# UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
**Region 4**
**Atlanta, Georgia**

# Preliminary Determination & Statement of Basis
**for**
**Okeelanta Cogeneration Station**
**New Hope Power Company**

**January 21, 2014**

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# 1.0 Introduction

New Hope Power Company (the Applicant or NHPC) has applied for a Prevention of Significant Deterioration (PSD) air permit for the emission of Greenhouse Gases (GHGs) pursuant to the Clean Air Act (CAA) from the United States Environmental Protection Agency (EPA) Region 4 for a proposed project (Project) at the Okeelanta Cogeneration Station (Okeelanta). NHPC is proposing to build one natural gas fired boiler (Boiler D) for steam generation at their existing 140-megawatt (MW) net electric cogeneration facility. The facility is located adjacent to the Okeelanta Corporation sugar mill and refinery, approximately 6 miles south of South Bay in Palm Beach County, Florida. The facility currently has two cogeneration boilers that combust primarily biomass (bagasse and wood), and one natural gas boiler to generate steam and electricity (Boilers A, B and C). The primary fuel for Boiler D will be natural gas, with very low sulfur distillate fuel oil (fuel oil) used as backup. The current maximum electrical generating capacity of the Okeelanta Cogeneration Plant of 140 megawatts, net (MW-net) will not be increased with the addition of the new boiler.

The Florida Department of Environmental Protection (FDEP) is responsible for issuing a separate construction and title V operating permit for the Project for regulated pollutants other than GHGs. A PSD permit application for GHG emissions from Boiler D was submitted to EPA Region 4. Also, a PSD application was submitted to the FDEP separately addressing nitrogen oxide ($NO_x$), carbon monoxide (CO), particulate matter with an aerodynamic diameter less than or equal to 10 microns ($PM_{10}$), and particulate matter with an aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$) emissions for the proposed Project. EPA Region 4 is the agency responsible for implementing and enforcing CAA requirements for GHG sources in Florida. EPA has completed review of the application and supplemental materials and is proposing to issue Permit No. *PSD-EPA-R4016* to NHPC, subject to the terms and conditions described in the permit. The draft permit incorporates the applicable requirements for GHGs from the federal PSD program.

This document serves as a fact sheet, preliminary determination, and Statement of Basis (SOB) for the draft permit. It provides an overview of the Project, a summary of the applicable requirements, the legal and factual basis for the draft permit conditions, and EPA's analysis of key aspects of the application and permit such as the Best Available Control Technology (BACT) analysis for GHG emissions. Additional information can be found in the draft permit accompanying this document as well as in the application materials and administrative record for this Project, as discussed in Section 8.0.[1]

Section 2.0 provides applicant and facility information followed by a description of the proposed Project in Section 3.0. Section 4.0 lists the legal authority and regulatory applicability. Pollutants emitted and emissions units are discussed in Section 5.0. BACT for all applicable units is listed in Section 6.0. Section 7.0 includes a description of additional requirements and how this Project complied with them. Finally, Section 8.0 gives information about public participation.

[1] The procedures governing the issuance of PSD permits are set forth at 40 CFR part 124, subparts A and C. *See* 40 CFR §§ 52.21(q) and 124.1. Accordingly, EPA has followed the procedures of 40 CFR part 124 in issuing this draft permit. This Preliminary Determination describes the derivation of the permit conditions and the reasons for them as provided in 40 CFR § 124.7, and also serves as a Fact Sheet as provided in 40 CFR § 124.8.

# 2.0 Applicant Information

## 2.1 Applicant Name and Mailing Address

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

## 2.2 Facility Location

NHPC is proposing to modify the existing facility located approximately six miles south of South Bay in Palm Beach County, Florida. The UTM coordinates of the facility are Zone 17, 524.9 kilometers (km) East and 2940.1 km North.

The site location and facility is illustrated in the following figures:

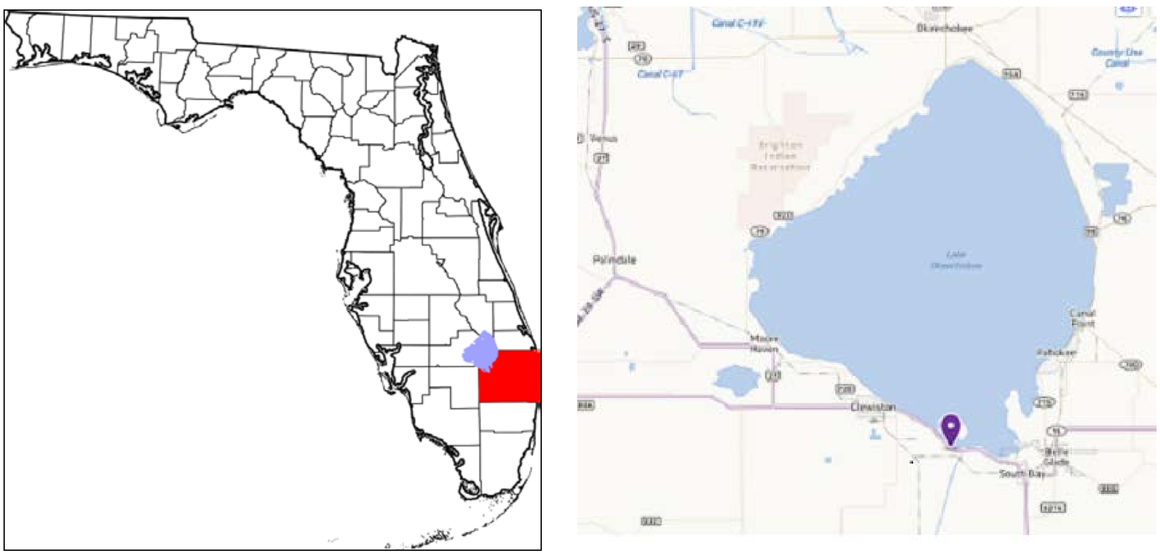

Figure 2-1 County and Site Location


Figure 2-2 Facility Areal View and Boiler D Location

# 3.0 Proposed Project

NHPC has applied for a PSD air permit for GHGs pursuant to the CAA from the United States EPA Region 4 for the proposed Project. NHPC is proposing to build one additional boiler at their existing 140 MW net electric cogeneration facility which will be fired by natural gas with fuel oil used as backup. The fuel oil will contain a maximum sulfur content of 0.05 percent. 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 current maximum electrical generating capacity of the Okeelanta Cogeneration Plant of 140 MW-net will not be increased with the addition of the new boiler.

The Project will result in a net emission increase greater than PSD threshold limits for $NO_x$, CO, $PM_{10}$, $PM_{2.5}$, and GHGs. On August 27, 2013, the FDEP issued their portion of the construction permit to the applicant (PSD-FL-196R/0990332-021-AC), which addressed all pollutants mentioned except for GHGs. The expiration date of the construction permit is December 31, 2016. EPA will be responsible for issuing the GHG portion of the PSD permit. The Project cannot be constructed until both the FDEP and EPA PSD permits are effective.

The Project will result in a significant net increase of 17.48 TPY of $PM_{10}$, 17.48 TPY of $PM_{2.5}$, 147.74 TPY of $NO_x$, 187.65 TPY of CO, and 274,446 TPY of GHG emissions (on a $CO_2e$ basis). Based on emissions estimates using 100% natural gas as fuel, and the applicable permitting thresholds, the Project will have significant emissions of GHGs on a mass basis and is subject to regulation for GHGs. GHG emissions will increase by 274,446 TPY of $CO_2e$.

Although the NHPC application sought a permit that authorized use of fuel oil for 15% hours of operation, the permit will not allow that. Instead, to qualify under the “Gas 1 subcategory” of 40 CFR part 63, subpart DDDDD (78 FR 7138), Boiler D will be allowed to burn fuel oil only 48 hours for periodic testing of liquid fuel, maintenance, or operator training during any consecutive 12 month period and also during periods of natural gas curtailment or supply interruption as defined at 40 C.F.R. § 63.7575.

Both the existing facility operating three existing boilers and the Project are located at 8001 U.S. Highway 27 South, approximately six miles south of Palm Beach, in Palm Beach County, Florida. The facility currently operates 3 boilers in order to generate steam and electricity. Boiler A was converted to natural gas fired under Permit Number 0990332-019-AC on June 6, 2012. Cogeneration Boilers B and C are authorized to combust primarily biomass (bagasse and wood).

# 4.0 Legal Authority and Regulatory Applicability

## 4.1 EPA Jurisdiction

In 2010, the EPA established a Federal Implementation Plan (FIP) to apply in each state that had not submitted by their established deadline a corrective State Implementation Plan (SIP) revision to apply their CAA PSD program to sources of GHGs. *See* 75 FR 82246 (Dec. 30, 2010). The State of Florida is subject to the FIP; therefore, the EPA is issuing this GHG PSD permit. FDEP is responsible for issuing a separate preconstruction and title V operating permit for the Project for regulated pollutants other than GHGs.

## 4.2 Prevention of Significant Deterioration (PSD)

The PSD program, as set forth at 40 CFR § 52.21, is applicable to major sources such as this proposed Project. The objective of the PSD program is to prevent significant adverse environmental impact from air emissions by a proposed new or modified source. The PSD program limits degradation of air quality to that which is not considered "significant." The PSD requires the utilization of BACT as determined on a case-by-case basis taking into account energy, environmental and economic impacts, and other costs.

Under the PSD regulations, a stationary source is "major" if, among other things, it emits or has the Potential To Emit (PTE) 100 or 250 TPY or more (depending on source category) of a "regulated New Source Review (NSR) pollutant" as defined in 40 CFR § 52.21(b)(50). See 40 CFR § 52.21(b)(1). "PTE" is defined as the maximum capacity of a source to emit a pollutant under its physical and operational design. "Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is enforceable." *See* 40 CFR § 52.21(b)(4).

Beginning on January 2, 2011, GHGs became subject to regulation under the PSD major source permitting program as a regulated NSR pollutant when emitted in amounts greater than certain applicable thresholds. GHGs are a single air pollutant defined in 40 CFR 52.21(b)(49)(i) as the aggregate group of the following six gases:

- Carbon dioxide ($CO_2$);
- Nitrous oxide ($N_2O$);
- Methane ($CH_4$);
- Hydrofluorocarbons (HFCs);
- Perfluorocarbons (PFCs); and
- Sulfur hexafluoride ($SF_6$).

Due to the nature of GHGs and their incorporation into the definition of "subject to regulation", the determination of whether a source is emitting GHGs in an amount that triggers PSD applicability involves a calculation of the source's $CO_2e$ emissions as well as its GHG mass emissions. Consequently, when determining the applicability of PSD to GHGs, there is a two-part applicability process that evaluates both:

- The sum of the $CO_2e$ emissions in TPY of the six GHGs, in order to determine whether the source's emissions are a regulated NSR pollutant; and, if so;

- The sum of the mass emissions in TPY of the six GHGs, in order to determine if there is a major source or major modification of such emissions.

For PSD permits issued on or after July 1, 2011, PSD applies to new sources as well as existing sources not already subject to title V that emit, or have the potential to emit, at least 100,000

TPY $CO_2e$ and greater than zero TPY on a mass basis. In addition, sources that emit or have the potential to emit at least 100,000 TPY $CO_2e$ and that undertake a modification that increases net emissions of GHGs by at least 75,000 TPY $CO_2e$ and equal to or greater than 100/250 TPY on a mass basis will also be subject to PSD requirements.[2]

Table 5-1 lists the annual emissions for each regulated NSR pollutant from the Project, based on the use of 100% natural gas, as well as the significant emission rate for each regulated NSR pollutant. The permit application and Section 5.0 of this document contain information on the emissions factors used to determine the annual emissions for the Project.

Okeelanta is an existing PSD source and the net increase in GHG emissions associated with the Project exceeds the threshold of 75,000 TPY. Section 6.0 of this document contains a discussion of the BACT analysis.

### 4.3 Title V

Upon issuance of this PSD permit, the State of Florida will incorporate these permit conditions into the existing title V permit for the facility.

### 4.4 Federal Requirements for GHGs

*New Source Performance Standards (NSPS) Subpart TTTT*

On January 8, 2014, EPA proposed an NSPS (75 FR 1430) that could influence the ultimate emission requirements for this source. The definition of BACT in PSD rules at 40 CFR 52.21(b)(12) states that "in no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61." Although this facility may be within the source category covered by the proposed NSPS, the proposed NSPS emission limits are not a controlling floor for BACT purposes since the proposed NSPS is not a final action and the proposed standard may change. However, the NSPS is an independent requirement that will apply to any source subject to the NSPS that commences construction after the date the NSPS is proposed (unless that source is covered by a transitional source exemption adopted in the NSPS). Thus, this facility may ultimately be subject to, and need to comply with, the NSPS after it is finalized, even if the emissions limits in the final permit are higher than the NSPS. *See* EPA, "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011) at 25.

## 5.0 Project Emissions

The maximum annual potential emissions for the Project, firing 100% natural gas, include GHG emissions from Boiler D. Table 5-1 summarizes the maximum annual emissions changes, submitted by the applicant. This table addresses the relevant regulated NSR pollutants, as required under PSD.

[2] 75 FR 31514 (June 3, 2010)

**Table 5-1 Summary of Annual Project Emissions Changes**

| Pollutant | PTE* (TPY) | Significant Emission Rate (TPY) | PSD Review Required |
|---|---|---|---|
| **$SO_2$** | 19.54 | 40 | No |
| **PM** | 17.48 | 25 | No |
| **$PM_{10}$** | **17.48** | 15 | **Yes** |
| **$PM_{2.5}$** | **17.48** | 10 | **Yes** |
| **$NO_x$** | **147.74** | 40 | **Yes** |
| **CO** | **187.65** | 100 | **Yes** |
| **VOC** | 12.65 | 40 | No |
| **Sulfuric Acid Mist** | 0.06 | 7 | No |
| **Lead** | 0.18 | 0.6 | No |
| **GHGs ($CO_2e$)** | **274,446** | 75,000 (subject to regulation threshold) | **Yes** |
| **HAP** | 4.35 | N/A | N/A |
| **Mercury** | 6.5 (lb/yr) | 200 lb/yr | No |

* based on 100% natural gas firing, 8760 hours/year

**As seen in the emissions summary table, the project emissions are based upon changes to facility emissions associated with future equipment.**

As described below, Boiler D will be subject to restrictions from 40 CFR Subpart DDDDD, which limits the use of fuel oil to 48 hours per calendar year; however, the limitations in the regulation allow for an unknown amount of fuel oil use during times of “natural gas curtailment and supply interruption”. Consequently, the worst case emissions scenario for Boiler D is difficult to calculate. As seen in Table 5-1 above, the Project triggers PSD for GHG emissions even with the use of 100% natural gas. Therefore, any amount of fuel oil use will not affect the PSD applicability determination for GHG emissions. Based on the application, EPA estimates an additional 2,093 TPY of $CO_2$ emissions for 48 hours of fuel oil use, which is less than 0.76% increase in $CO_2$ above the 100% natural gas scenario in Table 5-1. EPA has included in the draft permit fuel oil restrictions which are similar to those included in 40 CFR DDDDD as well as output-based $CO_2e$ emission limits (lb $CO_2e$/1,000 lbs steam produced) for both natural gas and fuel oil usage. These emission limits will apply at all times to the respective fuel, regardless of how long the boiler may operate on fuel oil due to a “natural gas curtailment of supply interruption”.

## 5.1 Unit Analysis

Emissions calculations for equipment used during operation of Boiler D were made based on the assumptions described below:

Boiler D will be a natural gas boiler with a 1-hour maximum heat input rate of 589 MMBtu/hr and a 24-hr maximum heat input rate of 535.5 MMBtu/hr and a minimum thermal efficiency of 85%. The 1-hour maximum steam production rate will be 440,000 lb/hr steam and 24-hour maximum steam production will be 400,000 lb/hr steam. Boiler D will be equipped with Ultra-low $NO_x$ burners and will fire natural gas and operate with good combustion practices. Boiler D will be designed to operate burning 100% natural gas, with fuel oil as backup during periods of natural gas curtailment or supply interruption. To enable Boiler D to qualify for the Gas 1 subcategory under 40 CFR part 63, subpart DDDDD (Industrial, Commercial, and Institutional Boilers and Process Heaters), the permit restricts Boiler D’s fuel oil usage to no more than 48 hours per consecutive 12 month period for testing purposes (aside from use during periods of natural gas curtailment or supply interruption). As a result, only work practice standards from subpart DDDDD will apply.

### 5.2 Compliance Methodology (Monitoring, Recordkeeping, and Reporting)

The applicant proposed to monitor compliance with the $CO_2e$ BACT limits for the Boiler through the installation and use of a continuous monitoring system. The applicant proposes to use the monitored data (including gross steam output rate, fuel type and amount, hours of operation, and heat input rate) to determine $CO_2e$ emissions based on 40 CFR Part 98, Subpart C. The applicant will calculate, record, and maintain record files according to requirements in the permit.

## 6.0 Best Available Control Technology (BACT) and Recordkeeping Requirements

A major modification of a major stationary source subject to PSD requirements is required to apply BACT for each pollutant subject to regulation under the CAA that it would have the potential to emit in significant amounts. *See* 40 CFR § 52.21(j). Based on the emissions analysis summarized in Table 5-1, the Project has the potential to emit $NO_x$, CO, $PM_{10}$/$PM_{2.5}$, and GHGs in quantities that equal or exceed the significant emission rate. Based on their authority, FDEP has permitted the $NO_x$, CO, $PM_{10}$, and $PM_{2.5}$ emissions for the Project. However, EPA is responsible for permitting the GHG emissions. Therefore, BACT must be determined for the emission unit that emits GHGs as part of the EPA-issued permit.

Emissions from the Project are included in the source's potential to emit, as required by 40 CFR 52.21(b)(4), and the facility is subject to operating limits and requirements for monitoring, recordkeeping and reporting to ensure they will not exceed the potential emissions assumed in the application and impact review.

BACT is defined in the applicable permitting regulations at 40 CFR § 52.21(b)(12), in part, as:

> *an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from 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, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event, shall application of best available control technology 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 technology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology.*

The CAA contains a similar BACT definition, although the 1990 CAA amendments added "clean fuels" after "fuel cleaning or treatment" in the above definition. *See* CAA § 169(3).

On December 1, 1987, the EPA issued a memorandum describing the top-down approach for determining BACT. *See, e.g., In re Prairie State Generating Co.,* 13 E.A.D. 1 (EAB 2006). In brief, the top-down approach provides that all available control technologies be ranked in descending order of control effectiveness. Each alternative is then evaluated, starting with the most stringent, until BACT is determined. The top-down approach consists of the following steps:

> *Step 1*: Identify all available control technologies.
>
> *Step 2*: Evaluate technical feasibility of options from Step 1 and eliminate options that are technically infeasible based on physical, chemical and engineering principles.
>
> *Step 3*: Rank the remaining control technologies from Step 2 by control effectiveness, in terms of emission reduction potential.
>
> *Step 4*: Evaluate the most effective controls from Step 3, considering economic, environmental and energy impacts of each control option. If the top option is not selected, evaluate the next most effective control option.
>
> *Step 5*: Select BACT (the most effective option from Step 4 not rejected).

## 6.1 GHG BACT Analyses for Natural Gas Boiler

<u>Step 1: Identify all available control technologies</u>

The applicant identified the following available control technologies for the proposed boiler in their permit application dated February 4, 2013, supplemental information dated May 17, 2013, and in an email dated November 11, 2013, responding to a request from the EPA for additional information:

1. Maximized Energy Efficiency
2. Carbon Capture and Storage (CCS)
3. Cleaner Fuels

**Maximized Energy Efficiency:** Energy efficiency falls under the general category of lower polluting processes/practices. Applying technologies, measures and options that are energy efficient translates not only in the reduction of emissions of the particular regulated NSR air pollutant undergoing BACT review, but it also may achieve collateral reductions of emissions of other pollutants. There are different categories of energy efficient improvements:

- Technologies or processes that maximize the efficiency of the individual emissions unit, and
- Options that could reduce emissions by improving the utilization of thermal energy and electricity that is generated and used onsite.

When the efficiency of the steam generation process is increased, less fuel is burned to produce the same amount of electricity. This provides the benefits of lower fuel costs and reduced air pollutant emissions (including $CO_2$). In addition, a boiler that is a cogeneration unit produces both useful thermal energy and additional electric energy, which adds significantly to the overall energy efficiency of the unit. The applicant has proposed implementation of the following measures to maximize the overall energy efficiency of the Project:

- Effective Burner Design
- Optimization
- Instrumentation and controls
- Economizer
- Air pre-heater
- Insulation and insulating jackets
- Capture energy from boiler blow down
- Condensate return
- Reduce slagging and fouling of heat transfer surfaces
- Reduce steam trap leaks
- Use of natural gas as primary fuel source.

**CCS:** CCS falls under the category of add-on controls, which are air pollution control technologies that remove pollutants from a facility's emissions stream. CCS is an add-on pollution control technology that is available for large $CO_2$ emitting facilities, including fossil fuel-fired power plants and industrial facilities with high purity $CO_2$ streams. CCS is composed of three main components: $CO_2$ capture and/or compression, transport, and storage.

**Cleaner Fuels:** The use of natural gas as a fuel source is an inherently lower emitting practice than the use of fuel oil. The combustion of natural gas has the lowest emissions of GHGs of any fossil fuel and emits almost 30% less $CO_2$ than oil, and about 45% less $CO_2$ than coal on a lb/MMBtu basis.

<u>Step 2: Eliminate technically infeasible control options</u>

**CCS:** The applicant contends that CCS is technically infeasible for their project because (1) there has not been a full scale commercial demonstration of $CO_2$ capture for boilers and (2) there is no known suitable geological formation within a reasonable distance from the site. While EPA recognizes there are certain challenges with capturing $CO_2$ from lower concentration exhaust streams (such as a 10% $CO_2$ by volume stream that is typical for a natural gas-fired boiler), we believe that $CO_2$ capture systems exist that have been demonstrated in practice and can be transferred to boilers of the size proposed for use in this Project. Further, the applicant did not provide sufficient specificity with regard to dismissing geologic storage based on availability and distance. Accordingly, for the purposes of this draft permit, EPA considers CCS to be a technically feasible option for the proposed new natural gas-fired boiler at NHPC.

<u>Step 3: Ranking remaining control technologies</u>

Of the three potential emission control methods discussed, EPA has determined CCS, energy efficiency and use of clean fuels are all technically feasible options for reducing GHG emissions from the natural gas-fired boiler and were further evaluated in Step 4 of the BACT analysis.

Step 4: Evaluation of Impacts

**CCS:** The EPA recognizes that the logistical hurdles of installing and operating a CCS system set this pollution control technology apart from other types of add-on controls that are typically used to reduce emissions of other pollutants. Logistical hurdles identified by the applicant for CCS include: obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, developing a site for secure long term storage, and environmental permitting for underground GHG sequestration. In addition to these logistical factors, the EPA considered economic feasibility, in conjunction with energy and environmental impacts, in evaluating CCS for this project.

The applicant stated that, as an independent cogeneration facility, it did not have the financial resources to implement a CCS system and if such a system was required, it would render the Project economically infeasible. *See* Application at 10. In addition, NHPC provided EPA with an estimate of the total capital cost of the natural gas boiler Project as $14,000,000.[3] Based on a post-combustion capture capital cost factor of $86/ton $CO_2$e, taken from the CCS Task Force Report (page 34)[4], the estimated upfront capital cost to capture 90% of the $CO_2$ emissions (247,001 TPY) for the Project would be $21,242,086. Therefore, the estimated post-combustion capture capital costs for the Project ($21,242,086) are more than one and a half the total capital costs of the proposed natural gas boiler ($14,000,000). In addition, we estimate that there would be other capital costs for the CCS system, specifically with respect to the transportation component of a CCS system. Given that a $CO_2$ pipeline does not currently exist in the vicinity of the NHPC facility, one would have to be built on yet to be acquired land. Given these factors, we believe the costs would increase substantially over what is already projected for the $CO_2$ capture system. Furthermore, there are additional energy requirements to operate a $CO_2$ capture and compression system that would increase the overall cost of the CCS system, and potentially increase emissions of other pollutants. As such, CCS is rejected under Step 4 of the BACT analysis for this natural gas boiler Project.

Step 5: Select BACT

Based on the above evaluation, the most effective control options for GHG emissions are maximized energy efficiency and the use of natural gas as the primary fuel source with limited use of fuel oil. The boiler chosen for this project has a thermal efficiency of 85%. Neither the applicant nor EPA was able to identify a similarly sized natural gas-fired boiler with a permitted efficiency of greater than 85%. In addition, the applicant will implement the additional measures identified to ensure that the highest level of thermal efficiency is maintained. Maximized energy efficiency will be achieved by implementing the measures identified in the application, which includes but is not limited to: efficient burner design and optimization, insulation of the unit, use of instrumentation/controls to achieve high-efficiency/low-emissions performance, and capture of energy from boiler blowdown. The EPA concurs with the applicant that these control measures and operational practices together satisfy requirements for the BACT determination at this time, and EPA is proposing the following GHG BACT emission limits for this draft permit:

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[3] Emails dated 01/15/14 and 01/20/14 from Phil Cobb of Golder Associates to EPA

[4] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010)

- 157 pounds (lbs) of $CO_2$e per 1,000 lbs of steam produced (lbs $CO_2$e/1,000 lbs Steam) while firing natural gas; based on a 30-day rolling average
- 218 lb $CO_2$e/1,000 lbs Steam while firing fuel oil; based on a 3-hour rolling average
- Fuel oil operation will be limited to 48 hours annually (12-month rolling total) and during periods of natural gas curtailment or gas supply interruption

Additionally, a minimum thermal efficiency of 85% will also be maintained in any month, averaged on a 30 day rolling average basis and determined by the following formula:

Thermal Efficiency = (lbs steam produced) / (boiler heat input)

Compliance with the minimum thermal efficiency requirement will be demonstrated by fuel use records and steam production records.

# 7.0 Additional Requirements

## 7.1 Endangered Species

Section 7(a)(2) of the Endangered Species Act (ESA) requires federal agencies, in consultation with the National Oceanic and Atmospheric Administration (NOAA) National Marine Fisheries Service (NMFS) and/or the U.S. Fish and Wildlife Service (FWS) (collectively, "the Services"), to ensure that any action authorized, funded, or carried out by the agency is not likely to jeopardize the continued existence of a species listed as threatened or endangered, or result in the destruction or adverse modification of designated critical habitat of such species. *See* 16 U.S.C. §1536(a)(2); *see also* 50 CFR §§ 402.13 and 402.14. The federal agency is also required to confer with the Services on any action which is likely to jeopardize the continued existence of a species proposed for listing as threatened or endangered or which will result in the destruction or adverse modification of critical habitat proposed to be designated for such species. *See* 16 U.S.C. §1536(a)(4); *see also* 50 CFR 402.10. Further, the ESA regulations provide that where more than one federal agency is involved in an action, the consultation requirements may be fulfilled by a designated lead agency on behalf of itself and the other involved agencies. *See* 50 CFR § 402.07.

Based upon the best available data and informal consultation with the Services, the EPA determined that the issuance of this permit to NHPC is not likely to cause any adverse effects on listed species and essential fish habitats. The applicant will enforce standard protection measures during construction to ensure none of the potentially identified endangered species is harmed. The proposed permit includes a condition requiring NHPC to comply with all other applicable federal regulations. EPA received concurrence by email on March 27, 2013, from the FWS that the proposed Project is not likely to adversely affect resources protected by the ESA of 1973, as amended (16 U.S.C. 1531). The FWS also confirmed the ESA consultation requirements were met.

## 7.2 Essential Fish Habitat of Magnuson-Stevens Act

Section 305(b)(2) of the Magnuson-Stevens Fishery Conservation and Management Act (MSA) requires federal agencies to consult with NOAA with respect to any action authorized, funded, or undertaken by the agency that may adversely affect any essential fish habitat identified under the

MSA. On July 01, 2013, NOAA's NMFS Southeast Region, HCD determined in an email copied to EPA, there were no resources affected by the Project for which the NMFS would consult.

## 7.3 National Historic Preservation Act

Section 106 of the NHPA requires federal agencies to take into account the effects of their undertakings on historic properties. Section 106 requires the lead agency official to ensure that any federally funded, permitted, or licensed undertaking will have no effect on historic properties that are on or may be eligible for the NRHP

The Florida Division of Historical Resources (DHS) indicated in a letter dated December 4, 2013, that review of information from the Florida Master Site File (FMSF) determined that there are no previously recorded archaeological sites or historic standing structures within the NHPC property and due to the location and nature of the project effect would be unlikely. Due to environmental conditions consistent with those found at other archaeological sites in Palm Beach County and lack of professional archeological or historical investigation, there is some potential for undiscovered sites to occur. EPA will include a permit condition requiring EPA and FDEP be notified and proper procedures be followed in the event historical or archaeological artifacts are discovered during construction.

## 7.4 Coastal Zone Management Act

Executive According to the Coastal Zone Management Act of 1972 (CZMA), the State may develop and adopt a management program for its coastal zone in accordance with Federal rules and regulations promulgated by the Secretary, after notice, and with the opportunity of full participation by relevant Federal agencies, State agencies, local governments, regional organizations, port authorities, and other interested parties and individuals, public and private, which is adequate to carry out the purposes of the CZMA and is consistent with the policy declared in the CZMA.

The Florida Coastal Management Act (§380.205-380.27, Florida Statutes) requires that the CZM Section of FDEP be responsible for certification of consistency with the FCMP for all Federal licenses, permits, activities, and projects listed in §380.23(3)(c), Florida Statutes, when such activities are subject to Federal consistency review and affect land or water use, are seaward of the jurisdiction of the state, or there is no State agency with sole jurisdiction for such consistency review. The issuance of Federal permits listed in §380.23(3)(c), Florida Statutes is not required for NHPC.

## 7.5 Executive Order 12898 - Environmental Justice

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal PSD permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHGs, controlled by what we have determined is the BACT for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no NAAQS for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGs at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

### 7.6 Executive Order 13175 – Tribal Consultation

In accordance with Executive Order 13175 and the EPA Policy on Consultation and Coordination with Indian Tribes, the Miccosukee Tribe of Indians of Florida (Miccosukee Tribe) and the Seminole Tribe of Florida (Seminole Tribe) were offered the opportunity to consult regarding EPA's consideration of the PSD permit application submitted by NPHC. Neither Tribe responded to the EPA invitation for consultation sent on March 6, 2013 about the NHPC permit action. EPA sent a letter confirming their lack of response on August 1, 2013. Both tribes were informed that regardless of whether they elected to consult on the permit application, they would also have the opportunity to submit comments during any forthcoming public comment period.

The objective of such consultation, in EPA's view, is to improve EPA's understanding of the perspectives of the Seminole Tribe and Miccosukee Tribe and to identify any issues or concerns they may have regarding EPA's consideration of the NHPC application. During the course of any consultation on this matter, the EPA can offer such things as education and outreach, holding conference call(s) to discuss issues and concerns, and providing feedback through written communication explaining how the EPA considered any issues and concerns raised.

## 8.0 Public Participation

### 8.1 Opportunity for Public Comment

These proceedings are subject to EPA Procedures for Decision-making, set forth at 40 CFR Part 124. As provided in part 124, EPA is seeking public comment on NHPC air permit PSD-EPA-R4016 during the public comment period as specified in the public notice.

Any interested person may submit written comments on the draft permit during the public comment period. If you believe any condition of the permit is inappropriate, you must raise all reasonably ascertainable issues and submit all reasonably available arguments supporting your position by the end of the comment period. Any documents supporting your comments must be included in full and may not be incorporated by reference unless they are already part of the record for this permit or consist of state or federal statutes or regulations, EPA documents of general applicability, or other generally available referenced materials.

Comments should focus on the proposed air quality permit, the permit terms, and the air quality aspects of the Project. The objective of the air quality program is to prevent significant adverse environmental impact from air emissions by a new or modified source. All timely comments will be considered in making the final decision, included in the record, and responded to by EPA. EPA may group similar comments together in our response, and will not respond to each individual commenter directly.

All comments on the draft permit must be received by email or postmarked by February 24, 2014. Requests for a Public Hearing (see below) must be received by email or mail by February 7, 2014. An extension of the 30-day comment period may be granted if the request for an extension adequately demonstrates why additional time is required to prepare comments. Comments must be sent or delivered in writing to the address below. All comments will be included in the public docket without change and may be made available to the public, including any personal information provided, unless the comment includes Confidential Business Information or other information in which disclosure is restricted by statute. Information that you consider Confidential Business Information or otherwise protected should be clearly identified as such and should not be submitted through e-mail. If you send e-mail directly to the EPA, your email address will be captured automatically and included as part of the public comment. Please note that an e-mail or postal address must be provided with your comments if you wish to receive direct notification of the EPA's final decision regarding the permit and the EPA's response to comments submitted during the public comment period. For questions on the draft permit, please contact: Mr. James Purvis at 404-562-9139 or R4GHGpermits@epa.gov.

Submit comments on the draft permit and requests for a public hearing to:

EPA Region 4, APTMD
61 Forsyth Street, SW
Atlanta, GA 30303
ATTN: James Purvis

Fax: (404) 562-9019
Email: R4GHGpermits@epa.gov

## 8.2 Public Hearing

EPA has discretion to hold a public hearing if we determine there is a significant amount of public interest in the draft permit. Requests for a public hearing must be received by EPA by email or mail by February 7, 2014, at the address given above, and state the nature of the issues proposed to be raised in the hearing. You may submit oral or written comments on the draft permit at the public hearing. You do not need to attend the public hearing to submit written comments. If there is significant public interest, EPA will hold a public hearing on the draft GHG permit on February 26, 2014, at the location given in the public notice. If no timely request for a public hearing is received, or EPA determines that there is not significant interest, *the hearing will be cancelled.* An announcement of cancellation will be posted on the EPA's website at: http://www.epa.gov/region4/air/permits/ghgpermits/ghgpermits.html or you may call EPA at the contact number above to determine if the public hearing will be held.

## 8.3 Administrative Record

The administrative record contains the application, supplemental information submitted by NHPC, and correspondence, including e-mails, between NHPC and its consultants and EPA clarifying various aspects of the NHPC application. The draft permit and the administrative record are available for public review at the EPA Region 4 office and the Belle Glade Library at the addresses listed below. Please call in advance for available viewing times.

**Belle Glade Library/Civic Center**
725 North West 5th Street
Belle Glade, Florida 33430
(561) 993-0728

**EPA Region 4 Office**
61 Forsyth Street, SW
Atlanta, GA 30303
Phone: (404) 562-9643

The administrative record and draft permit are also available on EPA's website at: http://www.epa.gov/region4/air/permits/ghgpermits/ghgpermits.html.

To request a copy of the draft permit, preliminary determination or notice of the final permit action, please contact: Ms. Rosa Yarbrough, Permit Support Specialist at: 404-562-9643, or R4GHGpermits@epa.gov.

## 8.4 Final Determination

A decision to issue a final permit, or to deny the application for the permit, shall be made after all timely comments have been considered. Notice of the final decision shall be sent to each person who has submitted written comments or requested notice of the final permit decision, provided the EPA has adequate contact information.