This concentration was used as the 1-hour background NO_2 concentration in the modeling analysis.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

5.1 Introduction

The 1977 CAA Amendments established requirements for the approval of pre-construction permit applications under the PSD program. As discussed in Subsection 3.2.1, one of these requirements is that BACT be applied to pollutants that are subject to PSD review. This section presents the proposed BACT for these pollutants. The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as consideration of EPA's current policy guidelines requiring a "top-down" approach. A BACT determination requires a site-specific analysis of the technical, economic, environmental, and energy impacts of the proposed and alternative control technologies [40 CFR 52.21 (b)(12)].

The "top-down" approach consists of the following five steps, as described in the New Source Review Workshop Manual-Draft (EPA, 1990):

1) Identification of all available control technologies
2) Elimination of technically infeasible control options
3) Ranking of the technically feasible control technologies based on their effectiveness
4) Evaluation of the economic, environmental, and energy impacts of the feasible control options
5) Selection of BACT based on consideration of the above factors

For the proposed NHPC Boiler D project, PM/PM_{10}/$PM_{2.5}$, NO_x, CO, and GHGs are subject to PSD review and as a result, BACT review is required for these pollutants. In each case, BACT is an emission limitation that meets the maximum degree of emission reduction after taking into account the proposed project's specific economic, environmental, and energy impacts, while considering the application of the technologies proposed. If it is impractical to impose an emission limit, a work practice standard may be specified.

The following sections provide the required BACT analysis for non-GHGs. As will be evident, the emission rates proposed for the new Boiler D are consistent with recent PSD determinations for other similar projects. The BACT analysis for GHGs is being provided in a separate report, which will be submitted to EPA Region 4 for review and approval.

5.2 Overview of Proposed BACT

As previously noted, the new natural gas-fired Boiler D is intended to provide NHPC with additional fuel and operating flexibility related to steam production. The BACT proposed for the new natural gas-fired boiler is as follows:

- NO_x – Ultra-Low NO_x burners

- CO – Good combustion practices
- PM_{10} and $PM_{2.5}$ – Use of pipeline-quality natural gas as the primary fuel and existing combustion controls to assure maximum unit operating efficiency
- GHG – Use of pipeline-quality natural gas as the primary fuel and good combustion practices and controls to assure maximum unit operating efficiency

5.3 Nitrogen Oxides – NO_x

As part of the BACT analysis, a review was performed of previous NO_x BACT determinations for similar natural gas-fired industrial and electric utility boilers listed in the RACT/BACT/LAER Clearinghouse on EPA's web page. From this information, BACT determinations issued within the last 10 years (i.e., since 2002) were identified. A summary of these BACT determinations is presented in Table 5-1. Auxiliary boilers were separated out from the analysis as their operation is non-continuous.

From the review of previous BACT determinations, NO_x BACT determinations for new natural gas-fired industrial and electric utility boilers have been based on low NO_x and ultra-low NO_x burners, flue gas/ induced draft recirculation, and GCPs, with a few employing selective catalytic reduction (SCR). Auxiliary and package boilers, although shown in Table 5-1, are not designed to operate continuously therefore were not considered in this analysis.

Previous NO_x BACT determinations are in the range of 0.0076 to 0.09 lb/MMBtu. The lowest determination (0.0076 lb/MMBtu) was based on the use of low-NO_x burners, flue gas recirculation, and SCR. The next lowest determination at 0.0125 lb/MMBtu was based on low-NO_x burners and flue gas recirculation. All determinations based on low-NO_x burners and flue gas recirculation range from 0.0125 lb/MMBtu to 0.09 lb/MMBtu. Of the thirteen (13) total BACT determinations for NO_x, only two (2) are based on SCR. The BACT emission limits for these two cases were 0.0076 lb/MMBtu and 0.0186 lb/MMBtu.

5.3.1 Step 1 – Identification of Control Technologies

The BACT analysis was performed based on those available and feasible control technologies that can provide the maximum degree of emission reduction for NO_x emissions. Emissions of NO_x are produced by the high-temperature reactions of molecular nitrogen and oxygen in the combustion air (termed "thermal NO_x") and by fuel-bound nitrogen with O_3 (termed "fuel-bound NO_x"). The relative amount of each depends on the combustion conditions and the amount of nitrogen in the fuel. Formation of thermal NO_x depends on the combustion temperature and becomes rapid above 1,400 degrees Celsius (°C) (2,550°F). The equations developed by Zeldovich are recognized as the reactions that form thermal NO_x:

$$N_2 + O \rightarrow NO + N$$
$$N + O_2 \rightarrow NO + O$$
$$N + OH \rightarrow NO + H$$

The important parameters in thermal NO_x formation are combustion temperatures, gas residence time, and local stoichiometric ratio of fuel and air. Fuel-bound NO_x is formed by the nitrogen in the fuel that reacts with combustion air. With some fossil fuels, such as natural gas or distillate fuel oil, emissions of fuel-bound NO_x are usually small compared to thermal NO_x. However, fuel-bound NO_x can be significant with fossil fuels such as No. 6 fuel oil and coal.

Another mechanism for NO_x formation is the reaction of molecular nitrogen with free hydrogen (H) radicals. This mechanism is known as "prompt NO_x" and occurs within the combustion zone with the following major reactions:

$$N_2 + CH \rightarrow HCN + N$$

$$N + O_2 \rightarrow NO + O$$

The contribution of prompt NO_x to overall NO_x levels is relatively small (less than 5 percent).

The primary ways to reduce NO_x emissions are through either combustion process controls or through catalytic or non-catalytic reactions.

Combustion controls are the primary engineering choice in reducing NO_x concentrations within the boiler. Combustion controls include, but are not limited to, low NO_x burners (LNB) and over-fire air (OFA). Such controls are considered "pollution preventing", because the formation of NO_x is limited in the combustion process by reducing the peak temperature and reducing the residence time at peak temperature. A combustion technology referred to as reburn has also been installed as a retrofit technology on existing units to reduce NO_x emissions (see description below).

Post-combustion NO_x control processes include catalytic and non-catalytic conversion of NO_x, typically to nitrogen. Non-catalytic processes (e.g., SNCR) use ammonia (NH_3) or urea injection at high temperatures, generally about 1,800°F. These technologies can achieve from 50- to 60-percent NO_x removal (depending on the fuel), and are primarily applicable to boilers that can maintain a relatively constant temperature for the reaction. Catalytic processes (SCR) operate at lower temperatures (550 to 800°F) compared to SNCR processes. There are only a few SCR processes operating on natural gas-fired boilers. SCR can achieve NO_x control efficiencies in the range of 70 to 90 percent.

5.3.1.1 Removal of Nitrogen

Ultra-Low Nitrogen Fuel – The fuels combusted in the new boiler will be natural gas and No. 2 fuel oil (as a backup). Combustion of these fuels results in emissions of NO_x that are lower than other fuels, such as No. 6 fuel oil or coal, due to the characteristically low levels of nitrogen associated with these fuels. Among other things, NHPC will control NO_x emissions from the boiler through the use of low nitrogen content fuels.

5.3.1.2 Oxidation of NO_x with Subsequent Absorption

Inject Oxidant – The oxidation of nitrogen to its higher valence states makes NO_x soluble in water. When this is done, a gas absorber can be effective. Oxidants that have been injected into the gas stream are ozone, ionized oxygen, or hydrogen peroxide. This NO_x reduction technique has not been demonstrated on large-scale boilers and, consequently, it is not considered technically feasible for the new natural gas-fired boiler.

Non-Thermal Plasma Reactor (NTPR) – This technique generates electron energies in the gas stream that generate gas-phased radicals, such as hydroxyl (OH) and atomic oxygen (O) through collision of electrons with water and oxygen molecules present in the flue gas stream. In the flue gas stream, these radicals oxidize NO_x to form nitric acid (HNO_3), which can then be condensed out through a wet condensing precipitator. NTPR has not been demonstrated on large-scale boilers and it is not considered technically feasible for the new natural gas-fired boiler.

5.3.1.3 Chemical Reduction of NO_x

Selective Catalytic Reduction (SCR) – A catalytic NO_x removal process that has been demonstrated and proven is SCR, including regenerative SCR (RSCR). SCR is a widely used post-combustion NO_x-control technology that has been used on a variety of fuels (e.g., coal, natural gas, residual and distillate oil, and Orimulsion®) and applications (e.g., fossil steam units, combined cycle units, diesel engines, and simple cycle gas turbines).

Developing NO_x control technologies include some processes that either combine the removal of various pollutants or specifically target the removal of NO_x. Such technologies, including Electro-Catalytic Oxidation™, SO_x-NO_x-RO_x Box, and THERMALONO$_x$™, have future promise but have not been demonstrated on large (>100 MW) thermal power facilities. For this reason, they are not evaluated further in this application.

The fundamental reaction for SCR (i.e., the selective reaction of NH_3 with NO in the presence of a catalyst and excess oxygen) was discovered by Engelhard Corporation in 1957. SCR technology was commercially developed in Japan and used there on a continuing basis for the first time. In an SCR process, either anhydrous or aqueous NH_3 is injected into the flue gas upstream of a catalyst bed. The catalysts are arranged in modules set up into single or multiple stages. The selective reduction reactions occur at temperatures between 550 and 800°F on the surface of the SCR catalysts to produce molecular nitrogen gas and water. The reactions are as follows:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6\ H_2O$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6\ H_2O$$

SCR catalysts consist of two types: base metal oxides and zeolite. In an SCR system, a base metal oxide catalyst (either vanadium, titanium, or platinum) is embedded into a ceramic matrix structure. The zeolite catalysts are ceramic molecular sieves extruded into modules of honeycomb shape. Different catalysts exhibit advantages and disadvantages in terms of exhaust gas temperatures, NH_3/NO_x ratio, and exhaust gas O_3 concentrations for optimum control.

A common disadvantage for all catalyst systems is the limited temperature window where the NO_x reduction process takes place. The reaction occurs typically between about 320 and 400°C (600 to 800°F). Use of platinum catalysts allows this temperature window to be lowered to about 550°F, while special low temperature catalysts have been developed to operate as low as 300°F. These temperatures occur after the economizer of the boiler. Operating outside this temperature range results in failure to remove NO_x and/or harm to the catalyst system. Chemical poisoning can occur at lower temperature conditions, while thermal degradation can occur at higher temperatures. Additional NO_x emissions can be produced at higher temperatures. Reactivity can only be restored through catalyst replacement. Sufficient O_2 is required to ensure successful reactions. For most SCR applications that have been effective, O_2 concentrations have been in excess of 2 percent in the flue gas. The SCR catalyst typically has a finite life. Some NH_3 typically slips through the catalyst without being reacted.

There are two types of SCR systems that potentially could be applied to the proposed natural gas-fired boiler: conventional SCR and "tail-end" SCR. In a conventional SCR system, the catalyst is located just downstream of the boiler economizer. This location is necessary to operate in the appropriate temperature window for SCR (550 to 800°F). The proposed fuels (natural gas and No. 2 fuel oil) do not present a significant possibility of catalyst poisoning; therefore, this configuration could be possible in the new natural gas-fired boiler.

The other possible configuration is a "tail-end" configuration. This type of installation allows the SCR to be placed downstream of all other pollution controls (particularly PM controls), minimizing the chance of severe catalyst degradation or fouling due to the ash constituents. This configuration would also be possible in the new natural gas-fired boiler, but is not necessary since there are no PM controls required for the natural gas-fired boiler.

A technology marketed by EmeraChem that is available for clean burning fuels such as natural gas and distillate fuel oil is EMx. According to the company, this technology is the next generation of SCONOx and is a multi-pollutant technology in a single system that significantly reduces NO_x, sulfur oxides (SO_x), CO, VOC, and PM for air emission requirements.

EMx uses a catalyst for NO_x and CO reduction. EMx does not utilize NH_3.

SCR on a natural gas-fired boiler can achieve a NO_x control efficiency of between 70 and 90 percent. However, catalyst costs increase significantly as the removal efficiency increases above 70 percent.

Selective Non-Catalytic Reduction (SNCR) – In an SNCR system, NH_3 or urea is injected within the boiler or in ducts downstream of the boiler in a region where the temperature is between 900 and 1,100°C (1,650 to 1,800°F). This technology is based on temperature ionizing the NH_3 or urea, instead of using a catalyst or non-thermal plasma. The temperature window for SNCR is very important because, outside of it, either (a) more NH_3 slips through the system or (b) more NO_x is generated than is being chemically reduced. NH_3 slip has the potential to affect boiler operation as well as ammonium bisulfate formation on the downstream boiler components. SNCR has been demonstrated as a feasible technology and can achieve NO_x reductions of up to 50 to 60 percent. However, SNCR is not feasible on a natural gas-fired boiler, because temperatures are too high in the furnace (>2,000°F), and there is not sufficient residence time in the proper temperature window downstream of the boiler. As shown in Table 5-1, SNCR has not been deemed to be BACT for a natural gas-fired boiler.

5.3.1.4 Reducing Residence Time at Peak Temperature

Air Staging of Combustion – In this system, combustion air is divided into two streams. The first stream is mixed with fuel in a ratio that produces a reducing flame. The second stream is injected downstream of the flame and creates an oxygen-rich zone. The new Boiler D will utilize an OFA system, which acts as air staging of combustion.

Fuel Staging of Combustion – In this system, combustion is staged using fuel instead of air. Fuel is divided into two streams. The first stream feeds primary combustion that operates in a reducing fuel to air ratio. The second stream is injected downstream of primary combustion, causing the net fuel to air ratio to be slightly oxidizing. Excess fuel in the primary combustion zone dilutes heat to reduce temperature. The second stream oxidizes the fuel while reducing the NO_x to nitrogen.

Inject Steam – Injection of steam causes the stoichiometry of the mixture to be changed and dilutes calories generated by combustion. These actions cause combustion temperatures to be lower, and in turn reduce the amount of thermal NO_x formed. Steam injection is normally applied to gas turbines and not to boilers, as injecting water into the boiler would reduce the boiler thermal efficiency considerably.

Each of these techniques to reduce residence time at peak temperature is technically feasible. However, as stated above, injecting steam has not been applied to natural gas-fired boilers, and therefore was not considered further.

5.3.1.5 Reducing Peak Temperature

Flue Gas Recirculation (FGR) – This technology involves recirculation of cooled flue gas back to the boiler, which reduces combustion temperature by diluting the oxygen content of the combustion air and by causing heat to be diluted in a greater mass of flue gas. Heat in the flue gas can be recovered by a heat exchanger. This reduction of temperature lowers the thermal NO_x concentration that is generated. FGR is normally used to quench the flame, reducing both temperature and oxygen levels, thereby reducing the uncontrolled NO_x emissions.

Natural Gas Reburning (NGR) – The natural gas reburning process involves the introduction of natural gas into the burning zones of the boiler. The first zone is the primary combustion area where 80 to 85 percent of the fuel is burned. In this area, fuel is fired typically using the existing burner systems, which also can be low-NO_x burners. In the second zone, downstream of the primary combustion zone, remaining fuel is introduced to form a slightly fuel rich combustion zone. This area is often referred to as the reburn zone, where hydrocarbon compounds are formed that react with nitrogen oxide, the primary form of NO_x in combustion processes. The reactions of these hydrocarbon radicals and nitrogen oxide ultimately form nitrogen, which therefore inhibits the NO_x formation process (i.e., Zeldovich reaction). The third zone, downstream of the reburn zone, is often referred to as the burnout zone where combustion air is added to combust the remaining hydrocarbon compounds. The overall combustion process is typically fuel lean. This technology requires no catalysts, chemical reagents, or changes to any existing burners. Typical reburn systems also incorporate redesign of the combustion air system to provide less excess air (LEA).

Reburn has been demonstrated using natural gas, coal, residual oil, and Orimulsion®. Reductions in NO_x from 40 to 70 percent have been demonstrated with this wide variety of fuels. For the proposed boiler, natural gas reburn is a feasible technology.

Over-Fire Air (OFA) – When primary combustion uses a fuel-rich mixture, use of OFA completes the combustion. Because the mixture is always off-stoichiometric when combustion is occurring, the combustion temperature is reduced. After all other stages of combustion, the remainder of the fuel is oxidized in the OFA zone. The new natural gas-fired boiler will utilize an OFA system to promote vigorous mixing of the combustion gases to maximize combustion efficiency and reduce pollutant emissions. The OFA system injects hot air at high velocities into the furnace.

Less Excess Air (LEA) – The amount of excess air in the combustion zone has been correlated to the amount of NO_x generated. Limiting excess air to the boiler can limit the NO_x content of the flue gas.

Combustion Optimization – Combustion optimization refers to the active control of combustion by measuring boiler oxygen level, combustion zone temperature, etc., and adjusting boiler operating parameters in response. The active combustion control measures seek to find optimum combustion efficiency and to control combustion at that efficiency. The new natural gas-fired Boiler D will be optimized for maximum combustion efficiency, and boiler operating parameters will be continuously monitored (see Section 2.0).

Low NO_x Burners (LNB) – A LNB provides a stable flame that has several different burning zones. For example, the first zone can be primary combustion; the second zone can be Fuel Reburning (FR) with fuel added to chemically reduce NO_x; and the third zone can be the final combustion in low excess air to limit the temperature. Low-NO_x burners can be employed for natural gas and fuel oil firing. Ultra-low-NO_x burners have been designed in recent years, which achieve very low levels of NO_x emissions. These type burners will be utilized on the new natural gas-fired boiler.

5.3.2 Step 2 – Technical Feasibility

The technically feasible NO_x controls for the new natural gas-fired boiler are listed in Table 5-2. As shown, there are several types of NO_x abatement methods with various techniques for each method. Each available technique was listed with its associated efficiency estimate, identified as feasible or infeasible, and ranked based on control efficiency. Combustion controls, using ultra-low nitrogen fuel, and low/ultra-low NO_x burners are the initial choices for reducing NO_x from the combustion process. Adding additional controls (SCR, FGR) are technically feasible for the new natural gas-fired Boiler D.

5.3.3 Step 3 – Rank Control Technologies by Control Effectiveness

SCR and ultra-low-NO_x burners are highly effective in controlling NO_x emissions and will achieve the maximum degree of NO_x emission reduction. As shown in Table 5-2, SCR has an estimated NO_x removal efficiency of 90 percent, ultra-low-NO_x burners have an estimated NO_x removal efficiency of 85 percent, and low NO_x burners with FGR (reducing residence time at peak temperatures) have an estimated NO_x removal efficiency of 50 to 60 percent. Reducing peak temperatures provides an efficiency of 15 to 25 percent. FGR systems employ a combination of these methods to achieve NO_x reduction. Other technologies have not demonstrated equivalent levels of control for NO_x.

5.3.4 Step 4 – Evaluation of Economic, Environmental, and Energy Impacts of Feasible Technologies

5.3.4.1 Economic Impacts

The top ranked technically feasible control technologies, as shown in Table 5-2, is ultra-low-NO_x burners coupled with SCR. NHPC is proposing to use ultra-low-NO_x burners. Therefore, a cost analysis for SCR only was prepared, based on a recent cost quote (see Appendix C). This cost analysis is presented in Table 5-3. The catalyst is guaranteed for only 1 year; however, the cost estimate reflects total replacement of the catalyst once every 2 years.

As shown, the estimated capital cost of SCR is approximately $2.8 million for the 70 percent NO_x reduction case and $3.9 million for the 90 percent reduction case. The total annual costs are estimated at almost $530,000 per year and $745,000 per year for the two cases. Based on a controlled NO_x emission rate of 0.06 lb/MMBtu with ultra low-NO_x burners, and the estimated 90 percent reduction in NO_x emissions (reduction of 127 TPY), the total cost effectiveness is $5,900 per ton of NO_x removed. However, if 0.03 lb/MMBtu NO_x can be achieved by ultra low-NO_x burners, the cost effectiveness increases to almost $12,000 per ton of NO_x removed. The cost of SCR is therefore high for NO_x reduction.

5.3.4.2 Environmental

No additional significant environmental impacts from the use of SCR are anticipated. SCR requires disposal of the catalyst every 3 years.

5.3.4.3 Energy

Energy penalties occur with SCR. SCR requires energy and NH_3. The additional energy required to operate the SCR system comes in the form pressure drop across the catalyst, which requires more fan energy. The pressure drop for the proposed natural gas-fired boiler system is 2.8 inches water. An additional energy requirement is for pumping the ammonia. The total increase in energy requirements is approximately 35 kilowatts (kW).

5.3.5 Step 5 – Selection of BACT and Rationale

The identification, technical evaluation, and ranking of the available control technologies indicate that ultra-low-NO_x burners coupled with SCR provides the maximum degree of NO_x emission reduction. The evaluation of the energy, environmental, and economic impacts demonstrates that incremental cost of SCR is extremely costly. At approximately $2.9 to 3.9 million in capital costs and $745,000 in annual costs, the SCR system would be expensive. If NO_x emissions can be limited to 0.03 lb/MMBtu or less with ultra low-NO_x burners, the cost effectiveness is well over $10,000 per ton of NO_x reduced.

The next most effective NO_x control technology, ultra-low NO_x burners, along with advanced combustion design and controls, is selected as BACT for Boiler D. Based on the previous BACT determinations for this technology, a NO_x emission rate of between 0.0125 and 0.09 lb/MMBtu is achievable. Since the new boiler manufacturer has not yet been selected, a NO_x emission rate of 0.06 lb/MMBtu, 30-day rolling average, is proposed as BACT for Boiler D. A lower NO_x emission rate may be determined to be achievable after selecting a boiler manufacturer.

The NSPS Subpart Da contains NO_x emission standards for fossil fuel firing. The applicable standards for natural gas or fuel oil firing, for units for which construction commenced after May 11, 2011, are as follows:

- NO_x – emissions limited to 0.70 lb/MW-hr gross energy output, or 0.76 lb/MW-hr net energy output, based on a 30-day rolling average.
- NO_x + CO – as an alternative to meeting the NO_x standard above, the owner/operator may elect to meet a combined limit for NO_x plus CO emissions of 1.1 lb/MW-hr gross energy output, or 1.2 lb/MW-hr net energy output, based on a 30-day rolling average.

The proposed NO_x BACT limit will comply with the Subpart Da emission standards. The proposed limit of 0.06 lb/MMBtu is equivalent to approximately 0.40 lb/MW-hr gross energy output. Refer to Appendix B for calculations.

5.4 Carbon Monoxide – CO

As part of the BACT analysis, a review was performed of previous CO BACT determinations for industrial and electric utility boilers listed in the RACT/BACT/LAER Clearinghouse on EPA's web page. A summary of BACT determinations for natural gas-fired industrial and electric utility boilers from this review is presented in Table 5-4. From the review of previous BACT determinations, CO BACT determinations for new natural gas-fired industrial and electrical utility boilers have been based primarily on GCPs, with a few using oxidation catalysts. The BACT limits range from 0.024 to 1.0 lb/MMBtu. Auxiliary and package boilers, which are not designed to operate continuously, were not considered in this analysis.

5.4.1 Step 1 – Identification of Control Technologies

The BACT analysis was performed based on those available and feasible control technologies that can provide the maximum degree of emission reduction for CO emissions. CO emissions, which result from incomplete combustion of carbon in the fuel, are controlled by boiler design features and combustion air systems. The new natural gas-fired Boiler D will be designed and operated for high-combustion efficiency, which will inherently minimize the production of CO. Carbon in the fuel which does not experience the required temperature or residence time at the required temperature can form CO or other organic compounds instead of being fully oxidized to CO_2. The important parameters in CO formation are combustion temperatures, gas residence time, and local stoichiometric ratio of fuel and air (i.e., mixing of fuel and air).

Oxidation Catalyst – CO emissions can be reduced by passing the flue gas over an oxidation catalyst at suitable temperature (550 to 1,000°F). Lower temperature catalysts have also been developed but are unnecessary for this application. The catalyst material is made of vanadium. Oxidation catalysts can reduce CO emissions by 70 to 90 percent.

Overfire Air (OFA) Systems – There are several novel OFA systems being offered on the market today. OFA attempts to improve air/fuel mixing and turbulence in the furnace, while maximizing gas residence time. Cold spots are reduced, and more complete combustion is accomplished.

Incinerators – Incineration systems include direct flame incinerators, thermal oxidizers, and afterburners. Incineration or thermal oxidation is the process of oxidizing combustible materials by raising the temperature of the material above its auto-ignition point in the presence of oxygen, and maintaining it at high temperature for sufficient time to complete combustion to carbon dioxide and water. Time, temperature, turbulence (for mixing), and the availability of oxygen all affect the rate and efficiency of the combustion process. The auto-ignition temperature of CO is 1,300°F. The use of oxidation catalyst can reduce the temperature requirement down to 500°F for CO oxidation.

The use of thermal oxidation, while also theoretically possible, is not feasible as BACT. While thermal oxidation has been demonstrated on a cement kiln in Texas, RTO systems are not considered technically feasible for boilers with large gas flows, such as that associated with the proposed natural gas-fired boiler. The proposed boiler will have an estimated stack gas flow rate of approximately 331,100 actual cubic feet per minute (acfm). Thermal oxidation systems are typically designed for flow rates in the range of 500 to 50,000 cfm (EPA Air Pollution Control Fact Sheet – Thermal Oxidation) with custom designed systems for flow rates up to 200,000 cfm. For the natural gas-fired Boiler D, the gas stream has little or no heating value, and therefore would require a huge supplemental fuel supply to support further combustion. Therefore, thermal oxidation is considered technically and economically infeasible for the new natural gas boiler.

5.4.2 Step 2 – Technical Feasibility

The technically feasible CO controls for the new natural gas-fired boiler are listed in Table 5-5. As shown, there are four types of CO abatement methods with various techniques of each method. Each available technique was listed with its associated efficiency estimate, identified as feasible or infeasible, and ranked based on control efficiency. Oxidation catalyst, OFA systems, and combustion controls are all technically feasible for reducing CO emissions from the combustion process. Recent PSD permits issued for natural gas-fired boilers have required the use of combustion controls and overfire air systems to control CO because these controls are generally available, technically feasible, well proven, and provide the maximum degree of emission reduction. A CO catalyst has only been required as BACT at one facility, on two refinery boilers.

5.4.3 Step 3 – Rank Control Technologies by Control Effectiveness

The technically feasible CO control methods are ranked in Table 5-5 based on effectiveness. CO oxidation catalyst is the most effective method for controlling CO emissions and will achieve the maximum degree of CO emission reduction. As shown in Table 5-5, the CO oxidation catalyst system has a CO removal efficiency of 70 to 90 percent, based on vendor quotes (see Appendix C). The next most effective methods for CO control are enhanced OFA systems, with a control efficiency of 70 percent. GCPs rank next in effectiveness.

Previous BACT emission limits established for natural gas-fired units have required combustion control as the method used to control CO emissions. Oxidation catalysts have also been determined to be BACT for CO for two boilers at one facility (an oil refinery). Other technologies such as thermal oxidation are not demonstrated or feasible for boilers.

5.4.4 Step 4 – Evaluation of Economic, Environmental, and Energy Impacts of Feasible Technologies

5.4.4.1 Economic

The cost analysis for the CO oxidation catalyst system is presented in Table 5-6. As shown, the estimated capital cost of CO oxidation catalyst is approximately $1.4 to 1.9 million. The total annual costs are estimated at between $300,000 and $400,000 per year. The total cost effectiveness of oxidation catalyst is over $2,000 per ton of CO reduced.

5.4.4.2 Environmental

No additional significant environmental impacts from CO oxidation catalyst technology are anticipated. The replacement of the CO catalyst every three years will result in solid waste disposal.

5.4.4.3 Energy

Energy penalties occur with CO oxidation catalyst. The additional energy required to operate the CO catalyst system comes in the form pressure drop across the catalyst, which requires more fan energy. The pressure drop for the proposed natural gas-fired boiler system is 0.7 inches water. The total increase in energy requirements is approximately 7 kW.

5.4.5 Step 5 – Selection of BACT and Rationale

The identification, technical evaluation, and ranking of the available control technologies indicate that combustion controls and CO oxidation catalyst provide the maximum degree of CO emission reduction. The evaluation of the energy, environmental, and economic impacts demonstrate that oxidation catalyst is extremely costly. At approximately $1.4 to 1.9 million capital cost and $300,000 to $400,000 annual cost, the cost of the oxidation catalyst system is high. The cost effectiveness is over $2,000 per ton of CO reduced. This cost is unreasonable. In addition, a CO catalyst is not necessary on Boiler D for organic HAPs control, as Boiler D will be a minor source of HAPs without a CO catalyst. For these reasons, oxidation catalyst is rejected as BACT for CO emissions for the new natural gas boiler.

The next most effective CO control technology, advanced OFA system and good combustion practices and controls, is selected as BACT for the proposed boiler. Good combustion design and practices are feasible and reasonable based on the economic, environmental, and energy impacts. A CO emission rate of 0.08 lb/MMBtu, 30-day rolling average, is proposed as BACT for the new natural gas boiler. This limit is within the range of recent CO BACT limits, which range from 0.024 to 1.00 lb/MMBtu. Three of the four most recent determinations were at 0.12, 0.122 and 0.15 lb/MMBtu. The proposed BACT for the NHPC Boiler D is significantly lower than these most recent determinations.

5.5 Particulate Matter – PM, PM_{10}, and $PM_{2.5}$

As part of the BACT analysis, a review was performed of previous BACT determinations for PM/PM_{10}/$PM_{2.5}$ emissions from natural gas-fired industrial and electric utility boilers listed in the RACT/BACT/LAER Clearinghouse on EPA's web page. From this information, BACT determinations issued within the last 10 years (i.e., since 2002) were identified. A summary of these BACT determinations is presented in Table 5-7.

From the review of previous BACT determinations, it is evident that the overwhelming majority of PM/PM_{10}/$PM_{2.5}$ BACT determinations for new natural gas-fired industrial and electric utility boilers have been based on use of clean natural gas fuel and GCPs. BACT determinations have been in the range of 0.0050 to 0.10 lb/MMBtu emissions.

5.5.1 Step 1 – Identification of Control Technologies

This section identifies potentially applicable PM/PM_{10}/$PM_{2.5}$ control technologies, based upon the review conducted above, and review of the published literature regarding PM control devices. Since the same technologies are used to control PM, PM_{10}, and $PM_{2.5}$ emissions, they will be referred to collectively as "PM" in the remainder of Section 5.5.

5.5.1.1 Fuel Techniques

Fuel substitution, or fuel switching, is a common means of reducing emissions from combustion sources, such as electric utilities and industrial boilers. It involves replacing the current fuel with a fuel that emits less of a given pollutant when burned. Since the proposed fuels are natural gas and No. 2 fuel oil, and natural gas is the primary fuel and the fuel that emits the lowest amount of PM on a heat input basis, then this technique will be used in the new natural gas boiler.

5.5.1.2 Pretreatment Devices

The performance of PM control devices can often be improved through pretreatment of the gas stream. For PM control devices, pretreatment consists of the following techniques:

- Settling Chambers
- Elutriators
- Momentum Separators
- Mechanically-Aided Separators
- Cyclones

Of these five techniques, cyclones offer the most control efficiency, typically in the range of 60 to 90 percent. All of the other techniques have control efficiencies less than 30 percent.

Cyclones use inertia to remove particles from a spinning gas stream. Gas enters the cyclone tangentially, causing a cyclonic, spinning motion. The larger particles move outwards toward the cyclone walls due to centrifugal force. For particles that are large, typically greater than 10 microns, inertial momentum overcomes the fluid drag forces so that the particles reach the cyclone walls and fall down into a discharge hopper. After leaving the cyclonic flow area, the gas spirals upwards through the cyclone discharge. For smaller particles, the fluid drag forces are greater than the momentum forces and the particles follow the gas out of the cyclone. Gas leaves the cyclone through a port at the top of the vessel, and is ducted to the induced draft (ID) fan inlet or to a secondary PM control device, such as an ESP, baghouse, or wet scrubber.

Pretreatment devices are potentially applicable to the new natural gas boiler.

5.5.1.3 Electrostatic Precipitators (ESPs)

Collection of PM by ESPs involves the ionization of the gas stream passing through the ESP, the charging, migration, and collection of particles on oppositely charged surfaces, and the removal of particles from the collection surfaces. There are two basic types of ESPs: dry and wet. In dry ESPs, the particulate is removed by rappers, which vibrate the collection surface, dislodging the material and allowing it to fall into the collection hoppers. Wet ESPs use water to rinse the particulates off of the collection surfaces.

ESPs have several advantages when compared with other control devices. They are very efficient collectors, even for small particles, with greater than 99 percent control efficiency. ESPs can also treat large volumes of gas with a low pressure drop. ESPs can operate over a wide range of temperatures and generally have low operating cost. The disadvantages of ESPs are large capital cost, large space requirements, and difficulty in controlling particles with high resistivity.

ESPs are potentially applicable to the new natural gas boiler.

5.5.1.4 Fabric Filters

Baghouses, or fabric filters, utilize porous fabric to remove PM from a gas stream. In a fabric filter, PM is removed from the flue gas as it passes through a fabric filter media, such as woven cloths or felts; hence the term "fabric filter." During fabric filtration, dusty gas is sent through the fabric by forced-draft fans. The fabric is responsible for some filtration, but more significantly it acts as support for the dust layer that accumulates on the fabric. The layer of dust, also known as the "filter cake", is a highly efficient filter, even for submicron particles. Woven fabrics rely on the filtration of the dust cake much more than felted fabrics.

The filters are normally arranged as a number of cylinders or tubes (commonly referred to as "bags") through which the flue gas is directed. The filters are contained in a housing which has gas inlets and outlets. The flue gas enters the cylindrical filter from the bottom and flows upward, from either the inside of the cylinder to the outside or the opposite depending upon the design. Particulate collection occurs through several mechanisms, including filtration, gravitational settling, direct impaction, inertial impaction, diffusion, and electrostatic attraction.

When the pressure drop reaches a predefined level, indicating the filter cake is becoming too thick, a section of the filters is taken offline for cleaning. Various methods are used to clean the bags in the fabric filter. The three general types of cleaning are shaker cleaning, reverse-air cleaning, and pulse-jet cleaning. All three types of cleaning methods ensure the fabric filter achieves the same low emission rates. PM/PM_{10} control efficiencies for fabric filters are typically greater than 99 percent.

The shaker cleaning is accomplished by taking the bags off-line, shaking the bags of the fabric filter, and then deflating the bag by inducing a vacuum. The PM collected on the bags is dislodged and then falls into the collection hoppers at the bottom of the fabric filter.

In reverse air fabric filters, the PM is collected on the inside of the filter bags. Cleaning is accomplished by introducing a reverse flow of air through the bags. This causes the bag to collapse, thereby dislodging the filter cake. The dislodged PM falls into the collection hoppers for disposal.

In the pulse-jet method of cleaning, cleaning is accomplished off-line by directing a short burst of compressed air inside the filter bags. This burst produces a shock wave, which travels down the length of the bag, dislodging the accumulated dust cake. The collected PM then falls into the hoppers located below the bags. This is currently the best practice for cleaning.

Fabric filters offer high efficiencies and are flexible to treat many types of dusts and a wide range of volumetric gas flow rates. In addition, fabric filters can be operated with low pressure drop.

Potential disadvantages of fabric filters are:

- High moisture gas streams and sticky particles can plug the fabric and blind the filter, requiring bag replacement
- High temperatures can damage fabric bags
- Fabric filters have a potential for fire or explosion

5.5.1.5 Wet Scrubbers

Wet scrubbers are systems that involve particle collection by contacting the particles with a liquid, usually water. The aerosol particles are transferred from the gaseous airstream to the surface of the liquid by several different mechanisms. Wet scrubbers create a liquid waste that must be treated prior to disposal. PM/PM_{10} control efficiencies for wet scrubbing systems range from about 50 to 95 percent, depending on the type of scrubbing system used and the characteristic of the gas stream. Typical wet scrubber types are as follows:

- Spray Chamber
- Packed-Bed
- Impingement Plate
- Venturi
- Orifice
- Condensation

The advantages of wet scrubbers compared to other PM collection devices are that they can collect flammable and explosive dusts safely, absorb gaseous pollutants, and collect mists. Scrubbers can also cool hot gas streams. The disadvantages are the potential for corrosion and freezing, the potential of water and solid waste pollution problems, and high energy costs. All types of wet scrubbers are potentially applicable to the new natural gas-fired boiler.

5.5.1.6 Summary

The potentially applicable control technologies for the new natural gas boiler are listed in Table 5-8.

5.5.2 Step 2 – Technical Feasibility

In this section, the technical feasibility of each potentially applicable control technology is assessed. Those technologies that are found to be technically infeasible will not be considered further in the BACT analysis.

5.5.2.1 Fuel Techniques

The proposed boiler will already burn the cleanest fuel available, i.e., natural gas. The primary fuel will be natural gas, with No. 2 fuel oil as a backup fuel (no more than 15-percent of the heat input to the boiler on an annual basis).

5.5.2.2 Good Combustion Practices

GCPs are considered technically feasible for the proposed natural gas-fired boiler. GCPs include proper mixing of air and fuel to ensure complete combustion, which minimizes the amount of unburned carbon (and PM) in the flue gas stream.

5.5.2.3 Pretreatment Devices

Pretreatment devices such as cyclones are considered technically infeasible for application to the new natural gas-fired boiler. PM emissions from natural gas combustion are assumed to all be under 1 micron in size, which would not be effectively removed in settling chambers, separators, or cyclones. In addition, no pretreatment devices are known to have been installed on a natural gas-fired boiler, since PM emissions are already adequately controlled by burning clean natural gas. Therefore, pretreatment devices were not considered further.

5.5.2.4 Electrostatic Precipitators

ESPs are not technically feasible for application to the new natural gas boiler. PM emissions from natural gas combustion are assumed to all be under 1 micron in size, which would not effectively removed in ESPs. In addition, no ESP devices are known to have been installed on a natural gas-fired boiler, since PM emissions are already adequately controlled by burning clean natural gas. Therefore, ESPs were not considered further.

5.5.2.5 Fabric Filters

Fabric filters are considered technically infeasible for application to the new natural gas-fired boiler. PM emissions from natural gas combustion are assumed to all be under 1 micron in size, which would not effectively removed in fabric filters. In addition, no fabric filter devices are known to have been installed on a natural gas-fired boiler, since PM emissions are already adequately controlled by burning clean natural gas. Therefore, fabric filters were not considered further.

5.5.2.6 Wet Scrubbers

Wet scrubbers are not technically feasible for the new natural gas boiler. PM emissions from natural gas combustion are assumed to all be under 1 micron in size, which would not effectively removed in wet scrubbers. In addition, no wet scrubber devices are known to have been installed on a natural gas-fired boiler, since PM emissions are already adequately controlled by burning clean natural gas. Therefore, wet scrubbers were not considered further.

5.5.2.7 Summary

The technically feasible PM/PM_{10}/$PM_{2.5}$ controls for the new natural gas boiler are listed in Table 5-8. As shown, there are several types of PM abatement methods with various techniques of each method. Each available technique is listed, and identified as feasible or infeasible. As presented in Table 5-8, pretreatment devices, ESPs, fabric filters, and wet scrubbers are not considered technically feasible as a control alternative for the proposed boiler. Feasible control techniques include burning a clean fuel and GCPs.

5.5.3 *Step 3 – Rank Control Technologies by Control Effectiveness*

Each available PM control technique is listed with its associated efficiency estimate in Table 5-8. Based on the estimated size of PM generated from natural gas combustion, it is impossible to estimate and rank the control efficiencies of the add-on control technologies. The use of natural gas as the primary fuel is considered to be the most efficient control for PM emissions.

5.5.4 *Step 4 – Evaluation of Economic, Environmental, and Energy Impacts of Feasible Technologies*

5.5.4.1 Economic

GCPs will already be employed on the proposed boiler. Therefore, there is no economic impact from use of GCPs.

5.5.4.2 Environmental

GCPs will already be employed on the proposed boiler. Therefore, there is no environmental impact from use of GCPs.

5.5.4.3 Energy

The electrical energy required to run any add-on control technology would reduce the amount of electricity available to NHPC's customers. GCPs will already be employed on the proposed boiler. Therefore, there is no energy impact from use of GCPs.

5.5.5 *Step 5 – Selection of BACT and Rationale*

The identification, technical evaluation, and ranking of the available control technologies demonstrates that the proposed control technology for the proposed boiler of primarily firing natural gas and GCPs provides the maximum degree of emission reduction for PM emissions from the proposed boiler. The evaluation of the energy and environmental impacts demonstrate that these controls do not have significant environmental or energy impacts. Based on these technologies, no PM emission limit is proposed for the new Boiler D.

5.6 Greenhouse Gases – GHG

The GHG BACT analysis has been submitted separately to the EPA. The efficiency of the generation technology in producing electricity and fuel utilized are the most important aspects in GHG emissions from electric generation facilities. Together, efficiency and fuel type dictate the amount of GHG emissions per unit of generation. The new natural gas boiler will be operated very efficiently using clean fuels such as natural gas and low-sulfur fuel oil. Therefore, no additional improvements in energy efficiency are necessary.

Natural gas will be used as the primary fuel in the proposed boiler, with No. 2 fuel use as a backup and/or supplemental fuel. This is consistent with the definition of BACT, which states that a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT.

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 Significant Impact Analysis

6.1.1 General

Air quality impacts due to the proposed project will be associated with emissions from the proposed Boiler D stack. Emissions from Boilers A, B, and C are not changing due to the addition of Boiler D and the proposed Boiler D structure will be considerably lower than the existing structures. Therefore, only the proposed Boiler D stack was included in the significant impact analysis.

The general modeling approach for the significant impact analysis for NHPC followed the EPA and FDEP modeling guidelines for determining compliance with AAQS and PSD increments. For all criteria pollutants that will be emitted in excess of the PSD significant emission rate due to a proposed project, a significant impact analysis is performed to determine whether the emission and/or stack configuration changes due to the project alone will result in predicted impacts that are in excess of the EPA SILs. For the proposed project, emission increases above the PSD significant emission rates occur for the following criteria pollutants:

- NO_x
- PM_{10}
- $PM_{2.5}$
- CO

As AAQS and PSD increments exist for NO_2, PM_{10}, $PM_{2.5}$, and CO, a significant impact analysis is required for these pollutants.

6.1.2 Site Vicinity

If the maximum project-only impacts are above the SILs in the vicinity of the project site, then two additional, more detailed air modeling analyses are required. The first analysis demonstrates compliance with federal and Florida AAQS, and the second analysis demonstrates compliance with allowable PSD Class II increments. Current FDEP policies stipulate that, for NO_2 and PM_{10}, the highest predicted annual average concentrations are to be compared to the applicable SILs. However, for $PM_{2.5}$, the maximum predicted 5-year average annual concentration, on a receptor-by-receptor basis, is compared to the SIL. For short-term averaging times, the highest predicted 1- and 8-hour CO and highest predicted 24-hour PM_{10} concentrations are compared to the respective SIL, while the highest predicted 5-year average concentrations, on a receptor-by-receptor basis, are compared to the SIL for 24-hour $PM_{2.5}$ and 1-hour NO_2 concentrations (see Table 3-1).

6.1.3 Far Field

Generally, if a major new facility or major modification is located within 200 km of a PSD Class I area, then a significant impact analysis is also performed to evaluate the impacts of the project alone at the PSD Class I area. The ENP, located about 91 km from the project site, is the only PSD Class I area that is located within 200 km of the NHPC site. The maximum predicted impacts are compared to EPA's SILs for the PSD Class I area (Table 3-1). These recommended levels are the currently accepted criteria to determine whether a proposed project will result in a significant impact on a PSD Class I area. If the maximum project-only impacts at the ENP are above the proposed EPA PSD Class I SILs, then a cumulative source analysis is performed to demonstrate compliance with allowable PSD Class I increments.

Additionally, for each pollutant emitted in excess of the EPA significant emission rate, analyses are required to determine the project's maximum impacts on AQRVs at PSD Class I areas. For the ENP PSD Class I area, the AQRVs of interest are visibility impairment and sulfur and nitrogen deposition. For PSD Class I areas that are located within 50 km of a proposed project site, visibility impairment is in the form of plume blight. For PSD Class I areas that are located beyond 50 km from a proposed project site, visibility impairment is in the form of regional haze. Visibility impairment is determined for a 24-hour averaging time. Total nitrogen and total sulfur deposition are predicted for an annual averaging time.

An initial screening criterion that could exempt a source from AQRV impact review based on its maximum annual emissions and distance from a Class I area has been provided by the Federal Land Managers' (FLMs') AQRV Workgroup (FLAG): Phase I Report-Revised 2010 document. According to the FLAG report, a project that is located more than 50 km from a Class I area will likely not be required to conduct AQRV impacts if the total emissions increase of SO_2, NO_x, PM_{10}, and SAM annual emissions (Q, in TPY, based on 24-hour maximum allowable emissions), divided by the distance from the Class I area (D, in km), Q/D, is 10 or less.

Based on the maximum 24-hour emissions presented in Table 2-2 for SO_2, NO_x, PM_{10}, and SAM, the Q for proposed Boiler D is 408.17 TPY, resulting in a Q/D of 4.49 at the ENP. As this ratio is well below the screening criterion of 10, the proposed project is considered to not likely pose a significant impact on AQRVs at the ENP, pursuant to FLMs' guidance from the 2010 FLAG Report.

6.2 Cumulative Source Impact Analyses Approach

6.2.1 AAQS and PSD Class II Analyses

If the project-only impacts are greater than the SILs, the air modeling analyses must consider other nearby sources and background concentrations, and determine the cumulative impact of these sources for comparison to AAQS and PSD increments.

As described in Section 6.9, NHPC's project-only maximum impact for 1-hour NO_2 is predicted to be greater than the SILs. Therefore, an additional air modeling analysis must be performed for this pollutant and averaging time that considers other nearby sources and a background concentration, and that determines the cumulative impact of these sources for comparison to ambient air standards.

The 1-hour NO_2 AAQS is a probabilistic standard and compliance is based on the highest predicted 98th percentile (i.e., 8th highest) daily maximum 1-hour average concentrations, on a receptor-by-receptor basis, averaged over 5 years of meteorological data.

The AAQS analysis is a cumulative source analysis that evaluates whether the air quality impact concentrations from all sources will comply with the AAQS. The analysis considers the modeled impacts from existing and future sources at the NHPC Site and, as applicable, emissions from other nearby facility sources, and a non-modeled background concentration that is intended to account for all sources not included in the modeling analysis.

The PSD Class II analysis is a cumulative source analysis that evaluates whether the air quality impact concentrations for increment-affecting sources will comply with the allowable PSD Class II increments. These concentrations include the modeled impacts from PSD increment-affecting sources at NHPC, plus nearby PSD increment-affecting sources at other facilities. Because a 1-hour PSD Class II increment does not exist for NO_2, an increment analysis is not required for the proposed project.

6.2.2 PSD Class I Analysis

The project's maximum annual average NO_2, PM_{10}, and $PM_{2.5}$ impacts from the AERMOD screening procedure were predicted to be less than the Class I SILs. Therefore, cumulative source impact analyses to demonstrate compliance with the allowable PSD Class I increments are not required.

6.3 Model Selection

The selection of one or more air quality models to estimate maximum air quality impacts must be based on the model's ability to simulate impacts in all key areas surrounding a project site. For predicting concentrations at receptors that are located within 50 km of a project site, FDEP recommends using the American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model. The AERMOD model was selected and used for predicting concentrations in the vicinity of the NHPC site. For predicting concentrations at receptors that are located more than 50 km from a project site, the California Puff model (CALPUFF) is recommended for use by FDEP and the FLM.

The AERMOD model calculates hourly concentrations based on hourly meteorological data and is applicable for most applications, since it is recognized as containing the latest scientific algorithms for simulating plume behavior in all types of terrain. AERMOD Version 12345 is the most recent available version on EPA's Internet web site: Support Center for Regulatory Air Models (SCRAM) within the Technology Transfer Network (TTN). The following EPA-recommended regulatory default options in AERMOD are applicable to this project:

- Use of elevated terrain algorithms
- Stack-tip downwash
- Missing data processing routines
- Calm wind processing routines

EPA regulatory default options were used to address maximum impacts. Given the rural nature of the area surrounding the NHPC site, which is surrounded by sugarcane fields in all directions, the urban mode option was not used.

6.4 Meteorological Data

Meteorological data used with the AERMOD model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations from the National Weather Service (NWS) office located at the Palm Beach International (PBI) Airport and upper air sounding data collected at the Florida International University (FIU) in Miami. The period of record is 2006 through 2010. The NWS office at PBI is located approximately 66 km (41 miles) east-northeast of the NHPC site and is the closest primary weather station to the study area considered to have meteorological data representative of the Project site. As the PBI meteorological station is only 66 km from the project site and the terrain between the two sites is mostly flat, the wind direction and wind speed frequencies that are experienced at PBI are considered to be very similar to that experienced at the NHPC Site. As such, the PBI wind direction and wind speed frequencies are considered to be representative of the NHPC Site.

AERMOD incorporates land use parameters for determining boundary layer parameters that are used for dispersion. AERSURFACE reads land use files developed by the U.S. Geological Survey (USGS) and provides average land use values for albedo, Bowen ratio, and surface roughness within a specified radius. Current air modeling guidance suggests that the land use parameters should be representative of the data measurement site (i.e., PBI). In January 2008, EPA released new recommendations for determining the surface land use characteristics in its AERMOD Implementation Guide. The Guide recommends the following procedures:

- Surface roughness length should be based on an inverse-distance weighted geometric mean for the default upwind distance of 1 km relative to the measurement site.
- The Bowen ratio should be based on a simple, unweighted geometric mean over a default 10-km by 10-km domain. There should be no direction or distance dependency for the data.
- The albedo should be based on a simple unweighted arithmetic mean for the same domain used for the Bowen ratio.

AERSURFACE Version 13016 (EPA, January 16, 2013) was used to calculate these surface characteristics. Land cover data were obtained from the USGS National Land Cover Data 1992 archives (NLCD92) in the form of a GeoTIFF file covering the entire state of Florida. The USGS data were downloaded from the following website: http://edcftp.cr.usgs.gov/pub/data/landcover/states/.

Besides the PBI data, the Fort Myers Southwest Florida Regional (RSW) Airport data were also considered for use in this project based on recent modeling in the area. Land use data values that exist within a 1-km radius of PBI, RSW, and the NHPC site were extracted from 7.5-degree land use files from the USGS using the AERSURFACE program. For an average wind direction sector, the average land use values within 1 km of each site area are as follows:

Average land use around RSW:

- Albedo – 0.15
- Bowen ratio – 0.38
- Surface roughness – 0.074 meter (m)

Average land use around PBI:

- Albedo – 0.17
- Bowen ratio – 0.83
- Surface roughness – 0.073 m

Average land use around the NHPC site:

- Albedo – 0.18
- Bowen ratio – 0.54
- Surface roughness – 0.140 m

The AERSURFACE analysis results indicate that the average albedo for PBI was closer to the albedo at the NHPC Site. In addition, the surface roughness values for both PBI and RSW are very similar to the source roughness at the NHPC Site. However, since PBI is closer to the NHPC Site, the PBI data are considered to be the best choice for this area for modeling purposes.

6.5 Emission Inventory

6.5.1 Significant Impact Analysis

A load analysis was initially conducted to determine the maximum air quality impacts due to the proposed Boiler D only for the following range of operating conditions:

- 100-percent load
- 91-percent load
- 75-percent load
- 50-percent load

For the load analysis, a generic emission rate of 10 grams per second (g/s) was used to represent the emissions of the proposed Boiler D for each load. Maximum pollutant-specific air impacts for Boiler D were then determined by multiplying the maximum pollutant-specific emission rate, in lb/hr, by the maximum predicted generic impact divided by 79.365 lb/hr (10 g/s). The pollutant-specific annual concentrations derived from the load analysis are based on the annual emission rate for Boiler D, while the pollutant-specific short-term concentrations are based on the higher emission rate of either natural gas or fuel oil operation. A summary of the maximum criteria pollutant emission rates for Boiler D was presented in Table 2-2. Based on these emissions, a significant impact analysis was performed for NO_x, PM_{10}, $PM_{2.5}$, and CO.

As shown in Section 6.9, all maximum pollutant concentrations were predicted to be less than the SIL except for the 1-hour NO_2 concentrations. As the maximum 1-hour NO_2 concentration occurred during 75 percent load operation, this boiler load was used for the proposed Boiler D in the AAQS analysis.

Physical stack and stack operating parameters for the proposed project that were used in the air modeling analysis are presented in Table 2-5. The proposed Boiler D will have a stack height of 150 ft and an inner stack diameter of 8.2 ft.

6.5.2 NO_2 Modeling Approach

Based on the EPA guidance documents, EPA recommends a multi-tiered screening approach for estimating annual and 1-hour NO_2 concentrations, where:

- Tier 1 assumes full conversion of NO_x to NO_2
- Tier 2 assumes a 75-percent ambient equilibrium ratio of NO_2 to NO_x for the annual averaging time and an 80-percent ambient equilibrium ratio for the 1-hour averaging time.
- Tier 3 allows detailed screening techniques on a case-by-case basis.

For the proposed project, the predicted NO_2 impacts were based on the Tier 2 approach.

6.5.3 1-Hour NO_2 AAQS Analyses

For addressing the 1-hour NO_2 AAQS, EPA has provided guidance (Fox, March 1, 2011) that suggests that the emphasis on determining which nearby sources to include in the modeling analysis should focus on the area within about 10 km of a project location in most cases. As stated by EPA, the routine inclusion of all sources within 50 km of a project location, the nominal distance for which AERMOD is applicable, is likely to produce an overly conservative result in most cases for 1-hour NO_2 AAQS compliance demonstrations.

Data on current NO_2 background sources were obtained from FDEP and all facilities located within 30 km of the proposed project are summarized in Table 6-1. The proposed project's maximum significant impact distance is 5.0 km, based on the worst case 75-percent operating load. Within this distance, termed as the modeling area, the only emission sources are NHPC's existing cogeneration Boilers A, B, and C, which are located approximately 60 meters southwest of proposed Boiler D. Boilers A, B, and C are rated at 760 MMBtu/hr while the permitted NO_x emission limit for each boiler is 0.15 lb/MMBtu, based on a 30-day rolling average. A worst-case 1-hour emission rate for the existing boilers, based on review of CEMS data from the boilers, is 0.25 lb/MMBtu (i.e., 190 lb/hr), and was assumed for this analysis.

Beyond the modeling area, the next closest facilities to the proposed project are South Florida Water Management District (SFWMD) Pump Station G-372 and Sugar Cane Growers Co-Op, both located about 17 km away. The emissions for this pump station were not provided but, but based on the other SFWMD pump stations shown in Table 6-1, the NO_x emissions are expected to be between 10 TPY and 26 TPY.

Because the existing Boilers A, B, and C are dominant sources adjacent to proposed Boiler D, the highest predicted 1-hour impacts are expected to be due to the combined impacts of the four NHPC boilers and to occur near the proposed project site. The impacts due to this interaction will mask any secondary maximums that are due to the proposed project's interaction with any other facility that is beyond 10 km from NHPC. For this reason, the existing boilers are the only background sources considered in the modeling analysis. The emissions and stack parameters for NHPC's existing boilers and proposed Boiler D are summarized in Table 6-2.

It is further noted that the non-modeled NO_2 background concentration, 79 $\mu g/m^3$, obtained from the Lantana monitoring station, is considered to conservatively represent the air quality in the vicinity of the NHPC site and more than adequately represents the potential impacts due to emission sources that are not directly included in the modeling analysis.

6.5.4 PSD Class I Analyses

A screening analysis consisting of receptors located at a distance of 50 km and in the direction of the ENP was performed with AERMOD. The maximum impacts due to the project only were predicted to be less than the PSD Class I SILs for all applicable pollutants and averaging periods. Because the Q/D of the proposed Boiler D is less than 5, AQRV analyses for visibility impairment and acid deposition were not performed.

6.6 Building Downwash Effects

Aerodynamic forces in the vicinity of structures and obstacles, such as buildings, disturb atmospheric flow fields. This flow disturbance near buildings and other structures can enhance the dispersion of emissions from stacks affected by the disturbed flow. The disturbance can also reduce the effective height of emissions from stacks located near buildings and obstacles. The height of these disturbances can be compared to the release points of modeled sources. For sources with release points above these disturbances, the effect on dispersion is not significant.

The AERMOD model specifically incorporates the effects of atmospheric downwash by utilizing downwash algorithms based on stack and building locations and heights which are input to the model. Significant existing and proposed building structures at NHPC were identified by the site plot plan (see Figure 2-2). Building dimensions for the structures were entered into the EPA's Building Profile Input Program (BPIPPRM, Version 04274) for the purpose of developing wind direction-specific building dimensions for input to AERMOD. The dimensions of the existing and proposed structures are as follows:

Structure	Height (ft)	Width (ft)	Length (ft)
Existing			
ESP Buildings A, B, and C	107	45	71
Boilers A, B, and C Building	139	109	204
Proposed			
Boiler D Building	100[a]	59	60

[a] Assumed for analysis. Actual height will be lower.

6.7 Receptor Locations

6.7.1 Site Vicinity

Receptor locations used in the modeling analysis were based on Universal Transverse Mercator (UTM) coordinates from Zone 17, North American Datum 198327 (NAD83). The air modeling origin was assumed to be located at the approximate center of the NHPC site, UTM east and north coordinates of 525,200 and 2,939,500 m, respectively.

For the Class II significant impact analysis, a Cartesian receptor grid was used extending from the NHPC/Okeelanta plant property boundary out to 7 km (see Figure 6-1). Receptors were located at the following intervals and distances:

- Every 50 m along the NHPC/Okeelanta property boundary
- Every 100 m from the plant property boundary to 2,000 m from the origin
- Every 250 m from 2,000 to 5,000 m from the origin
- Every 500 m from 5,000 to 7,000 m from the origin

The heights above mean sea level (msl) for all receptors were extracted from 1-second National Elevation Dataset (NED) data obtained from the USGS seamless server. The NED data were extracted for all sources and receptors using AERMOD's terrain preprocessing program AERMAP, Version 11103.

Based on the results of the significant impact analyses, the receptor grid used in determining compliance with the 1-hour NO_2 AAQS extended out to 5.0 km.

6.7.2 PSD Class I Areas

An array of receptors located 50 km from the NHPC site was developed for input to AERMOD. The receptors were spaced at 1-degree intervals in the direction of the ENP PSD Class I area (i.e., 166° to 223° from the NHPC site). The maximum elevation throughout the ENP (i.e., 1 m) was used to represent the elevation and hill scale for each receptor.

6.8 Background Concentrations

Background concentrations are used to determine total ambient air quality impacts to demonstrate compliance with the AAQS. "Background concentrations" are defined as concentrations due to sources other than those specifically included in the modeling analysis. For all pollutants, background includes other point sources not included in the modeling analysis (i.e., distant sources or small sources), fugitive emission sources, and natural background sources. In general, monitoring data collected near the area in which the air quality impact is performed is used for this purpose.

There are no NO_2 monitoring stations in the vicinity of the NHPC site, which is near Belle Glade, and the closest station to the proposed project is located in Lantana on the east coast of Palm Beach County. A summary of the measured 1-hour NO_2 concentrations is presented in Section 4.0. These measurements are considered very conservative for the rural area of the proposed site. The non-modeled NO_2 background concentration of 79 $\mu g/m^3$, obtained from the Lantana monitoring station, is considered to conservatively represent the air quality in the vicinity of the NHPC site.

6.9 Model Results

6.9.1 PSD Class II Significant Impact Analysis

The maximum pollutant concentrations predicted for the proposed Boiler D project are compared to the PSD Class II SILs in Table 6-3. The modeling results demonstrate that maximum concentrations due to the proposed project are predicted to be less than the SILs for all pollutants except for the 1-hour NO_2 impacts. As a result, additional modeling analyses were required to determine compliance with the 1-hour NO_2 AAQS.

6.9.2 PSD Class I Significant Impact Analysis

The maximum pollutant concentrations predicted for the proposed Boiler D project are compared to the PSD Class I SILs in Table 6-4. The modeling results indicate that maximum concentrations due to the proposed project are predicted to be less than the Class I SILs for all pollutants. As a result, detailed analyses to demonstrate compliance with the allowable PSD Class I increments is not required.

6.9.3 1-Hour NO_2 AAQS Analysis

A summary of the results of the NO_2 AAQS analysis is presented in Table 6-5. The maximum predicted 98th-percentile 1-hour concentration averaged over 5 years is 63.7 µg/m^3, which when added to a background concentration of 79 µg/m^3, results in a total concentration of 143 µg/m^3, which is well below the AAQS of 188 µg/m^3.

6.10 Conclusions

Based on the air quality modeling analyses, the maximum pollutant concentrations due to the Boiler D project are predicted to be less than the PSD Class II SILs for all pollutants except for the 1-hour NO_2 impacts. Based on the PSD Class I significant impact analysis, the maximum pollutant concentrations due to the Boiler D project at the ENP are predicted to be less than the PSD Class I SILs for all pollutants. As a result, a more detailed NO_2 modeling analysis was performed to address compliance with the AAQS. The results of the air modeling analyses demonstrate that the proposed Boiler D project will comply with all applicable AAQS and PSD increments, and will not have an adverse effect on human health.

7.0 ADDITIONAL IMPACT ANALYSIS

This section presents the impacts that the proposed project will have on associated growth; impacts to vegetation, soils, and visibility in the vicinity of NHPC Boiler D; and impacts at the PSD Class I area of the ENP related to AQRVs. Specifically, this section addresses FDEP Rules 62-212.400(4)(e), (8)(a) and (b), and (9), F.A.C. These rules are:

> *(4) Source Information. (e) The air quality impacts, and the nature and extent of any or all general commercial, residential, industrial, and other growth which has occurred since August 7, 1977, in the area the source or modification would affect.*
>
> *(8) Additional Impact Analyses.*
>
> *(a) The owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.*
>
> *(b) The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification.*
>
> *(9) Sources Impacting Federal Class I Areas. Sources impacting Federal Class I areas are subject to the additional requirements provided in 40 CFR 52.21(p), adopted by reference in Rule 62-204.800, F.A.C.*

7.1 Impacts Due to Associated Growth

Construction of Boiler D will occur over a 24-month period requiring an average of approximately 25 workers during that time. It is anticipated that many of these construction personnel will commute to the site. Boiler D will employ a total of about 5 operational workers after the project begins operation in 2015. The operational workforce will also include annual contracted maintenance workers to be hired for periodic routine services. The workforce needed to construct and operate the Project represents a tiny fraction of the population already present in the immediate area. Therefore, while there would be a small increase in vehicular traffic in the area, the effect on air quality levels would be minimal.

There are also expected to be no air quality impacts due to associated commercial and industrial growth given the location of Boiler D. The existing commercial and industrial infrastructure is adequate to provide any support services that Boiler D might require, and would not increase with the operation of Boiler D. The addition of the project will have little effect on the increase of growth in the area. The area to the west is expected to remain agricultural, the areas to the south and east contain the Loxahatchee National Wildlife Refuge (NWR), and the areas to the far east (near the coast) have already been designated as areas for potential development.

The existing commercial and transportation infrastructure should be adequate to provide any support services that might be required during construction and operation of Boiler D. The workforce needed to operate the proposed Boiler D represents a tiny fraction of the labor force present in the immediate and surrounding areas.

The air quality data measured in the region of Boiler D indicate that the maximum air quality concentrations are well below the AAQS. Based on the trends presented of these maximum concentrations, the air quality has generally improved in the region since the baseline date of August 7, 1977. As demonstrated in Section 6.0, the maximum air quality impacts resulting from Boiler D are predicted to be low and, for most pollutants and averaging times, below the SILs. The cumulative 1-hour average NO_2 impact analyses demonstrate that the NHPC and background sources will comply with the PSD Increments and AAQS. As a result, the air quality concentrations in the region are expected to remain below the AAQS when NHPC Boiler D becomes operational.

7.2 Potential Air Quality Effect Levels on Soils, Vegetation, and Wildlife

7.2.1 Soils

The potential and hypothesized effects of atmospheric deposition on soils include:

- Increased soil acidification
- Alteration in cation exchange
- Loss of base cations
- Mobilization of trace metals

The potential sensitivity of specific soils to atmospheric inputs is related to two factors. First, the physical ability of a soil to conduct water vertically through the soil profile is important in influencing the interaction with deposition. Second, the ability of the soil to resist chemical changes, as measured in terms of pH and soil cation exchange capacity (CEC), is important in determining how a soil responds to atmospheric inputs.

7.2.2 Vegetation

The concentrations of the pollutants, duration of exposure, and frequency of exposure influence the response of vegetation to atmospheric pollutants. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively high ground-level concentration, which occur during certain meteorological conditions, interspersed with long periods of extremely low ground-level concentrations. If there are any effects of stack emissions on plants, they will be from the short-term, higher doses. A dose is the product of the concentration of the pollutant and duration of the exposure.

In general, the effects of air pollutants on vegetation occur primarily from SO_2, NO_2, O_3, and PM. Effects from minor air contaminants, such as fluoride, chlorine, hydrogen chloride, ethylene, NH_3, hydrogen sulfide, CO, and pesticides, have also been reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury," as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage, which is considered to be the major pathway of exposure.

Injury to vegetation from exposure to various levels of air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high-contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which result in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant. In this assessment, 100 percent of the particular air pollutant in the ambient air was assumed to interact with the vegetation, which is a very conservative approach.

7.2.3 Wildlife

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1981; Newman and Schreiber, 1988). The most severe of these effects have been observed at concentrations above the secondary AAQS. Physiological and behavioral effects have been observed in experimental animals at or below these standards.

7.3 Impacts on Soils, Vegetation, Wildlife and Visibility in the Project's Vicinity

7.3.1 Impacts on Vegetation and Soils

The primary vegetation, as well as agricultural crop, in the vicinity of the NHPC is sugar cane. The site is surrounded by sugar cane fields for a large distance in all directions. Other agricultural areas are common in the local area, including rice fields, vegetable farming, nurseries, and sod farms. The west edge of the Arthur R. Marshall Loxahatchee NWR is located to the east of the NHPC; vegetative communities in this area include freshwater tree islands, marsh, shrubs, and cattails. Exotic species have extensively colonized the northern, southeastern, and western portions of the Loxahatchee NWR, most notably melaleuca (*Melaleuca quinquenervia*), Brazilian pepper (*Schinus terebinthifolius*), Old World climbing fern (*Lygodium microphyllum*), water lettuce (*Pistia stratioides*), and water hyacinth (*Eichhornia crassipes*).

Soils in the area are primarily histosols, which are peat soils with high amounts of organic matter. The agricultural lands surrounding the Site are part of the Everglades Agricultural Area, which is noted for its "muck", i.e., rich, black soil that is very fertile.

According to the modeling results presented in Section 6.0, the maximum air quality impacts due to the project are predicted to be below the PSD SILs for all pollutants except for NO_2. For NO_2, the maximum predicted impacts are below the AAQS. The AAQS were established to protect both public health and welfare. Public welfare is protected by the secondary AAQS, which Florida has adopted. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation, and buildings (EPA, 2007).

Since the Project's impacts on the local air quality are predicted to be less than the AAQS, impacts on soils, vegetation, and wildlife in the Project's vicinity are expected to be negligible.

7.3.2 Impacts on Wildlife

The major air quality risk to wildlife in the United States is from continuous exposure to pollutants above the National AAQS. This occurs in non-attainment areas, e.g., Los Angeles Basin. Risks to wildlife also may occur for wildlife living in the vicinity of an emission source that experiences frequent upsets or episodic conditions resulting from malfunctioning equipment, unique meteorological conditions, or startup operations (Newman and Schreiber, 1988). Under these conditions, chronic effects (e.g., particulate contamination) and acute effects (e.g., injury to health) have been observed (Newman, 1981).

Although air pollution impacts to wildlife have been reported in the literature, many of the incidents involved acute exposures to pollutants, usually caused by unusual or highly concentrated releases or unique weather conditions. It is highly unlikely that emissions from NHPC Boiler D will cause adverse effects to wildlife due to the project's low impacts, well below the AAQS. Coupled with the mobility of wildlife, the potential for exposure of wildlife to the project's impacts is extremely unlikely.

7.4 Impacts to AQRVs in the ENP PSD Class I Area

Because the proposed project's Q/D ratio is 4.49 (see Section 6.1.3), the project's emissions are not expected to significantly impact AQRVs of the ENP. As a result, additional analyses to assess visibility impairment and acid deposition at the ENP were not performed. The ENP is the closest Class I area to the Site, located approximately 91 km southwest of the NHPC Site.

TABLES

Table 2-1. Maximum Fuel Usage and Heat Input Rates for New Natural Gas-Fired Boiler New Hope Power Company

Fuel	Heat Input	Heat Transfer Efficiency (%)	Heat Output	Fuel Firing Rate
	Maximum 1-Hour [c]			
	(MMBtu/hr)		(MMBtu/hr)	
No. 2 Fuel Oil	589	85	501	4,331 gal/hr
Natural Gas	589	85	501	577,532 scf/hr
	Maximum 24-Hour [c]			
	(MMBtu/hr)		(MMBtu/hr)	
No. 2 Fuel Oil	536	85	455	3,938 gal/hr
Natural Gas	536	85	455	525,029 scf/hr
	Annual Average [c]			
	(MMBtu/yr)		(MMBtu/yr)	
MAXIMUM NATURAL GAS FIRING				
Natural Gas	4,691,238	85	3,987,552	4,599 MMscf/yr
No. 2 Fuel Oil	0	85	0	0 gal/yr
TOTAL	4,691,238		3,987,552	
MAXIMUM OIL FIRING (15%)				
Natural Gas	3,987,552	85	3,389,419	3,909 MMscf/yr
No. 2 Fuel Oil	703,686	85	598,133	5,174,159 gal/yr
TOTAL	4,691,238		3,987,552	

Net Steam Enthalpy = 1460 - 322 = 1,138 Btu/lb

[c] Maximum 1-hour heat input based on 440,000 lb/hr steam.
Maximum 24-hour and annual average based on 400,000 lb/hr steam.

Total heat input required = 589 MMBtu/hr; 1-hr
536 MMBtu/hr; 24-hr
4,691,238 MMBtu/yr

Total heat output required = 3,987,552 MMBtu/yr

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

Based on fuel heating values as follows:

No. 2 Fuel Oil - 136,000 Btu/gal
Natural gas - 1,020 Btu/scf

Table 2-2. Maximum Short-Term Emission Rates for Natural Gas-Fired Boiler
New Hope Power Company

Regulated Pollutant		Natural Gas Emission Factor [a] (lb/MMBtu)	Natural Gas Activity Factor [b] (MMBtu/hr)	Natural Gas Emissions (lb/hr)	No. 2 Fuel Oil (backup) Emission Factor [c] (lb/MMBtu)	No. 2 Fuel Oil (backup) Activity Factor [b] (MMBtu/hr)	No. 2 Fuel Oil (backup) Emissions (lb/hr)	Maximum Emissions for any fuel (lb/hr)
Particulate (PM)	-- 3-hr Average	0.00745	589	4.39	0.0243	589	14.29	14.29
	-- 24-hr Average		536	3.99		536	13.01	13.01
Particulate (PM_{10})	-- 3-hr Average	0.00745	589	4.39	0.0193	589	11.39	11.39
	-- 24-hr Average		536	3.99		536	10.37	10.37
Particulate ($PM_{2.5}$)	-- 3-hr Average	0.00745	589	4.39	0.0114	589	6.71	6.71
	-- 24-hr Average		536	3.99		536	6.11	6.11
Sulfur Dioxide (SO_2)	-- 3-hr Average	5.88E-04	589	0.35	0.052	589	30.75	30.75
	-- 24-hr Average		536	0.32		536	27.98	27.98
Nitrogen Oxides (NO_x)	-- 3-hr Average	0.10 [d]	589	58.90	0.010 [d]	589	5.89	58.90
	-- 24-hr Average	0.10 [d]	536	53.60	0.010 [d]	536	5.36	53.60
	-- 30-day Rolling Average	0.06 [d]	536	32.16	0.06 [d]	536	32.16	32.16
Carbon Monoxide (CO)	-- 3-hr Average	0.16 [d]	589	94.24	0.16 [d]	589	94.24	94.24
	-- 24-hr Average	0.16 [d]	536	85.76	0.16 [d]	536	85.76	85.76
	-- 30-day Rolling Average	0.08 [d]	536	42.88	0.08 [d]	536	42.88	42.88
Volatile Organic Compounds (VOC)	-- 3-hr Average	0.0054	589	3.18	0.00147	589	0.87	3.18
	-- 24-hr Average		536	2.89		536	0.79	2.89
Lead (Pb)	-- 3-hr Average	4.90E-07	589	2.89E-04	9.0E-06	589	5.30E-03	5.30E-03
	-- 24-hr Average		536	2.63E-04		536	4.82E-03	4.82E-03
Mercury (Hg)	-- 3-hr Average	2.55E-07	589	1.50E-04	3.0E-06	589	1.77E-03	1.77E-03
	-- 24-hr Average		536	1.37E-04		536	1.61E-03	1.61E-03
Fluorides (F)	-- 3-hr Average	--	589	--	2.74E-05	589	1.62E-02	1.62E-02
	-- 24-hr Average	--	536	--		536	1.47E-02	1.47E-02
Sulfuric Acid Mist (SAM)	-- 3-hr Average	2.62E-05 [e]	589	1.54E-02	2.32E-03 [e]	589	1.37E+00	1.37E+00
	-- 24-hr Average		536	1.40E-02		536	1.24E+00	1.24E+00
Greenhouse Gases (GHG)[f]:								
Carbon Dioxide (CO_2):		116.89	589	68,848	163.05	589	96,039	96,039
Methane (CH_4):		0.0022	589	1.30	0.0066	589	3.90	3.90
Nitrous Oxide (N_2O):		0.00022	589	0.13	0.00132	589	0.78	0.78
Total GHGs (mass):		116.89	589	68,849	163.062	589	96,043	96,043
Total GHGs-CO_2 equivalent (CO_2e)[g]:		117.0036	589	68,915	163.60	589	96,362	96,362

[a] Based on AP-42 for natural gas combustion, Section 1.4, AP-42, July 1998, unless otherwise noted (natural gas= 1,020 Btu/scf):
- PM(total) = 7.6 lb/MMscf (filterable + condensable)
- PM_{10} = 7.6 lb/MMscf (filterable + condensable)
- $PM_{2.5}$ = 7.6 lb/MMscf (filterable + condensable)
- SO_2 = 0.6 lb/MMscf
- VOC = 5.5 lb/MMscf
- Pb = 0.0005 lb/MMscf
- Hg = 2.6E-04 lb/MMscf

[b] Maximum 3-hour heat input based on 440,000 lb/hr steam; maximum 24-hour heat input based on 400,000 lb/hr steam.

[c] Based on AP-42 for fuel oil combustion, Section 1.3, AP-42, September 1998. No. 2 fuel oil = 136,000 Btu/gal.
- PM(total) = (2+1.3) = 3.3 lb/1000 gal (filterable + condensable)
- PM_{10} = (1.33+1.3)= 2.63 lb/1000 gal (filterable + condensable)
- $PM_{2.5}$ = (0.25+1.3) = 1.55 lb/1000 gal (filterable + condensable)
- SO_2 = 142*S lb/1000 gal, S= 0.05%
- VOC = 0.2 lb/1000 gal
- Pb = 9 lb/10^{12} Btu
- Hg = 3 lb/10^{12} Btu

[d] Proposed BACT limits.

[e] Based on 4% of the SO_2 emissions becomes SO_3 from AP-42 for fuel oil burning; then convert to SAM (98/80).

[f] Based on 40 CFR Part 98, Subpart C:
- Natural gas: CO_2- 53.02 kg/MMBtu; CH_4- 1.0E-03 kg/MMBtu; N_2O- 1.0E-04 kg/MMBtu.
- No. 2 Fuel Oil: CO_2- 73.96 kg/MMBtu; CH_4- 3.0E-03 kg/MMBtu; N_2O- 6.0E-04 kg/MMBtu.

[g] GWP: CO_2 = 1, CH_4 = 21, N_2O = 310.

Table 2-3. Maximum Annual Emission Rates for Natural Gas-Fired Boiler
New Hope Power Company

Regulated Pollutant	Natural Gas Emission Factor [a] (lb/MMBtu)	Natural Gas Activity Factor [b] (MMBtu/yr)	Natural Gas Annual Emissions (TPY)	No. 2 Fuel Oil Emission Factor [a] (lb/MMBtu)	No. 2 Fuel Oil Activity Factor [b] (MMBtu/yr)	No. 2 Fuel Oil Annual Emissions (TPY)	Total Annual Emissions (TPY)
	100% Natural Gas						
Particulate (PM)	0.00745	4,691,238	17.48	--	--	--	17.48
Particulate (PM_{10})	0.00745	4,691,238	17.48	--	--	--	17.48
Particulate ($PM_{2.5}$)	0.00745	4,691,238	17.48	--	--	--	17.48
Sulfur dioxide	5.88E-04	4,691,238	1.38	--	--	--	1.38
Nitrogen oxides	0.06	4,691,238	140.74	--	--	--	140.74
Carbon monoxide	0.080	4,691,238	187.65	--	--	--	187.65
VOC	0.0054	4,691,238	12.65	--	--	--	12.65
Lead	4.90E-07	4,691,238	0.00115	--	--	--	0.00115
Mercury	2.55E-07	4,691,238	0.00060	--	--	--	0.00060
Fluorides	--	4,691,238	--	--	--	--	--
Sulfuric acid mist	2.62E-05	4,691,238	0.06	--	--	--	0.061
<u>Greenhouse Gases</u>							
Carbon Dioxide (CO_2)	116.89	4,691,238	274,177	--	--	--	274,177
Methane (CH_4)	0.0022	4,691,238	5.17	--	--	--	5.17
Nitrous Oxide (N_2O)	0.00022	4,691,238	0.52	--	--	--	0.52
Total GHGs (mass)	116.89	4,691,238	274,183	--	--	--	274,183
Total GHGs-CO_2 equivalent (CO_2e)	117.00	4,691,238	274,446	--	--	--	274,446
	85% Natural Gas / 15% No. 2 Fuel Oil						
Particulate (PM)	0.00745	3,987,552	14.86	0.0243	703,686	8.54	23.39
Particulate (PM_{10})	0.00745	3,987,552	14.86	0.0193	703,686	6.80	21.66
Particulate ($PM_{2.5}$)	0.00745	3,987,552	14.86	0.0114	703,686	4.01	18.87
Sulfur dioxide	0.00059	3,987,552	1.17	0.052	703,686	18.37	19.54
Nitrogen oxides	0.060	3,987,552	119.63	0.060	703,686	21.11	140.74
Carbon monoxide	0.080	3,987,552	159.50	0.080	703,686	28.15	187.65
VOC	0.0054	3,987,552	10.75	0.00147	703,686	0.52	11.27
Lead	4.90E-07	3,987,552	0.00098	9.0E-06	703,686	0.00317	0.00414
Mercury	2.55E-07	3,987,552	0.00051	3.0E-06	703,686	0.00106	0.00156
Fluorides	--	3,987,552	--	2.74E-05	703,686	0.00965	0.010
Sulfuric acid mist	2.62E-05	3,987,552	0.05	2.32E-03	703,686	0.82	0.87
<u>Greenhouse Gases</u>							
Carbon Dioxide (CO_2)	116.89	3,987,552	233,050	163.05	703,686	57,369	290,420
Methane (CH_4)	0.0022	3,987,552	4.40	0.0066	703,686	2.33	6.72
Nitrous Oxide (N_2O)	0.00022	3,987,552	0.44	0.00132	703,686	0.47	0.90
Total GHGs (mass)	116.89	3,987,552	233,055	163.06	703,686	57,372	290,427
Total GHGs-CO_2 equivalent (CO_2e)	117.00	3,987,552	233,279	163.60	703,686	57,562	290,841

[a] Refer to Table 2-2 for emission factors.
[b] Refer to Table 2-1 for activity factors.

Table 2-4. Maximum Annual HAP Emissions for Natural Gas-Fired Boiler
New Hope Power Company

HAP	Natural Gas Emission Factor (lb/10^6 scf)	Ref	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/yr)	Annual Emissions (TPY)	No. 2 Fuel Oil Emission Factor (lb/10^3 gal)	Emission Factor (lb/10^{12} Btu)	Ref	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/yr)	Annual Emissions (TPY)	Maximum Emissions for All Fuels[4] (TPY)	
Acetaldehyde	9.0E-04	1	8.82E-07	4,691,238	2.07E-03	ND			ND		ND	2.07E-03	Acetaldehyde
Arsenic	2.0E-04	2	1.96E-07	4,691,238	4.60E-04		4	3	4.00E-06	703,686	1.41E-03	1.87E-03	Arsenic
Benzene	2.1E-03	2	2.06E-06	4,691,238	4.83E-03	2.14E-04		3	1.57E-06	703,686	5.54E-04	5.38E-03	Benzene
Beryllium	1.2E-05	2	1.18E-08	4,691,238	2.76E-05		3	3	3.00E-06	703,686	1.06E-03	1.08E-03	Beryllium
Cadmium	1.1E-03	2	1.08E-06	4,691,238	2.53E-03		3	3	3.00E-06	703,686	1.06E-03	3.59E-03	Cadmium
Chromium	1.4E-03	2	1.37E-06	4,691,238	3.22E-03		3	3	3.00E-06	703,686	1.06E-03	4.28E-03	Chromium
Cobalt	8.4E-05	2	8.24E-08	4,691,238	1.93E-04	ND			ND		ND	1.93E-04	Cobalt
1,4-Dichlorobenzene(p)	1.2E-03	2	1.18E-06	4,691,238	2.76E-03	ND			ND		ND	2.76E-03	1,4-Dichlorobenzene(p)
Ethylbenzene	ND		ND		ND	6.36E-05		3	4.68E-07	703,686	1.65E-04	1.65E-04	Ethylbenzene
Formaldehyde	7.5E-02	2	7.35E-05	4,691,238	0.17	6.10E-02		2	4.49E-04	703,686	1.58E-01	0.33	Formaldehyde
Hexane	1.8E+00	2	1.76E-03	4,691,238	4.14	ND			ND		ND	4.14	Hexane
Lead-Total	5.0E-04	2	4.90E-07	4,691,238	1.15E-03		9	3	9.00E-06	703,686	3.17E-03	4.32E-03	Lead-Total
Manganese	3.8E-04	2	3.73E-07	4,691,238	8.74E-04		6	3	6.00E-06	703,686	2.11E-03	2.98E-03	Manganese
Mercury	2.6E-04	2	2.55E-07	4,691,238	5.98E-04	1.13E-04	3	3	3.00E-06	703,686	1.06E-03	1.65E-03	Mercury
Nickel	2.1E-03	7	2.06E-06	4,691,238	4.83E-03		3	3	3.00E-06	703,686	1.06E-03	5.88E-03	Nickel
Selenium	2.4E-05	2	2.35E-08	4,691,238	5.52E-05		15	3	1.50E-05	703,686	5.28E-03	5.33E-03	Selenium
Toluene	7.8E-03	1	7.65E-06	4,691,238	1.79E-02	6.20E-03		3	4.56E-05	703,686	1.60E-02	3.40E-02	Toluene
o-Xylene	ND		ND		ND	1.09E-04		3	8.01E-07	703,686	2.82E-04	2.82E-04	o-Xylene
POMs													**POMs**
2-Methylnaphthalene	2.4E-05	2	2.35E-08	4,691,238	5.52E-05	ND			ND	0	ND	5.52E-05	2-Methylnaphthalene
3-Methylchloranthrene	1.8E-06	2	1.76E-09	4,691,238	4.14E-06	ND			ND	0	ND	4.14E-06	3-Methylchloranthrene
7,12-Dimethylbenz(a)anthracene	1.6E-05	2	1.57E-08	4,691,238	3.68E-05	ND			ND	0	ND	3.68E-05	7,12-Dimethylbenz(a)anthracene
Acenaphthene	1.8E-06	2	1.76E-09	4,691,238	4.14E-06	2.11E-05		3	1.55E-07	703,686	5.46E-05	5.87E-05	Acenaphthene
Acenaphthylene	1.8E-06	2	1.76E-09	4,691,238	4.14E-06	2.53E-07		3	1.86E-09	703,686	6.55E-07	4.79E-06	Acenaphthylene
Anthracene	2.4E-06	2	2.35E-09	4,691,238	5.52E-06	1.22E-06		3	8.97E-09	703,686	3.16E-06	8.68E-06	Anthracene
Benz(a)anthracene	1.8E-06	2	1.76E-09	4,691,238	4.14E-06	4.01E-06		3	2.95E-08	703,686	1.04E-05	1.45E-05	Benz(a)anthracene
Benzo(a)pyrene	1.2E-06	2	1.18E-09	4,691,238	2.76E-06	ND			ND	0	ND	2.76E-06	Benzo(a)pyrene
Benzo(b)fluoranthene	1.8E-06	2	1.76E-09	4,691,238	4.14E-06	ND			ND	0	ND	4.14E-06	Benzo(b)fluoranthene
Benzo(b,k)fluoranthene	ND		ND	0	ND	1.48E-06		3	1.09E-08	703,686	3.83E-06	3.83E-06	Benzo(b,k)fluoranthene
Benzo(g,h,i)perylene	1.2E-06	2	1.18E-09	4,691,238	2.76E-06	2.26E-06		3	1.66E-08	703,686	5.85E-06	8.61E-06	Benzo(g,h,i)perylene
Benzo(j,k)fluoranthene	1.8E-06	2	1.76E-09	4,691,238	4.14E-06	ND			ND		ND	4.14E-06	Benzo(j,k)fluoranthene
Chrysene	1.8E-06	2	1.76E-09	4,691,238	4.14E-06	2.38E-06		3	1.75E-08	703,686	6.16E-06	1.03E-05	Chrysene
Dibenzo(a,h)anthracene	1.2E-06	2	1.18E-09	4,691,238	2.76E-06	1.67E-06		3	1.23E-08	703,686	4.32E-06	7.08E-06	Dibenzo(a,h)anthracene
Fluoranthene	3.0E-06	2	2.94E-09	4,691,238	6.90E-06	4.84E-06		3	3.66E-08	703,686	1.25E-05	1.94E-05	Fluoranthene
Fluorene	2.8E-06	2	2.75E-09	4,691,238	6.44E-06	4.47E-06		3	3.29E-08	703,686	1.16E-05	1.80E-05	Fluorene
Indeno(1,2,3-cd)pyrene	1.8E-06	2	1.76E-09	4,691,238	4.14E-06	2.14E-06		3	1.57E-08	703,686	5.54E-06	9.68E-06	Indeno(1,2,3-cd)pyrene
Naphthalene	6.1E-04	2	5.98E-07	4,691,238	1.40E-03	1.13E-03		3	8.31E-06	703,686	2.92E-03	4.33E-03	Naphthalene
Phenanthrene	1.7E-05	2	1.67E-08	4,691,238	3.91E-05	1.05E-05		3	7.72E-08	703,686	2.72E-05	6.63E-05	Phenanthrene
Pyrene	5.0E-06	2	4.90E-09	4,691,238	1.15E-05	4.25E-06		3	3.13E-08	703,686	1.10E-05	2.25E-05	Pyrene
Total POMs	6.98E-04		6.85E-07		1.61E-03	1.19E-03			8.75E-06		3.08E-03	4.69E-03	Total POMs
MAXIMUM SINGLE HAP					4.14						0.16	4.14	MAXIMUM SINGLE HAP
TOTAL					4.35						0.20	4.55	TOTAL

UD = Undetected
ND = No Data available
References
1. Ventura County APCD, AB 2588 Combustion Emission Factors, 2001.
2. Based on AP-42 emission factors for natural gas combustion (Section 1.4).
3. Based on AP-42, Section 1.3, for No. 2 fuel oil firing.
4. Represents the sum of maximum natural gas firing and maximum fuel oil firing which is an overestimate of the actual emissions.

Table 2-5. Stack and Operating Parameters Used in the New Gas Boiler Modeling Analysis, NHPC

		UTM Coordinates [a]		Stack Data [b]					Operating Data [b]				
	Model	East	North	Height		Diameter		Heat Input	Temperature		Gas Flow	Velocity	
Emission Unit	ID	(m)	(m)	ft	m	ft	m	(MMBtu/hr)	°F	°K	(acfm)	ft/s	m/s
100% Load- Maximum 1-Hour													
Boiler D	BLRD	524,900	2,940,100	150	45.7	8.20	2.50	589	350	450	314,379	99.2	30.2
91% Load- Maximum 24-Hour													
Boiler D	BLRD	524,900	2,940,100	150	45.7	8.20	2.50	536	350	450	286,085	90.3	27.5
75% Load													
Boiler D	BLRD	524,900	2,940,100	150	45.7	8.20	2.50	442	350	450	235,784	74.4	22.7
50% Load													
Boiler D	BLRD	524,900	2,940,100	150	45.7	8.20	2.50	295	350	450	157,189	49.6	15.1

[a] Universal transverse coordinates, Zone 17.

[b] Stack and operating data based on engineering estimate.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significant Impact Levels (µg/m^3)

		National AAQS		Florida AAQS[a]	PSD Increments[a]		Significant Impact Levels[b]	
Pollutant	Averaging Time	Primary Standard	Secondary Standard		Class I	Class II	Class I	Class II
Particulate Matter[c]								
PM_{10}	Annual Arithmetic Mean	50	50	50	4	17	0.2	1
	24-Hour Maximum	150	150	150	8	30	0.3	5
$PM_{2.5}$	Annual Arithmetic Mean	15	15	15	1	4	0.06	0.3
	24-Hour Maximum	35	35	35	2	9	0.07	1.2
Sulfur Dioxide	Annual Arithmetic Mean	NA	NA	NA	2	20	0.1	1
	24-Hour Maximum	NA	NA	NA	5	91	0.2	5
	3-Hour Maximum	NA	1,300	1,300	25	512	1.0	25
	1-Hour Maximum[d]	196	NA	NA	NA	NA	NA	7.86
Carbon Monoxide	8-Hour Maximum	10,000	10,000	10,000	NA	NA	NA	500
	1-Hour Maximum	40,000	40,000	40,000	NA	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	0.1	1
	1-Hour Maximum[e]	189	NA	189	NA	NA	NA	7.52
Ozone	1-Hour Maximum[f]	235	235	235	NA	NA	NA	NA
	8-Hour Maximum[g]	147	147	147	NA	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA	NA
	3-Month Average	0.15	0.15	0.15	NA	NA	NA	NA

Note: NA = Not applicable, i.e., no standard exists.
Particulate matter (PM_{10}) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
Particulate matter ($PM_{2.5}$) = particulate matter with aerodynamic diameter less than or equal to 2.5 micrometers.

[a] Short-term maximum concentrations are not to be exceeded more than once per year, except for PM_{10} and O_3 AAQS, which are based on expected exceedances.

[b] Maximum concentrations are not to be exceeded.

[c] On October 17, 2006, EPA promulgated revised PM_{10} and $PM_{2.5}$ AAQS. The $PM_{2.5}$ AAQS had been promulgated on July 18, 1997. For PM_{10}, the annual standard was revoked and the 24-hour standard was retained. The 24-hour $PM_{2.5}$ standard was revised to 35 µg/m^3 based on the 3-year averages of the 98th percentile values. The annual $PM_{2.5}$ standard of 15 µg/m^3, based on 3-year averages at community monitors, was retained. FDEP has not yet adopted the revised standards, which must be implemented in the 2009-2010 timeframe.

[d] The 1-hour SO_2 standard is met when the 3-year average of the 99th percentile of the daily 1-hour maximum values is less than 196 µg/m^3.

[e] The 1-hour NO_2 standard is met when the 3-year average of the 98th percentile of the daily 1-hour maximum values is less than 188 µg/m^3.

[f] 0.12 ppm; achieved when the expected number of days per year with concentrations above the standard is fewer than 1.

[g] On March 27, 2008, EPA promulgated revised AAQS for ozone. The O_3 standard was modified to be 0.075 ppm (147 µg/m^3) for the 8-hour average; achieved when the 3-year average of 99th percentile values is 0.075 ppm or less. FDEP has not yet adopted the revised standards.

Sources: 40 CFR 50; 40 CFR 52.21, Florida Chapter 62.204, F.A.C.

Table 3-2: PSD Significant Emission Rates and *de Minimis* Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration [a] ($\mu g/m^3$)
Sulfur Dioxide (SO_2)	NAAQS, NSPS	40	13, 24-hour
Total Particulate Matter (PM)	NSPS	25	10, 24-hour
Particulate Matter <10 microns (PM_{10})	NAAQS	15	10, 24-hour
Fine Particulate Matter ($PM_{2.5}$)	NAAQS	10; or 40 SO_2 or NO_x	4, 24-hour
Nitrogen Oxides (NO_x)	NAAQS, NSPS	40	14, annual
Carbon Monoxide (CO)	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (VOC)	NAAQS, NSPS	40	100 TPY [b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist (SAM)	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Mercury	NESHAP	0.1	0.25, 24-hour
MWC Organics	NSPS	$3.5x10^{-6}$	NM
MWC Metals	NSPS	15	NM
MWC Acid Gases	NSPS	40	NM
MSW Landfill Gases	NSPS	50	NM
Greenhouse Gases- Mass Basis, and	--	0, and	NM
- CO_2e Basis [c]	--	75,000	NM

[a] Short-term concentrations are not to be exceeded.
[b] No *de minimis* concentration; an increase in VOC or NO_x emissions of 100 TPY or more will require monitoring analysis for ozone.
[c] Excludes biogenic CO_2.

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

CO_2e= Carbon dioxide equivalents

MSW = municipal solid waste

MWC = municipal waste combustor

NAAQS = National Ambient Air Quality Standards

NESHAP = National Emission Standards for Hazardous Air Pollutants

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

NSPS = New Source Performance Standards

Source: 40 CFR 52.21

Table 3-3: PSD Applicability Analysis, New Natural Gas-Fired Boiler, NHPC

	Pollutant Emission Rate (TPY)												
Emissions Category	**SO_2**	**NO_x**	**CO**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**VOC**	**SAM**	**Lead**	**Mercury**	**Fluorides**	**GHG [d]**	**CO_2e [d]**
FUTURE POTENTIAL Emissions [a]													
- New Natural Gas Boiler	19.54	140.74	187.65	23.39	21.66	18.87	12.65	0.869	0.0041	0.00156	0.0096	290,427	290,841
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	10 [e]	40	7	0.6	0.1	3	0 and	75,000
PSD NETTING ANALYSIS REQUIRED?	No	Yes	Yes	No	Yes	Yes	No	No	No	No	No	Yes	
Contemporaneous Emissions [b]													
Boiler A Natural Gas Conversion	--	6.56	43.98	--	0.51	2.99	--	--	--	--	--	61,763	62,587
(Permit No. 0990332-019-AC; 6/6/2012)													
Total Increase [c]	**19.54**	**147.30**	**231.63**	**23.39**	**22.17**	**21.86**	**12.65**	**0.869**	**0.0041**	**0.00156**	**0.0096**	**352,190**	**353,428**
PSD SIGNIFICANT EMISSION RATE	40	40	100	25	15	10 [e]	40	7	0.6	0.1	3	0 and	75,000
PSD REVIEW REQUIRED?	**No**	**Yes**	**Yes**	**No**	**Yes**	**Yes**	**No**	**No**	**No**	**No**	**No**	**Yes**	

[a] See Table 2-3.

[b] Contemporaneous emissions increases and decreases at the facility for all projects that occurred over the previous five-year period for the pollutants that triggered PSD netting analysis.

[c] Total increase from the new natural gas boiler as well as all contemporaneous emissions increases and decreases.

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

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

[e] An increase of 40 TPY of SO_2 or 40 TPY of NO_x emissions is also considered to be significant for $PM_{2.5}$.

Table 3-4. Maximum Predicted Impacts for NHPC Boiler D Project Only Compared to EPA *de Minimis* Concentration Levels

Pollutant	Averaging Time	Maximum Predicted Concentration [a] (ug/m^3)	*De Minimis* Monitoring Concentration (ug/m^3)
NO_2	Annual	0.08	14
CO	8-Hour	21.9	575
PM_{10}	24-Hour	0.75	10
$PM_{2.5}$	24-Hour	0.30	4

[a] Refer to Section 6.0 for results.

Table 4-1. Summary of Maximum Measured NO_2 Concentrations for Palm Beach County, 2010 to 2011

					NO_2 Concentration ($\mu g/m^3$)			
					1-Hour			Annual
			Measurement Period					
Site No.	Operator	Location	Year	Months	Highest	2nd Highest	98th Percentile	Arithmic Mean
Nitrogen dioxide		**Florida AAQS:**			**NA**	**NA**	**188**	**100**
12-099-1020	PBCHD	Lantana- Palm Beach County	2010	Jan-Dec	111	98	87	10
			2011	Jan-Dec	92	90	71	8
Average:					**102**	**94**	**79**	**9**

Note: NA = not applicable
AAQS = ambient air quality standard
PBCHD = Palm Beach County Health Department

Source: FDEP Quick Look Reports, 2011 and 2012.

Table 5-1. Summary of NO_x BACT Determinations for Large (> 250 MMBtu/hr) Natural Gas-Fired Boilers (2002 - 2012)

RBLCID	Company Name - Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Emission Limit	Control Method	Control Efficiency
Normal Use Boilers									
IA-0088	Archer Daniels Midland - Corn Processing, Cedar Rapids	IA	57-01-080	6/29/2007	Natural Gas Boiler	293 MMBtu/hr	0.0200 lb/MMBtu (30-day rolling average)	Ultra Low NOx Burners w/ FGR and Good Combustion Practices	--
WI-0244	Appleton Coated - Combined Locks Mill	WI	06-DCF-270	6/19/2007	Boiler B05 - Natural Gas / Distillate Oil Fired Boiler	285 MMBtu/hr	0.0900 lb/MMBtu	Low NOx Burners and FGR	--
PA-0253	Conocophillips Company - Trainer Refinery	PA	23-0003I	2/6/2007	Boiler 9	349,600 scf/hr	0.0076 lb/MMBtu	Ultra Low NOx Burners, FGR, SCR	--
TX-0511	BASF Fina Petrochemicals - Ethylene/Propylene Cracker	TX	PSD-TX 903M1	2/3/2006	Boiler	425 MMBtu/hr	0.0200 lb/MMBtu	Low NOx Burners	--
LA-0177	Amerada Hess Corp - Sea Robin Gas Processing Plant	LA	PSD-LA-712	9/8/2005	Natural Gas-Fired Boiler	363 MMBtu/hr	0.0400 lb/MMBtu (1-hr maximum)	Low NOx Burners and FGR	79
WA-0301	British Petroleum - Cherry Point Refinery	WA	PSD-02-04	4/20/2005	Boiler, Natural Gas	363 MMBtu/hr	0.0280 lb/MMBtu (calendar day maximum)	Ultra Low NOx Burners and FGR	75
AZ-0046	Arizona Clean Fuels Yuma Llc	AZ	1001205	4/14/2005	Steam Boilers Nos. 1 And 2	419 MMBtu/hr	0.0125 lb/MMBtu (3-hr average)	Low NOx Burners and FGR	--
TX-0479	The Dow Chemical Company - Texas Operations Freeport	TX	PSD-TX-986M1 / 46306	12/2/2004	Four Gas-Fired Steam Boilers	410 MMBtu/hr	0.0186 lb/MMBtu	Low NOx Burners and SCR	--
NE-0024	Cargill, Inc. - Blair Plant	NE	57902CS6	6/22/2004	Boilers A, B &Amp; C	198 MMBtu/hr	0.0700 lb/MMBtu	Low NOx Burners and Induced Draft FGR	--
NE-0024	Cargill, Inc. - Blair Plant	NE	57902CS6	6/22/2004	Boiler D (No. 21)	277 MMBtu/hr	0.0500 lb/MMBtu (30-day average)	Low NOx Burners and Induced FGR	--
SC-0091	Columbia Energy Center	SC	0460-0024-CE	7/3/2003	Boiler, Natural Gas	550 MMBtu/hr	0.0400 lb/MMBtu	Low NOx Burners and FGR	--
AL-0199	Weyerhaeuser Company	AL	109-0001-X017, X018, X019	11/15/2002	Boiler, Natural Gas	300 MMBtu/hr	0.0500 lb/MMBtu	Low NOx Burners	--
TX-0373	Huntsman Polymers Corporation - Odessa Petrochemical Plant	TX	PSD-TX-967	10/24/2002	F Boiler	370 MMBtu/hr	0.0500 lb/MMBtu	Dry Low NOx Combustors & FGR	--
						Maximum	0.0900		
						Minimum	0.0076		
						Average	0.0382		
Auxiliary/Package Boilers									
LA-0254	Entergy Louisiana LLC - Ninemile Point Electric Generating Plant	LA	PSD-LA-752	8/16/2011	Auxiliary Boiler (Aux-1)	338 MMBtu/hr	0.0002 lb/MMBtu	Proper Operation And Good Combustion Practices	--
LA-0248	Consolidated Environmental Management Inc - Nucor	LA	PSD-LA-751	1/27/2011	Dri Unit #1 Package Boiler	1,760 Billion Btu/yr	0.0032 lb/MMBtu	Low NOx Burners and SCR	90
LA-0231	Lake Charles Cogeneration, LLC - Lake Charles Gasification Facility	LA	PSD-LA-742	6/22/2009	Auxiliary Boiler	938 MMBtu/hr	0.0350 lb/MMBtu	Ultra Low NOx Burners	--
AR-0094	Southwest Electric Power Company - John W. Turk Jr. Power Plant	AR	2123-AOP-R0	11/5/2008	Auxiliary Boiler	555 MMBtu/hr	0.1100 lb/MMBtu (30-day rolling average)	Low NOx Burners	--
OH-0307	Biomass Energy - South Point Biomass Generation	OH	07-00534	4/4/2006	Auxiliary Boiler	247 MMBtu/hr	0.0600 lb/MMBtu	--	--
OH-0269	Biomass Energy - South Point Biomass Generation	OH	07-00534	1/5/2004	Auxiliary Boiler, Natural Gas	247 MMBtu/hr	0.0600 lb/MMBtu	--	--
TX-0469	Texas Petrochemicals LP - Houston Facility	TX	P999	10/8/2003	Auxillary Steam Boiler (2)	664 MMBtu/hr	0.0182 lb/MMBtu	Good Combustion Practices	--
IA-0067	Midamerican Energy Company - Walter Scott Jr. Energy Center	IA	PROJECT 02-528	6/17/2003	Auxiliary Boiler	429 MMBtu/hr	0.1400 lb/MMBtu	Low NOx Burners	--
NJ-0043	Liberty Generating Station - Liberty Generating Station	NJ	BOP990001	3/28/2002	Auxiliary Boiler	200 MMBtu/hr	0.0360 lb/MMBtu	SCR	--
TX-0386	Calpine Construction Finance Co. LP - Amella Energy Center	TX	N-O37	3/26/2002	Auxiliary Boiler	155 MMBtu/hr	0.0400 lb/MMBtu	--	--

Table 5-2. Summary and Ranking of NO_x Control Technologies

NO_x Control Method	Technique Now Available	Estimated Efficiency	Feasible and Demonstrated? (Y/N)	Rank Based on Control Efficiency	Employed by NHPC Boiler? (Y/N)
1. Removal of Nitrogen	Ultra-Low Nitrogen Fuel	No Data	Y	7	Y
2. Oxidation of NO_x with Subsequent Absorption	Inject Oxidant	60 - 80%	NTF	NTF	N
	Non-Thermal Plasma Reactor (NTPR)	60 - 80%	NTF	NTF	N
3. Chemical Reduction of NO_x	Selective Catalytic Reduction (SCR)	70 - 90%	Y	3	N
	Selective Non-Catalytic Reduction (SNCR)	50 - 60%	Y	4	N
4. Reducing Residence Time at Peak Temperature	Air Staging of Combustion	50 - 65%	Y	5	N
	Fuel Staging of Combustion	50 - 65%	Y	5	N
	Inject Steam	50 - 65%	Y	5	N
5. Reducing Peak Temperature	Flue Gas Recirculation (FGR)	15 - 25%	Y	6	N
	Natural Gas Reburning (NGR)	15 - 25%	Y	6	N
	Over Fire Air (OFA)	15 - 25%	Y	6	N
	Less Excess Air (LEA)	15 - 25%	Y	6	N
	Combustion Optimization	15 - 25%	Y	6	Y
	Low NO_x Burners (LNB)	15 - 25%	Y	6	N
	Ultra-Low NO_x Burners (ULNB)	80 - 90%	Y	2	Y
5. Combination of Technologies	SCR & Ultra-Low NO_x Burners	90 - 99%	Y	1	N

Note: NTF = Not Technically Feasible.

Table 5-3: Cost Effectiveness of NO_x Control Technology

Cost Items	Cost Factors[a]	SCR Cost (70% Eff.) ($)	SCR Cost (90% Eff.) ($)
DIRECT CAPITAL COSTS (DCC):			
Purchased Equipment Costs (PEC)			
SCR Catalyst System	Vendor Quote [b]	1,117,000	1,507,000
Extra Catalyst Section (w/o catalyst)	Vendor Quote [b]	63,000	63,000
Anhydrous Ammonia Tank and Supply	Estimate	100,000	100,000
Piping - NH_3 system	Estimate	10,000	10,000
Total- Purchased Equipment		1,290,000	1,680,000
Freight	5% of Equipment Costs	64,500	64,500
Instrumentation	10% of Equipment Costs	168,000	168,000
Emission Monitoring	5% of Equipment Costs	64,500	64,500
Foundation and Structure Support	8% of Equipment Costs	103,200	103,200
Direct Installation Costs (DIC):			
Erection, Installation	20% of Equipment Costs	258,000	672,000
Taxes	6% of Equipment Costs	77,400	77,400
Total DCC (PEC+DIC):		2,025,600	2,829,600
INDIRECT CAPITAL COSTS (ICC):			
General Facilities	5% of DCC	101,280	141,480
Engineering and home office fees	10% of DCC	202,560	282,960
Process Contingency	5% of DCC	101,280	141,480
Total ICC:		405,120	565,920
PROJECT CONTINGENCY	15% of DCC+ICC	364,608	509,328
TOTAL CAPITAL INVESTMENT (TCI):		2,795,328	3,904,848
DIRECT OPERATING COSTS (DOC):			
Maintenance	1.5% of TCI	41,930	58,573
Electricity	30 kW; $0.060/kW-hr	15,768	18,922
Anhydrous Ammonia Cost [b]	22/30 lb/hr NH_3; $850/ton NH_3	81,906	111,690
Catalyst replacement	Every 2 Years	125,000	187,500
		264,604	376,684
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	263,879	368,618
ANNUALIZED COSTS (AC):	DOC + CRC	528,483	745,302
Total Uncontrolled NO_x Emissions:	**0.06 lb/MMBtu, 536 MMBtu/hr**	141	141
Total Controlled NO_x Emissions:	70% or 90% Reduction	42	14
Total NO_x Reduction:		99	127
NO_x Cost Effectiveness:	$/ton NO_x Reduced	5,360	5,879
Total Uncontrolled NO_x Emissions:	**0.03 lb/MMBtu, 536 MMBtu/hr**	70	70
Total Controlled NO_x Emissions:	70% or 90% Reduction	21	7
Total NO_x Reduction:		49	63
NO_x Cost Effectiveness:	$/ton NO_x Reduced	10,719	11,758

[a] Unless otherwise specified, factors and cost estimates reflect EPA Air Pollution Control Cost Manual, Sixth edition. Operating hours at 8,760 hr/yr.

[b] Based on vendor quote, 2012.

Table 5-4. Summary of CO BACT Determinations for Large (> 250 MMBtu/hr) Natural Gas-Fired Boilers (2002 - 2012)

RBLCID	Company Name - Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Emission Limit	Control Method	Control Efficiency
Normal Use Boilers									
LA-0233	Citgo Petroleum Company - Lake Charles Complex	LA	PSD-LA-577(M-1)	1/30/2009	3(K-6)8 Powerhouse Boiler B-5A	338 MMBtu/hr	0.122 lb/MMBtu	Good Combustion Control	--
LA-0227	Cleco Power LLC - Rodemacher Power Station	LA	PSD-LA-728	5/8/2008	Unit 2 Boiler (1-74)	5,445 MMBtu/hr	0.150 lb/MMBtu (annual average)	Overfire Air, Good Combustion Practices	--
IA-0088	Archer Daniels Midland - Corn Processing, Cedar Rapids	IA	57-01-080	6/29/2007	Natural Gas Boiler (292.5 Mmbtu/H)	293 MMBtu/hr	0.072 lb/MMBtu (30-day rolling average)	Good Combustion Practices	--
WI-0244	Appleton Coated - Combined Locks Mill	WI	06-DCF-270	6/19/2007	Boiler B05 (#11) Natural Gas / Distillate Oil Fired Boiler	285 MMBtu/hr	0.120 lb/MMBtu	Good Combustion Control	--
PA-0253	Conocophillips Company - Trainer Refinery	PA	23-0003I	2/6/2007	Boiler 9	349,600 scf/hr	0.019 lb/MMBtu	CO Catalyst	--
					Boiler 10	349,600 scf/hr	0.019 lb/MMBtu	CO Catalyst	--
WA-0303	Longview Fibre Paper And Packaging, Inc	WA	PSD-01-03, AMENDMENT 2	11/1/2006	Power Boilers 12 And 13	444 MMBtu/hr	1.000 lb/MMBtu	--	--
TX-0511	BASF Fina Petrochemicals - Ethylene/Propylene Cracker	TX	PSD-TX 903M1	2/3/2006	Boiler (2)	425 MMBtu/hr	0.070 lb/MMBtu	--	--
WA-0301	British Petroleum - Cherry Point Refinery	WA	PSD-02-04	4/20/2005	Boiler, Natural Gas	363 MMBtu/hr	0.050 lb/MMBtu (24-hr average)	Good Combustion Practices	--
AZ-0046	Arizona Clean Fuels Yuma LLC	AZ	1001205	4/14/2005	Steam Boilers Nos. 1 And 2	419 MMBtu/hr	0.016 lb/MMBtu (3-hr average)	--	--
TX-0479	The Dow Chemical Company - Texas Operations, Freeport	TX	PSD-TX-986M1 / 46306	12/2/2004	Combustion Via Four Gas-Fired Steam Boilers	410 MMBtu/hr	0.068 lb/MMBtu	Good Combustion Practices	--
NE-0024	Cargill, Inc. - Blair Plant	NE	57902CS6	6/22/2004	Boiler D (No. 21)	277 MMBtu/hr	0.140 lb/MMBtu	Good Combustion Practices	--
MS-0075	Georgia Pacific Corp. - Monticello Mill	MS	1500-00007	7/9/2003	Power Boiler - Ng	766 MMBtu/hr	0.040 lb/MMBtu	--	--
SC-0091	Columbia Energy Center	SC	0460-0024-CE	7/3/2003	Boiler, Natural Gas	550 MMBtu/hr	0.060 lb/MMBtu	Good Combustion Practices	--
VA-0255	Virginia Power - Possum Point	VA	70225	11/18/2002	Boiler, Tangentially-Fired, Unit 4	2,350 MMBtu/hr	0.024 lb/MMBtu	Good Combustion Practices	--
					Boiler, Tangentially-Fired, Unit 3	1,150 MMBtu/hr	0.024 lb/MMBtu	Good Combustion Practices	--
AL-0199	Weyerhaeuser Company	AL	109-0001-X017, X018, X019	11/15/2002	Boiler, 300 Mmbtu/H, Natural Gas	300 MMBtu/hr	0.100 lb/MMBtu	--	--
TX-0373	Huntsman Polymers Corporation - Odessa Petrochemical Plant	TX	PSD-TX-967	10/24/2002	F Boiler Stack, Eyfblrst	370 MMBtu/hr	0.065 lb/MMBtu	Good Combustion Practices	--
					C Boiler Stack, Ey003St	320 MMBtu/hr	0.084 lb/MMBtu	--	--
						Maximum:	1.000		
						Minimum:	0.024		
						Average:	0.118		
Auxiliary Boilers									
LA-0254	Entergy Louisiana LLC - Ninemile Point Electric Generating Plant	LA	PSD-LA-752	8/16/2011	Auxiliary Boiler (Aux-1)	338 MMBTU/H	0.0824 lb/MMBtu (annual average)	Good Combustion Practices	--
LA-0248	Consolidated Environmental Management Inc - Nucor	LA	PSD-LA-751	1/27/2011	Dri-109 - Dri Unit #1 Package Boiler Flue Stack	1,760 Billion Btu/yr	0.039 lb/MMBtu	Good Combustion Practices	--
LA-0231	Lake Charles Cogeneration, LLC - Lake Charles Gasification Facility	LA	PSD-LA-742	6/22/2009	Auxiliary Boiler	938 MMBTU/H	0.0360 lb/MMBtu	Good Design And Proper Operation	--
AR-0094	Southwest Electric Power Company - John W. Turk Jr. Power Plant	AR	2123-AOP-R0	11/5/2008	Auxiliary Boiler	555 MMBTU/H	0.0360 lb/MMBtu (30-day rolling average)	--	--
OH-0307	Biomass Energy - South Point Biomass Generation	OH	07-00534	4/4/2006	Auxiliary Boiler	247 MMBTU/H	0.1100 lb/MMBtu	--	--
OH-0269	Biomass Energy - South Point Biomass Generation	OH	07-00534	1/5/2004	Auxiliary Boiler, Natural Gas	247 MMBTU/H	0.1100 lb/MMBtu	--	--
TX-0469	Texas Petrochemicals LP - Houston Facility	TX	P999	10/8/2003	Auxillary Steam Boiler (2)	664 MMBTU/H	0.0387 lb/MMBtu	Good Combustion	--
IA-0067	Midamerican Energy Company - Walter Scott Jr. Energy Center	IA	PROJECT 02-528	6/17/2003	Auxiliary Boiler	429 MMBTU/H	0.0840 lb/MMBtu	Good Combustion Practices	--
NJ-0043	Liberty Generating Station	NJ	BOP990001	3/28/2002	Auxiliary Boiler	200 MMBTU/H	0.0870 lb/MMBtu	CO Catalyst	80
TX-0386	Calpine Construction Finance Co. LP - Amelia Energy Center	TX	N-O37	3/26/2002	Auxiliary Boiler	155 MMBTU/H	0.0800 lb/MMBtu	--	--

Table 5-5. Summary and Ranking of CO Control Technologies

CO Control Method	Technique Now Available	Estimated Efficiency	Feasible and Demonstrated? (Y/N)	Rank Based on Control Efficiency	Employed by NHPC Boiler? (Y/N)
Oxidation	Oxidation Catalyst	70 - 90%	Y	1	N
	Conventional SCR	Variable	NTF	NTF	N
Enhanced Over-Fire Air Systems	Nalco Mobotec OFA	70%	Y	2	N
	Synterprise Ecojet	70%	Y	2	N
Good Combustion Practices	Air Staging of Combustion	50 - 75%	Y	3	Y
	Increased Gas Residence Time	50 - 75%	Y	3	Y
	Combustion Optimization	50 - 75%	Y	3	Y
Incinerators	Thermal	>80%	NTF	NTF	N
	Catalytic	>80%	NTF	NTF	N

Note: NTF = Not Technically Feasible.

Table 5-6: Cost Effectiveness of CO Control Technology

Cost Items	Cost Factors[a]	Oxidation Catalyst Cost (70% Eff.) ($)	Oxidation Catalyst Cost (90% Eff.) ($)
DIRECT CAPITAL COSTS (DCC):			
Purchased Equipment Costs (PEC)			
Oxidation Catalyst System	Estimated from Vendor Quote [b]	600,000	725,000
Extra Catalyst Section (w/o catalyst)	Vendor Quote [b]	63,000	63,000
Total- Purchased Equipment		663,000	788,000
Freight	5% of Equipment Costs	33,150	33,150
Instrumentation	10% of Equipment Costs	78,800	78,800
Emission Monitoring	5% of Equipment Costs	33,150	33,150
Foundation and Structure Support	8% of Equipment Costs	53,040	53,040
Direct Installation Costs (DIC):			
Erection, Installation	20% of Equipment Costs	132,600	315,200
Taxes	6% of Equipment Costs	39,780	39,780
Total DCC (PEC+DIC):		1,033,520	1,341,120
INDIRECT CAPITAL COSTS (ICC):			
General Facilities	5% of DCC	51,676	67,056
Engineering and home office fees	10% of DCC	103,352	134,112
Process Contingency	5% of DCC	51,676	67,056
Total ICC:		206,704	268,224
PROJECT CONTINGENCY	15% of DCC+ICC	186,034	241,402
TOTAL CAPITAL INVESTMENT (TCI):		1,426,258	1,850,746
DIRECT OPERATING COSTS (DOC):			
Maintenance	1.5% of TCI	21,394	27,761
Electricity	30 kW; $0.060/kW-hr	15,768	18,922
Catalyst replacement	Every 2 Years	120,000	182,500
		157,162	229,183
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	134,639	174,710
ANNUALIZED COSTS (AC):	DOC + CRC	291,801	403,893
Total Uncontrolled CO Emissions:	**0.08 lb/MMBtu, 536 MMBtu/hr**	188	188
Total Controlled CO Emissions:	70% or 90% Reduction	56	19
Total CO Reduction:		131	169
CO Cost Effectiveness:	\$/ton NO_x Reduced	2,220	2,389

[a] Unless otherwise specified, factors and cost estimates reflect EPA Air Pollution Control Cost Manual, Sixth edition. Operating hours at 8,760 hr/yr.

[b] Based on vendor quote, 2012.

Table 5-7. Summary of $PM/PM_{10}/PM_{2.5}$ BACT Determinations for Large (> 250 MMBtu/hr) Natural Gas-Fired Boilers (2002 - 2012)

RBLCID	Company Name - Facility Name	State	Permit Number	Permit Date	Process Name	Throughput	Emission Limit	Control Method	Control Efficiency
Normal Use Boilers									
MN-0078	Sappi Fine Paper PLC - Sappi Cloquet LLC	MN	01700002-011	10/28/2009	Boiler	350 MMBtu/hr	0.0071 lb/MMBtu (3-hr average)	--	--
IA-0088	Archer Daniels Midland - Corn Processing, Cedar Rapids	IA	57-01-080	6/29/2007	Natural Gas Boiler (292.5 Mmbtu/H)	293 MMBtu/hr	0.0050 lb/MMBtu	Natural Gas Fuel Only	--
WI-0244	Appleton Coated - Combined Locks Mill	WI	06-DCF-270	6/19/2007	Boiler B05 (#11) Natural Gas / Distillate Oil Fired Boiler	285 MMBtu/hr	0.0080 lb/MMBtu	Fuel Oil Restriction, Natural Gas as main fuel	--
PA-0253	Conocophillips Company - Trainer Refinery	PA	23-0003I	2/6/2007	Boiler 9	349,600 scf/hr	0.0088 lb/MMBtu	Natural Gas Fuel Only and RFG	--
PA-0253	Conocophillips Company - Trainer Refinery	PA	23-0003I	2/6/2007	Boiler 10	349,600 scf/hr	0.0088 lb/MMBtu	Natural Gas Fuel Only and RFG	--
WA-0303	Longview Fibre Paper And Packaging, Inc	WA	PSD-01-03, Amendment 2	11/1/2006	Power Boilers 12 And 13	444 MMBtu/hr	0.1000 lb/MMBtu	--	--
TX-0511	BASF Fina Petrochemicals - Ethylene/Propylene Cracker	TX	PSD-TX 903M1,N-007M1 AND 36644	2/3/2006	Boiler (2)	425 MMBtu/hr	0.0149 lb/MMBtu	--	--
TX-0479	The Dow Chemical Company - Texas Operations Freeport	TX	PSD-TX-986M1 / 46306	12/2/2004	Combustion Via Four Gas-Fired Steam Boilers	410 MMBtu/hr	0.0160 lb/MMBtu	Natural Gas Fuel Only	--
MS-0075	Georgia Pacific Corp. - Monticello Mill	MS	1500-00007	7/9/2003	Power Boiler - Ng	766 MMBtu/hr	0.0050 lb/MMBtu	--	--
SC-0091	Columbia Energy Center	SC	0460-0024-CE	7/3/2003	Boiler, Natural Gas	550 MMBtu/hr	0.0050 lb/MMBtu	Good Combustion Practices	--
VA-0255	Virginia Power - Possum Point	VA	70225	11/18/2002	Boiler, Tangentially-Fired, Unit 4	2,350 MMBtu/hr	0.0110 lb/MMBtu	Clean Fuel And Good Combustion Practices	--
VA-0255	Virginia Power - Possum Point	VA	70225	11/18/2002	Boiler, Tangentially-Fired, Unit 3	1,150 MMBtu/hr	0.0230 lb/MMBtu	Clean Fuel And Good Combustion Practices	--
TX-0373	Huntsman Polymers Corporation - Odessa Petrochemical Plant	TX	PSD-TX-967	10/24/2002	F Boiler Stack, Eyfblrst	370 MMBtu/hr	0.0070 lb/MMBtu	Natural Gas Fuel Only	--
TX-0373	Huntsman Polymers Corporation - Odessa Petrochemical Plant	TX	PSD-TX-967	10/24/2002	C Boiler Stack, Ey003St	320 MMBtu/hr	0.0150 lb/MMBtu	--	--
						Maximum:	0.1000		
						Minimum:	0.0050		
						Average:	0.0168		
Auxiliary/Package Boilers									
LA-0254	Entergy Louisiana LLC - Ninemile Point Electric Generating Plant	LA	PSD-LA-752	8/16/2011	Auxiliary Boiler (Aux-1)	338 MMBTU/H	0.0075 lb/MMBtu (annual average)	Natural Gas Fuel Only and Good Combustion Practices	--
LA-0254	Entergy Louisiana LLC - Ninemile Point Electric Generating Plant	LA	PSD-LA-752	8/16/2011	Auxiliary Boiler (Aux-1)	338 MMBTU/H	0.0075 lb/MMBtu (annual average)	Natural Gas Fuel Only and Good Combustion Practices	--
LA-0248	Consolidated Environmental Management Inc - Nucor	LA	PSD-LA-751	1/27/2011	Dri-109 - Dri Unit #1 Package Boiler Flue Stack	1,760 Billion Btu/yr	0.0118 lb/MMBtu	Good Combustion Practices	--
LA-0248	Consolidated Environmental Management Inc - Nucor	LA	PSD-LA-751	1/27/2011	Dri-209 - Dri Unit #2 Package Boiler Flue Stack	1,760 Billion Btu/yr	0.0118 lb/MMBtu	Good Combustion Practices	--
LA-0231	Lake Charles Cogeneration, LLC - Lake Charles Gasification Facility	LA	PSD-LA-742	6/22/2009	Auxiliary Boiler	938 MMBTU/H	0.0074 lb/MMBtu	Good Design And Proper Operation	--
AR-0094	Southwest Electric Power Company - John W. Turk Jr. Power Plant	AR	2123-AOP-R0	11/5/2008	Auxiliary Boiler	555 MMBTU/H	0.0040 lb/MMBtu (3-hr average)	--	--
OH-0307	Biomass Energy - South Point Biomass Generation	OH	07-00534	4/4/2006	Auxiliary Boiler	247 MMBTU/H	0.0070 lb/MMBtu	--	--
OH-0269	Biomass Energy - South Point Biomass Generation	OH	07-00534	1/5/2004	Auxiliary Boiler, Natural Gas	247 MMBTU/H	0.0070 lb/MMBtu	--	--
TX-0469	Texas Petrochemicals LP - Houston Facility	TX	P999	10/8/2003	Auxillary Steam Boiler (2)	664 MMBTU/H	0.0040 lb/MMBtu	Natural Gas Fuel Only and Good Combustion Practices	--
IA-0067	Midamerican Energy Company - Walter Scott Jr. Energy Center	IA	PROJECT 02-528	6/17/2003	Auxiliary Boiler	429 MMBTU/H	0.0076 lb/MMBtu	Good Combustion Practices	--
IA-0067	Midamerican Energy Company - Walter Scott Jr. Energy Center	IA	PROJECT 02-528	6/17/2003	Auxiliary Boiler	429 MMBTU/H	0.0076 lb/MMBtu	Good Combustion Practices	--
NJ-0043	Liberty Generating Station	NJ	BOP990001	3/28/2002	Auxiliary Boiler	200 MMBTU/H	0.0080 lb/MMBtu	--	--
TX-0386	Calpine Construction Finance Co. LP - Amelia Energy Center	TX	N-O37	3/26/2002	Auxiliary Boiler	155 MMBTU/H	0.0200 lb/MMBtu	--	--

Table 5-8. Summary and Ranking of PM/PM_{10}/$PM_{2.5}$ Control Technologies

PM Control Method	Technique Now Available	Estimated Efficiency	Feasible and Demonstrated? (Y/N)	Rank Based on Control Efficiency	Employed by NHPC Boiler? (Y/N)
Fuel Techniques	Fuel Substitution	NA	Y	1	Y
Pretreatment	Settling Chambers	< 10%	NTF	NTF	N
	Elutriators	< 10%	NTF	NTF	N
	Momentum Separators	10 - 20%	NTF	NTF	N
	Mechanically-Aided Separators	20 - 30%	NTF	NTF	N
	Cyclones	60 - 90%	NTF	NTF	N
Electrostatic Precipitators (ESP)	Dry ESP	>99%	NTF	NTF	N
	Wet ESP	>99%	NTF	NTF	N
	Wire-Plate ESP	>99%	NTF	NTF	N
	Wire-Pipe ESP	>99%	NTF	NTF	N
Fabric Filters	Shaker-Cleaned	>99%	NTF	NTF	N
	Reverse-Air	>99%	NTF	NTF	N
	Pulse-Jet	>99%	NTF	NTF	N
Wet Scrubbers	Spray Chambers	50 - 95 %	NTF	NTF	N
	Packed-Bed	50 - 95 %	NTF	NTF	N
	Impingement Plate	50 - 95 %	NTF	NTF	N
	Venturi	50 - 95 %	NTF	NTF	N
	Orifice	50 - 95 %	NTF	NTF	N
	Condensation	50 - 95 %	NTF	NTF	N
Combustion	Good Combustion Controls	NA	Y	1	Y

Note: NTF = Not Technically Feasible.

Table 6-1. Summary of the NO_x Facilities Considered for Inclusion in the 1-hr AAQS Air Modeling Analyses

			UTM Coordinates		Relative to NHPC [a]				Maximum	Include in
AIRS Number	Facility	Detail	East (km)	North (km)	X (km)	Y (km)	Distance (km)	Direction (deg)	NO_x Emissions (TPY)	Modeling Analysis ?
Modeling Area [c]										
990332	New Hope Power Company (Existing Plant)	Okeelanta Cogeneration Plant	525.18	2,939.36	-0.05	-0.03	0.06	239.04	2,497	YES
Screening Area										
990615	South Florida Water Management District	SFWMD / Pump Station G-372	519.34	2,923.61	-5.895	-15.782	16.85	200.48	[b]	NO
990026	Sugar Cane Growers Co-Op	Sugar Cane Growers Co-Op	534.87	2,953.86	9.64	14.47	17.39	33.67	484	NO
990614	South Florida Water Management District	SFWMD / Pump Station G-370	540.90	2,918.52	15.673	-20.869	26.10	143.09	[b]	NO
110351	South Florida Water Management District	SFWMD Pump Station S-8 & G-404	522.30	2,912.20	-2.93	-27.19	27.35	186.15	26	NO
990549	South Florida Water Management District	SFWMD / Pump Station G-310	554.20	2,940.45	28.97	1.06	28.99	87.90	11	NO

Note:The significant impact distance for the project is approximately: 5.0 km

[a] New Hope Power Company East and North Coordinates (km) are: 525.18 2,939.36

[b] No emission rate provided by FDEP.

[c] "Modeling Area" is the area in which the project is predicted to have a significant impact.

Table 6-2. Model Parameters Used for 1-hr NO_2 AAQS Analysis

						Stack Parameters							
			NO_x	UTM NAD83		Physical				Operating			
			Emissions[a]	East	North	Height		Diameter		Temperature		Velocity	
Source ID	Model ID	Description	(lb/hr)	(m)	(m)	(ft)	(m)	(ft)	(m)	(°F)	(K)	(fps)	(m/s)
Point Sources													
Boiler A	BLRA	Boiler A	190	525,159	2,939,358	199	60.7	10	3.05	352	451	80.0	24.38
Boiler B	BLRB	Boiler B	190	525,178	2,939,358	199	60.7	10	3.05	352	451	80.0	24.38
Boiler C	BLRC	Boiler C	190	525,197	2,939,358	199	60.7	10	3.05	352	451	80.0	24.38
Boiler D[b]	BLRD	Proposed Boiler D	44.18	525,230	2,939,392	150	45.7	8	2.50	350	450	74.4	22.68

[a] Emissions for Boilers A, B, and C are based on 0.25 lb/MMBtu heat input.

[b] Emissions and operating stack parameters for proposed Boiler D are based on a 75% load operating condition.

Table 6-3. New Hope Power - Boiler Load and Class II Significant Impact Analysis for Proposed Boiler D as Compared to EPA Class II Significant Impact Levels

			Maximum Emission Rate (lb/hr) by Operating Load				Concentration ($\mu g/m^3$)[a]				EPA Significant Impact Level
Pollutant	Averaging Time	Receptor Rank	100%	91%	75%	50%	100%	91%	75%	50%	($\mu g/m^3$)
Generic[b] (10 g/s)	Annual	Highest	79.37	79.37	79.37	79.37	0.19	0.21	0.25	0.34	
	Annual	Highest 5-yr Average					0.17	0.19	0.22	0.30	
	24-Hour	Highest					3.16	3.43	4.04	5.44	
	24-Hour	Highest 5-yr Average					2.74	2.98	3.49	4.62	
	8-Hour	Highest					8.98	10.02	11.98	16.28	
	1-Hour	Highest					30.31	32.68	37.47	46.33	
	1-Hour	Highest 5-yr Average					24.86	27.04	34.34	41.93	
NO_2[c]	Annual	Highest	32.13	29.24	24.10	16.07	0.06	0.06	0.06	0.05	1
	1-Hour	Highest 5-yr Average	58.90	53.60	44.18	29.45	14.8	14.6	15.3	12.4	7.52
PM_{10}	Annual	Highest	3.99	3.63	2.99	2.00	0.010	0.010	0.009	0.008	1
	24-Hour	Highest	10.37	9.43	7.77	5.18	0.413	0.408	0.395	0.356	5
$PM_{2.5}$ (NAAQS)	Annual	Highest 5-yr Average	3.99	3.63	2.99	2.00	0.009	0.008	0.008	0.007	0.3
	24-Hour	Highest 5-yr Average	6.11	5.56	4.58	3.05	0.21	0.21	0.20	0.18	1.2
$PM_{2.5}$ (Increment)	Annual	Highest	3.99	3.63	2.99	2.00	0.010	0.010	0.009	0.008	0.3
	24-Hour	Highest	6.11	5.56	4.58	3.05	0.24	0.24	0.23	0.21	1.2
CO	8-Hour	Highest	94.24	85.76	70.68	47.12	10.7	10.8	10.7	9.7	500
	1-Hour	Highest	94.24	85.76	70.68	47.12	36.0	35.3	33.4	27.5	2,000

[a] Concentrations are based on highest predicted concentrations from AERMOD using 5 years of meteorological data for 2006 to 2010 consisting of surface and upper air data from the National Weather Service stations at Palm Beach International and Florida International University, respectively.

[b] Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s). Pollutant-specific concentrations were then estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the pollutant-specific emission rate to the modeled emission rate of 10 g/s.

[c] For annual and 24-hour averaging times, 75 and 80 percent of NO_x is assumed converted to NO_2, respectively (EPA Ambient Ratio Method, Tier 2).

Table 6-4. New Hope Power - Boiler Load and Class I Significant Impact Analysis for Proposed Boiler D as Compared to EPA Class I Significant Impact Levels

Pollutant	Averaging Time	Rank	Maximum Emission Rate (lb/hr) by Operating Load				Concentration ($\mu g/m^3$)[a]				EPA Significant Impact Level ($\mu g/m^3$)
			100%	91%	75%	50%	100%	91%	75%	50%	
Generic[b]	Annual	Highest	79.37	79.37	79.37	79.37	0.0093	0.0095	0.0100	0.0110	
(10 g/s)	24-Hour	Highest					0.1930	0.2008	0.2165	0.2484	
NO_2[c]	Annual	Highest	32.13	29.24	24.10	16.07	0.0028	0.0026	0.0023	0.0017	0.1
PM_{10}	Annual	Highest	3.99	3.63	2.99	2.00	0.0005	0.0004	0.0004	0.0003	0.2
	24-Hour	Highest	10.37	9.43	7.77	5.18	0.025	0.024	0.021	0.016	0.3
$PM_{2.5}$	Annual	Highest	3.99	3.63	2.99	2.00	0.0005	0.0004	0.0004	0.0003	0.06
(Increment)	24-Hour	Highest	6.11	5.56	4.58	3.05	0.015	0.014	0.012	0.010	0.07

[a] Concentrations are based on highest predicted concentrations from AERMOD using 5 years of meteorological data for 2006 to 2010 consisting of surface and upper air data from the National Weather Service stations at Palm Beach International and Florida International University, respectively.

[b] Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr (10 g/s). Pollutant-specific concentrations were then estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the pollutant-specific emission rate to the modeled emission rate of 10 g/s.

[c] For annual averaging time, 75 percent of NO_x is assumed converted to NO_2 (EPA Ambient Ratio Method, Tier 2).

Table 6-5. Maximum Predicted NO_2 Impacts for all Sources, Compared to the AAQS

Averaging Time and Rank	Maximum Concentration (µg/m³) [a]			Receptor Location		AAQS (µg/m³)
	Background[b] (A)	Modeled Sources[c] (B)	Total (A+C)	UTM- East (m)	UTM- North (m)	
NO_2						
1-Hour, H8H	79.0	63.7	143	526336.75	2936801.56	188

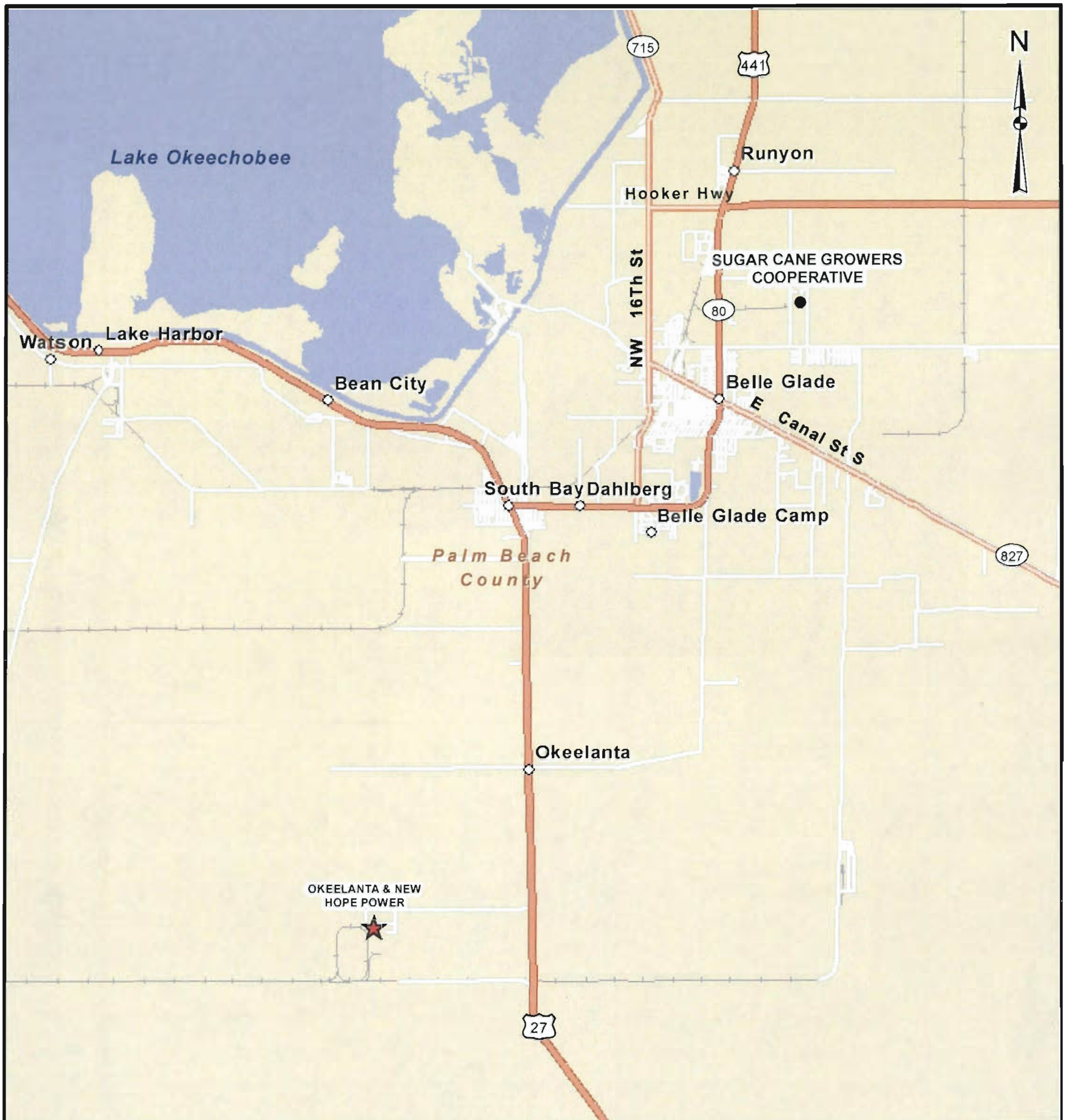
Note:
H8H = Highest, eighth-highest

[a] Modeled concentration is based on 5-year meteorological record, 2006 to 2010, comprised of surface and upper air data from the National Weather Service stations at West Palm Beach International Airport and FIU, respectively.

[b] Based on the 2-year average of the 98th percentile 1-hr concentrations from the Lantana monitoring station.

[c] Assumes 80 percent of NO_x emissions are converted to NO_2 (EPA Tier 2 Approach)

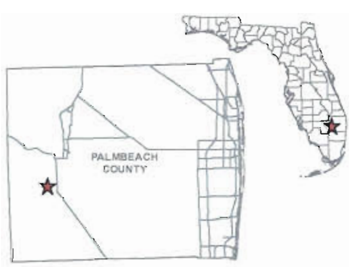
FIGURES



2 0 2 Miles

LEGEND

- ★ Okeelanta & New Hope Power
- ● Sugar Cane Growers Cooperative



REFERENCES

1. Approximate Project Location, New Hope Power Co , Golder Associates Inc , 2012

Coordinate System. NAD 1983 StatePlane Florida East FIPS 0901 Feet
Projection Transverse Mercator
Datum: North American 1983

REV	DATE	DES	REVISION DESCRIPTION	GIS	CHK	RVW
0						

PROJECT

NEW HOPE POWER
BOILER "D" PROJECT

TITLE

SITE LOCATION

Golder Associates

PROJECT No		123-87582	FILE No	12387582_B001
DESIGN	JDG	13 Sep 2012	SCALE AS SHOWN	REV 0
GIS	NRL	13 Sep 2012		
CHECK	NG	13 Sep 2012	**FIGURE: 2-1**	
REVIEW	DB	13 Sep 2012		

G:\PROJECTS\New_Hope_Power\Okeelanta\123-87582 NHPC_PSD\B - REPORT\Figures\123-87582B001 SITE LOCATION.mxd

400 0 400
Feet

LEGEND

- Source Location
- Certified Site Boundary
- Buildings

REV	DATE	DES	REVISION DESCRIPTION	GIS	CHK	RVW
0						

PROJECT
NEW HOPE POWER
BOILER "D" PROJECT

TITLE
NHPC EXISTING CERTIFIED SITE BOUNDARY AND EXISTING BOILERS

REFERENCES

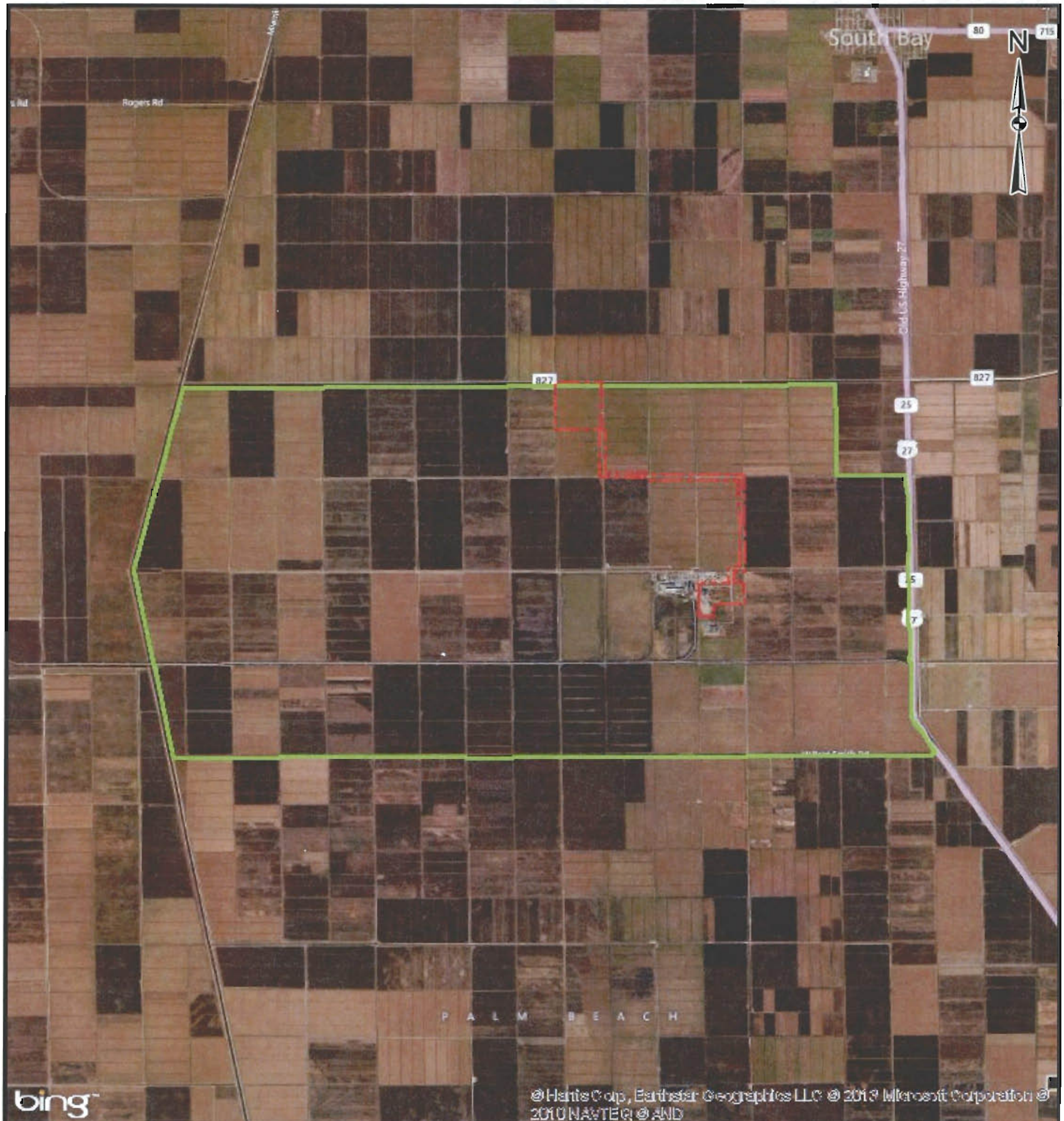
1. Approximate Project Location, New Hope Power Co., Golder Associates Inc., 2012
2. Certified Site Boundary, New Hope Power Co., 2012

Coordinate System: NAD 1983 StatePlane Florida East FIPS 0901 Feet
Projection: Transverse Mercator
Datum: North American 1983

Golder Associates

PROJECT NO. 123-87582			FILE No. 123-87582B002	
DESIGN	JDG	11 Sep. 2012	SCALE: AS SHOWN	REV 1
GIS	NRL	10 Jan. 2013	FIGURE 2-2	
CHECK	NG	10 Jan. 2013		
REVIEW	DB	10 Jan. 2013		

Map Document: / Modified by rlamar / Exported by rlamar



LEGEND

- Certified Site Boundary
- Okeelanta Property Boundary

REFERENCES

1. Approximate Project Location, New Hope Power Co., Golder Associates Inc., 2012
2. Certified Site Boundary, New Hope Power Co., 2012

Coordinate System: NAD 1983 StatePlane Florida East FIPS 0901 Feet
Projection: Transverse Mercator

REV	DATE	DES	REVISION DESCRIPTION	GIS	CHK	RVW
0						

PROJECT

NEW HOPE POWER
BOILER "D" PROJECT

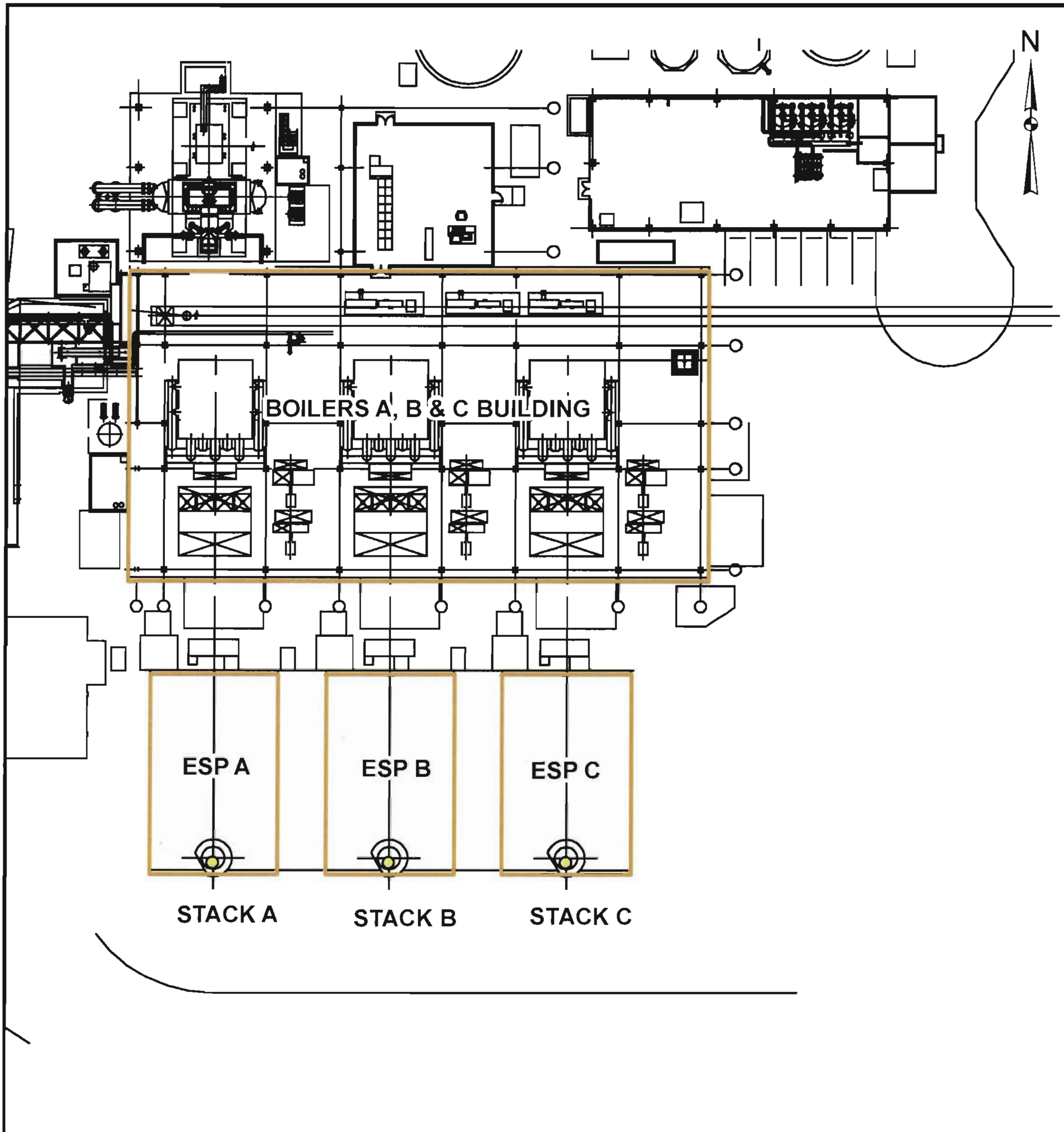
TITLE

NHPC EXISTING PROPERTY BOUNDARY AND CERTIFIED SITE BOUNDARY

Golder Associates

PROJECT NO. 123-87582			FILE No. 123-87582B003	
DESIGN	JDG	11 Sep. 2012	SCALE: AS SHOWN	REV 0
GIS	NRL	25 Jan. 2013	FIGURE 2-3	
CHECK	NG	25 Jan. 2013		
REVIEW	DB	25 Jan. 2013		

Map Document: / Modified by rlamar / Exported by rlamar



LEGEND

- Source Location
- Buildings

50 0 50 Feet

REV.	DATE	DES	REVISION DESCRIPTION	GIS	CHK	RVW
0						

PROJECT

NEW HOPE POWER
BOILER "D" PROJECT

TITLE

NHPC EXISTING PLOT PLAN AND BOILER LOCATIONS

REFERENCES

1. Plot Plan, New Hope Power Co., and Golder Associates Inc., 2012
2. Building Locations and Source Locations, Golder Associates Inc., 2012

Coordinate System: NAD 1983 UTM Zone 17N
Projection: Transverse Mercator
Datum: North American 1983

Golder Associates

PROJECT NO. 123-87582			FILE No. 123-87582B004	
DESIGN	JDG	11 Sep. 2012	SCALE: AS SHOWN	REV 0
GIS	JDG	11 Jan. 2013		
CHECK	NG	11 Jan. 2013		
REVIEW	DB	11 Jan. 2013		

FIGURE 2-4

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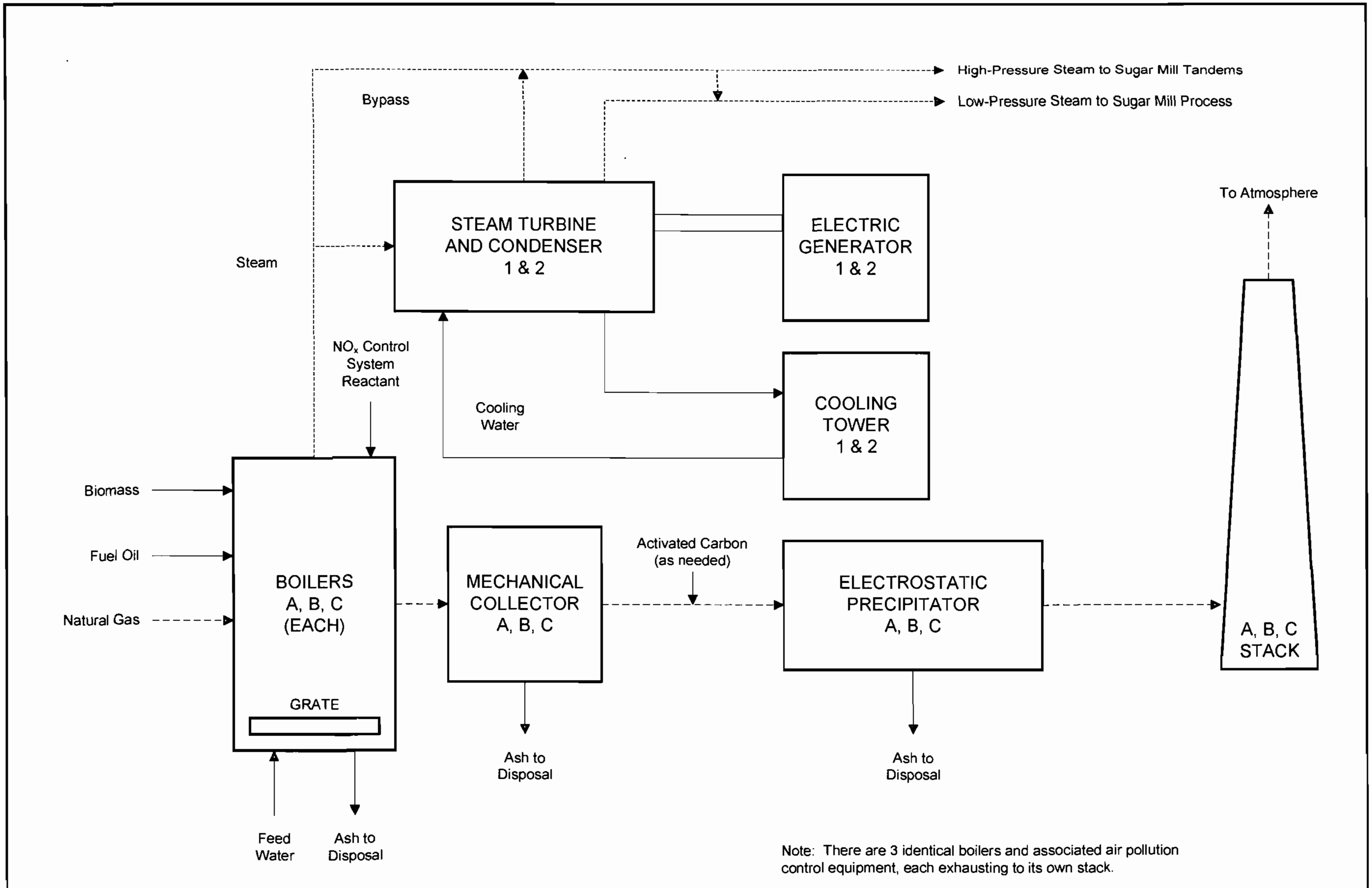


Figure 2-5
Simplified Flow Diagram – Existing Boilers
New Hope Power Company, Okeelanta Cogeneration Facility
South Bay, FL

Process Flow Legend
Solid/Liquid ⟶
Steam ---->
Gas - - - ->

Golder Associates

400 0 400 Feet

LEGEND

- Source Location
- Certified Site Boundary
- Buildings

REFERENCES

1. Buildings and Source Locations, Golder Associates Inc., 2012
2. Certified Site Boundary, New Hope Power Co., 2012

Coordinate System: NAD 1983 StatePlane Florida East FIPS 0901 Feet
Projection: Transverse Mercator

Map Document: / Modified by rlamar / Exported by rlamar

REV	DATE	DES	REVISION DESCRIPTION	GIS	CHK	RVW
0						

PROJECT

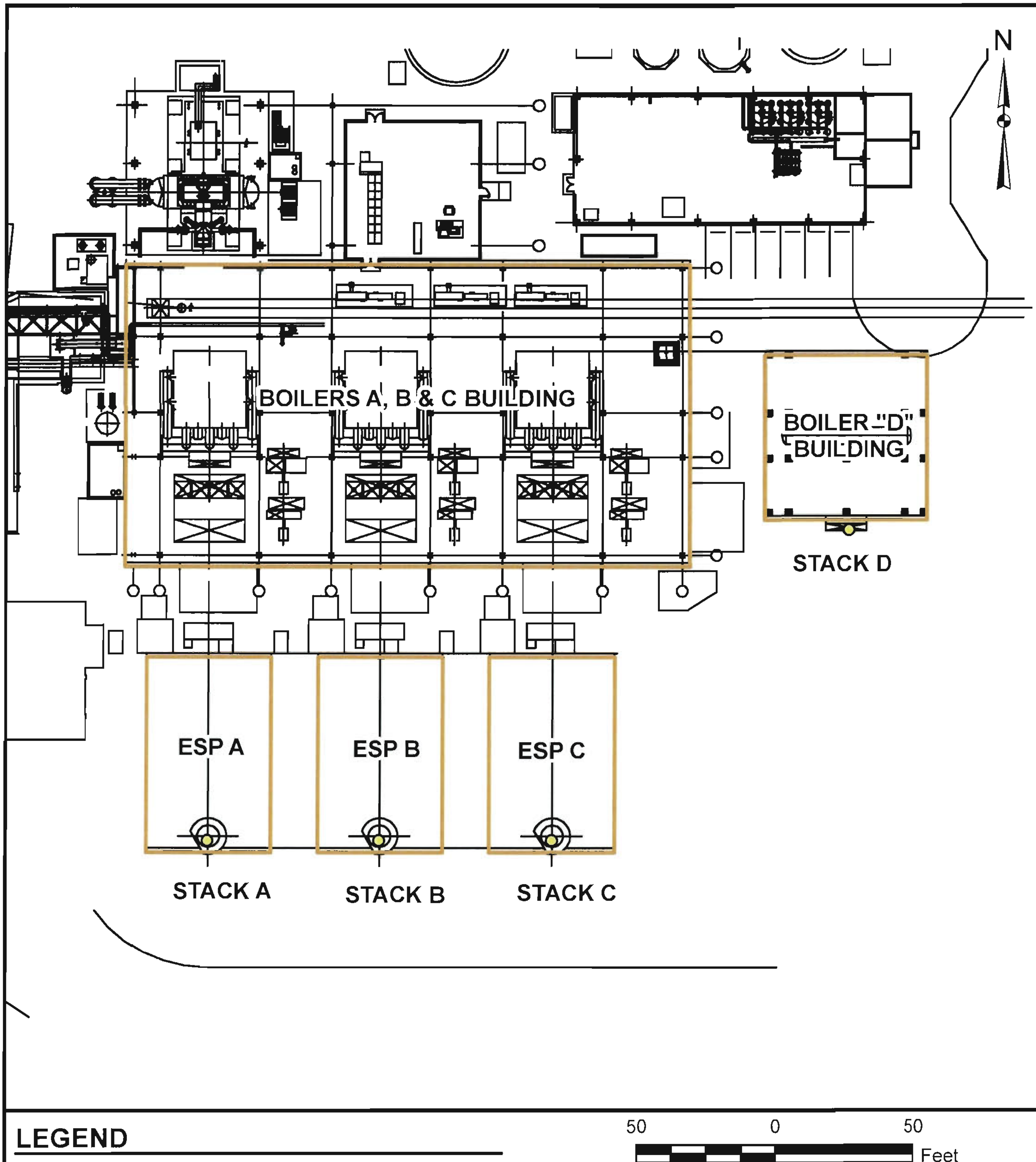
NEW HOPE POWER
BOILER "D" PROJECT

TITLE

NHPC EXISTING CERTIFIED SITE BOUNDARY AND BOILER "D" LOCATION

Golder Associates

PROJECT NO	123-87582		FILE No. 123-87582B005	
DESIGN	JDG	11 Sep. 2013	SCALE: AS SHOWN	REV 1
GIS	NRL	21 Jan. 2013		
CHECK	NG	21 Jan. 2013	**FIGURE 2-6**	
REVIEW	DB	10 Jan. 2013		



LEGEND

- Source Locations
- Buildings

REFERENCES

1. Building and Source Locations, New Hope Power Co., and Golder Associates Inc., 2012
2. Plot Plan, New Hope Power Co., 2012

Coordinate System: NAD 1983 UTM Zone 17N
Projection: Transverse Mercator

REV.	DATE	DES	REVISION DESCRIPTION	GIS	CHK	RVW
0						

PROJECT

NEW HOPE POWER
BOILER "D" PROJECT

TITLE

PROPOSED BOILER "D" LOCATION

Golder Associates

PROJECT NO. 123-87582		
DESIGN	JDG	11 Sep. 2012
GIS	NRL	11 Jan. 2013
CHECK	NG	11 Jan. 2013
REVIEW	DB	11 Jan. 2013

FILE No. 123-87582B006
SCALE: AS SHOWN REV. 0

FIGURE 2-7

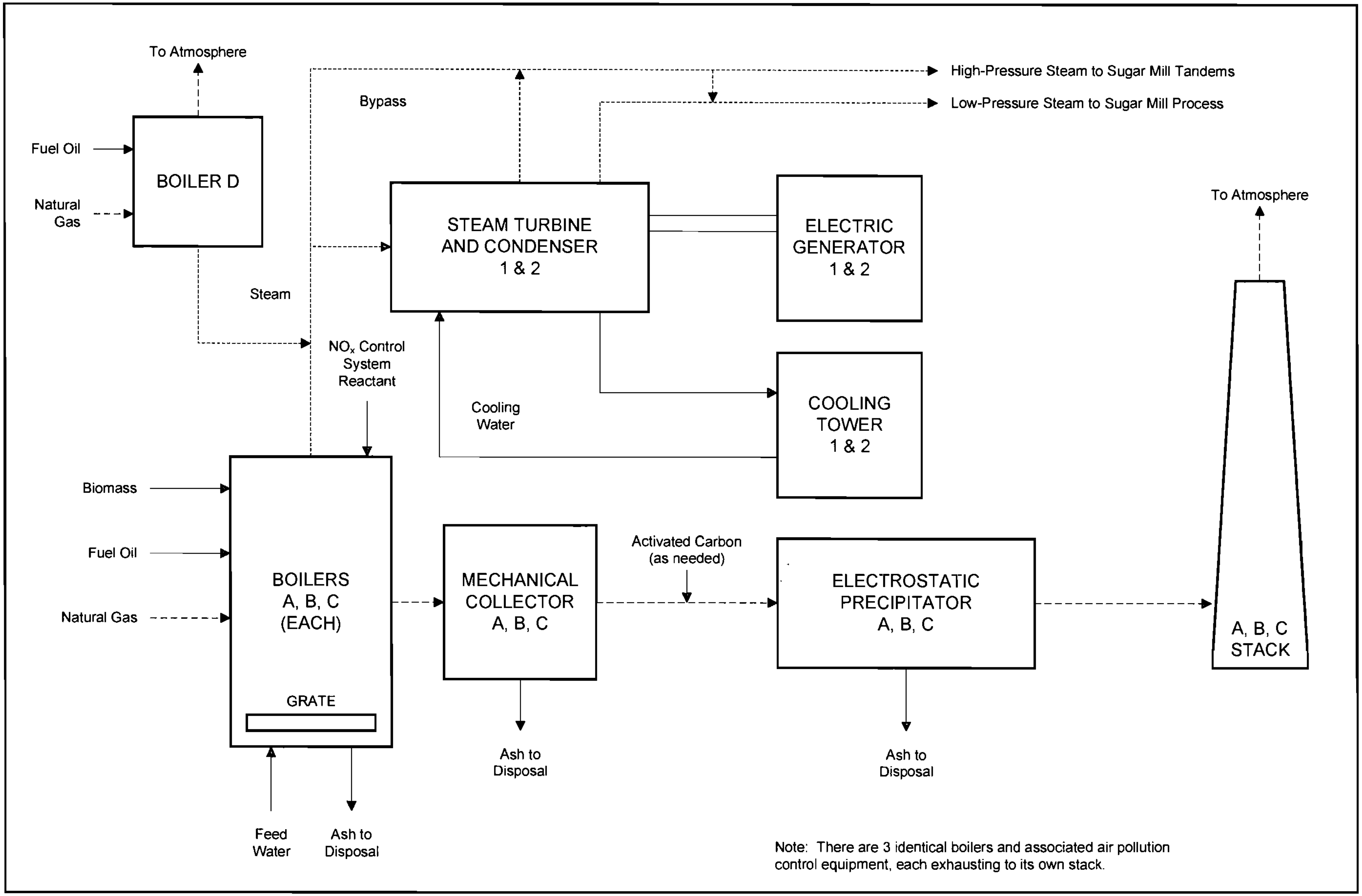
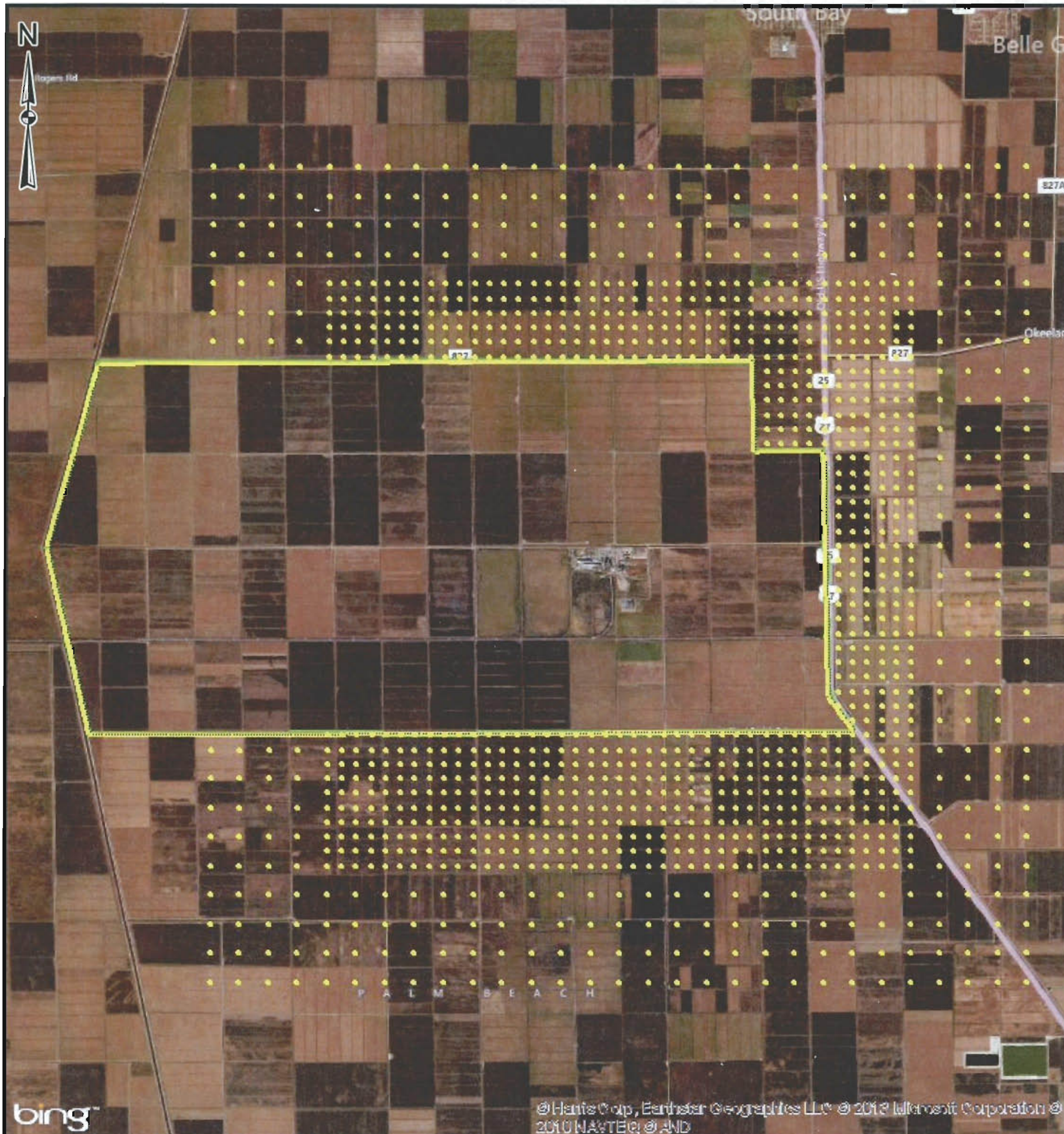


Figure 2-8
Simplified Flow Diagram – With Boiler D
New Hope Power Company, Okeelanta Cogeneration Facility
South Bay, FL

Process Flow Legend
Solid/Liquid
Steam
Gas

Golder Associates

Y:\Projects\2012\123-87582 NHPC PSD\FDEP\Final\5 Figures\Fig 2-5, 2-8.vsd



8,000 0 8,000
Feet

LEGEND

- Risk Receptors
- Okeelanta Property Boundary

REV	DATE	DES	REVISION DESCRIPTION	GIS	CHK	RVW

PROJECT

NEW HOPE POWER
BOILER "D" PROJECT

TITLE

NHPC RECEPTOR GRID
USED FOR MODELING ANALYSIS

REFERENCES

1. Approximate Project Location, New Hope Power Co., Golder Associates Inc., 2012
2. Risk Receptors, Golder Associates Inc., 2012

Coordinate System: NAD 1983 StatePlane Florida East FIPS 0901 Feet
Projection: Transverse Mercator
Datum: North American 1983

Golder Associates

PROJECT NO. 123-87582			FILE No. 123-87582B007	
DESIGN	JDG	11 Sep. 2012	SCALE: AS SHOWN	REV. 1
GIS	NRL	25 Jan. 2013	**FIGURE 6-1**	
CHECK	NG	25 Jan. 2013		
REVIEW	DB	25 Jan. 2013		

Map Document: / Modified by rlamar / Exported by rlamar

APPENDIX A

BOILER D DESIGN DATA

APPENDIX A
BOILER D DESIGN DATA

1. Steam Production Basis:

Maximum 1-hour: 440,000 lb/hr steam
Maximum 24-hour: 400,000 lb/hr steam

2. Steam Enthalpy Calculation

A. Steam conditions: 1,500 psig, 905°F
= 1,515 psia, 905°F
Enthalpy = 1,460 Btu/lb

B. Feedwater condition: 1349 psig, 350°F
= 1364 psia, 350°F
Enthalpy = 322 Btu/lb

C. Net Enthalpy: 1,460 – 322 = 1,138 Btu/lb steam

3. Heat Input Calculation (based on 85 percent thermal efficiency for natural gas or No. 2 fuel oil)

A. Maximum 1-hour:
440,000 lb/hr steam x 1,138 Btu/lb ÷ 0.85 = 589 MMBtu/hr

B. Maximum 24-hour:
400,000 lb/hr steam x 1,138 Btu/lb ÷ 0.85 = 535.5 MMBtu/hr

C. Annual rate:
536 MMBtu/hr x 8,760 hr/yr = 4,691,238 MMBtu/yr

APPENDIX B

CALCULATION OF NO_X AND CO_2 EMISSIONS FROM NEW NATURAL GAS-FIRED BOILER

Appendix B

Calculation of NO_x Emissions From Boiler D- Natural Gas or No. 2 Fuel Oil Firing

Scenario assumes steam sent to Mill which is used by the Mill to generate an additional 7 MW of electrical energy is not counted.

Natural Gas Boiler Data

Net enthalpy =	1,138	Btu/lb
Steam Rate (full load) =	400,000	lb/hr steam
Efficiency =	85	%
Heat Input =	536	MMBtu/hr
NO_x emission factor =	0.06	lb/MMBtu
NO_x @ 400,000 lb/hr steam =	32.13	lb NO_x/hr
NO_x @ 300,000 lb/hr steam =	24.10	lb NO_x/hr
NO_x @ 120,000 lb/hr steam =	9.64	lb NO_x/hr

Crop Season Operation (Natural gas boiler provides 300,000 lb/hr steam)

Gross Electrical output =	17.5	MW	(1,200,000 lb/hr steam from all boilers generates 70 MW) NG boiler's portion of this is 70 MW x (300,000/1,200,000)
Useful thermal output to Mill:			
High pressure steam =	67,500	lb/hr	All boilers generate 270,000 lb/hr of HP steam to Mill not used for electrical energy production:
Enthalpy =	1,336	Btu/lb	
Heat output =	90.2	MMBtu/hr	NG boiler's portion of this is 270,000 x (300,000/1,200,000)
Low pressure steam =	97,500	lb/hr	All boilers generate 390,000 lb/hr of LP steam to Mill and Refinery;
Enthalpy =	1,177	Btu/lb	NG boiler's portion of this is 390,000 x (300,000/1,200,000)
Heat output =	114.8	MMBtu/hr	
Total useful thermal output =	204.9	MMBtu/hr	
=	60.1	MW	
Total Gross Output = (gross elect. + 75% of thermal)	62.6	MW	
NO_x emissions =	0.39	lb NO_x/MWh	

Off-Season Operation (Natural Gas Boiler provides 120,000 lb/hr steam)

Gross Electrical output =	8.8	MW	(300,000 lb/hr steam from all boilers generates 22 MW) NG boiler's portion of this is 22 MW x (120,000/300,000)
Useful thermal output to Mill:			
High pressure steam =	0	lb/hr	No HP steam is sent to mill during off-season
Enthalpy =	1,336	Btu/lb	
Heat output =	0.0	MMBtu/hr	
Low pressure steam =	60,000	lb/hr	All boilers generate 150,000 lb/hr of LP steam to Refinery;
Enthalpy =	1,177	Btu/lb	NG boiler's portion of this is 150,000 x (120,000/300,000)
Heat output =	70.6	MMBtu/hr	
Total useful thermal output =	70.6	MMBtu/hr	
=	20.7	MW	
Total Gross Output = (gross elect. + 75% of thermal)	24.3	MW	
NO_x emissions =	0.40	lb NO_x/MWh	

Appendix B
Calculation of CO_2 Emissions From Boiler D - Natural Gas Firing

Scenario assumes steam sent to Mill which is used by the Mill to generate an additional 7 MW of electrical energy is not counted.

Natural Gas Boiler Data

Net enthalpy =	1,138	Btu/lb	
Steam Rate (full load) =	400,000	lb/hr steam	
Efficiency =	85	%	
Heat Input =	536	MMBtu/hr	
CO_2 emission factor =	53.02	kg/MMBtu	
CO_2 @ 400,000 lb/hr steam =	62,541	lb CO_2/hr	
CO_2 @ 300,000 lb/hr steam =	46,906	lb CO_2/hr	
CO_2 @ 120,000 lb/hr steam =	18,762	lb CO_2/hr	

Crop Season Operation (Natural gas boiler provides 300,000 lb/hr steam)

Gross Electrical output =	17.5	MW	(1,200,000 lb/hr steam from all boilers generates 70 MW) NG boiler's portion of this is 70 MW x (300,000/1,200,000)
Useful thermal output to Mill:			
High pressure steam =	67,500	lb/hr	All boilers generate 270,000 lb/hr of HP steam to Mill not used for electrical energy production: NG boiler's portion of this is 270,000 x (300,000/1,200,000)
Enthalpy =	1,336	Btu/lb	
Heat output =	90.2	MMBtu/hr	
Low pressure steam =	97,500	lb/hr	All boilers generate 390,000 lb/hr of LP steam to Mill and Refinery; NG boiler's portion of this is 390,000 x (300,000/1,200,000)
Enthalpy =	1,177	Btu/lb	
Heat output =	114.8	MMBtu/hr	
Total useful thermal output =	204.9	MMBtu/hr	
=	60.1	MW	
Total Gross Output = (gross elect. + 75% of thermal)	62.6	MW	
CO_2 emissions =	750	lb CO_2/MWh	

Off-Season Operation (Natural Gas Boiler provides 120,000 lb/hr steam)

Gross Electrical output =	8.8	MW	(300,000 lb/hr steam from all boilers generates 22 MW) NG boiler's portion of this is 22 MW x (120,000/300,000)
Useful thermal output to Mill:			
High pressure steam =	0	lb/hr	No HP steam is sent to mill during off-season
Enthalpy =	1,336	Btu/lb	
Heat output =	0.0	MMBtu/hr	
Low pressure steam =	60,000	lb/hr	All boilers generate 150,000 lb/hr of LP steam to Refinery; NG boiler's portion of this is 150,000 x (120,000/300,000)
Enthalpy =	1,177	Btu/lb	
Heat output =	70.6	MMBtu/hr	
Total useful thermal output =	70.6	MMBtu/hr	
=	20.7	MW	
Total Gross Output = (gross elect. + 75% of thermal)	24.3	MW	
CO_2 emissions =	771	lb CO_2/MWh	

Appendix B
Calculation of CO_2 Emissions From Boiler D - No. 2 Fuel Oil Firing

Scenario assumes steam sent to Mill, which is used by the Mill to generate an additional 7 MW of electrical energy, is not counted.

Natural Gas Boiler Data

Net enthalpy =	1,138	Btu/lb	
Steam Rate (full load) =	400,000	lb/hr steam	
Efficiency =	85	%	
Heat Input =	536	MMBtu/hr	
CO_2 emission factor =	73.96	kg/MMBtu	
CO_2 @ 400,000 lb/hr steam =	87,242	lb CO_2/hr	
CO_2 @ 300,000 lb/hr steam =	65,431	lb CO_2/hr	
CO_2 @ 120,000 lb/hr steam =	26,173	lb CO_2/hr	

Crop Season Operation (Natural gas boiler provides 300,000 lb/hr steam)

Gross Electrical output =	17.5	MW	(1,200,000 lb/hr steam from all boilers generates 70 MW) NG boiler's portion of this is 70 MW x (300,000/1,200,000)
Useful thermal output to Mill:			
High pressure steam =	67,500	lb/hr	All boilers generate 270,000 lb/hr of HP steam to Mill not used for electrical energy production:
Enthalpy =	1,336	Btu/lb	
Heat output =	90.2	MMBtu/hr	NG boiler's portion of this is 270,000 x (300,000/1,200,000)
Low pressure steam =	97,500	lb/hr	All boilers generate 390,000 lb/hr of LP steam to Mill and Refinery; NG boiler's portion of this is 390,000 x (300,000/1,200,000)
Enthalpy =	1,177	Btu/lb	
Heat output =	114.8	MMBtu/hr	
Total useful thermal output =	204.9	MMBtu/hr	
=	60.1	MW	
Total Gross Output = (gross elect. + 75% of thermal)	62.6	MW	
CO_2 emissions =	1,046	lb CO_2/MWh	

Off-Season Operation (Natural Gas Boiler provides 120,000 lb/hr steam)

Gross Electrical output =	8.8	MW	(300,000 lb/hr steam from all boilers generates 22 MW) NG boiler's portion of this is 22 MW x (120,000/300,000)
Useful thermal output to Mill:			
High pressure steam =	0	lb/hr	No HP steam is sent to mill during off-season
Enthalpy =	1,336	Btu/lb	
Heat output =	0.0	MMBtu/hr	
Low pressure steam =	60,000	lb/hr	All boilers generate 150,000 lb/hr of LP steam to Refinery; NG boiler's portion of this is 150,000 x (120,000/300,000)
Enthalpy =	1,177	Btu/lb	
Heat output =	70.6	MMBtu/hr	
Total useful thermal output =	70.6	MMBtu/hr	
=	20.7	MW	
Total Gross Output = (gross elect. + 75% of thermal)	24.3	MW	
CO_2 emissions =	1,076	lb CO_2/MWh	

Appendix B
Performance and Proposed GHG BACT Limit (Gross Basis)

Category	Units	Estimated Performance			
Season		Crop Season		Off Season	
Fuel		Gas	Oil	Gas	Oil
Heat Input	MMBtu/hr (HHV)	536	536	536	536
CO_2	lb/hr	46,906	65,431	18,762	26,173
Gross Output	MW	62.55	62.55	24.32	24.32
Gross Heat Rate	Btu/kWh (HHV)	8,562	8,562	22,016	22,016
Gross Efficiency					
CO_2	lb CO_2/MWh	750	1,046	771	1,076
Average On/Off Season	lb CO_2/MWh	750	1,046	771	1,076
Margin for Guarantee	%	5%	5%	5%	5%
Margin for Degredation	%	5%	5%	5%	5%
Proposed CO_2	**lb CO_2/MWh[a]**	**825**	**1,151**	**848**	**1,184**
Season Days	Days	150	150	215	215
Fuel Percentage	%	85%	15%	85%	15%
12-Month Average	**lb CO_2/MWh[b]**		**888**		

[a] Crop Season or Off-Season average.

[b] 12-month rolling average.

Golder Associates

APPENDIX C

VENDOR CATALYST QUOTES

PPC Industries
3000 East Marshall Longview, TX 75601
903-758-3395 Fax 903-758-6487

QUOTATION

Quotation No. 12153A, Rev. 0

Date: 11/13/12

Golder & Associates

Delivery: See Sect. IX.
F.O.B. Point of Manufacture

Attention: Mr. Dave Buff
Email: dbuff@golder.com

Location: Florida

Contact: Link Landers

We are pleased to offer you the following firm quotation for one of our **Model C1x99** CO and **Model N1x180** NOx removal systems.

I. SYSTEM DESIGN BASIS

General system properties at the Inlet to the system

Heat input (MMBTU/hr)	536
Flow (ACFM @ design temperature)	391,000
Flow (lbs/hr)	942,919
Temperature (° F)	550
Basis of tons/yr calculations (hrs/yr)	8,760
Design operating pressure	negative

Inlet loadings at the inlet to the system

CO (lbs/MMBTU) [lbs/hr] {tons/yr}	(0.03) [16.08] {70.4}
NO_x (lbs/MMBTU) [lbs/hr] {tons/yr}	(0.4) [214.4] {939}
Acid gas	none

Guaranteed emission rates at the outlet of the system to atmosphere

CO (lbs/MMBTU) [lbs/hr] {tons/yr}	(0.009) [4.82] {21.1}
NO_x (lbs/MMBTU) [lbs/hr] {tons/yr}	(0.12) [64.32] {281.7}

Removal efficiencies of the system

CO (%)	70
NO_x (%)	70

Miscellaneous items

Pollutant source	Liquid Fuel Boiler
Fuel	Natural Gas or #2 Fuel Oil
Full load power consumption (Kw)	30
Maximum operating duct pressure (inches-wc positive)	2.0
Overall pressure drop (inches – wc)	6.5

<u>**Utilities Required**</u>

CO Removal

Supply power voltage/frequency	480 / 3 phase / 60 Hz

Control voltage/frequency .... 120 / 1 phase / 60 Hz

NOx Removal

Instrument Air (dry to -40°F): 70-90 psi .... 1 acfm
Supply power voltage/frequency .... 480 / 3 phase / 60 Hz
Control voltage/frequency .... 120 / 1 phase / 60 Hz
Heat Trace Power .... 240 V / 1 phase / 60 Hz/ 15 amps
Ammonia Type .... Anhydrous
Ammonia (lbs/hr) 97
Ammonia (gals/hour @ 19%) 66.3
Ammonia delivery system must include appropriate heat/insulation to maintain pressure

The purchaser is responsible for the confirmation of all estimated design conditions shown above before a purchase order is finalized. If this is not done, PPC's estimated conditions will apply for meeting guarantees.

II. SCOPE OF EQUIPMENT SUPPLY BY PPC INDUSTRIES

CO AND NOx REMOVAL SYSTEM

PPC is offering one **Model C1 X 99** CO and one **Model N1x180** NO_x removal catalyst systems.

The CO removal catalyst system will have the following design features:

Flow distribution devices .... as required
Catalyst layers 1
Structural design temp. (°F.) 750

The NOx removal catalyst system will have the following design features:

NOx Reduction Reagent .... Ammonia
Catalyst layers 1
Structural design temp. (°F.) 750
Ammonia injection grid location .... after CO Catalyst

NOx SYSTEM SPECIFICS

Ammonia Injection Grid (AIG): PPC will provide a sectioned ammonia distribution grid. The reactor housing will come complete with injection grid supports and piping as required. The system will be complete with flow balancing valves to allow tuning of the ammonia distribution system to the SCR removal elements.

Ammonia will be metered to the SCR process through a factory assembled and mostly prefabricated skid including an ammonia flow controller proportionally controlled by a customer supplied 4-20 ma flow control signal. PPC will fabricate the ammonia flow control system consisting of stainless steel tubing including all necessary filters, gauges, regulators, etc, The ammonia system will also include isolating bypass and drain valves as required to make a complete operating system.

Also included is an air dilution system with dilution air blowers capable of discharge pressure exceeding 20" w.c. The dilution air fan will be powered by 480 volt 3 phase, TEFC, 60 Hz, 3600 rpm. The dilution air fan will be mounted on a mounting surface provided for local maintenance disconnects to be mounted and installed by others.

Piping from the fans to the ammonia distribution system will be fabricated and supplied by others. Ammonia will be metered into the dilution fan exhaust (or evaporator when using aqueous ammonia) which will then flow in to the ammonia injection grid (AIG).

The catalyst system is based Haldor Topsoe catalyst or equal. The catalyst will be mounted in honeycomb blocks approximately 18" x 18" x 22.5". The catalyst bed(s) will be separated by a sufficient distance to allow each bed to have its own knife system.

CATALYST HOUSING

PPC will furnish a housing fabricated from 3/16" thick ASTM A-36 steel plate with external ASTM A-36 structural stiffeners as required to support the shell pressure, wind, live, and shell and catalyst dead loads. The shell will be seal welded to form a gas tight structure.

Catalyst loading opening with manways will be supplied to allow access to any catalyst carrier element.

The housing will be equipped with an inlet and outlet flanged connections. The housing will be fabricated from externally stiffened 3/16" thick ASTM A-36 steel plate.

The catalyst housing will include all structural steel with self-lubricating slide plates between the housing and support structure. The slide pads shall be designed for the high temperatures.

Each bed will be cleaned with its own high pressure high volume "air knife" system. Each air knife system consists of a high pressure blower, a section of flexible blower hose, which is connected to a knife plenum. The knife plenum are supported by a flat bar railing on each side of the reactor housing. The dead space on one end of the reactor housing will hold the "knife" when it is not in use. The plenum housing will be moved across the bed using a stainless steel cable system and a small gear reducer. Limit switches will be provided to indicate to the operating system when the knife has completed its cycle. The air knife system will be controlled by PPC.

The system will be activated based on pressure drop readings through the plant PLC. PPC will provide blower skid for mounting near the cleaning sections

Catalyst will ship with the housing. The purchaser will be responsible for storing the catalyst in a clean and dry location until it is installed. The catalyst cannot be installed until the boiler is proven reliable and able to run continuously.

CATALYST PORT ACCESS

A separate inspection/cleanout port will be supplied at each catalyst bed to facilitate inspection of catalyst and ductwork. Inspection/cleanout ports will be bolted shut and have gas tight seals. Test ports will be supplied up and down stream of the catalyst bed for sampling and testing of the flue gas.

The inspection/cleanout ports and test ports will be accessible from purchaser furnished temporary access.

CATALYST HOUSING INSULATION & SIDING

PPC will provide factory insulation of the housing. The insulation will consist of 3" of 8# density mineral wool on the hot gas surfaces in contact with the 3/16" shell on the housing.

The housing will be covered with 0.032" thick, unpainted, stucco embossed, Type 3003, 1 x 4 box ribbed aluminum sheeting. The siding will run vertically and will be overlapped one section at all seams.

The insulation seams will be covered with 0.032" thick, flat, unpainted, stucco embossed, Type 3003 flat sheeting. All openings will be filled with EPDM synthetic rubber closure strips to match the siding contour.

The siding material will be attached with TEK #5 12-24 x 1¼" Climaseal screws with neoprene washers. The sheet to sheet connections will be with ¼ - 14 x 3/8" stitching screws with neoprene washers. All siding seams that are subject to moisture infiltration will be sealed with clear silicon sealant before assembly.

CATALYST HOUSING PAINTING

PPC will paint the structural supports and all final exposed surfaces with one coat of red primer and one coat of medium industrial gray enamel finish paint. All hot metal surfaces that will be exposed after the field insulation is completed will be painted with high temperature black paint. All ladders, platforms (including supports) and railings will be finish painted with safety yellow enamel.

All metal surfaces that will be exposed after the field insulation is completed will be painted with two coats of high temperature black paint.

III. EQUIPMENT ACCESS:

NOx Catalyst Access: PPC will provide equipment access stairs or ladder (when required) from grade of each bed of NOx catalyst in the housing. The equipment access stairs will be 2' - 6" wide with galvanized steps and painted integral railings. The equipment access stairs will have intermediate landings as required. The landings will have painted kick plates and painted integral railings. The handrails and posts will be 2" square tubing. Paint system will be as per base proposal.

CO Catalyst Access: Access doors will be provided to access the CO catalyst.

IV. ENGINEERING AND TECHNICAL SERVICES:

PPC will supervise the equipment check out and will train the purchaser's personnel in the operation and maintenance of the equipment. The charge for this service will be as set forth in the attached Standard Terms and Rates for PPC Service Representative.

PPC will provide the following:

- General arrangement drawings
- Foundation loading diagrams and anchor bolt patterns
- Erection and interface drawings
- Operators manual (1 electronic copy)
- Recommended spare parts list
- Installation procedure
- Complete electrical package on AutoCad

V. FIELD CONSTRUCTION SERVICES:

Mechanical: All field mechanical construction is to be by the purchaser. The price in this quotation is based on installation by others. See the Options Section for installation by PPC.

Electrical: PPC will provide a factory wired ammonia control skid. PPC will furnish the electrical equipment shown in the base bid for the ammonia flow control system. All power, control and alarm wiring will be by others. All field electrical work is to be by the purchaser

VI. WORK BY OTHERS:

All work not specifically mentioned as part of PPC's scope of work will be by the purchaser or by other parties. In addition to the items listed below, the purchaser is to supply foundations, anchor bolts, equipment setting pads, housekeeping pads, etc. in order to allow PPC to install the above referenced equipment.

NOx REMOVAL SYSTEM WORK BY OTHERS

All work not specifically mentioned as part of PPC's scope of work will be by the purchaser or by other parties. Work by others includes, but is not limited to:

- Ammonia cylinder rack or tank
- Ammonia cylinder manifolding (if applicable)
- Ammonia cylinder heating and insulation (if applicable)
- Any required ammonia cylinder containment or security facilities
- Safety Showers, Eyewash Stations and Protective Equipment if required
- Ammonia Leak Detection system, if required
- Ammonia Storage Area, if required
- Ammonia Demand Signal for control of PPC supplied Ammonia Flow Control Valve

The purchaser is responsible for supplying and installing minimum ½" stainless steel supply tubing from ammonia supply area to the PPC supplied flow control valve. All field wiring will be by others.

VII. PERFORMANCE AND TESTING GUARANTEE

CO: The proposed equipment, when operating at design conditions and at an inlet load of 0.03 lbs of CO per mmbtu is guaranteed to emit not more than 0.009 lbs of CO per mmbtu or to remove 70% by weight of the inlet CO load. If the inlet particulate load is greater than the design conditions the efficiency of 70% is guaranteed; if it is equal or less than the design conditions a residual of 0.009 lbs of CO per mmbtu is guaranteed.

NO_x: The proposed equipment, when operating at design conditions and at an inlet load of 0.4 lbs of NO_x per mmbtu is guaranteed to emit not more than 0.12 lbs of NO_x per mmbtu or to remove 70% by weight of the inlet NO_x load. If the inlet particulate load is greater than the design conditions the efficiency of 70% is guaranteed; if it is equal or less than the design conditions a residual of 0.12 lbs of NO_x per mmbtu is guaranteed.

AMMONIA SLIP: PPC guarantees the maximum ammonia slip to be less than 10 ppmvd at 3% O2.

BED LIFE: PPC warrants the minimum bed life to be more than 8,760 hours.

TEST PERIOD: The unit must be tested within 30 days after initial equipment operation or 90 days after the final truck shipment; whichever occurs first. If the unit is not tested within this time period, it shall be considered as accepted.

Conditions for valid guarantees

The purchaser is responsible for the confirmation of all estimated design conditions shown in Section I before a purchase order is finalized. Where percent removal and fixed emission levels are guaranteed, simultaneous testing of the inlet and outlet is required. If the actual emission rate is less than the guaranteed outlet level or the actual percent removal is greater than the guaranteed level then PPC is considered to have met their performance guarantee for that pollutant. If actual outlet emission level is great than specified outlet emission level and the actual percent removal is less than guaranteed percent removal PPC will incur the cost of the testing company to retest for that pollutant.

INLET DUCT DESIGN: Laminar & uniform flow of the flue gas is essential for operation and guarantees.

VIII. PRICING AND OPTIONS

All prices quoted are valid for 30 days from the quotation date. No duties, fees or taxes are included. Sales tax or an equivalent amount will be charged if a sales tax exemption certificate is not sent to PPC by the purchaser.

The total price F.O.B. Point of Manufacture for the work as set forth in Sections I through IV is .... U.S. $ 1,117,000.00
This price is based in part on the current market prices of precious metals. We reserve the right to adjust our prices based on documented market fluctuations (the current prices are Pt $1580 and Pd $603).

Estimated freight cost to transport the equipment to jobsite*** .... U.S. $ later
***Logistical issues dictate the necessity of a PPC installation of equipment if this option is selected.

GENERAL OPTIONS:

Mechanical Installation by PPC (non-union and non Davis Bacon rates)

Note: Plant requirements for manlifts, hole watch or fire watch costs are not included. Customer is to supply manlift for up to three weeks if required, at no cost to PPC.

Installation of CO/NOx Removal System: PPC will set the CO/NOx removal reactor vessel on foundations supplied by others and will install any access included with this system.

An inspection by the purchaser shall be made at the completion of the field erection. The correction of any punch list items shall be made before the construction advisor leaves the jobsite. PPC's quotation is based on no delay between the completion and the correction of the punch list items. Any additional trips and/or delays required by purchaser and not the fault of PPC will be billed per our attached Standard Terms and Conditions of Sale of Field Services.

Total for installation by PPC* .... U.S. $ 45,000.00

Any items marked with an * mean that PPC field manpower crew availability may preclude PPC supplying this option. Whether PPC can do the installation will be determined at the time of purchase.

NOx CATALYST SYSTEM OPTIONS:

Installation of NOx Catalyst Loading*: PPC can return to the jobsite after the initial startup and load the catalyst into the SCR housing. The purchaser must furnish any required lift equipment (manlift, forklift, mobile scaffolding, crane, etc.) to permit manual loading of the catalyst elements into the SCR housing.

Price .... U.S. $ Later

Aqueous Ammonia System: In lieu of the anhydrous ammonia system for the SCR, PPC will provide a 19% aqueous system. The system will include one stainless steel aqueous ammonia pump, one spare pump (not piped), one high pressure blower, a stainless steel vaporizer vessel with two phase nozzles and all the instruments and associated equipment to make the system operational. The purchaser must supply the aqueous ammonia storage tank.

Price F.O.B. Point of Manufacture .... U.S. $ 45,700.00
Installation by PPC* .... U.S. $ 2,500.00
Freight .... U.S. $ 1,000.00

Catalyst Storage: In the event the purchaser does not have a clean and dry location to store the catalyst, PPC can provide cargo containers for onsite storage. The containers will become the property of the purchaser.

Price each F.O.B. Point of Manufacture .... U.S. $ 5,000.00

19% Ammonia Solution Tank: PPC will provide a 10,000 gallon (nominal) ARI 650 fiberglass tank with loading line and standard fittings for installation on foundations supplied by purchaser.

Price F.O.B. Point of Manufacture .... U.S. $ 10,700.00
Installation by PPC* .... U.S. $ 800.00
Freight .... U.S. $ 1,900.00

NOx Extra Layer(s) Capability: PPC will provide an extra NOx catalyst section without catalyst for future catalyst maintenance. The extra section will include the air knife, access and support matrix. In short, everything provided for the other catalyst sections minus the catalyst.

Add to base quotation (including freight and installation for each layer). .... U.S. $ 63,000.00

NOx Extra Duct Capacity: PPC will provide additional space to add another layer of NOx catalyst including access extension and access door. This includes no air knife or penetrations.

Price F.O.B. Point of Manufacture .... U.S. $ 23,000.00

Wide Platform: Instead of the 4'-0" platform provided in the base quote, PPC can extend platform section in front of the catalyst loading doors by five feet creating a 9'-0" wide working platform.

Price F.O.B. Point of manufacture .... U.S. $ 14,700.00

Current NOx Catalyst Replacement Cost:
Price F.O.B. Point of Manufacture .... U.S. $ 250,000.00

CO CATALYST SYSTEM OPTIONS:

CO Extra Duct: PPC will provide additional space to add another layer of CO catalyst (does not include any additional penetrations).

Price F.O.B. Point of Manufacture .... U.S. $ 5,700.00

CO Capability: PPC will provide a CO catalyst section without catalyst for future catalyst addition. This section will include the air knife, access and support matrix. In short, everything but the catalyst.

Add to base quotation (including freight and installation for each layer). .... U.S. $ 63,000.00

Current CO Catalyst Replacement Cost:
Price F.O.B. Point of Manufacture .... U.S. $ 240,000

IX. SCHEDULE OF DELIVERY

PPC will provide the proposed equipment according to the following schedule. Time is calculated from the receipt of order by PPC.
Equipment Arrangement and Loading Diagrams .... 5 weeks
Material Shipment .... to be negotiated at time of purchase order

X. SCHEDULE OF PAYMENT

All invoices are Net 30 Days.
The schedule of payment is:
- 15% of contract price upon receipt of order
- 20% four weeks after receipt of order
- 20% eight weeks after receipt of order
- 20% twelve weeks after receipt of order
- 20% upon initial shipment

Balance upon successful performance test completion or 90 days after shipment, whichever is sooner.

XI. TERMS AND CONDITIONS OF SALE

Raw Materials: This quotation is based on current steel pricing and is good for the number of days specified in section VIII from the date of the quotation. PPC Reserves the right to adjust the sales price, for any escalation in raw materials such as steel, platinum, palladium, etc.., at the time of a purchase order is issued.

The following attachments are made a part of this quotation:

Standard Terms and Conditions of Sale
Standard Terms and Conditions of Sale for CO and NOx Catalyst System
Standard Terms and Rates for PPC Service Representative

INSURANCE
The above sales price is contingent on PPC's standard levels of insurance which are: General Liability $1,000,000 per occurrence, Business Auto - $1,000,000 per each accident, Products Liability - $1,000,000 per occurrence and Umbrella Liability - $3,000,000 per occurrence /aggregate. If any extra levels of insurance are required or if additional endorsements are required, they will be invoiced at cost.

PPC Industries
3000 East Marshall Longview, TX 75601
903-758-3395 Fax 903-758-6487

QUOTATION

Quotation No. 12153B, Rev. 0

Date: 11/13/12

Golder & Associates

Delivery: See Sect. IX.
F.O.B. Point of Manufacture

Attention: Mr. Dave Buff
Email: dbuff@golder.com

Location: Florida

Contact: Link Landers

We are pleased to offer you the following firm quotation for one of our **Model C1x108** CO and **Model N1x192** NOx removal systems.

I. SYSTEM DESIGN BASIS

General system properties at the Inlet to the system

Heat input (MMBTU/hr) 536
Flow (ACFM @ design temperature) 391,000
Flow (lbs/hr) 942,919
Temperature (° F) 550
Basis of tons/yr calculations (hrs/yr) 8,760
Design operating pressure ..... negative

Inlet loadings at the inlet to the system

CO (lbs/MMBTU) [lbs/hr] {tons/yr} ..... (0.03) [16.08] {70.4}
NO_x (lbs/MMBTU) [lbs/hr] {tons/yr} ..... (0.4) [214.4] {939}
Acid gas ..... none

Guaranteed emission rates at the outlet of the system to atmosphere

CO (lbs/MMBTU) [lbs/hr] {tons/yr} ..... (0.003) [1.61] {7}
NO_x (lbs/MMBTU) [lbs/hr] {tons/yr} ..... (0.04) [21.4] {93.9}

Removal efficiencies of the system

CO (%) 90
NO_x (%) 90

Miscellaneous items

Pollutant source ..... Liquid Fuel Boiler
Fuel ..... Natural Gas or #2 Fuel Oil
Full load power consumption (Kw) 30
Overall pressure drop (inches – wc) 6.5

<u>Utilities Required</u>

CO Removal

Supply power voltage/frequency ..... 480 / 3 phase / 60 Hz
Control voltage/frequency ..... 120 / 1 phase / 60 Hz

NOx Removal

Instrument Air (dry to -40°F): 70-90 psi	1 acfm
Supply power voltage/frequency	480 / 3 phase / 60 Hz
Control voltage/frequency	120 / 1 phase / 60 Hz
Heat Trace Power	240 V / 1 phase / 60 Hz/ 15 amps
Ammonia Type	Anhydrous
Ammonia (lbs/hr)	123
Ammonia (gals/hour @ 19%)	84

Ammonia delivery system must include appropriate heat/insulation to maintain pressure

The purchaser is responsible for the confirmation of all estimated design conditions shown above before a purchase order is finalized. If this is not done, PPC's estimated conditions will apply for meeting guarantees.

II. SCOPE OF EQUIPMENT SUPPLY BY PPC INDUSTRIES

CO AND NOx REMOVAL SYSTEM

PPC is offering one **Model C1x108** CO and **Model N1x192** NO_x removal catalyst systems.

The CO removal catalyst system will have the following design features:

Flow distribution devices	as required
Catalyst layers	1
Structural design temp. (°F.)	750

The NOx removal catalyst system will have the following design features:

NOx Reduction Reagent	Ammonia
Catalyst layers	1
Structural design temp. (°F.)	750
Ammonia injection grid location	after CO Catalyst

NOx SYSTEM SPECIFICS

Ammonia Injection Grid (AIG): PPC will provide a sectioned ammonia distribution grid. The reactor housing will come complete with injection grid supports and piping as required. The system will be complete with flow balancing valves to allow tuning of the ammonia distribution system to the SCR removal elements.

Ammonia will be metered to the SCR process through a factory assembled and mostly prefabricated skid including an ammonia flow controller proportionally controlled by a customer supplied 4-20 ma flow control signal. PPC will fabricate the ammonia flow control system consisting of stainless steel tubing including all necessary filters, gauges, regulators, etc, The ammonia system will also include isolating bypass and drain valves as required to make a complete operating system.

Also included is an air dilution system with dilution air blowers capable of discharge pressure exceeding 20" w.c. The dilution air fan will be powered by 480 volt 3 phase, TEFC, 60 Hz, 3600 rpm. The dilution air fan will be mounted on a mounting surface provided for local maintenance disconnects to be mounted and installed by others.

Piping from the fans to the ammonia distribution system will be fabricated and supplied by others. Ammonia will be metered into the dilution fan exhaust (or evaporator when using aqueous ammonia) which will then flow in to the ammonia injection grid (AIG).

The catalyst system is based Haldor Topsoe catalyst or equal. The catalyst will be mounted in honeycomb blocks approximately 18" x 18" x 22.5". The catalyst bed(s) will be separated by a sufficient distance to allow each bed to have its own knife system.

CATALYST HOUSING

PPC will furnish a housing fabricated from 3/16" thick ASTM A-36 steel plate with external ASTM A-36 structural stiffeners as required to support the shell pressure, wind, live, and shell and catalyst dead loads. The shell will be seal welded to form a gas tight structure.

Catalyst loading opening with manways will be supplied to allow access to any catalyst carrier element.

The housing will be equipped with an inlet and outlet flanged connections. The housing will be fabricated from externally stiffened 3/16" thick ASTM A-36 steel plate.

The catalyst housing will include all structural steel with self-lubricating slide plates between the housing and support structure. The slide pads shall be designed for the high temperatures.

Each bed will be cleaned with its own high pressure high volume "air knife" system. Each air knife system consists of a high pressure blower, a section of flexible blower hose, which is connected to a knife plenum. The knife plenum are supported by a flat bar railing on each side of the reactor housing. The dead space on one end of the reactor housing will hold the "knife" when it is not in use. The plenum housing will be moved across the bed using a stainless steel cable system and a small gear reducer. Limit switches will be provided to indicate to the operating system when the knife has completed its cycle. The air knife system will be controlled by PPC.

The system will be activated based on pressure drop readings through the plant PLC. PPC will provide blower skid for mounting near the cleaning sections

Catalyst will ship with the housing. The purchaser will be responsible for storing the catalyst in a clean and dry location until it is installed. The catalyst cannot be installed until the boiler is proven reliable and able to run continuously.

CATALYST PORT ACCESS

A separate inspection/cleanout port will be supplied at each catalyst bed to facilitate inspection of catalyst and ductwork. Inspection/cleanout ports will be bolted shut and have gas tight seals. Test ports will be supplied up and down stream of the catalyst bed for sampling and testing of the flue gas.

The inspection/cleanout ports and test ports will be accessible from purchaser furnished temporary access.

CATALYST HOUSING INSULATION & SIDING

PPC will provide factory insulation of the housing. The insulation will consist of 3" of 8# density mineral wool on the hot gas surfaces in contact with the 3/16" shell on the housing.

The housing will be covered with 0.032" thick, unpainted, stucco embossed, Type 3003, 1 x 4 box ribbed aluminum sheeting. The siding will run vertically and will be overlapped one section at all seams.

The insulation seams will be covered with 0.032" thick, flat, unpainted, stucco embossed, Type 3003 flat sheeting. All openings will be filled with EPDM synthetic rubber closure strips to match the siding contour.

The siding material will be attached with TEK #5 12-24 x 1¼" Climaseal screws with neoprene washers. The sheet to sheet connections will be with ¼ - 14 x 3/8" stitching screws with neoprene washers. All siding seams that are subject to moisture infiltration will be sealed with clear silicon sealant before assembly.

CATALYST HOUSING PAINTING

PPC will paint the structural supports and all final exposed surfaces with one coat of red primer and one coat of medium industrial gray enamel finish paint. All hot metal surfaces that will be exposed after the field insulation is completed will be painted with high temperature black paint. All ladders, platforms (including supports) and railings will be finish painted with safety yellow enamel.

All metal surfaces that will be exposed after the field insulation is completed will be painted with two coats of high temperature black paint.

III. EQUIPMENT ACCESS:

NOx Catalyst Access: PPC will provide equipment access stairs or ladder (when required) from grade of each bed of NOx catalyst in the housing. The equipment access stairs will be 2' - 6" wide with galvanized steps and painted integral railings. The equipment access stairs will have intermediate landings as required. The landings will have painted kick plates and painted integral railings. The handrails and posts will be 2" square tubing. Paint system will be as per base proposal.

CO Catalyst Access: Access doors will be provided to access the CO catalyst.

IV. ENGINEERING AND TECHNICAL SERVICES:

PPC will supervise the equipment check out and will train the purchaser's personnel in the operation and maintenance of the equipment. The charge for this service will be as set forth in the attached Standard Terms and Rates for PPC Service Representative.

PPC will provide the following:

- General arrangement drawings
- Foundation loading diagrams and anchor bolt patterns
- Erection and interface drawings
- Operators manual (1 electronic copy)
- Recommended spare parts list
- Installation procedure
- Complete electrical package on AutoCad

V. FIELD CONSTRUCTION SERVICES:

Mechanical: All field mechanical construction is to be by the purchaser. The price in this quotation is based on installation by others. See the Options Section for installation by PPC.

Electrical: PPC will provide a factory wired ammonia control skid. PPC will furnish the electrical equipment shown in the base bid for the ammonia flow control system. All power, control and alarm wiring will be by others. All field electrical work is to be by the purchaser

VI. WORK BY OTHERS:

All work not specifically mentioned as part of PPC's scope of work will be by the purchaser or by other parties. In addition to the items listed below, the purchaser is to supply foundations, anchor bolts, equipment setting pads, housekeeping pads, etc. in order to allow PPC to install the above referenced equipment.

NOx REMOVAL SYSTEM WORK BY OTHERS

All work not specifically mentioned as part of PPC's scope of work will be by the purchaser or by other parties. Work by others includes, but is not limited to:

- Ammonia cylinder rack or tank
- Ammonia cylinder manifolding (if applicable)
- Ammonia cylinder heating and insulation (if applicable)
- Any required ammonia cylinder containment or security facilities
- Safety Showers, Eyewash Stations and Protective Equipment if required
- Ammonia Leak Detection system, if required
- Ammonia Storage Area, if required
- Ammonia Demand Signal for control of PPC supplied Ammonia Flow Control Valve

The purchaser is responsible for supplying and installing minimum ½" stainless steel supply tubing from ammonia supply area to the PPC supplied flow control valve. All field wiring will be by others.

VII. PERFORMANCE AND TESTING GUARANTEE

CO: The proposed equipment, when operating at design conditions and at an inlet load of 0.03 lbs of CO per mmbtu is guaranteed to emit not more than 0.003 lbs of CO per mmbtu or to remove 90% by weight of the inlet CO load. If the inlet particulate load is greater than the design conditions the efficiency of 90% is guaranteed; if it is equal or less than the design conditions a residual of 0.003 lbs of CO per mmbtu is guaranteed.

NO_x: The proposed equipment, when operating at design conditions and at an inlet load of 0.4 lbs of NO_x per mmbtu is guaranteed to emit not more than 0.04 lbs of NO_x per mmbtu or to remove 90% by weight of the inlet NO_x load. If the inlet particulate load is greater than the design conditions the efficiency of 90% is guaranteed; if it is equal or less than the design conditions a residual of 0.04 lbs of NO_x per mmbtu is guaranteed.

AMMONIA SLIP: PPC guarantees the maximum ammonia slip to be less than 10 ppmvd at 3% O2.

BED LIFE: PPC warrants the minimum bed life to be more than 8,760 hours.

TEST PERIOD: The unit must be tested within 30 days after initial equipment operation or 90 days after the final truck shipment; whichever occurs first. If the unit is not tested within this time period, it shall be considered as accepted.

Conditions for valid guarantees

The purchaser is responsible for the confirmation of all estimated design conditions shown in Section I before a purchase order is finalized. Where percent removal and fixed emission levels are guaranteed, simultaneous testing of the inlet and outlet is required. If the actual emission rate is less than the guaranteed outlet level or the actual percent removal is greater than the guaranteed level then PPC is considered to have met their performance guarantee for that pollutant. If actual outlet emission level is great than specified outlet emission level and the actual percent removal is less than guaranteed percent removal PPC will incur the cost of the testing company to retest for that pollutant.

INLET DUCT DESIGN: Laminar & uniform flow of the flue gas is essential for operation and guarantees.

VIII. PRICING AND OPTIONS

All prices quoted are valid for 30 days from the quotation date. No duties, fees or taxes are included. Sales tax or an equivalent amount will be charged if a sales tax exemption certificate is not sent to PPC by the purchaser.

The total price F.O.B. Point of Manufacture for the work as set forth in Sections I through IV is .... U.S. $ 1,507,000.00
This price is based in part on the current market prices of precious metals. We reserve the right to adjust our prices based on documented market fluctuations (the current prices are Pt $1580 and Pd $603).

Estimated freight cost to transport the equipment to jobsite*** .... U.S. $ later
***Logistical issues dictate the necessity of a PPC installation of equipment if this option is selected.

GENERAL OPTIONS:

Mechanical Installation by PPC (non-union and non Davis Bacon rates)

Note: Plant requirements for manlifts, hole watch or fire watch costs are not included. Customer is to supply manlift for up to three weeks if required, at no cost to PPC.

Installation of CO/NOx Removal System: PPC will set the CO/NOx removal reactor vessel on foundations supplied by others and will install any access included with this system.

An inspection by the purchaser shall be made at the completion of the field erection. The correction of any punch list items shall be made before the construction advisor leaves the jobsite. PPC's quotation is based on no delay between the completion and the correction of the punch list items. Any additional trips and/or delays required by purchaser and not the fault of PPC will be billed per our attached Standard Terms and Conditions of Sale of Field Services.

Total for installation by PPC* .... U.S. $ 60,000.00

Any items marked with an * mean that PPC field manpower crew availability may preclude PPC supplying this option. Whether PPC can do the installation will be determined at the time of purchase.

NOx CATALYST SYSTEM OPTIONS:

Installation of NOx Catalyst Loading*: PPC can return to the jobsite after the initial startup and load the catalyst into the SCR housing. The purchaser must furnish any required lift equipment (manlift, forklift, mobile scaffolding, crane, etc.) to permit manual loading of the catalyst elements into the SCR housing.

Price .... U.S. $ Later

Aqueous Ammonia System: In lieu of the anhydrous ammonia system for the SCR, PPC will provide a 19% aqueous system. The system will include one stainless steel aqueous ammonia pump, one spare pump (not piped), one high pressure blower, a stainless steel vaporizer vessel with two phase nozzles and all the instruments and associated equipment to make the system operational. The purchaser must supply the aqueous ammonia storage tank.

Price F.O.B. Point of Manufacture .... U.S. $ 45,700.00
Installation by PPC* .... U.S. $ 2,500.00
Freight .... U.S. $ 1,000.00

Catalyst Storage: In the event the purchaser does not have a clean and dry location to store the catalyst, PPC can provide cargo containers for onsite storage. The containers will become the property of the purchaser.

Price each F.O.B. Point of Manufacture .... U.S. $ 5,000.00

19% Ammonia Solution Tank: PPC will provide a 10,000 gallon (nominal) ARI 650 fiberglass tank with loading line and standard fittings for installation on foundations supplied by purchaser.

Price F.O.B. Point of Manufacture .... U.S. $ 10,700.00
Installation by PPC* .... U.S. $ 800.00
Freight .... U.S. $ 1,900.00

NOx Extra Layer(s) Capability: PPC will provide an extra NOx catalyst section without catalyst for future catalyst maintenance. The extra section will include the air knife, access and support matrix. In short, everything provided for the other catalyst sections minus the catalyst.

Add to base quotation (including freight and installation for each layer). .... U.S. $ 63,000.00

NOx Extra Duct Capacity: PPC will provide additional space to add another layer of NOx catalyst including access extension and access door. This includes no air knife or penetrations.

Price F.O.B. Point of Manufacture .... U.S. $ 23,000.00

Wide Platform: Instead of the 4'-0" platform provided in the base quote, PPC can extend platform section in front of the catalyst loading doors by five feet creating a 9'-0" wide working platform.

Price F.O.B. Point of manufacture .... U.S. $ 14,700.00

Current NOx Catalyst Replacement Cost:
Price F.O.B. Point of Manufacture .... U.S. $ 375,000.00

CO CATALYST SYSTEM OPTIONS:

CO Extra Duct: PPC will provide additional space to add another layer of CO catalyst (does not include any additional penetrations).

Price F.O.B. Point of Manufacture .... U.S. $ 5,700.00

CO Capability: PPC will provide a CO catalyst section without catalyst for future catalyst addition. This section will include the air knife, access and support matrix. In short, everything but the catalyst.

Add to base quotation (including freight and installation for each layer). .... U.S. $ 63,000.00

Current CO Catalyst Replacement Cost:
Price F.O.B. Point of Manufacture .... U.S. $ 365,000

IX. SCHEDULE OF DELIVERY

PPC will provide the proposed equipment according to the following schedule. Time is calculated from the receipt of order by PPC.
Equipment Arrangement and Loading Diagrams .... 5 weeks
Material Shipment .... to be negotiated at time of purchase order

X. SCHEDULE OF PAYMENT

All invoices are Net 30 Days.
The schedule of payment is:

15% of contract price upon receipt of order
20% four weeks after receipt of order
20% eight weeks after receipt of order
20% twelve weeks after receipt of order
20% upon initial shipment

Balance upon successful performance test completion or 90 days after shipment, whichever is sooner.

XI. TERMS AND CONDITIONS OF SALE

Raw Materials: This quotation is based on current steel pricing and is good for the number of days specified in section VIII from the date of the quotation. PPC Reserves the right to adjust the sales price, for any escalation in raw materials such as steel, platinum, palladium, etc.., at the time of a purchase order is issued.

The following attachments are made a part of this quotation:

Standard Terms and Conditions of Sale
Standard Terms and Conditions of Sale for CO and NOx Catalyst System
Standard Terms and Rates for PPC Service Representative

INSURANCE
The above sales price is contingent on PPC's standard levels of insurance which are: General Liability $1,000,000 per occurrence, Business Auto - $1,000,000 per each accident, Products Liability - $1,000,000 per occurrence and Umbrella Liability - $3,000,000 per occurrence /aggregate. If any extra levels of insurance are required or if additional endorsements are required, they will be invoiced at cost.

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.

Africa	+ 27 11 254 4800
Asia	+ 852 2562 3658
Australasia	+ 61 3 8862 3500
Europe	+ 356 21 42 30 20
North America	+ 1 800 275 3281
South America	+ 55 21 3095 9500

solutions@golder.com
www.golder.com

Golder Associates Inc.
6026 NW 1st Place
Gainesville, FL 32607 USA
(352) 336-5600 - Phone
(352) 336-6603 - Fax

Golder Associates