TECHNICAL EVALUATION

&

PRELIMINARY DETERMINATION

APPLICANT

Highlands Ethanol, LLC
2202 North West Shore Boulevard
Tampa, Florida 33607

BP Biofuels – Highlands
ARMS Facility ID No. 0550061

PROJECT

BP Biofuels – Highlands
Project Modification
ARMS Facility ID No. 0550061

DEP No. 0550061-004-AC (PSD-FL-406B)

COUNTY

Highlands County, Florida

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Office of Permitting and Compliance
2600 Blair Stone Road, MS#5505
Tallahassee, Florida 32399-2400

November 28, 2012

1. GENERAL PROJECT INFORMATION

1.1. Facility Description and Location

BP Biofuels – Highlands (BPH) will be a cellulosic ethanol production facility with a Standard Industrial Classification (SIC) Code No. 2869 Industrial Organic Chemicals Not Elsewhere Classified. The new facility will be located in Highlands County north of State Road (SR) 70, approximately 3 kilometers (km) east-northeast of Brighton, Florida. The UTM coordinates are Zone 17; 493.2 km East and 3,013.2 km North. The location of Highlands County is shown in Figure 1, while a close aerial view of the site is shown in Figure 2. A map view of the site is shown in Figure 3.

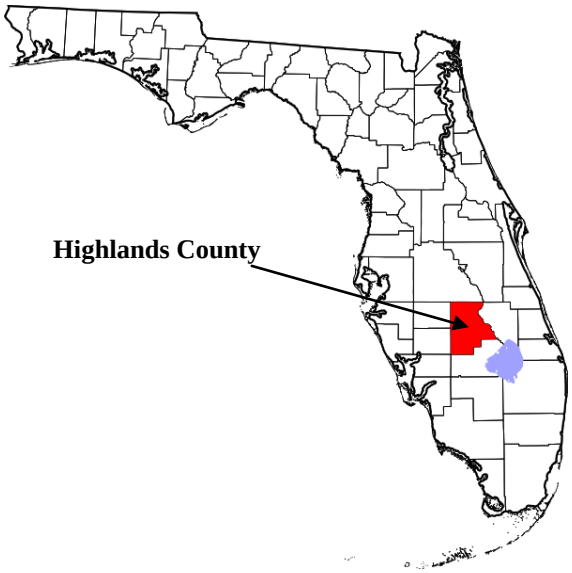

Figure 1 – Highlands County, Florida.

Figure 2 – Close Aerial View of Highlands Site.

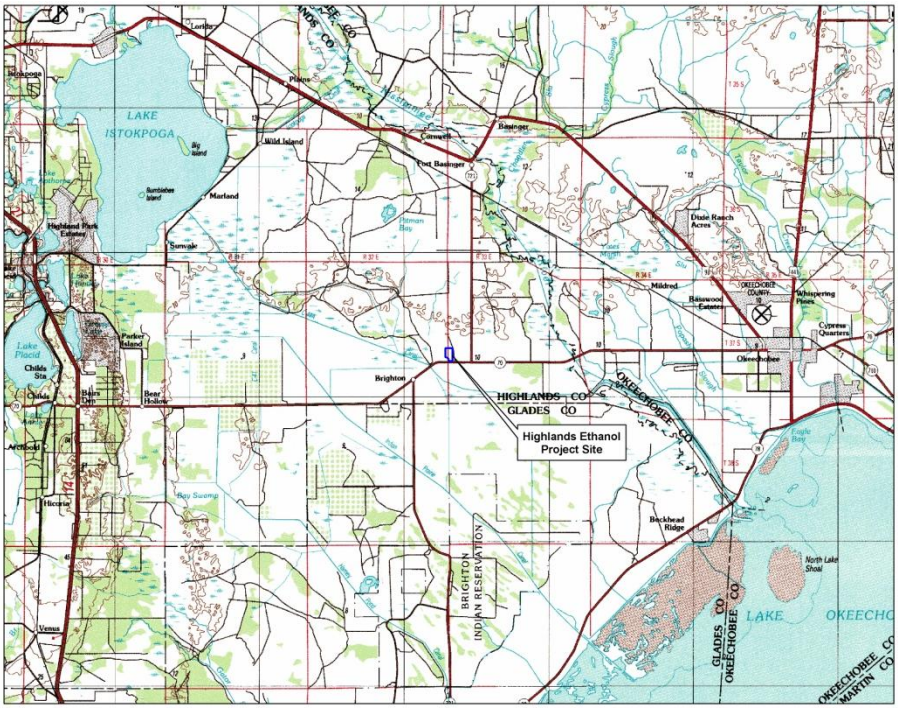

Figure 3 – Map View of BP Biofuels – Highlands Ethanol Site.

Highlands County is bounded by the Kissimmee River and Okeechobee County to the east and Glades County to the south. Lake Okeechobee is located approximately 20 km to the southeast. Most of Highlands County is agricultural. Pictures are provided in Figures 4 through 9 below that show some of the work that has taken place to date at the site of BFH.

Figure 4 – New Drainage Structure. Figure 5 – New Drainage Canal. Figure 6 – New Pump Station.

Figure 7 – Construction HQ. Figure 8 – Planted Energy Cane. Figure 9 – Mature Cane.

The BPH is located on a 95.7 acre site surrounded by Lykes Bros. property, with an easement allowing access to the site from SR 70. The line between Highlands and Glades Counties is approximately 3 km south of the BPH site. The nearest point of the Brighton Seminole Reservation is approximately 8 km south of the site.

The nearest Prevention of Significant Deterioration (PSD) Class I area is the large Everglades National Park (ENP) that straddles Monroe, Collier and Miami-Dade Counties. The nearest boundary point of the ENP is located 154 km south of the proposed BPH site.

1.2. Overview of Current Project

This permitting action involves the modification of the original air construction permit (Air Permit No. 0550061-001-AC, PSD-FL-406) that was issued to BPH on March 22, 2010 by the Department, pursuant to the rules for the PSD at Section 62-212.400, Florida Administrative Code (F.A.C.). A subsequent extension of this permit was granted by the Department on August 25, 2011 (Air Permit No. 0550061-002-AC, PSD-FL-406A). This modification reflects process and equipment changes that have arisen as more detailed engineering for the project has taken place. The modified project will result in net emission decreases of all regulated PSD pollutants. However, PSD is still triggered thus requiring a Best Available Control Technology (BACT) Determination for: nitrogen oxide (NO_X); sulfur dioxide (SO_2); carbon monoxide (CO); volatile organic compounds (VOC); particulate matter with a mean diameter of 10 micrometer (µm) or less (PM_{10}); and PM with a mean diameter of 2.5 µm or less ($PM_{2.5}$). The applicant took a natural gas usage limit thereby allowing classification as a synthetic minor source of greenhouse gases (GHG).

Table 1 below compares the emission units (EU) of the original project to the modified project. Significant changes are highlighted in yellow.

Table 1 – Modified BP Biofuels – Highlands Project Emission Units (EU).

Old EU ID No.	Original Project EU Description	New EU ID No.	Modified Project EU Description
001	Feedstock handling	001	Feedstock handling
002	Hydrolysis, liquid/solids separation, neutralization	---	Obsolete, emissions now vented to regenerative thermal oxidizer (RTO)
003	Fermentation, distillation and bacteria/enzyme propagation	002	RTO (includes hydrolysis, fermentation, distillation and bacteria/enzyme propagation, liquid/solid separation, product loadout (**flare is also an option for product loadout portion of EU, see EU 002A**)
006	Product loadout and flare	002A	Product loadout and flare
004	Solids (stillage and gypsum) separation, dewatering and loadout	003	Stillage separation, dewatering and loadout
005	Denaturing and product storage	004	Denaturing and product storage
007	Wastewater treatment system (WWTP), biogas conditioning and flare	005	Anaerobic digestion, biogas conditioning and biogas backup flare
008	Bubbling fluidized bed (BFB) combustion biomass-fueled boiler	006	Bubbling fluidized bed (BFB) combustion biomass and natural gas fueled boiler
009	BFB combustion biomass-fueled boiler	---	Obsolete
010	Backup fossil-fueled boiler primarily fueled by NG, propane or ULSD FO	007	Natural gas fired Peaking boiler
011	Cooling tower	008	Cooling tower
012	Miscellaneous storage silos	009	Miscellaneous storage silos
013	Miscellaneous storage tanks	010	Miscellaneous storage tanks
014	Emergency generators	011	Emergency generators
015	Emergency fire pump engine	012	Emergency fire pump engine
016	Facility-wide fugitive VOC equipment leaks	013	Facility-wide fugitive VOC equipment leaks

Overall, as a result of this project modification, three emission units have been eliminated. A regenerative thermal oxidizer (RTO) was not previously planned for the project and is now used to control several previously defined emission points. Specifically, emissions from the hydrolysis, liquid/solids separation and neutralization process (old EU 002) that previously were controlled by wet scrubbers before being vented to the atmosphere are now controlled by a RTO. Also the ethanol product loadout flare (old EU 006) is now a flexible design option allowing the emissions from product loadout to be controlled by the currently permitted flare or by the RTO. One of the two biomass-fired boilers (old EU 009) with a heat input rate of 198 million British thermal units per hour (MMBtu/hr) has been eliminated. Instead one bubbling fluidized bed (BFB) boiler primarily fueled by biomass will be used with a heat input rating of 270 MMBtu/hr. This biomass boiler will also have the capability of firing up to 250 MMBtu/hr of natural gas for startup, shutdown, bed stabilization, contingencies, e.g., shortage of biomass. Also of note, the previous 198 MMBtu/hr natural gas-fired backup boiler has been replaced by a smaller 95 MMBtu/hr natural gas-fired peaking boiler to provide steam during high production process conditions and when the larger boiler is unavailable.

Following is a brief general background of the project followed by a detailed description of the modified ethanol production process.

1.3. Project Background

On September 11, 2012, Highlands Ethanol, LLC submitted an application for an air construction permit modification subject to the preconstruction review requirements of the Prevention of Significant Deterioration (PSD) of Air Quality pursuant to Rule 62-212.400, F.A.C. The applicant is in the process of building the first large commercial application of a cellulosic ethanol process. Cellulosic ethanol is produced by converting the abundant cellulose and hemicellulose in biomass feedstock to sugars that are then fermented to produce ethanol. The feedstock will principally be dedicated energy crops, such as energy cane and other perennial grasses, grown on adjacent farmland. The ethanol currently produced in the United States is produced from food based feedstock, primarily corn.

The nominal design ethanol production capacity of the BPH is approximately 36 million gallons per year and is based on an operating schedule of 8,000 hours per year. However, the project is permitted for an operating capacity of 39.42 million gallons per year to allow for an operating schedule of 8,760 hours per year. The ethanol is denatured with gasoline, with a denaturant content ranging from 2 to 5 percent by volume. For air permitting purposes, maximum potential emissions occur when the denaturant content is 5 percent. The capacity of the facility to produce this ethanol-gasoline blend, referred to as E95, is 41.49 million gallons per year when accounting for the denaturant.

1.4. Modified Ethanol Production Process

A process flow diagram for the BPH is given below in Figure 10, followed by descriptions of each major process step including the emission unit number, if applicable.

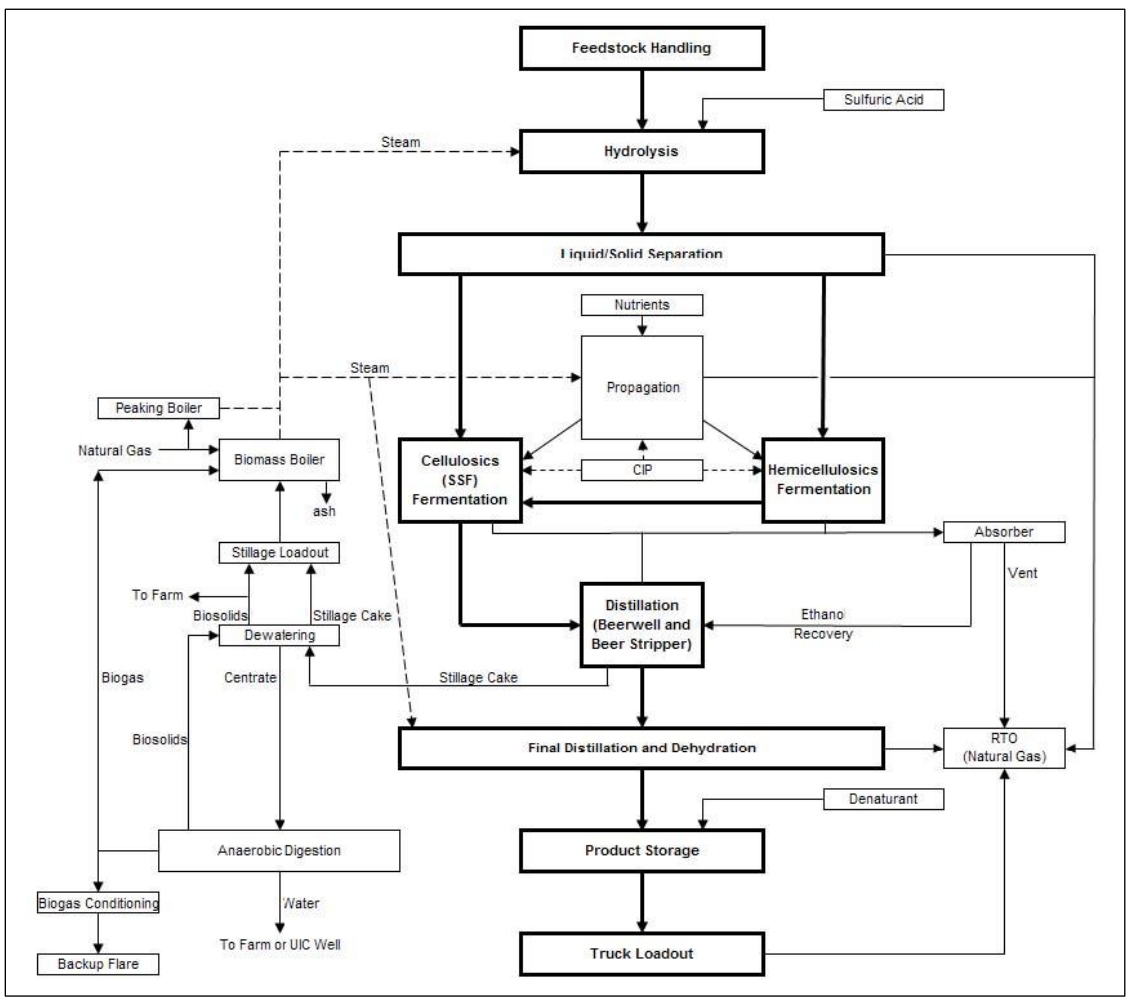

Figure 10 – BP Biofuels – Highlands Production Process Diagram (Modified Project).

The major BPH processes steps, each of which is discussed further below, include:

- Feedstock handling;
- Hydrolysis;
- Liquid/solid separation and neutralization;
- Fermentation, distillation, and propagation;
- Product and denaturant storage tanks;
- Product loadout;
- Miscellaneous storage tanks;
- Miscellaneous storage silos;
- Stillage loadout;
- Anaerobic digestion;
- Cooling tower;
- Steam production; and
- Emergency engines.

1.4.1. Feedstock Handling (EU 001)

Feedstocks will be delivered to the facility by truck from adjacent farmland. The feedstocks will be freshly harvested material with high moisture content. The facility is designed to receive 4,000 green tons per day (TPD) and 167 green tons per hour (TPH) of feedstock.

Upon receipt, the feedstock will be offloaded to one of three locations: (a) directly to the plant's feedstock hopper; (b) a conveyor feed system; or (c) onto a feedstock day storage pad that is designed to hold 24 hours of feedstock. Because the storage pads and the conveyor system will be handling predominantly fresh, moist feedstock material, fugitive emissions from these process areas are expected to be minimal. Daytime delivery of feedstock is expected to occur at a rate faster than the design feedstock receiving rate. This occurs because feedstock will generally be delivered during daylight hours but the plant will be running 24 hours a day, thus the day pad effectively serves as a feedstock buffer for the ethanol production process. The feedstock will be moved via a conveyor system from the day pad to the feedstock hopper at the plant. The day pad and much of the conveyor will be located on the farmland adjacent to the project site. The day pad will be roughly 1.7 acres in size.

A separate and larger medium-term storage pad adjacent to the day pad is proposed for the modified project. The medium-term pad will accommodate 4 days of fresh feedstock material as well as excess bagasse from the feedstock handling and processing step. Both fresh feedstock and bagasse (from the juice extraction process) will be delivered to the medium-term storage pad by truck. The medium-term storage pad will be roughly four acres in size. The medium-term storage pad will be used for production feedstock during times of inclement weather when harvesting and transportation of feedstock may be disrupted.

Feedstock will be loaded from the conveyor directly into the plant feedstock hopper and subsequently conveyed through a washing process. The feedstock will then be shredded, passed through a series of three roller mills and delivered to a bagasse storage silo for conveying to the hydrolysis step. Juice recovered from the roller mill operations will be pasteurized and used in the liquid-solid separation area for dilution of hydrolyzed bagasse. Excess bagasse that cannot be accommodated by the bagasse storage silo will be transferred to trucks/trailers and delivered to the medium-term storage pad. Best management practices (BMP) will be employed at the excess bagasse transfer points to reduce the potential for fugitive dust emissions. Otherwise, the process from the feedstock hopper through to the bagasse silo is analogous to those steps in a sugar mill and fugitive dust emissions are expected to be minimal due to the high moisture content inherent in the feedstock. The feedstock handling area is considered to be an insignificant source of air emissions.

One difference from the previous design is that the storage and handling of supplemental biomass for the biomass boiler is not required. The use of supplemental biomass drove a requirement in the original project for covered conveyors and for dust collectors at drop and transfer points because the moisture content of the supplemental biomass was unknown. Since supplemental biomass is no longer being considered, the applicant has requested that covered conveyors and dust collectors at drop and transfer points not be considered a requirement for the modified project.

1.4.2. Hydrolysis and Liquid/Solid Separation and Neutralization (EU 002)

1.4.2.1. *Hydrolysis*

The bagasse will be delivered from the bagasse silo via conveyor to a live bottom bin that feeds a plug screw and subsequently a steam mixing conveyor. The bagasse is subject to increasing temperature and pressure and mixed with dilute sulfuric acid during these steps in preparation for introduction to a digester for acid hydrolysis. The resulting slurry will consist of cellulose/lignin solids mixed with a liquid fraction containing a variety of pentoses (i.e., xylose, arabinose, and others) and hexoses (i.e., glucose, mannose, galactose, and others). At the outlet of the hydrolyzer, pressure is released and the resulting flash steam is condensed and sent to the anaerobic digester.

1.4.2.2. *Liquid/Solid Separation and Neutralization*

The slurry is separated into liquid and solid fractions using three screw presses arranged in a parallel configuration. The resulting cellulose/lignin solids stream, which has high water content, will be diluted with hemicellulosic fermentation beer and neutralized with magnesium hydroxide in a cake mixer. The resulting liquid filtrate stream, which contains most of the hemicellulosic sugars, will be neutralized with magnesium hydroxide in a neutralization tank and subsequently mixed with aqueous ammonia to allow for survival of the fermentation microorganisms. The entire process is operated at elevated temperature and pressure. Emissions from the process will be collected and exhausted directly to the RTO.

1.4.3. Fermentation, Distillation, Bacteria/Enzyme Propagation and Product Loadout (EU 002)

A set of six hemicellulosic fermentation vessels will be used to ferment the hemicellulosic sugars. The sugars will be fermented with a proprietary microorganism to produce a dilute ethanol beer. The fermentations will occur in batches, and the fermented beer will be split between a beer surge tank for use in the cake mixer or the beerwell feeding the distillation column.

A set of six cellulosic fermentation vessels will be used to simultaneously saccharify and ferment the cellulose from the cake mixer. The cellulose will be saccharified by a proprietary enzyme, producing glucose sugars. These sugars will in turn be fermented with a proprietary microorganism to produce a dilute ethanol beer. The fermentations will occur in batches, and the fermented mash will be passed to a beerwell upon completion of each fermentation batch. The beer will then be transferred to a beer stripper that initiates the distillation process.

The heads (vapors) from the beer stripper will be passed to a stripper/rectifier for further distillation and then a molecular sieve system to remove remaining water (dehydration) from the product. The purified ethanol will then be denatured with gasoline, resulting in a product that contains approximately 95 to 98 percent ethanol by volume and 2 to 5 percent gasoline by volume.

The proprietary enzyme and microorganism will be produced on site in the propagation system. Nutrients required to produce the enzyme and microorganism will be stored adjacent to the propagation system, and are described later in this section.

Emissions from the fermentation area and distillation area will first be vented to an ethanol recovery absorber. The absorber is considered to be integral to the process as it returns a significant amount of volatilized ethanol back to the process. The absorber is vented to the RTO. Emissions from the propagation area will be vented directly to the RTO.

The fermentation and propagation vessels will require a clean-in-place (CIP) system to provide sanitary conditions for the enzymes and microorganism. The CIP system will use a disinfectant solution such as caustic soda or sodium hypochlorite.

E95 product will be loaded onto tank trucks at a rate of 600 gallons per minute. Vapors displaced from the trucks during product loading will be exhausted directly to the RTO or optionally, a flare. The trucks are assumed not to be in dedicated E95 service (i.e., some trucks will have returned from delivering gasoline and gasoline vapors will be displaced) which maximizes potential VOC emissions.

1.4.4. Solids Separation, Dewatering and Loadout (EU 003)

Stillage cake will be removed from the bottom of the beer stripper, dewatered by centrifuges to remove some of the water fraction, and conveyed to the biomass boiler. The stillage cake will not be dried and will consist of lignin fibers, unhydrolyzed cellulose fibers, and other material with biomass fuel value. Stillage will be generated at a rate of 11 dry TPH with moisture content between 50 and 65 percent. Handling will be performed entirely within a closed system except for the conveyor system that sends the material to the biomass boiler. Due to the high moisture content of the stillage cake the conveyor system will not be covered. The centrifuges are not closed systems and will be vented to atmosphere.

The boiler feedstock will consist of stillage cake and biosolids that will be transferred from dewatering centrifuges to a sandwich conveyor. The time of transit through the centrifuges and conveyor to the boiler will be less than 6 minutes. The sandwich conveyor incorporates two belts: one that carries the feedstock much like a traditional belt conveyor, and the other that covers the feedstock. The sandwich conveyor is required in this case to convey materials up a steep incline. From an air emissions perspective, sandwich conveyors provide an added benefit of minimizing fugitive VOC emissions from the stillage cake. Note that the feedstock will be wet, so fugitive dust emissions from the conveyor are not expected. Note also that the biosolids come from the anaerobic digester which efficiently removes hydrocarbons from process wastewaters so fugitive VOC emissions from the biosolids are not expected. However, the moisture fraction of the stillage cake will contain some VOC. The short transit time and BMPs proposed by the applicant will minimized the potential for fugitive VOC emissions from this process.

The VOC emissions calculations used by the applicant are based on stillage cake at temperature as high as 200°F sitting on open storage pads for extended duration, so it is believed the calculation is conservative due to the short transit time from centrifuge to boiler and the proposed BMPs that minimize the exposure of stillage cake to atmosphere.

1.4.5. Denaturing and Product Storage (EU 004)

The facility will include one storage tank for denatured ethanol product (referred to as E95 hereto) and one gasoline (denaturant) storage tank. Each of these tanks will be designed with an internal floating roof. The facility will also include three ethanol product shift tanks. The shift tanks will be vented to the ethanol recovery absorber which in turn is vented to the RTO.

1.4.6. Anaerobic Digestion, Biogas Conditioning and Biogas Backup Flare (EU 005)

The facility will include an anaerobic digestion system to treat process wastewaters and recover energy from the thin stillage for use in the facility. The biogas produced by the anaerobic reactors will be burned in the biomass boiler and the facility will include a backup flare in the event that biogas cannot be combusted in the biomass boiler (either due to boiler shutdown or the production of surplus biogas). The biomass boiler and flare will each be designed with a maximum biogas heat input capacity of 100 MMBtu/hr. The anaerobic digestion system will be equipped with a hydrogen sulfide (H_2S) removal system for biogas burned in the flare (the biomass boiler is equipped with limestone injection and dry sorbent injection for SO_2 control and as such H_2S removal will not be required). Biosolids recovered from the centrifuge at a rate of approximately 2.75 dry TPH will also be burned in the biomass boiler.

1.4.7. Steam Production

1.4.7.1. *Bubbling Fluidized Bed (BFB) Biomass- and Natural Gas-Fired Boiler (EU 006)*

One biomass boiler with a maximum heat input capacity of 270 MMBtu/hr, will be used to combust the stillage cake and biosolids. The boiler will be based on BFB technology. The boiler will also be equipped to burn the biogas produced by anaerobic digestion at 100 MMBtu/hr, and will also be equipped to burn natural gas at a rate of up to 250 MMBtu/hr. The site will be supplied with natural gas by Florida Gas Transmission (FGT) via pipeline located along the north side of State Route 70. Biosolids will be burned when insufficient stillage cake is available. Supplemental biomass will not be combusted, nor will ultra low sulfur distillate fuel oil or propane as in the previous design. The biogas will be introduced to the boiler by means of dedicated lances. The biogas and natural gas maximum heat input limits will be physically restricted by the burners/lances.

The biomass boiler will produce base load steam at a variety of pressures for the ethanol production process. In addition, the steam will be used in a steam turbine generator to produce as much 7.6 megawatts (MW) of power for the project site. The electricity will not be sold to the grid and is solely intended for plant purposes.

1.4.7.2. *Peaking Natural Gas-Fired Boiler (EU 007)*

The facility will include a 95 MMBtu/hr peaking boiler to provide steam during peak process demand conditions and auxiliary steam if the biomass boiler is down. The boiler will be equipped to combust natural gas as the sole fuel.

1.4.8. Cooling Tower (EU 008)

An induced draft evaporative cooling tower will cool the process water for the project. The tower will be a rectangular mechanical-draft design with four cells. Each cell will be equipped with its own fan and a high efficiency drift eliminator to minimize water drift losses.

1.4.9. Miscellaneous Storage Silos (EU 009)

The facility will include equipment and silos for the handling and storage of dry materials. These materials include nutrients for the propagation of the proprietary enzyme and microorganism, and materials associated with the biomass boilers. These materials will be stored in silos, each of which will be equipped with fabric filters (bin vent filters) to control emissions during material handling. The materials stored in these silos will be as follows:

- Powdered Cellulose;
- Wheat Bran;
- Ammonium Sulfate;
- Potassium Phosphate;
- Urea;
- Ash;
- Sand;
- Limestone; and
- Hydrated Lime.

In addition to these silos, there will be two day bins located in the propagation area, one each for wheat bran and urea. These day bins will also be equipped with bin vent filters.

1.4.10. Miscellaneous Storage Tanks (EU 010)

The facility will include several other chemical storage tanks; however, all of these tanks will be insignificant sources of air emissions. These tanks include a number of storage tanks to store wet chemicals used in the process. Sulfuric acid (93 percent solution) will be used in hydrolysis. Magnesium

hydroxide (61 percent solution) will be used to neutralize hydrolyzed material prior to fermentation. The propagation and fermentation nutrients will include corn syrup, phosphoric acid (85 percent solution), and aqueous ammonia (19 percent solution). A flocculant solution may be used in the stillage loadout area to recover additional solids. Caustic soda (50 percent solution) will be used for CIP. All of these tanks will be of a vertical fixed roof design.

1.4.11. Emergency Generators and Fire Pump Engine (EU 011 and 012)

Three emergency generators, each rated at 1,500 kilowatts (kW), will be installed to provide backup electrical power in the event of a power outage at the facility. A backup 850 horsepower (hp) diesel fire pump will also be installed to provide firewater during power outages. All of these units will fire ultra low sulfur distillate fuel oil and will be limited to 100 hours per year of operation for testing and maintenance purposes. Each engine will be designed to meet EPA's emission standards listed in Title 40 of the Code of Federal Regulations, Part 60 (40 CFR 60), Subpart IIII – Stationary Compression Ignition Internal Combustion Engines (ICE).

1.4.12. Facility-Wide Fugitive VOC Equipment Leaks (EU 013)

Fugitive VOC emissions are grouped for the entire process and will be minimized by implementation of a monthly leak detection and repair (LDAR) monitoring program per 40 CFR 60, Subpart VVa – Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry (SOCMI).

1.5. Primary Regulatory Categories

- The facility is not a major source of hazardous air pollutants (HAP).
- The facility has no units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400, F.A.C.
- The facility is subject to Chapter 62-204-800, F.A.C for New Source Performance Standards (NSPS) under Section 111 of the Clean Air Act (CAA) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) under Section 112 of the CAA.

1.6. Processing Schedule

September 11, 2012:	Department received the application for an air pollution construction permit modification;
October 11, 2012:	Department issued request for additional information to the applicant (application deemed incomplete);
November 08, 2012	Department received additional information from applicant; and
November 28, 2012	Department issued Draft Permit package and posted documents.

2. APPLICABLE REGULATIONS

2.1. State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.).

This project is subject to the applicable rules and regulations defined in the following Chapters of the F.A.C.: 62-4 (Permitting Requirements); 62-204 (Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference); 62-210 (Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms); 62-212 (Preconstruction Review including PSD Review and Best Available Control Technology); 62-213 (Title V Air Operation Permits for Major Sources of Air Pollution); 62-296 (Emission Limiting Standards); and 62-297 (Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures).

PSD applicability and the preconstruction review requirements of Rule 62-212.400, F.A.C. are discussed in Section 3 of this report. Additional details of the other state regulations are provided in Section 4 of this report.

2.2. Federal Regulations

The U.S. Environmental Protection Agency (EPA) establishes air quality regulations in 40 CFR. Part 60 identifies NSPS for a variety of industrial activities. Part 61 specifies NESHAP based on specific pollutants. Part 63 specifies NESHAP provisions based on the Maximum Achievable Control Technology (MACT) for given source categories. Federal regulations are adopted in Rule 62-204.800, F.A.C. Additional details of the applicable federal regulations are provided in Section 4 of this report.

3. PSD APPLICABILITY REVIEW

3.1. General PSD Applicability

The Department regulates major stationary sources in accordance with Florida's PSD program pursuant to Rule 62-212.400, F.A.C. PSD preconstruction review is required in areas that are currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or areas designated as "unclassifiable" for these regulated pollutants. As defined in Rule 62-210.200, F.A.C., a facility is considered a "major stationary source" if it emits or has the potential to emit 5 tons per year (TPY) of lead, 250 TPY or more of any PSD pollutant, or 100 TPY or more of any PSD pollutant and the facility belongs to one of the 28 listed PSD major facility categories.

PSD pollutants include: CO; NO_X; SO_2; PM; PM_{10}; $PM_{2.5}$; VOC; lead (Pb); Fluorides (F); sulfuric acid mist (SAM); hydrogen sulfide (H_2S); total reduced sulfur (TRS), including H_2S; reduced sulfur compounds, including H_2S; municipal waste combustor organics measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans; municipal waste combustor metals measured as particulate matter; municipal waste combustor acid gases measured as SO_2 and hydrogen chloride (HCl); municipal solid waste landfills emissions measured as nonmethane organic compounds (NMOC); and mercury (Hg).

For major stationary sources, PSD applicability is based on emissions thresholds known as the "significant emission rates" (SER) as defined in Rule 62-210.200, F.A.C. Emissions of PSD pollutants from the project exceeding these rates are considered "significant" and the Best Available Control Technology (BACT) must be employed to minimize emissions of each PSD pollutant. Although a facility may be "major" for only one PSD pollutant, a project must include BACT controls for any PSD pollutant that exceeds the corresponding SER. Rule 62-210.200, F.A.C. defines "BACT" as:

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; and*
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.

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.

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

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, 61, and 63.

In addition, applicants must provide an Air Quality Analysis that evaluates the predicted air quality impacts resulting from the project for each PSD pollutant.

Although a facility may be "major" (i.e. emits or has the potential to emit 100 or 250 TPY as applicable) for only one PSD pollutant, a project must include BACT controls for any PSD pollutant that exceeds the corresponding significant emission rates given in Table 2.

Table 2 - List of Significant Emission Rates by PSD-Pollutant Relevant to the Facility. [2]

Pollutant	SER (tons/year)	Pollutant	SER (tons/year)
PM	25	PM_{10}	15
$PM_{2.5}$	10	MWC metals as PM	15
$PM_{2.5}$ (NO_X)	40	$PM_{2.5}$ (SO_2)	40
CO	100	NO_X	40
Ozone (NO_X) [1]	40	Ozone (VOC) [1]	40
SO_2	40	MWC acid gases as HCl and SO_2	40
fluoride	3	lead	0.6
mercury	0.1	Sulfuric acid mist (SAM)	7
MWC organics as dioxin/furan	3.5×10^{-6}	MSW Landfill Emissions as NMOC	50

1. $PM_{2.5}$ is also regulated through precursors (NO_X and SO_2); Ozone (O_3) is regulated through precursors (VOC and NO_X).
2. There is federal SER of 75,000 tons/year for Greenhouse Gases (GHG) as carbon dioxide equivalent (CO_2e) that has not been incorporated into Department rules.

According to 40 CFR 52.21, six greenhouse gases (GHG), are also be subject to regulation. At a new PSD-anyway stationary source that will emit or have the potential to emit 75,000 tons/year expressed as the carbon dioxide equivalent emissions (CO_2e) PSD is triggered for GHG. As previously mentioned, the applicant took a natural gas usage limit allowing the BPH facility to be classified as a synthetic minor source of greenhouse gases (GHG).

The 40 CFR 52.21 requirement has not been incorporated into Department rules but is a separate requirement of the EPA. Federal PSD applicability to the CO_2 contribution to GHG emissions from bioenergy and biogenic stationary sources was recently deferred by EPA until the second half of 2014. Refer to: Link to Final CO_2 PSD Deferral

3.2. PSD Applicability for the Modified Project

The project is located in Highlands County, which is in an area that is currently in attainment with the state and federal AAQS or otherwise designated as unclassifiable. The facility is a chemical process plant, which is one of the 28 listed PSD major facility categories, and emits or has the potential to emit (PTE) 100 TPY or more of at least one PSD pollutant. However in 2007, EPA changed the definition of what a chemical processing plant is and specifically excluded ethanol production by natural fermentation. This change in definition moved ethanol production out of the listed source categories where the 100-ton rule applied and moved it into the 250-ton category. Recently, Florida adopted this new definition into its own rules. However, since BPH has the potential to generate steam from fossil fuel at a heat input rate of greater than 250 MMBtu/hr (250 MMBtu/hr potential natural gas firing from the biomass boiler plus 95 MMBtu/hr from the peaking boiler) it still falls into one of the 28 listed PSD major facility categories and is subject to the 100-ton per year threshold. The source category is No. 24 - Fossil fuel boilers (or combinations thereof) totaling more than 250 million Btu/hr heat input.

Table 3 is a listing of the applicant's PSD-pollutant emission estimates with and without the product loadout flare option. As shown in the table, the project is subject to PSD preconstruction review for emissions of: CO, NO_X, $PM_{10}/PM_{2.5}$, SO_2 and VOC.

Table 3 - Summary of the Applicant's PSD Applicability Analysis.

Pollutant	Previous Design Permitted PTE (TPY)	Modified Project Increase (TPY) Applicable to PSD Determination		Max. Change Between Previous & New Project Designs (TPY)	PSD SER (TPY)	Subject to PSD Review?
		No Product Loadout Flare	Product Loadout Flare			
CO	192.0	136.9	139.0	-55.1	100	Yes
NO_X	156.5	113.4	113.5	-43.1	40	Yes
PM/PM_{10}	33.6	22.0/20.1	22.0/20.1	-11.6/12.5	25/15	No/Yes
$PM_{2.5}$	24.7	19.7	19.7	-5.0	10	Yes
SAM	<< 7	2.94	2.94	---	7	No
SO_2	104.1	73.4	73.4	-30.7	40	Yes
VOC	71.3	60.5	63.2	-11.3	40	Yes
Hg	<< 0.1	0.01	0.01	---	0.1	No
Pb	0.1	0.06	0.06	-0.04	0.6	No
Total CO_2e [1]	---	522,323	522,418	---	---	---
(Non-Biogenic) CO_2e [2]	---	73,715	73,809	---	75,000	No

1. Previous design was permitted prior to GHG regulation so no GHG calculations were done.
2. Applicant is taking synthetic limit on natural gas usage in the two boilers of 1,065 million standard cubic feet per year (MMscf/yr) to be permitted as a synthetic minor source for non-biogenic GHG.

Table 4 is a list of PSD emissions by operation, i.e. process step. It includes both the product loadout flare and RTO alone options. It is clear that the greatest emission source by far is steam production, which accounts for the majority of all PSD-pollutants to be emitted from the BPH. Other meaningful pollutant emissions include NO_X and CO emissions from emergency equipment and VOC emissions from the RTO and equipment leaks.

Table 4 - Emissions by Process Step and EU for Project (Totals are for Flare Option).

Process (EU)	CO	NO_X	PM/PM_{10}	$PM_{2.5}$	SO_2	VOC	HAP
RTO (002) – No Loadout Flare	0.81	0.77	0.05/0.05	0.05	0.12	12.5	8.5
RTO + Product Loadout Flare (002)	3.11	1.19	0.07/0.07	0.07	0.12	17.8	8.9
Product Loadout Flare (by itself)	2.3	0.42	0.015/0.015	0.015	0.004	5.3	0.37
Denaturing & Product Storage (004)						1.18	0.07
Biogas Backup Flare (005)	0.30	0.055	0.002/0.002	0.002	0.0005	0.11	
Steam Production (006, 007)	134	109	13.5/13.5	13.5	73.3	6.5	7.3
Cooling Tower (008)			1.5/1.5	1.5		9.2	0.5
Miscellaneous Storage Silos (009)			4.5/4.5	4.5			
Emergency Engines (011, 012)	1.98	3.26	0.11/0.11	0.11	0.0005	0.36	0.01
Subtotal, Point Sources	**139.0**	**113.7**	**19.6/19.6**	**19.6**	**73.4**	**35.2**	**16.8**
Roadway Emissions (001)			2.3/0.43	0.057			
Stillage Loadout (003)						8.4	
Facility-Wide Equipment VOC Leaks (013)						19.6	0.98
Subtotal, Fugitive Sources			**2.3/0.43**	**0.057**		**28.0**	**0.98**
Totals (deviations due to rounding)	**139.0**	**113.7**	**22.0/20.1**	**19.7**	**73.4**	**63.2**	**17.8**

According to the application, the BPH will not be a major source of HAP because it will not emit 10 TPY or more of a single HAP or 25 TPY or more of all HAP. The main source of HAP is steam production and is primarily comprised of hydrogen chloride (HCl) and Hexane (C_6H_{14}). The other meaningful HAP emission is acetaldehyde (C_2H_4O) from the fermentation and distillation steps (controlled by the RTO), the cooling tower and fugitive equipment leaks.

4. DEPARTMENT'S PROJECT REVIEW

4.1. Applicable State Regulations

There are no EU presently operating at the project site though the project has started construction. The modified project will establish 13 new EU as described above. Following are some of the key state regulations and a statute that are applicable to the modified project:

- Rule 62-212.400 (PSD), F.A.C., which regulates the entire project;
- Rule 62-296.320, F.A.C. – General Pollutant Emission Limitation Standards;
- Rule 62-296.410, F.A.C. – Carbonaceous Fuel Burning Equipment;
- Rule 62-296.406, F.A.C. – Fossil Fuel Steam Generators with Less than 250 MMBtu Heat Input, New and Existing Units; and
- Section 403.061(18), Florida Statutes (F.S.), which states "the department has the power and the duty to encourage and conduct studies, investigations, and research relating to pollution and its causes, effects, prevention, abatement and control".

4.2. NSPS and NESHAP

For this project, the following NSPS (40 CFR 60) or NESHAP (40 CFR 63) provisions are applicable:

- NSPS Subpart A – General Provisions, which regulates all EU that are subject to a NSPS standard;
- NSPS Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (EU 007);
- NSPS Subpart Db – Industrial-Commercial-Institutional Steam Generating Units (EU 006);
- NSPS Subpart IIII – Stationary Compression Ignition Internal Combustion Engines (ICE) (EU 011 and 012);
- NSPS Subpart Kb – Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 (regulates EU No. 004);
- NSPS Subpart VVa – Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry (SOCMI), which regulates EU 013; and
- NESHAP Subpart ZZZZ – Stationary Reciprocating Internal Combustion Engines (RICE) (EU 011 and 012).
- NESHAP Subpart JJJJJJ –Industrial, Commercial, and Institutional Boilers Area Sources (EU 011 and 012).

These NSPS do not apply to the project.

- NSPS Subpart CCCC – Standards of Performance for Commercial and Industrial Solid Waste Incineration (CISWI) Units;
- NSPS Subpart K – Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978;

- NSPS Subpart Ka – Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984;
- NSPS Subpart DD – Standards of Performance for Grain Elevators;
- NSPS Subpart VV – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry;
- NSPS Subpart XX – Standards of Performance for Bulk Gasoline Terminals; and
- NSPS Subpart III – Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes;

For reference, certain otherwise applicable NESHAP including MACT requirements do not apply to the project because it is an area source (not a major source) of HAP. They are:

- NESHAP Subpart F – Organic HAP from the SOCMI;
- NESHAP Subpart G – Organic HAP from the SOCMI for Process Vents, Storage Vessels, Transfer Operations, and Wastewater;
- NESHAP Subpart H – Organic HAP for Equipment Leaks;
- NESHAP Subpart I – Organic HAP for Certain Processes Subject to the Negotiated Regulation for Equipment Leaks;
- NESHAP Subpart Q – Industrial Process Cooling Towers; and
- NESHAP Subpart DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters (Major Sources).

4.3. Other Requests

By letter dated February 6, 2009, BP Biofuels – Highlands requested that EPA provide an applicability determination for the following two NSPS:

- NSPS Subpart NNN – VOC Emissions from SOCMI Distillation Operations; and
- NSPS Subpart RRR – VOC Emissions from SOCMI Reactor Processes.

By letter dated March 26, 2009 to the Department, EPA provided a determination that the subject NSPS do not apply to the project because ethanol produced by biological processes is outside their respective scopes.

5. BACT REVIEW

BACT determinations are required for the pollutants that are subject to PSD review, including CO, NO_X, $PM_{10}/PM_{2.5}$, SO_2 and VOC. These determinations are provided in the following sections and are organized and presented by process step and emission unit. Estimated emissions given below are for the worst case control option; use of an open flare (EU 002A) to control VOC emissions from product loadout.

5.1. BACT Review for Feedstock Handling (EU 001)

5.1.1. $PM_{10}/PM_{2.5}$ Emissions

Discussion. $PM_{10}/PM_{2.5}$ are the only pollutants of concern from EU 001. The trucks that will be used to deliver biomass feedstock will generate fugitive dust along with some of the biomass processing operations.

Upon receipt, the process feedstock will be offloaded to one of three locations: (a) directly to the plant's feedstock hopper, (b) a conveyor feed system or (c) onto a feedstock day storage pad that is designed to hold 24 hours of harvested feedstock. Because the storage pads and conveyor will be handling predominantly fresh biomass feedstock, fugitive emissions from these process areas are expected to be minimal. Feedstock will be loaded from the conveyor directly into the plant feedstock hopper and subsequently conveyed through a washing process. In addition, a separate and larger medium-term storage pad adjacent to the day pad is also planned. The medium-term pad will accommodate 4 days of fresh feedstock material as well as excess bagasse

Applicant's Proposal. The applicant proposes to use Best Management Practices (BMP) to control fugitive dust emission from this emission unit. To this end, the applicant submitted a preliminary BMP plan. Appendix BMP of the permit contains this BMP plan of reasonable precautions specific to the BPH to control fugitive $PM_{10}/PM_{2.5}$ emissions. General reasonable precautions can include the following:

- Paving and maintenance of plant roads, parking areas and yards;
- Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing;
- Application of asphalt, water, oil, chemicals or other dust suppressants to unpaved roads, yards, open stock piles and similar activities;
- Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the facility to prevent re-entrainment, and from buildings or work areas to prevent particulates from becoming airborne;
- Landscaping or planting of vegetation;
- Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter;
- Confining abrasive blasting where possible; and
- Sandwich conveyor systems.

The applicant estimates 2.3 TPY of PM and 0.43 TPY of PM_{10} from this emission unit.

Department's Review. The Department accepts the BMP plan described by the applicant as BACT for the Feedstock Handling emission unit.

5.2. BACT Review for RTO (EU 002/002A)

5.2.1. Principally VOC Emissions, But Including Other Emissions

Discussion. The ethanol production process principally generates emissions of VOC along with small amounts of other pollutants. These production processes include hydrolysis, fermentation, distillation and bacteria/enzyme propagation and liquid/solid separation. In addition, the loadout of the denatured ethanol product to tanker trucks also generates VOC emissions. Emissions from all these sources will be controlled by one device and RTO (EU 002). As an option, the product loadout process may be controlled separately by a flare (EU 002A).

The applicant estimates combine emissions from all these sources after control by the RTO/flare (worst case) to be: 3.11 TPY of CO; 1.19 TPY of NO_X; 0.07 TPY of PM_{10}; 0.07 of $PM_{2.5}$; 0.12 of SO_2; 17.8 TPY of VOC; and 8.9 TPY of HAP.

Applicant's proposal. The applicant proposes to control emissions, principally VOC, from the hydrolysis, fermentation, distillation and bacteria/enzyme propagation and liquid/solid separation ethanol process, and from product loadout utilizing an RTO. The applicant has also requested that as an option an open flare be used to control VOC vapors from product loadout process. The applicant requested this option based on more detailed design engineering, due to the potential high cost of the piping from the proposed location of the product loadout area to the proposed location of the RTO. The open flare would possibly be a lower cost alternative while providing nearly the same control efficiency; 99 percent for the RTO

versus 98 percent for the flare. For the RTO, the VOC emission rate after control is 3.46 lb/hr (15.14 TPY) including emissions from the natural gas burners.

Department's Review. The applicant proposed in the previous design to use wet scrubbers to control VOC emissions from ethanol processes. At that time, the Department stated that some type of thermal oxidizer (TO) would provide even greater control than wet scrubbers. However, the additional reduction in emissions (5 to 15 TPY) would not be cost-effective. Furthermore, the Department also indicated that combustion of additional fossil fuels as required by a TO would result in additional emissions of criteria pollutants, including VOCs, and greenhouse gases. By utilizing RTO technology, the concern about other pollutant emissions is minimized. The applicant is now willing to accept the additional cost of an RTO which will provide better control of VOC emissions from ethanol processes.

The use of an RTO versus a wet scrubber is further indicated due to the experience of the State of Minnesota. Specifically:

"*In 2002, new information regarding the air emissions from ethanol plant DDGS dryers was revealed by the Minnesota Pollution Control Agency that had a far-reaching effect in Nebraska and across the nation. It was found that ethanol plants emit some pollutants in greater quantities than previously believed.*

Until that time, it was believed that methanol and ethanol were the only significant volatile organic compounds (VOCs) emitted from the dryers. The Minnesota Pollution Control Agency conducted VOC testing at several Minnesota plants. The results from those tests indicate that methanol and ethanol are emitted in greater quantities than initially believed and there are numerous other pollutants emitted from the drying process including: acetaldehyde, acrolein, formaldehyde, 2-furaldehyde, acetic acid, and lactic acid. Some of these pollutants are considered hazardous air pollutants (HAPs)."[1]

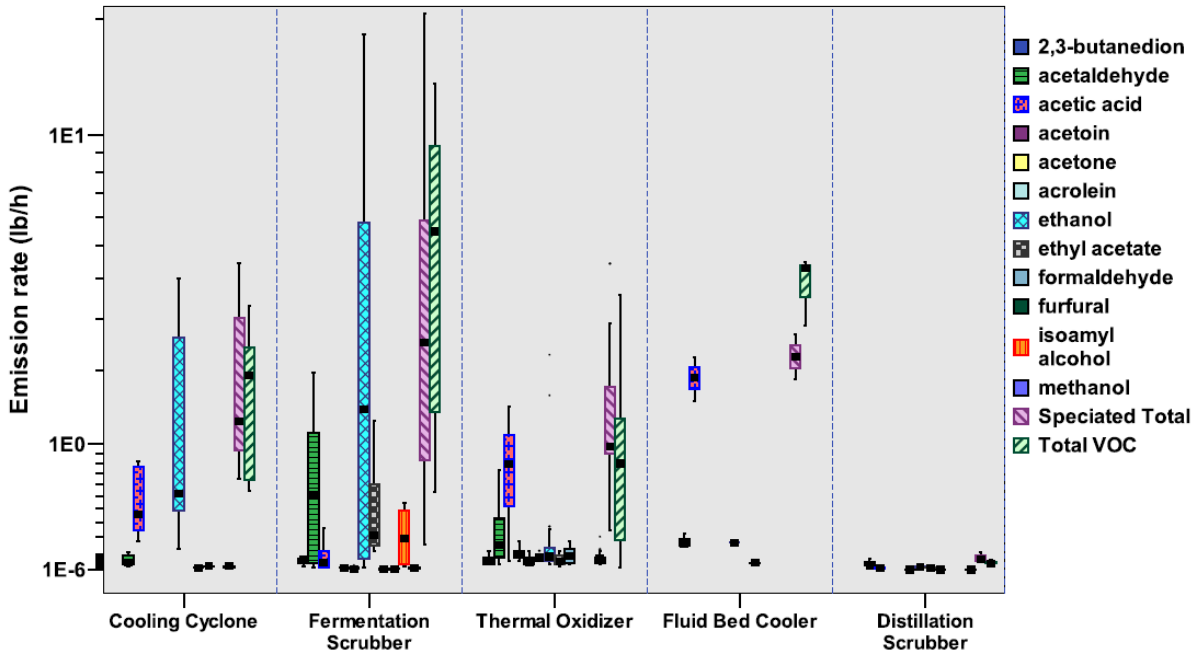

Figure 11 – VOC and HAP Control Efficiency of Ethanol Pollution Control Technologies.[2]

[1] Air Emissions from Ethanol Plants: Recent Findings, Minnesota Pollution Control Agency. May 2002, Publication No. ag1-21.pdf, June 17, 2002.

[2] Volatile Organic Compound Emissions from Dry Mill Ethanol Production, Minnesota Pollution Control Agency, Environmental Bulletin No. 8, August 2006.

In conjunction with this finding, the State of Nebraska found that:

"More recent tests in Nebraska and other states verified emissions from ethanol processes are substantially higher than anticipated. EPA Headquarters, EPA Regional offices, States and Locals have engaged in negotiations with existing plants for installation of control equipment to reduce these pollutants to permitted levels. Permits for new plants are incorporating these control techniques into their designs.

The recent testing of fermentation scrubbers has shown similar problems. While scrubbers are effective control devices for VOC emissions, they are less effective for certain HAPs, primarily acetaldehyde. Testing shows that there is wide variation in the results from one test to the next and from plant to plant. In addition, there can be wide variation in the results during a test run. The variation is large enough to where the emissions can be above major source levels. The industry and NDEQ are currently researching more viable options to reduce emissions from the fermentation process."[3]

Minnesota also developed the following chart shown in Figure 11 above.

Figure 11 is a graphical representation of the distributions of emission rates of the indicated pollutants from the various emission unit/control equipment combinations from 12 dry mill ethanol plants. In general, most facilities consistently reported detectable levels of acetaldehyde, acetic acid, ethyl acetate, formaldehyde, ethanol and methanol at one or more emissions units. The amount of each species and that which is the predominant constituent varies across sources. Acetic acid and ethanol were the predominant emissions from cooling cyclones. From the single fluid bed cooler tested, acetic acid was the dominant emission. Acetaldehyde and acetic acid accounted for most of the emissions from thermal oxidizers. Fermentation scrubbers had the most diverse and highest overall emissions with significant amounts of acetaldehyde, acetic acid, ethanol, ethyl acetate, and isoamyl alcohol. Overall, the thermal oxidizer appears to provide the best pollution control efficiency. The distillation scrubber can be discounted because pollutant emission concentrations entering the scrubber are low. This conclusion is supported by an associated paper submitted to the American Waste Management Association (AWMA) that states:

"The BACT-equivalent requirement for VOC emissions was fulfilled by a thermal oxidizer (TO) achieving at least 95 percent control efficiency."[4]

The Department accepts the applicant's proposal of an RTO as BACT for these pollutant emission sources, with the stipulation that its overall design control efficiency be at least 99 percent. The Department will require an initial stack test of the RTO to verify the VOC emissions rate of 2.85 lb/hr (12.5 TPY) for the flare option and 3.47 lb/hr (15.2 TPY) for the non-flare option.

The option of an open flare to control VOC vapors from the product loadout process is acceptable to the Department. This decision is based on two principal reasons. First, with the flare option, emissions after control are small. In the previous design, where an open flare was proposed to control emissions, based on the same product loadout volume (600 gallons per minute), the largest pollutant emission (VOC) was 5.3 TPY. The other reason for this decision is that the control efficiency of the flare is 98 percent which is only 1 percent less than the RTO. The Department will required that the flare be designed for and operated with no visible emissions (VE) except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

5.3. BACT Review for Stillage Cake Separation, Dewatering and Loadout (EU 003)

5.3.1. VOC Emissions

Discussion. Stillage cake will be removed from final distillation and dehydration process, sent to dewatering to remove some of the water fraction, and conveyed to the biomass boiler for use as fuel. The

[3] Air Quality and Ethanol Production – Nebraska's Experience, Nebraska Department of Environmental Quality, September 2007, Publication # 07-004.

[4] Daniel Brady and Gregory C. Pratt, Volatile Organic Compound Emissions from Dry Mill Fuel Ethanol Production, Minnesota Pollution Control Agency, Air & Waste Manage. Assoc. 57:1091–1102, September 2007.

stillage cake will not be further dried mechanically, or by any other means. Stillage cake will be generated at an approximate rate of 32 wet tons per hour with moisture content in the range of 50 to 65 percent and will consist primarily of lignin fibers and secondarily of unhydrolyzed cellulose fibers. The temperature of the stillage cake entering the dewatering centrifuges will be approximately 205°F, and is not expected to appreciably diminish while on the conveyor. The time of transit through the centrifuge and conveyor is designed to be approximately six minutes or less, with BMPs in place to minimize the exposure of the stillage cake to atmosphere during boiler shutdown conditions. Based on the consistency and moisture content of the material, PM emissions are expected to be negligible. VOC emissions will occur from the evaporation of trace organics dissolved in the water fraction and the applicant has accounted for the temperature conditions and transit time in their calculation of VOC emissions. The minimal transit time and the BMPs proposed by the applicant will reduce the exposure of stillage cake to the atmosphere during both facility operation and shutdown conditions and thereby will reduce the potential for fugitive VOC emissions.

VOC emissions are estimated at 1.9 lb/hr and 8.4 TPY.

Applicant's Proposal. According to the applicant, the only control option for this process would be to capture the emissions and vent them to an add-on control device such as a wet scrubber or RTO. However, the potential uncontrolled VOC emissions from this emission unit are calculated to be 8.4 TPY, which is comparable to the cooling tower (EU 008, 9.2 TPY) which is uncontrolled for VOC and the RTO with the flare option (EU 002, 12.5 TPY) which controls several emission sources. Based on this emission rate, capturing and controlling these emissions with an add-on control device would not be cost effective. Therefore, BACT is proposed to be maintaining the stillage cake as close as practicable at ambient temperature.

Department's Review. The Department concurs with the applicant's proposal to maintain the stillage cake as close as practicable to ambient temperature as BACT for this emissions unit. Corn-based ethanol plants typically have distiller's grain dryers that rely on energy recuperated from TO that also control VOC and odor. In the present case, use of the stillage in the biomass boiler will destroy much of the VOC and odor. The applicant shall comply with Rule 62-296.320(2), F.A.C. that prohibits objectionable odors. In addition, the BMP plan provides procedures during both facility operation and shutdown conditions that will reduce VOC emissions and the likelihood of odor problems.

5.4. BACT Review for Denaturing (Gasoline) and Product Storage (EU 004)

5.4.1. VOC Emissions

Discussion. The principal emissions from this unit are VOC. This emission unit includes three product shift tanks and one E95 storage tank. The facility also includes one gasoline (denaturant) storage tank. The product shift tanks will be fixed roof tanks and will have submerged fill pipes; these tanks will be vented to the ethanol absorber and subsequently to the RTO. Gasoline is used as a denaturant to render the ethanol undrinkable. The denaturant and E95 tank will each be designed with an internal floating roof to minimize VOC emissions.

Emissions after control are estimated at 0.27 lb/hr (1.18 TPY of VOC).

Applicant's Proposal. BP Biofuels – Highlands plans to install internal floating roofs on the E95 and denaturant storage tanks, which is the top level of control and represents BACT. For the product shift tanks, the tanks will be vented to the RTO, which is the top level of control and represents BACT.

Department's Review. The available control options for storage tanks include internal floating roofs, venting the storage tanks to a control device, and submerged pipe filling. Fixed roof tanks can be equipped with a pressure/vacuum conservation vent, which allows the tanks to operate at a slight internal pressure and prevents the release of vapors to the atmosphere during small changes in temperature, pressure, or liquid level.

The Department concurs with the applicant's selection of floating roofs on the both the E95 product tank and the denaturant tank and submerged fill pipes and venting of the product shift tanks to the RTO as BACT for this emissions unit.

5.5. BACT Review for Anaerobic Digestion, Biogas Conditioning & Biogas Backup Flare (EU 005)

5.5.1. All Emissions

Discussion. Anaerobic digestion is used to produce biogas from the organics in the thin stillage from the ethanol production processes. Anaerobic digestion produces a biogas that contains flammable levels of methane (CH_4) which requires that a safe disposal method be adopted. BP Biofuels – Highlands proposes to combust the biogas in the biomass boiler for the added benefit of energy recovery. During times when the biomass boiler is shut down, the biogas will be combusted in a flare having a rated capacity of up to 100 MMBtu/hr. Trace levels of organics in the biogas will also be combusted. Table 5 presents the emissions from this.

Table 5– Annual Emissions from Anaerobic Digestion including Biogas Flare (TPY)

Operation	CO	NO_X	PM/PM_{10}	$PM_{2.5}$	SO_2	VOC
Biogas Flare (005)	0.30	0.055	0.002	0.002	0.0005	0.11

Applicant's Proposal.

BP Biofuels – Highlands plans to combust the biogas that is generated by anaerobic digestion. The combustion will occur primarily in the biomass boiler with a flare used for backup purposes. According to the applicant, the current top level of BACT control in the industry is 98 percent. BP Biofuels – Highlands has determined that 98 percent control is achievable. Therefore, BACT for VOC emissions from anaerobic digestion is combusted in the biomass boiler with a backup flare achieving 98 percent control, which is the top level of control. In addition, the biogas will be scrubbed to remove sulfur compounds, principally hydrogen sulfide (H_2S), prior to combustion in the flare to minimize SO_2 emissions. Scrubbing is not necessary prior to the biogas being combusted in the boiler because the boiler has add-on control equipment to control emissions of SO_2.

Department's Review.

The use of the biogas in the biomass boilers will provide BACT level treatment of all pollutants. The biogas will provide a maximum of 100 MMBtu/hr of heat input towards the 270 MMBtu/hr heat input required by the biomass boiler. Combustion of the biogas in the boiler or in the flare will control odor from ammonia (NH_3) and H_2S.

The backup flare will generally not operate and emissions should be relatively low. Use of the biogas in the biomass boilers and operation of the backup flare constitutes BACT for this project, with the additional requirement that the biogas will be scrubbed of sulfur compounds prior to combustion in the flare. The Department accepts the procedures and equipment described by the applicant as BACT for this emissions unit.

5.6. BACT Review for Biomass and Natural Gas Fired BFB Boiler (EU 006)

5.6.1. NO_X Emissions

Discussion. The project is proposing one fluidized bed biomass boiler with a rated heat input capacity of 270 MMBtu/hr that will burn stillage cake, biosolids and biogas as the primary fuels with natural gas used as backup and supporting fuel. The characteristics of the biomass-fueled boiler are provided in Table 6.

Fuel NO_X is formed from nitrogen compounds contained in fuel (fuel nitrogen). Thermal NO_X is formed from molecular or atomic nitrogen (N_2) and oxygen (O_2) present in combustion air. The biomass boiler is expected to emit 94.6 TPY of NO_X.

Table 6 - Characteristics of Biomass-Fueled Boiler

Parameter	Description	
Boiler Type	BFB design	
Primary Solid Fuel Feed	Stillage and other biosolids at maximum rate of 11 TPH (dry)	
Supplemental Fuel	Natural Gas	
Ash Removal	To ash storage silo and shipment off-site	
Heat Input Rate	170 MMBtu/hr (stillage cake + biosolids) 100 MMBtu/hr (biogas) 250 MMBtu/hr (natural gas)	Overall Heat Input Limit 270MMBtu/hr 4-hour rolling average
Thermal Efficiency	To be established	
Steam Production	140,000 – 180,000 lb/hour (to be determined based on efficiency)	
Stack Parameters	7 feet diameter (maximum); 130 feet tall (minimum)	
Flue Gas	75,073 actual cubic feet per minute (acfm) at 175 °F	
Particulate Control	Fabric filter baghouse greater than 99 percent efficiency	
NO_X Control	Selective non-catalytic reduction (SNCR) based on urea injection in the furnace	
SO_2 Control	Dry limestone injection and scrubber	
VOC and CO Control	Good combustion practices (GCP)	

Applicant's Proposal for NO_X. The applicant's BACT proposal is 0.08 lb/MMBtu on a 30-day rolling basis and is included in the top row of Table 7. The BACT NO_X limit for the previous design was 0.075 lb/MMBtu on a 30-day rolling average basis. However, it should be noted that overall NO_X emissions from the biomass boiler are 35.5 TPY less than the estimated emissions from the two biomass boilers planned for the previous design.

Table 7 - Emissions in lb/MMBtu – Boilers with Uses or Capacities Similar to Proposed Project

Project Location	CO	VOC	NO_X	$PM/PM_{10}/PM_{2.5}$	SO_2
BPH, Highlands County, FL BFB - stillage, biosolids, natural gas, 270 MMBtu (proposed)	**0.10** 30-day GCP	**0.010** stack test GCP	**0.08** 30-day SNCR	**0.01 (f)** [1] **0.05 (f+c)** Stack test fabric filter	**0.06** 30-day BFB limestone Dry Scrubber
Southeast Renewable Fuels, FL BFB – sweet sorghum bagasse, wood chips including yard waste (MSW), biogas, fuel oil, propane 488 MMBtu/hr (proposed)	0.10 30-day GCP	0.005 stack test GCP	0.08 30-day SNCR	0.015 Stack test fabric filter	0.060 30-day Dry Sorben Injection
Highlands EnviroFuels, FL grate boiler – Sugarcane and sweet sorghum bagasse, energy crops, wood chips, vegetative debris, natural gas 504.3 MMBtu/hr (proposed)	0.30 30-day GCP	0.017 stack test GCP	0.10 30-day SNCR	0.015 Stack test fabric filter	0.060 30-day Dry Sorben Injection
GREC, Alachua, FL BFB – woody biomass ~1,358 MMBtu/hr (under construction)	0.12/0.08 [2] 30-day GCP	0.010/0.009 [3] stack test GCP	0.070 24-hour SCR	0.015 stack test fabric filter	0.0029 24-hour Dry Sorben Injection
Wheelabrator, Auburndale, FL grate boiler – wood and tires ~630 MMBtu/hr (1990s)	0.32 30-day GCP	0.035 stack test GCP	0.14 30-day SNCR	0.02 stack test fabric filter	0.10 30-day lime spray
U.S. Sugar Clewiston, FL grate boiler - bagasse ~1,000 MMBtu/hr (2003)	0.38 12-month GCP	0.05 Stack test GCP	0.14 30-day SNCR	0.26 stack test fabric filter	0.06 30-day no control
RBLC Survey All designs – any biomass $\geq$ 100 MMBtu/hr	0.1 – 0.78 typical 30-day GCP	0.005 – 0.05 stack test GCP	0.075-0.45 30-day various	0.0125 – 0.8 stack test various	0.02-1.54 typical 30-day various

Project Location	CO	VOC	NO_X	$PM/PM_{10}/PM_{2.5}$	SO_2
Whitefield Power & Light, NH whole tree chips (WTC) 15 MW	Not known	Not known	0.075 guarantee RSCR	Not known	Not known
Boralex Stratton, ME WTC 50 MW	Not known	Not known	0.075 guarantee RSCR	Not known	Not known
Bridgewater Power, NH WTC 16MW	Not known	Not known	0.075 guarantee RSCR	Not known	Not known
Burlington Electric, VT WTC 54 MW	Not known	Not known	0.065 guarantee RSCR	Not known	Not known
Palmer Springfield, MA construction/demolition (C&D) debris and WTC. 38 MW	Not known	Not known	0.065 guarantee RSCR	Not known	Not known
NSPS Subpart Db NG, wood, ULSD FO $\geq$ 100 < 250 MMBtu/hr	No standard	No standard	0.10-0.20 low/high heat release Natural Gas 0.30 Biomass [4]	0.03 20 percent opacity wood basis	0.20
NESHAP Subpart DDDDD [5] Fluidized bed units designed to burn biomass/bio-based solids $\geq$ 100 MMBtu/hr	~0.18 (0.21) 230 ppm @ 3% O_2 [6] (260 ppm @ 3% O_2)	No standard	No standard	0.0098 (0.012) stack test	No standard
NESHAP Subpart JJJJJJ [7]	No standard	No standard	No standard	0.03 [8]	No standard

1. f = filterable portion only, f+c = filterable plus condensable.
2. A CO limit of 0.12 lb/MMBtu on a rolling 30-day average applies from the startup of boiler operation through 360 calendar days after certification of the CO-CEMS. A CO limit of 0.08 lb/MMBtu applies thereafter.
3. A VOC limit of 0.010 lb/MMBtu applies from the startup of boiler operation through 360 calendar days after certification of the CO-CEMS. A VOC limit of 0.009 lb/MMBtu applies thereafter.
4. Where more than 10 percent of total annual output is electrical or mechanical, the unit may comply with an optional NO_X emission limit (expressed as NO_2) of 2.1 lb/MWh gross energy output on a 30-day rolling average basis [40 CFR 60.44b(l)(3)], and units complying with this output-based limit must demonstrate compliance according to the procedures of §60.48Da(i), and must monitor emissions according to §60.49Da(c), (k), through (n).
5. Final NESHAP Subpart DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters for major HAP sources date March 21, 2011. If applicable, values in parentheses are from the proposed NESHAP Subpart DDDDD dated December 23, 2012.
6. ppm @ 3% O_2 means parts per million by volume at 3 percent oxygen.
7. Final NESHAP Subpart JJJJJJ – Industrial, Commercial, and Institutional Boilers area HAP sources date March 21, 2011.
8. As stated in §63.11201, with fabric filter control, maintain opacity to less than or equal to 10 percent opacity (daily block average); or install and operate a bag leak detection system according to §63.11224 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period.

The proposed NO_X control technology is SNCR whereby NO_X emissions are controlled by reaction with NH_3 or urea at high temperature in the furnace. Some of the projects listed in the table triggered PSD and others took synthetic minor limits to avoid triggering PSD or Non-Attainment New Source Review. All include use of biomass, wood chips or woody debris. Most projects, especially those imbedded within the RACT/BACT/LAER Clearinghouse (RBLC) survey, rely on SNCR.

Selective catalytic reduction (SCR) and regenerative SCR (RSCR) involve the same reaction but in the presence of catalyst. The catalyst would be located in the dusty, medium temperature zone (prior to other control equipment) for the former or the clean, low temperature zone (after other controls) for the latter.

The applicant conducted a top/down BACT analysis for NO_X from the biomass boiler and concluded SCR is the top technology. However, the applicant claims with regard to energy impacts:

"The annual energy impacts resulting from using an SCR system would be the use of over 99,272,000 additional cubic feet of natural gas to re-heat the flue gas and 778,000 kWh per year of electricity to overcome the increased pressure drop across the catalyst reactor. The energy impact from natural gas consumption would be 629,500 cubic feet of natural gas per ton of NO_X controlled. The impact

associated with electricity consumption would be 4,933 kWh per ton of NO_X controlled. These values represent significant energy impacts and would be considered excessive given the level of NO_X emissions controlled. These energy impacts, aside from the high economic impact, eliminate SCR from further consideration as BACT."

The applicant also claims there are environmental impacts:

"The environmental impacts associated with using SCR are not inconsequential. These impacts result primarily from the combustion of additional fossil fuel to reheat the flue gas. Firing natural gas in a duct burner would not only increase NO_X emissions, the pollutant intended to be controlled by the SCR system, but would also increase emissions of CO, VOC, SO_2, and PM. In addition, a significant amount of greenhouse gas emissions (CO_2) would be generated. Estimated emissions from firing the required amount of natural gas were calculated using natural gas combustion emission factors from Section 1.4 of USEPA's AP-42 (USEPA, 1998) as follows:

- *VOC 0.3 TPY; NO_X 5.0 TPY; SO_2 0.03 TPY; CO 4.2 TPY; PM 0.4 TPY; and CO_2 5,596 TPY.*

The increase in emissions represents a significant environmental impact. Additionally, an SCR system would generate a solid waste stream in the form of spent catalyst that would also have a negative environmental impact."

Finally, the applicant indicates there is a problem with the variability of nitrogen in biomass fuels:

"Further, variable amounts of nitrogen in Highlands Ethanol's boiler fuel may occur due to nutrient additions to propagate the fermentation organisms. Boiler vendor guarantees of 0.07 lb/MMBtu NO_X could be obtained for biomass fuels that are well known and tightly defined, such as those proposed for Adage. However, because of the higher nitrogen content of the biomass fuels to be used at Highlands Ethanol and the greater variability of the feedstock composition, the biomass fuel to be combusted at Highlands Ethanol does not have a specific fuel definition that would support a limit of 0.07 lb/MMBtu."

The applicant calculated the capital costs of SCR at more than $16,000,000 based on a vendor quote for uninstalled capital cost and EPA OAQPS costing procedures for installation and operating costs. The applicant calculated annualized costs at more than $3,700,000 per year. The cost effectiveness calculated by the applicant is $23,500 per ton of NO_X removed ($/ton). The applicant claims that SCR is not cost-effective.

For the energy, environmental and economic reasons site above BP Biofuels – Highlands eliminated SCR from consideration as BACT. The next most stringent control technology available is SNCR. Because the top level of control was eliminated as BACT, the next most stringent level of control, SNCR, has been determined to be BACT. Therefore, BP Biofuels – Highlands proposes to install SNCR to control NO_X emissions from the biomass boiler.

<u>Department's Review.</u> The selection of a BFB boiler (a type of fluidized bed boiler) is a primary NO_X control measure by itself. Following are some considerations (in quotes) by Babcock and Wilcox (B&W) when comparing the emission characteristics of a typical stoker furnace with a BFB boiler.

"The combustion zone temperature is typically neither measured nor controlled and can range from 2200 to over 3000 °F." This promotes the formation of thermal NO_X. "The BFB bed temperature is both measured and controlled to an optimum temperature of approximately 1500 °F." This minimizes thermal NO_X formation but not fuel NO_X formation.

"Due to the improved combustion process previously described for a BFB, the uncontrolled (upstream of any post combustion air quality control systems) NO_X, CO and VOC emissions for a BFB are typically 10 to 25% less for a given biomass fuel than for a stoker. The BFB emissions are also less susceptible to variations in fuel properties that are inherent with any biomass plant. Under normal steady state operating conditions, both the BFB and stoker can be operated reliably within permitted emission limits.

"However, normal day-to-day operations in a typical plant are anything but steady state. Fuel variability is a fact of life, even when a conscious effort is made in the fuel yard to keep the fuel homogeneous. The

large mass of bed material in the BFB creates a "flywheel effect," which is better suited to minimize spikes in emissions due to any changes in fuel characteristics. Conversely, the relatively low fuel inventory on a grate will typically be much more susceptible to an upset and potential emissions spikes, under changing fuel conditions."

Based on the above discussion, and additional research, the Department considers the BFB feature as part of the BACT for the boiler[5]. The Department does not concur that SCR is not feasible for further (add-on) control in the dusty medium temperature zone. While there are few SCR applications to-date for biomass projects, the Department notes that such an application for a BFB biomass project (GREC) that will incorporate SCR in the dusty medium temperature zone is currently under construction as shown in Table 7.

The Department also disagrees that the cost effectiveness of SCR in the cleaner low temperature zone is as great as claimed by the applicant. The RSCR version of low temperature SCR is a relatively recent innovation wherein ceramic media are employed to heat the exhaust gases sufficiently to achieve a good reaction rate within the catalyst and then recover most of that heat in additional ceramic media after the catalyst. This reduces the heating costs and makes SCR more economical.

The vendor of the RSCR system (Babcock Power) claims a cost-effectiveness on the order of $4,000/ton NO_X removed for a single boiler producing 50 MW of electricity (~600 MMBtu/hr). When corrected for the smaller boilers at BPH, the figure will be somewhat greater. Most likely the cost-effectiveness is somewhere between the $4,000 figure and the $23,500 value estimated by the applicant. The cost-effectiveness could possibly be less than $10,000/ton NO_X removed.

The applicant proposes to achieve its proposed BACT NO_X limit by SNCR with performance that will almost match the guarantees listed for the RSCR system. In that case, the *marginal* cost-effectiveness of RSCR compared with SNCR may be substantial because the additional reduction in emissions of NO_X (on the order of 10-20 TPY) will be achieved at a relatively high additional capital cost.

The applicant will burn stillage (basically the remaining lignin from the process) rather than woody biomass as it principal fuel. Stillage may contain more fuel nitrogen because the crops contain more nitrogen than woody biomass and because nutrients such as urea are introduced to cultivate enzymes and fermentation microorganisms. Thus it may form more fuel NO_X when combusted than typical woody biomass.

The Department notes that there is little information available about grain ethanol stillage (distiller's grain) combustion, let alone cellulosic ethanol stillage combustion. Most distillers' grain is used as animal feed or fertilizer. Combustion optimization of the cellulosic ethanol stillage is one subject of on-going research at the BP Biofuels' pilot and demonstration plants in Jennings, Louisiana.

Based on the foregoing discussion, the Department will set BACT NO_X limit of 0.080 lb NO_X/MMBtu on a 30-day rolling basis achievable by combustion in a BFB boiler incorporating SNCR. Compliance shall be demonstrated by a continuous emission monitoring system (CEMS).

5.6.2. SO_2 Emissions

Discussion. SO_2 is formed from sulfur compounds contained in biomass. According to the application, the biomass boiler is expected to emit 71.0 TPY of SO_2, which is a 33 TPY reduction compared to the two biomass boilers of the pervious design. Also according to the application, stillage and other biosolids will have a feed rate of up to 11 TPH (dry) into the BFB biomass boiler. The application states:

"Control strategies for SO_2 emissions include pre-combustion controls, combustion zone controls, and post-combustion controls. Pre-combustion control strategies involve the use of low sulfur fuels and fuel sulfur scrubbing. Combustion zone control is achieved by sorbent (e.g., limestone) injection into the fluidized bed. Post-combustion controls comprise wet or dry flue gas scrubbing processes (e.g., spray

[5] Bubbling Fluidized Bed (BFB), When to use this Technology?, Jose Alberto Pascual Peña, Foster Wheeler Global Power Group, Madrid, Spain, IFSA 2011, Industrial Fluidization South Africa, TP_BFB_11_01, 15-17 Nov. 2011

dryer absorbers)."

Table 8 provides the heating value, ash and sulfur content of various types of biomass and fossil fuels, including stillage. The values are on a dry basis except as otherwise noted. As seen, stillage falls within the middle of the range of sulfur content of 0.1 percent to 0.009 percent for biomass feedstock, and is well below coal.

Table 8 - Characteristics of Biomass and Fossil Fuels – Heating Value, Ash and S

Fuel Class	Fuel	Gross Heating Value Btu/lb	Ash (%)	S (%)
Bioenergy Feedstocks	**BPH stillage (previous application)**	**4,200 (wet)**	**7**	**0.08**
	sweet sorghum	6,570	5.5	0.15
	sugarcane bagasse (generally)	7,720	3.2-5.5	0.10-0.15
	U.S. Sugar bagasse	3,600 (wet)	2.6-5.3	0.03-0.07
	hardwood	8,745	0.45	0.009
	softwood	8,360	0.3	0.01
	hybrid poplar	8,105	0.5-1.5	0.03
	Bamboo	8,085	0.8-2.5	0.03-0.05
	switchgrass	7,810	4.5-5.8	0.12
	miscanthus	7,785	1.5-4.5	0.1
	arundo donax	7,295	5-6	0.07
Liquid Biofuels	bioethanol	11,940	~0	<0.01
	biodiesel	17,050	<0.02	<0.05
Fossil Fuels	Coal (low rank)	6,400-8,100	5-20	1.0-3.0
	Coal (high rank)	11,500-12,800	1-10	0.5-1.5
	ULSD	18,150	negligible	<0.0015
	NG	1,030 Btu/cubic foot	negligible	< 0.002

Applicant's Proposal SO_2. The applicant's BACT proposal is 0.06 lb SO_2/MMBtu on a 30-day basis and is included in the top row of Table 7. Additional short term limits (not shown in the table) are 0.12 and 0.14 lb/MMBtu on 24-hour and 3-hour bases, respectively. The proposed SO_2 control technology is limestone ($CaCO_3$) injection with the addition of dry sorbent injection. Dry sorbent injection was not included in the previous design and is proposed now mainly to control hydrogen chloride (HCl) emissions and keep the BPH below the 10 TPY major individual HAP emission threshold (see further below).

According to the applicant:

"The boiler is designed to burn stillage cake, biosolids and biogas as its primary fuels. The sulfur content of the stillage cake, biosolids and biogas will be a function of the raw materials that are input to the process and the hydrolysis process which uses sulfuric acid. The sulfur content of these fuels will be variable and cannot be controlled. Therefore, use of low sulfur fuel is not technically feasible. The available SO_2 emissions control methods that are technically feasible are combustion zone controls (limestone injection), postcombustion controls (wet scrubber or spray dryer absorber) and pre-combustion removal of the sulfur in the biogas.

Spray dryer absorbers or wet scrubbers are typically understood to provide the highest level of SO_2 control possible in boiler applications. With the fluidized bed design, however, limestone injection can provide SO_2 controls equivalent to that of spray dryer absorbers or wet scrubbers. Therefore, all three technologies are considered equivalent in this application and represent the top level of control. Because the top level of control will be selected, an analysis of the economic, energy and environmental impacts of other emission reduction technologies is not required. The top controls are sufficient to control sulfur emissions to BACT levels for stillage, biosolids and biogas combustion, and therefore pre-combustion

control of sulfur in biogas, which would not reduce sulfur in the stillage or biosolids, would be redundant and not cost effective. Therefore, only the combustion zone and post-combustion technologies discussed above are further considered."

As indicated in the above discussion, BP Biofuels – Highlands plans to utilize limestone injection for the biomass boiler, which is the top level of control, and therefore represents BACT supplemented by dry sorbent injection. Consequently, the applicant did not provide a cost analysis for further SO_2 reductions.

The applicant also states:

"With respect to HCl emissions, the previous project required the use of CEMS to demonstrate compliance with the HCl emission limits. Because the currently proposed biomass boiler capacity is less than that in the existing permit, potential HCl emissions are now less than the previous project. As such, Highlands Ethanol is requesting that the requirement for HCl CEMS be eliminated."

Department's Review.

In the previous design, the Department disagreed with the applicant's assertion that limestone injection alone is the top technology for SO_2 control. For example, Jacksonville Electric Authority employs limestone injection on two coal-fueled circulating fluidized bed (CFB) boilers (a type of FBC boiler) and incorporates polishing scrubbers in addition to limestone injection. Similarly, the Virginia City Hybrid Energy Center located in Wise County, VA, which entered commercial operations on July 10, 2012, combust coal and 20 percent biomass in a 585 MW CFB-based power plant. This facility incorporates limestone injection into the fluidized beds and lime injection/dry scrubbing of the exhaust gas to achieve a BACT SO_2 limit of 0.022 lb/MMBtu on a 30-day basis.

The grate boiler at U.S. Sugar in Clewiston (see Table 7) fires primarily bagasse, supplemented with low sulfur fuel oil and complies with a SO_2 emission limit of 0.06 lb/MMBtu with no additional SO_2 control. Some of the SO_2 is removed in the fly ash without the addition of sorbent. The U.S. Sugar bagasse boiler is about 4 times the size of the proposed BPH biomass boiler.

In contrast to the U.S. Sugar project, the stillage biomass to be combusted at the BPH is devoid of much of the cellulosic and hemicellulosic fractions because the latter materials are converted to ash-free and sulfur free ethanol. Consequently, the BPH stillage biomass contains a relatively greater fraction of the ash and sulfur content inherent in the source materials.

For the purpose of further evaluation, the Department will assume that the maximum sulfur content of 0.08 percent for stillage cake stated by the applicant is on a wet basis and that the fuel heat content stated in Table 8 is also on a wet basis. The pre-control SO_2 emission potential is calculated as follows:

Some SO_2 will be removed by interaction with the combustion product fly ash in a manner similar to that of U.S. Sugar. Furthermore, the applicant will supplement the stillage with a substantial amount of natural gas that contains practically 0 percent sulfur. Co-firing the stillage with varying amounts of clean natural gas coupled with inherent removal characteristics of the stillage ash should control emissions to approximately 0.20 lb SO_2/MMBtu. Additional control by limestone injection and the newly proposed dry sorbent inject to 0.06 lb/MMBtu (~70 percent further reduction) is a conservative goal on a 30-day basis. The Department anticipates that the actual emission will be lower. However, the total estimated emissions of SO_2 from the biomass boiler are only 71TPY (73.4 TPY from the entire project), which makes it unnecessary to set a lower emission rate as BACT.

The Department accepts the BPH BACT proposal and notes:

- The project is the first full scale commercial installation of a biologically-based cellulosic ethanol facility using the resultant biomass stillage as fuel;
- The stillage biomass boiler is relatively small and will each emit only 71 TPY each; and

- The determination is strictly for a biomass boiler with stillage as its primary fuel within a biologically-based ethanol project and is not a BACT determination for biomass boilers in general.

Based on the foregoing discussion, the Department will set a limit of 0.060 lb SO_2/MMBtu on a 30-day rolling basis achievable by combustion in a BFB boiler, supplemental firing of clean natural gas and incorporation of limestone injection supplanted by dry sorbent inject. Compliance shall be demonstrated by an SO_2-CEMS. Further, with the addition of dry sorbent injection to the biomass boiler, the Department no longer feels it is necessary to require a HCl CEMS to provide reasonable assurance that the 10 TPY individual HAP threshold will not be exceeded.

5.6.3. CO and VOC Emissions

Discussion. VOC and CO are products of incomplete combustion. Refer to Table 7 above for a listing of CO and VOC limits from biomass projects.

Applicant's Proposal. The applicant's BACT proposals are 0.1 and 0.005 lb/MMBtu for CO and VOC respectively based on GCP. The proposed limit for CO is on a 30-day rolling basis while the VOC limit is on a 24-hour rolling basis. According to the applicant, the biomass boiler is expected to emit 118 TPY of CO and 5.91 TPY VOC, which are reductions compared to the previous design of 173.4 TPY (86.72 TPY per boiler) for CO and 8.7 TPY (4.34 TPY per boiler) for VOC. Refer to Table 6 above for a listing of CO and VOC limits from biomass projects.

The proposed CO and VOC limits are equivalent to the lowest permitted CO and VOC emission rates identified for FBC biomass boilers.

Department's Review. Due to the intimate contact between the bed material in a BFB boiler and the fuel, improved fuel burnout occurs. This results in very low CO and VOC emissions. The Department agrees that the proposed values represent BACT for CO and VOC.

For reference, the final NESHAP Subpart DDDDD (March 21, 2011) would require compliance with a CO limit of 230 ppm @ 3 percent O_2 as a surrogate for organic HAP which equates to approximately 0.18 lb/MMBtu. For further comparison, the proposed NESHAP Subpart DDDDD (dated December 23, 2011) would require compliance with a CO limit of 260 ppm @ 3 percent O_2 which would equate to approximately 0.21 lb/MMBtu.

The Department will set the CO BACT limit at 0.10 lb/MMBtu on a 30-day rolling average. Compliance shall be demonstrated by a CO-CEMS. The Department will set the VOC BACT limit at 0.005 lb/MMBtu. Compliance shall be demonstrated by an initial stack test and subsequent stack tests to be performed prior to permit renewal cycles.

5.6.4. $PM/PM_{10}/PM_{2.5}$ and Visible Emissions (VE)

Discussion. $PM/PM_{10}/PM_{2.5}$ emissions are formed from ash contained in the biomass, products of incomplete combustion and from chemical reactions between products of combustion that form alkali and ammoniated chlorides, sulfates, nitrates and other such species. According to Rule 62-210.200, F.A.C. (Definitions), $PM_{2.5}$ emissions shall include condensable $PM_{2.5}$. Condensable $PM_{2.5}$ is defined as gaseous emissions from a source or activity which condense at ambient temperatures to form $PM_{2.5}$. For the purposes of PSD, including determinations of applicability and establishment of limitations to avoid PSD, $PM_{2.5}$ emissions shall include condensable $PM_{2.5}$.

Rule 62-297.401, F.A.C specifies EPA Method 202 – Determination of Condensable Particulate Emissions from Stationary Sources, contained in 40 CFR 51, Appendix M, as the compliance method when a $PM_{2.5}$ limit is required by a Department rule or permit.

Refer to Figure 12. The typical $PM_{2.5}$ sampling train is a hybrid of EPA Methods 201A and 202 (EPA Method 5 may also be used in conjunction with Method 202). The first portion (left hand side) is used to sample the gas stream and, by inertial separation, remove filterable PM larger than 10 µm and then filterable PM between 10 and 2.5 µm in aerodynamic diameter.

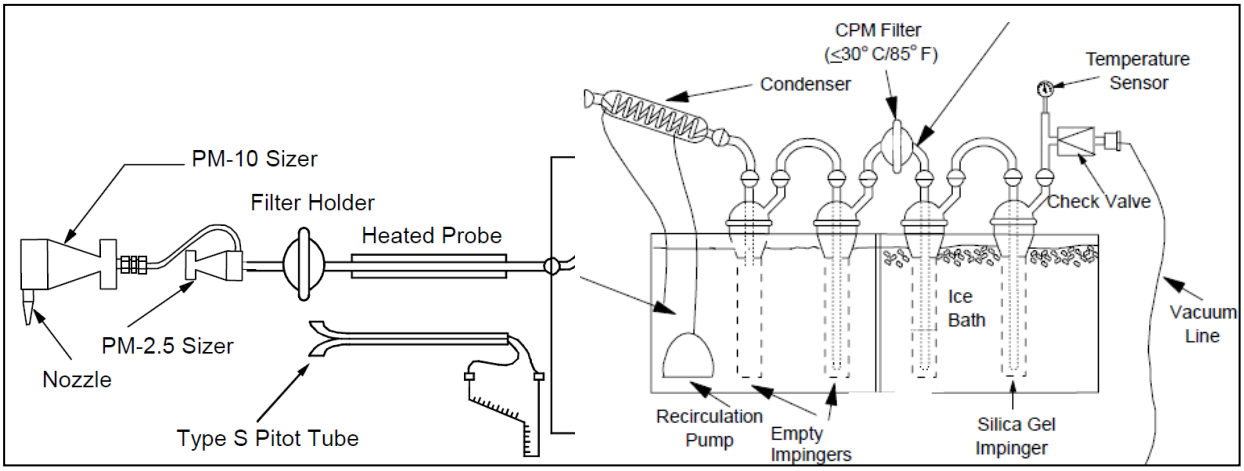

Figure 12 - EPA Hybrid Method 201A/202 Filterable and Condensable $PM_{2.5}$ Sampling Train.

A filter is then used to remove by mechanical impaction, interception and diffusion virtually all the filterable $PM_{2.5}$ existing at near-stack temperature conditions. The exhaust gas sample (cleansed of filterable $PM/PM_{10}/PM_{2.5}$) is maintained at a relatively high temperature in a heated probe and then passed through a condenser to nucleate condensable species allowing these gaseous components to condense to condensable PM (CPM) which are then passed through to the CPM filter that is operated at a "defined ambient temperature" $\leq$ 30°C (85°F).

Condensable PM is usually higher than filterable PM, but may be about the same as filterable PM or can even be around 10 times higher[6] In the case of BPH; condensable PM may be significantly higher than filterable PM because Urea will be injected via a SNCR system into the biomass boiler furnace to control NO_X emissions. This will cause ammonia (NH_3) to be liberated which reacts with NO_X to form molecular nitrogen and water. Excess NH_3 is typically required in a SNCR system to achieve significant NO_X reduction due to inefficient mixing with exhaust gases or insufficient residence time within the injection zone in the furnace. The excess NH_3 (commonly known as slip) ultimately comes into contact with combustion acid gases such as SO_2, SO_3 and HCl to form ammoniated sulfites/sulfates and ammonium chloride (NH_4Cl) as follows:

$$NH_3 + SO_2 + H_2O \rightarrow NH_4HSO_3 \quad \text{(ammonium bisulfite)}$$

$$NH_3 + SO_3 + H_2O \rightarrow NH_4HSO_4 \quad \text{(ammonium bisulfate)}$$

$$2NH_3 + SO_3 + H_2O \rightarrow (NH_4)_2SO_4 \quad \text{(ammonium sulfate)}$$

$$NH_3 + HCl + H_2O \rightarrow NH_4Cl \quad \text{(ammonium chloride)}$$

Such ammoniated species and sulfuric acid mist (SAM or H_2SO_4) can pass through the proposed fabric filter (baghouse) in gaseous form and thereafter condense at lower temperature outside of the stack. At sufficient concentrations, these emissions can cause a visible plume.

Similarly, these species can, to a large extent, pass through the front portion (Method 201A or Method 5) of the hybrid sampling train shown in Figure 12. Figure 13 is a graph (developed by Verhoff and Banchero, 1974) indicating the dew point variation of power plant exhaust gases at different concentrations of SAM and water. Link to graphs It only takes a concentration of 1 ppm of SAM to cause condensation at 250 °F and 15 percent H_2O. Figure 14 is from a Siemens brochure showing a non-steam visible plume caused by NH_3 slip and sulfur-laden gases. Siemens Brochure

[6] Compliance of Biomass Plants with $PM_{2.5}$ and MACT Emission Limits: The Risks of Emission Testing, The Avogrado Group, Source Emissions Testing and Emissions Specialists, Presentation, Craig Thiry and Kevin Crosby, International Biomass Conference and Expo, April 16–19, 2012, Denver, CO.

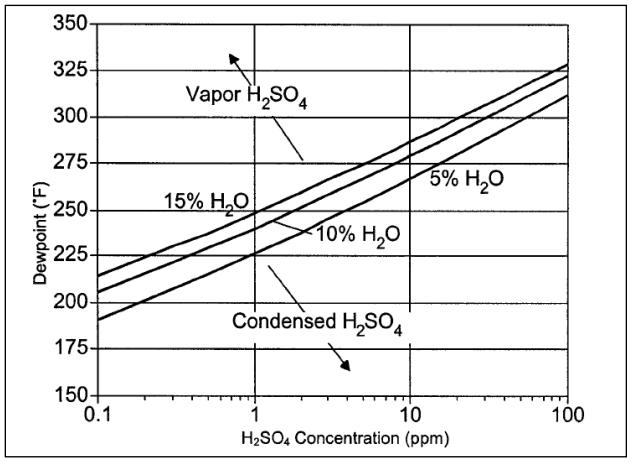

Figure 13 - Dew Point versus H_2SO_4 Concentration. **Figure 14 - Condensing Visible Plume.**

Similarly, the influence of NH_4HSO_4 on dew point is as high as 27°F, while NH_4Cl and $(NH_4)_2SO_4$ cause a dew point rise of 90 °F. Link to SNCR and Boiler Corrosion NH_4HSO_4 has a melting point of 297°F and some fraction would be in the gaseous state (and not collected) in a filter operated at high temperature. Thus, the drop in sampling train temperature in the condenser and capture of the nucleated species at ambient temperature (that would be gaseous at higher temperature) can cause condensable PM emissions to be much greater when compared to the PM emissions measured by EPA Method 5.

Based on the above discussion, there is great uncertainty in the amount of condensable $PM_{10}/PM_{2.}5$ that will be emitted from the BPH biomass boiler stack. This uncertainty must be taken into account when determining a BACT emissions limit for condensable $PM_{10}/PM_{2.5}$.

Applicant's Proposal. The applicant's BACT proposal is 0.01 lb/MMBtu for $PM_{10}/PM_{2.5}$ (filterable) and 0.05 lb/MMBtu for $PM_{10}/PM_{2.5}$ (filterable + condensable) using a fabric filter baghouse with compliance based on annual stack testing using either EPA Hybrid Method 201A/202 or Method 5/202. According to the applicant, the biomass boiler is expected to emit 59.1 TPY of filterable + condensabl) $PM_{10}\backslash PM_{2.5}$ which is a 28.6 TPY reduction compared to the two biomass boilers in the previous design. Refer to Table 7 above for a listing of PM/PM_{10} limits from biomass projects. Following is the main excerpt from the applicant's BACT analysis:

"*Technically feasible PM control technologies include fabric filters, electrostatic precipitators (ESP), cyclones and wet scrubbers. However, from a top-down perspective, the most effective types of PM control equipment being successfully applied to biomass boilers are fabric filters and ESP. Fabric filters have surpassed ESP as the preferred particulate control device because they provide better control for finer PM.*

"Highlands Ethanol intends to install fabric filters on the biomass boiler, which represents the top level of BACT control and no further analysis is required."

The applicant proposed a VE standard 20 percent opacity (6 minute blocks) except for one 6 minute block per hour of 27 percent opacity during normal operation conditions. The applicant also proposed VE standard 27 percent opacity (6 minute blocks) except for one 2 minute block per hour of 40 percent opacity during exceptional operation conditions.

Department's Review. Burnout in a BFB boiler is superior to that of a stoker furnace. This reduces the potential for fires in the pollution control equipment and allows for use of a baghouse to meet lower PM/PM_{10} limits and to minimize direct emissions of $PM_{2.5}$.

The Department will set the BACT PM/PM_{10} of 0.01 lb/MMBtu by fabric filtration for filterable $PM_{10}/PM_{2.5}$. Compliance shall be demonstrated by initial and annual stack tests. In addition, the Department will set a PM limit of 0.03 lb/MMBtu based on annual stack tests to show compliance with

NESHAP 40 CFR 63, Subpart JJJJJJ. The Department will specify a VE standard 10 percent opacity (6 minute blocks) except for one 6 minute block per hour of 20 percent opacity during all operating conditions.

The only $PM_{2.5}$ BACT limits from the EPA RACT/BACT/LAER Clearinghouse applicable to the BPH project is a November 2010 determination for a biomass boiler (spreader-stoker) at the Smart Paper-Hamilton facility in Ohio with a total $PM_{2.5}$ limit (filterable + condensable) of 0.71 lb/MMBtu. PM control for this boiler is via a baghouse; with the heat input rating of 249 MMBtu/hr which is similar to the BPH biomass boiler.

There is at least one key difference between the Smart and BPH facilities that affects the condensable part of $PM_{2.5}$. The Smart facility is not equipped with post-combustion NO_X control (SCR or SNCR) and consequently is not subject to NH_3 slip. For the reasons discussed above NH_3 slip can increase condensable $PM_{2.5}$ emissions.

A BFB boiler was permitted at the Graphic Packaging Macon Mill in Georgia (Biomass Boiler #3, B005). Biomass Boiler #3 is a proposed bubbling fluidized bed (BFB) rated at 620 MMBtu/hour. The boiler will be equipped with flue gas recirculation, SNCR, a baghouse, and potentially an acid gas control system. The facility proposes to combust biomass (i.e., virgin wood, green wood, forest thinnings, bark, sawdust, corn stover and other biomass crops used for energy production), natural gas, and mill wastewater treatment plant sludge. Based on the biomass types to be combusted and the boiler type and controls, this biomass boiler is most similar to the biomass boiler proposed for BP Biofuels Highlands. Therefore, the proposed TPM emission limits were reviewed for comparison with that proposed for BP Biofuels Highlands.

The proposed PM emission limits for Graphic Packaging's Biomass Boiler #3 are as follows:

- FPM: 0.03 lb/MMBtu
- $PM_{2.5}$ (FPM + CPM): 0.040 lb/MMBtu
- PM_{10} (FPM + CPM): 0.049 lb/MMBtu

The Department will specify an initial $PM_{10}/PM_{2.5}$ (filterable + condensable) emission limit of 0.05 lb/MMBtu as the BACT limit. This limit may be either decreased or increased in the future based on stack test results. To this end, during the first year of operation, the BPH shall conduct filterable + condensable $PM_{10}/PM_{2.5}$ stack testing biannually (total of three tests). Based on these stack tests, the Department in consultation with the permittee shall determine if the current filterable + condensable $PM_{10}/PM_{2.5}$ BACT limit of 0.05 lb/MMBtu is reasonable or needs revision to a higher or lower limit. If a revision of the limit is deemed necessary, this permit will be modified accordingly. All stack tests will be conducted with the boiler operating on biogenic fuel (stillage cake, biosolids, and biogas) as its primary fuel source. Stack tests may be postponed if the unit will operate less than 500 hours during the period since the last stack test. BPH will notify FDEP 21 days before postponement of a stack test. Based on results from these tests and in consultation with the permittee, the $PM_{10}/PM_{2.5}$ filterable + condensable limit may be adjusted to reflect actual emissions.

In addition to the above filterable + condensable $PM_{10}/PM_{2.5}$ limit, the Department has reviewed $PM_{2.5}$ and believes that measures have been incorporated into the overall BACT for the project that will adequately address this pollutant. These measures include:

- BACT emission limits and controls for SO_2 and NO_X that tend to form $PM_{2.5}$ in the environment;
- Acid gas control by limestone injection in the bed of the BFB boiler with subsequent polishing by dry sorbent injection;
- A VE limit that directly controls the fraction of $PM_{2.5}$ that interferes with light transmission; and
- The Department will establish a NH_3 limit of 20 ppm @ 15 percent O_2 ppm to minimize direct NH_3 emissions that can form ammoniated compounds in the exhaust stream and in the environment.

5.7. BACT Review for Natural Gas-Fueled Peaking Boiler (EU 007)

Discussion. The project includes a "peaking" boiler to produce steam during peak demand from the production process areas. The peaking boiler will have a maximum heat input capacity of 95 MMBtu/hr and will be fired solely with natural gas. The boiler will operate at all times during production and will cycle up and down dependent upon process demand. When the biomass boiler is down the peaking boiler can also provide auxiliary steam to the operations.

Based on the peaking boiler operating continuously at its maximum heat input rate its estimated emissions are: 1.7 TPY of $PM/PM_{10}/PM_{2.5}$, 14.6 TPY of NO_X, 15.4 TPY of CO, 2.3 TPY of SO_2 and 0.58 TPY of VOC. Compared to the previous design, these emissions represent reductions of: -5.0 TPY of $PM/PM_{10}/PM_{2.5}$, -70.4 TPY of NO_X, -56.0 TPY of CO, -2.5 TPY of SO_2 and -0.14 TPY of VOC.

Applicant's Proposal. The applicant's proposals for all of the pollutants in lb/MMBtu from the peaking boiler (and the biomass boiler) are included in Table 9 with comparison limits from the RBLC survey and other standards.

Table 9 - Emissions in lb/MMBtu – Boilers with Uses or Capacities Similar to Proposed Project

Project Location	CO	NO_X	VOC	$PM/PM_{10}/PM_{2.5}$
BPH, Highlands County natural gas, 95 MMBtu/hr	0.037	0.035	0.0014	0.004
Biomass Boilers 270 MMBtu/hr, stillage [1]	0.10	0.08	0.005	0.01 (f) 0.05 (f+c)
Recent RBLC Survey	0.036 – 0.08	0.011 – 0.05	0.0014 – 0.006	0.002 – 0.0076
Port Westward, OR	0.08	0.05	0.005	0.002
Sithe Mystic, MA	0.08	0.035	0.008	0.007
Sithe Fore River, MA	0.08 and 100 ppm @ 3% O_2	0.035/0.10 (NG/FO)	0.008/0.004 (NG/FO)	0.08 (FO) 0.007 (NG)
FPL West County, FL 99.8 MMBtu/hr, NG	0.08	0.05	2 gr S/100 SCF NG, 10% opacity	
NSPS Subpart Dc, natural gas ≥ 10 MMBtu/hr < 100	Record Keeping Required			
NESHAP Subpart DDDDD [2] ≥ 10 MMBtu/hr , Gas 1	Conduct a tune-up of the boiler annually as specified in §63.7540.			
NESHAP Subpart JJJJJJ	No subject to this NESHAP			

1. The BPH biomass (stillage) boiler values are included for comparison with those of the peaking boiler.
2. Both final (March 21, 2011) and proposed (December 23, 2011) versions.

SO_2 is controlled by specification of natural gas. The natural gas available in Florida generally contains less than 2 grains of sulfur per 100 standard cubic feet (gr/100 SCF). At this natural gas sulfur content, SO_2 emission from the peaking boiler would equal 0.0056 lb/MMBtu.

Overall, the applicant proposes the values listed for the BPH project in the table as BACT and will accomplish these values by use of inherently clean natural gas, flue gas recirculation (FGR), Low NO_X burners (LNB) and good combustion practices (GCP).

According to the applicant, *"The peaking boiler will be subject to the NSPS for Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Dc) because the boiler's maximum firing rate will be between 10-100 MMBtu/hr. However, NSPS Subpart Dc does not impose NO_X limits on subject boilers."*

In addition, the applicant stated:

"There are fifteen entries in the database that were listed in permit records as natural gas fired boilers rated less than 100 MMBtu/hr. Four of these boilers do not have their control type listed. The remaining boilers are controlled with low NO_X burners, four in conjunction with FGR, and four with ultra low NO_X burners."

"Proven add-on NO_X control technologies include SCR and SNCR. However, given the fact that the peaking boiler will utilize clean fuels and will have low emissions, add-on controls would not be cost effective. Therefore, the base level of control for the peaking boiler, low NO_X burners with FGR, is determined to be BACT."

Department's Review. The Department recognizes that emissions from the natural gas-fired peaking boiler will be low due to its small size (95 MMBtu/hour) and the fact that it will burn only clean natural gas. The low emissions from the boiler make the addition of add on pollution controls cost prohibitive when compared to the mass of pollutants removed, specifically NO_X and CO. Although there will be no hour restriction on the use of the peaking boiler, natural gas usage will be limited by the applicant's request to limit the combined heat input from natural gas to both the biomass and peaking boiler to 1,065 MMscf/yr in any consecutive 12 month period further limiting emission from the peaking boiler.

The applicant's proposed use of LNB, FGR and GCP for the boiler to control the emissions of VOC, CO and NO_X is acceptable to the Department as BACT. The use of clean natural gas to limit $PM/PM_{10}/PM_{2.5}$ and SO_2 emissions is also accepted by the Department as BACT. Compliance with the CO limit of 0.037 lb/MMBtu shall be demonstrated by initial stack testing and upon permit renewal. Compliance with the SO_2 limit shall be shown by fuel monitoring showing that the sulfur content of the natural gas is 2 gr/100 scf or less. Vendor certification can be used in lieu of fuel monitoring

Compliance with the NO_X and VOC limits of 0.035 lb/MMBtu and 0.0014 lb/MMBtu, respectively, shall be demonstrated by initial stack tests and upon permit renewal. The Department will also set an opacity limit of 10 percent opacity (6 minute blocks) except for on 6 minute block of 20 percent opacity per hour. Compliance with the opacity limit shall be demonstrated by initial stack testing and upon permit renewal.

Compliance with the filterable $PM_{10}/PM_{2.5}$ limit shall be demonstrated by an initial stack test, with subsequent compliance shown by fuel monitoring showing that the sulfur content of the natural gas is 2 gr/100 scf or less. Vendor certification can be used in lieu of fuel monitoring. So long as the peaking boiler is primarily fueled by natural gas there is no applicable PM limit with regard to NESHAP 40 CFR 63, Subpart JJJJJJ. However, per Subpart JJJJJJ, the peaking boiler may combust liquid fuel during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

Refer to the condensable PM write up dealing with the BFB boiler (EU 006). In that analysis, reasons were given on why condensable PM can be of concern and even greater than filterable PM when combusting biomass with NO_X control by urea injection. However, when combusting clean, low sulfur natural gas in the peaking boiler these same concerns are of much less importance.

In the peaking boiler, urea is not going to be injected via a SNCR system into the boiler furnace so no NH_3 will be liberated. Consequently, there will be no excess NH_3 (slip). Without excess NH_3, no reactions with combustion acid gases such as SO_2, SO_3 and HCl can occur to form ammoniated sulfites/sulfates and ammonium chloride (NH_4Cl.). Unlike the case of the BFB biomass boiler, these ammoniated species and sulfuric acid mist (SAM or H_2SO_4) cannot condense at lower temperatures outside of the stack. Consequently, condensable PM is of much less a concern with the peaking boiler and the Department will not set a condensable $PM_{10}/PM_{2.5}$ emission limit for the peaking boiler.

5.8. BACT Review for Cooling Tower (EU 008)

Discussion. The tower will be of rectangular mechanical-draft design with four cells. Each cell will be equipped with its own fan and a high efficiency drift eliminator to minimize water drift losses. The flow rate will be approximately 50,000 gallons per minute. Total dissolved solids in the cooling water are expected to be approximately 2,750 mg/l. Cooling towers may emit PM based on the loading in the recirculating water. They may also emit VOC as a result of heat exchanger leaks and their subsequent stripping from the water stream by the air flow. Estimated emissions after control are 1.5 TPY of $PM/PM_{10}/PM_{2.5}$, 9.2 TPY of VOC and 0.5 TPY of HAP.

Applicant's proposal. The applicant proposes to install a drift eliminator with cooling tower drift limited to 0.0005 percent of the water recirculation rate.

According to the applicant, the most practical method of controlling VOC emissions is to promptly repair any leaking components. BP Biofuels – Highlands proposes to collect a sample of cooling water on a weekly basis and analyze it for VOCs. This will enable the early detection of leaking heat exchangers, thereby minimizing VOC emissions and odors. Therefore, BACT for process heat exchanger leaks is establishment of a weekly monitoring program.

Department's review. The Department concurs with the applicant's proposal for BACT.

5.9. BACT Review for Miscellaneous Storage Silos (EU 009)

Discussion. The materials stored in these silos include powdered cellulose, wheat bran, ammonium sulfate, and potassium phosphate for the ethanol process, limestone and hydrated lime to control SO_2 emissions the biomass boiler, sand (makeup for the BFB boiler bed), urea (SNCR system) and ash related to the biomass boilers. The silos will emit small amounts of $PM/PM_{10}/PM_{2.5}$ estimated at 4.5 TPY total.

Applicant's proposal. The applicant proposes to control $PM/PM_{10}/PM_{2.5}$ emissions from the miscellaneous dry materials storage silos by fabric filter dust collectors achieving a concentration of 0.005 grains per dry standard cubic foot (gr/dscf).

Department's review. The Department concurs with the applicant's proposal for BACT.

5.10. BACT Review for Miscellaneous Storage Tanks (EU 010)

Discussion. The materials stored in these tanks include: sulfuric acid (93 percent solution) used in hydrolysis; magnesium hydroxide (61 percent solution) used to neutralize hydrolyzed material prior to fermentation; propagation and fermentation nutrients to include corn syrup, phosphoric acid (85 percent solution) and aqueous ammonia (19 percent solution); a flocculant solution used in the stillage loadout area to recover additional solids; and caustic soda (50 percent solution) used for the clean in place system for the fermentation and propagation vessels. According to the applicant, pollutant emissions are minimal to the point of being negligible.

Applicant's proposal. The applicant proposes to install vertical fixed roof design on these tanks that will achieve minimal emissions for the described liquids.

Department's review. The Department concurs with the applicant's proposal for BACT.

5.11. BACT Review for Emergency Generators (EU 011)

Discussion. Three emergency generators, each rated at 1,500 kW will be installed to provide backup electrical power in the event of a power outage at the facility. They will be used sparingly and limited to 100 hr/yr of operation for testing and maintenance. Operation during emergency situations is unlimited. The requirements of 40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (NSPS Subpart IIII) are given at: NSPS Subpart IIII

The area and major sources requirements of 40 CFR 63, Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (NESHAP Subpart ZZZZ) are given at: NESHAP Subpart ZZZZ.

A stationary reciprocating internal combustion engine subject to regulation under 40 CFR part 60 (i.e. NSPS) and that meets any of the criteria in paragraphs 63.6590(c) (1) through (7) of the NESHAP Subpart ZZZZ, must meet the requirements of this regulation by meeting the requirements of 40 CFR part 60, subpart IIII. No further requirements apply for such engines under 40 CFR part 63.

The estimated emissions from all three engines are: 0.50 TPY of $PM/PM_{10}/PM_{2.5}$; < 0.1 TPY of SO_2; 14.3 TPY of NO_X; 8.7 TPY of CO; and 1.6 TPY of VOC.

Applicant's Proposal. The applicant proposes to use ultra low sulfur distillate fuel oil to comply with the requirements of NSPS Subpart IIII (see Table 10).

Table 10 - Emission Standards for Emergency Generators (EU 011)

Emergency Generator (> 560 kW and ≤ 2,237 kW)	**CO** (g/kWH)[a]	**VOC** (g/kWH)	**NO_X** (g/kWH)	**PM** (g/kWH)	**SO_2** (oil sulfur spec.)
BACT Proposal	3.5	0.64	5.76	0.20	15 ppm
Subpart IIII (2006 and later)	3.5	6.4 (NMHC[b] + NO_X)		0.20	15 ppm

a. g/kWH means grams per kilowatt-hour.
b. NMHC is the acronym for non-methane hydrocarbons. NMHC are approximately equal to VOC for these sources.

Department's Review. The applicable Subpart IIII has been updated in recent years and includes progressively more stringent requirements based on the model year of the engine selected. The Subpart IIII values in the table above given for engines for model year 2006 and beyond are appropriate as BACT for this type of engine, service and hours of operation. By complying with Subpart IIII, compliance is attained for Subpart ZZZZ.

The limits on NMHC are sufficient to regulate VOC. The Department accepts the applicant's BACT proposal for this emission unit.

5.12. BACT Review for Emergency Fire Pump Engine (EU 012)

Discussion. The single 850-horsepower (hp) fire pump engine is proposed for the project. It will be used sparingly and limited to 100 hr/yr of operation for testing and maintenance. Operation during emergency situations is unlimited. As with the emergency generators (EU 011), the fire pump must meet the applicable requirements of NSPS Subpart IIII and meets the requirements of NESHAP Subpart ZZZZ by meeting the requirements of the NSPS.

The estimated emissions from the fire pump engine are: <0.1 TPY of $PM/PM_{10}/PM_{2.5}$; < 0.1 TPY of SO_2; 0.4 TPY of NO_X; 0.25 TPY of CO; and 0.05 TPY of VOC.

Applicant's Proposal. The applicant proposes to use ultra low sulfur distillate fuel oil to comply with the requirements of NSPS Subpart IIII (see Table 11).

Table 11 - Emission Standards for Emergency Fire Pump Engines

Emergency Pumps (≥ 750 hp)	**VOC** (g/kWH)	**NO_X** (g/kWH)	**PM** (g/kWH)	**CO** (g/kWH)	**SO_2** (oil sulfur spec.)
BACT proposal	0.64	5.76	0.20	3.5	15 ppm
Subpart IIII(2008 and later)	6.4 (NMHC+NO_X)		0.20	3.5	15 ppm

Department's Review. Subpart IIII has been updated in recent years and includes progressively more stringent requirements based on the model year of the engine selected. The Subpart IIII values in the table above given for engines for model year 2008 and beyond are appropriate as BACT for this type of engine, service and limited hours of operation. The limits on NMHC are sufficient to regulate VOC and to control CO emissions to an acceptable degree (0.5 TPY).

The Department accepts the applicant's BACT proposal for this emission unit.

5.13. BACT Review for VOC Fugitive Equipment Leaks (EU 013)

Discussion. Uncontrolled fugitive equipment leaks such as from pumps, compressors, relief devices, flanges, valves, etc. can be significant sources of VOC and HAP emissions. This equipment is part of several of the emission units associated with this project. Estimated emissions after control are 19.6 TPY of VOC and ~1.0 TPY of HAP.

Applicant's Proposal. It is not feasible to collect such leaks and treat them using the control devices (such as scrubbers and flares) installed in the individual units. The project is subject to NSPS Subpart VVa - Equipment Leaks in the Synthetic Organic Chemical Manufacturing Industry (for projects that commence construction or modifications after November 7, 2006).

Subpart VVa has specific requirements for controlling such leaks from pumps, compressors, relief devices, flanges, valves, etc. One requirement is the development of a Leak Detection and Repair (LDAR) program to insure compliance with VVa and any other requirements to control equipment leaks.

According to the applicant, 20 facilities have established such LDAR programs at ethanol production facilities. The applicant proposes development of a LDAR program and compliance with the requirements of Subpart VVa as BACT for this project. To this end the applicant has stated the preliminary LDAR plan issued with the final permit for the previous design is still applicable to this modified project. This LDAR program was developed pursuant to Subpart VV (the predecessor of Subpart VVa) for the smaller BP Biofuels pilot and demonstration projects in Jennings, LA. As with the previous design, the applicant proposes to rely upon the requirements of Subpart VVa and will provide a more comprehensive version for the larger commercial project at BPH no later than 90 days before BPH becomes operational.

Leak Detection and Repair (LDAR) Program

1. PURPOSE

   The objective of this procedure is to establish guidelines for implementing and managing a Leak Detection and Repair (LDAR) program at BPH located in Highlands County, Florida. The use of this procedure will assure compliance with federal and state regulations.

2. SCOPE

   This procedure applies to all regulated components used in Volatile Organic Compound (VOC) service at BP Biofuels – Highlands.

3. REFERENCES
   a. 40 CFR Part 60 Subpart VVa
   b. Florida Rule 62-204.800, F.A.C

2. PROJECT TASK
   a. Task 1 - Identification of Components
      - Identify each regulated component on a site plot plan or on a continuously updated equipment log.
      - Assign a unique identification (ID) number to each regulated component.
      - Purchase tags and physically locate each regulated component in the facility, verify its location on the piping and instrumentation diagrams (P&IDs) or process flow diagrams, and tag each component. Update the equipment log if necessary.
      - Record each regulated component and its unique ID number in a log.
      - Promptly note in the equipment log when new and replacement pieces of equipment are added and equipment is taken out of service.

b. Task 2 - Leak Definition

- Identify the leak definition for each regulated component. Leak definitions vary by regulation, component type, service (e.g., light liquid, heavy liquid, gas/vapor), and monitoring interval. Many equipment leak regulations also define a leak based on visual inspections and observations (such as fluids dripping, spraying, misting, or clouding from or around components), sound (such as hissing), and smell.

c. Task 3 - Monitoring Components

- Identify the monitoring intervals for each regulated component. Monitoring intervals vary according to the applicable regulation but are typically weekly, monthly, quarterly, or annually.
- Monitor all regulated components in accordance with EPA Method 21 (40 CFR Part 60 Appendix A) at the intervals specified by the regulations. Obtain background readings from regulated equipment designated as no detectable emissions initially, annually, and when requested by the Florida Department of Environmental Protection (FDEP).

d. Task 4 - Repairing Components

- Repair all leaking components as soon as practicable, but no later than five days for first attempt at repair and 15 days for final attempt at repair.
- Monitor the repaired component to ensure the component is not leaking above the applicable leak definition.
- Place all leaking components that would require a process unit shutdown on the Delayed Repair List. Record the component ID number and an explanation of why the component cannot be repaired immediately. Also include an estimated date for repairing the equipment.

e. Task 5 - Recordkeeping

- Maintain a list of all ID numbers for all equipment subject to an equipment leak regulation.
- For valves designated as “unsafe to monitor”, maintain a list of ID numbers and an explanation/review of conditions for the designation.
- Maintain detailed schematics, equipment design specifications (including dates and descriptions of any changes), and piping and instrumentation diagrams.
- Maintain the results of performance testing and leak detection monitoring, including leak monitoring results per the leak frequency, monitoring leak-less equipment, and non-periodic event monitoring.
- Attach ID tags to all leaking equipment.
- Maintain records of the equipment ID number, the instrument and operator ID numbers, and the date the leak was detected.
- Maintain a list of the dates of each repair attempt and an explanation of the attempted repair method.
- Maintain a list of the dates of successful repairs and include the results of monitoring test to determine the leak was repaired successfully.

Department’s Review. Subpart VVa is a comprehensive requirement. Together with the LDAR program, Subpart VVa will complement the BACT determinations for each process emission unit that is a source of VOC and possibly odor. The Department accepts the proposal and will include a requirement to submit the details of a site-specific LDAR program pursuant to Subpart VVa no later than 90 days before BPH becomes operational.

6. TOTAL HAP EMISSIONS

Discussion. According to the application, BPH will not be a major source of HAPs because it will not emit 10 TPY or more of a single HAP or 25 TPY or more of all HAPs combined. The main sources of HAP are steam production from the biomass boiler and the RTO. From the biomass boiler the primary HAP is HCl. The applicant estimated 6.39 TPY of HCl from the biomass boiler with total HAP emission from the steam production process estimated to by 7.3 TPY. From the RTO, the meaningful HAP emission is acetaldehyde (C_2H_4O) at 7.0 TPY. Total facility HAP emissions are estimated by the applicant at 17.8 TPY.

In the previous design, the main source of HAP was steam production and was primarily comprised of HCl. The applicant estimated 4.7 TPY of HCl from each of the biomass boilers or 9.4 TPY of HCl from both boilers combined. The other meaningful HAP emitted is acetaldehyde (C_2H_4O), but from the fermentation and distillation steps and the associated scrubbers. Total facility HAP emissions were estimated by the applicant at 17.7 TPY.

Applicant's HCl Proposal. The applicant estimated that emissions of HCl are less than 10 TPY and that emissions of all HAP are less than 25 TPY. Therefore, the applicant asserts, the facility is not a major source of HAP and is not subject to a case-by-case MACT determination. Unlike the previous design, the applicant in the modified project does propose a specific measure to control HCl from the biomass boiler; a dry sorbent inject system utilizing hydrated lime.

Department's Review. The following analysis was included in the Technical Evaluation and Preliminary Determination document for the previous design.

> *According to other sources consulted by the Department, untreated woody biomass will contain less than 0.02 percent Cl on a dry basis. Dry stillage should contain a larger fraction of HCl on a dry basis because much of the feedstock biomass turns into ethanol. However the stillage contains 35 to 60 percent moisture. A reasonable assumption is that the stillage will contain less than 0.02 percent Cl by weight on a wet basis. The NG, ULSD FO and propane are even lower in Cl content.*
>
> *The Cl can be released as HCl and or it can be bound to the ash. Cl can also condense in the form of alkali salts (NaCl and KCl) or as NH_4Cl in the presence of NH_3.*
>
> *If all Cl is converted to HCl, then the pre-control annual HCl emissions from both biomass boilers are calculated as follows:*
>
> *[(0.02 lb Cl/100 lb biomass)x(2000 lb biomass/ton biomass)x(36.45 lb HCl/35.45 lb Cl)]x [(ton HCl/2000 lb HCl)x(47 tons stillage biomass/hr)x(8,760 hr/year)] = 84.7 TPY HCl*
>
> *A conservative estimate is that as much as half of Cl will actually be converted to HCl. To insure that the PTE is limited to a value less than 10 TPY it will be necessary for the limestone injection system described for SO_2 control to also control HCl. The HCl will be converted to a particulate salt depending on the sorbent used.*

Based on the above analysis, ~89 percent control of HCl emissions is required to stay below the 10 TPY single HAP threshold. This level of control should be easily accomplished by the proposed limestone injection in the BFB biomass boiler, followed then by a dry sorbent injection system and fabric filter baghouse. The Department will set a limit of 2.15 lb HCl/hr (9.42 TPY). This limit will be validated by an initial stack test. So long as this HCl emission limit is met during the initial stack test, the HCl CEMS required in the previous design is no longer required to provide reasonable assurance to the Department that BPH is not a major source of HAP.

With regard to the RTO, the Department will require an initial and annual stack tests to verify the emission rate of acetaldehyde (C_2H_4O) to ensure that the 10 TPY single Hap threshold is not exceeded. The Department will set a limit 1.83 lb C_2H_4O/hr (8.0 TPY).

7. ODOR CONSIDERATIONS

Discussion. In previous sections, reference was made to Rule 62-296.320(2), F.A.C., which states: "no person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor". However, even with control measures, conventional grain ethanol plants are often associated with odors. The most important odor source in a conventional grain ethanol plant is from the residual grain material after fermentation and separation of the ethanol.

The residual grain material from conventional corn-based ethanol production is a mixture of protein, fat, oils, vitamins and minerals. It can produce significant odors as it breaks down before and during drying. The dried material is typically shipped as distiller's dried grain with solubles (DDGS) and marketed as animal feed.

DDGS drying is usually accomplished by use of a recuperative TO that destroys the VOC, including the odorous species. The energy recovered is used to accomplish the drying and to provide steam elsewhere in the process.

By contrast, the stillage cake at BPH will be comprised largely of unpalatable lignin which will contain far less materials with any food value. It will have significantly less odor potential. The cellulosic ethanol process does have certain steps in common with the corn-based process that can produce odor including fermentation, distillation, product storage and shipping.

Applicant's Proposal.

The applicant proposes the following measures that will control VOC and odors:

- Just-in-time delivery of ethanol process feedstock biomass with limited on-site storage;
- RTO to control VOC emissions from hydrolysis, fermentation, distillation, propagation, liquid/solid separation and product loadout steps;
- Floating roofs on product and denaturant storage tanks;
- A flare to control emissions from the biogas (if not used as fuel) produced by the anaerobic digestion step, a flare is optional for the product load out step;
- Use of enclosed vessels for the anaerobic digestion step rather than lagoons;
- Maintaining the wet stillage cake at an ambient temperature rather than drying;
- Prompt use of the stillage cake as fuel in the BFB biomass boiler to recover the energy and destroy potential VOC and odor emissions;
- Prompt repair of any leaking components (such as heat exchangers) within the cooling tower to minimize contamination of the water by and subsequent stripping of VOC to the atmosphere; and
- As per NSPS 40 CFR 60, Subpart VVa, BPH will implement a LDAR program to minimize VOC emissions from process equipment leaks. This will address a significant portion of the odor potential.

Department's Review. The Department agrees that the VOC control measures proposed by the applicant at BPH will reduce the generation potential for objectionable odors. However it is important to reiterate that objectionable odors are actually *prohibited*. The relevant rule states:

"No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor. An objectionable odor is defined in Rule 62-210.200(Definitions), F.A.C., as any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance."

Some additional common sense measures can be identified that can further reduce the potential for objectionable odors. The Department will require the following:

- The facility shall not store wet stillage cake out in the open for more than 3 days (72 hours), after which the stillage cake will either be stored in a closed container or shipped off-site;

- BPH shall submit an odor control plan (OCP) early in the design process that describes procedures to be implemented if objectionable odors occur. The OCP must be submitted to the Compliance Authority no later than 90 days prior to BPH commencing operation and will address contingency disposal provisions for stillage that cannot be used in the boilers within 3 days of its generation; and
- The OCP shall also include provisions for storing, disposing of or recycling off-specification enzymes and bacteria that could otherwise contribute to objectionable odors.

8. BIOMASS BOILER HEAT INPUT MONITORING

Monitoring of heat input is difficult when using biomass such as cellulosic stillage as fuel as there is little experience in this practice. Stillage cake has a high moisture content compared to other fuels proposed for the biomass boilers and boiler energy will be expended to evaporate that moisture thus reducing the boiler efficiency. In the case of biogas, the boiler will operate at a higher efficiency.

To accurately calculate heat input, the applicant proposes and the Department accepts the following methodology:

Boiler Performance Test: Within 180 days of first fire on the primary fuels (stillage and biogas with natural gas for flame stabilization), the permittee shall conduct a test to determine the boiler thermal efficiency. The test shall be conducted in general abbreviated accord with ASME PTC 4, 1998. The abbreviated test procedure shall be agreed upon by all parties. The test shall be conducted when firing only the primary fuels with as close of fuel mix and heating values to the boiler design fuel mix and heating value as practical and shall be at least three hours long.

The boiler steam conditions and production rate shall be monitored and recorded during the test. The primary fuels firing rates (tons per hour and cubic feet per minute as appropriate) shall be calculated and recorded based on the steam parameters. A sample of the as-fired stillage shall be analyzed for the heating value (Btu/lb) and moisture content (%). A sample of the as-fired biogas shall be analyzed for the heating value (Btu/ft^3). The actual heat input rate (MMBtu/hour) shall be determined using two methods: (a) steam parameters with enthalpies and the measured thermal efficiency, and (b) steam parameters with enthalpies and the design boiler thermal efficiency. Results of the test shall be submitted to the Compliance Authority within 45 days of completion. The boiler thermal efficiency test shall be repeated during the 12-month period prior to renewal of any operation permit. If the tested boiler thermal efficiency is less than 90 percent of the design boiler thermal efficiency, then the tested thermal efficiency shall be used in any future calculations of the heat input rate until a new test is conducted.

9. NON-BIOGENIC GHG EMISSIONS

Discussion. Since BPH has triggered PSD for multiple criteria pollutants, under EPA's GHG program it is consider a PSD "anyway" source. Such a source triggers PSD for GHG if it equals or exceeds 75,000 TPY of emissions of non-biogenic carbon dioxide and carbon dioxide equivalents (CO_2e) of methane and nitrous oxide for all fuels. Triggering PSD for GHG would require a BACT determination to minimize CO_2e emissions by such requirements as facility-wide efficiency improvements, more efficient equipment such as generators and pumps, etc.

Applicant's Proposal. To limit facility-wide emissions of non-biogenic CO_2e below the PSD anyway threshold of 75,000 TPY, the applicant has proposed to limit the natural gas usage in both the biomass and peaking boilers. The limit proposed is a bubble limit over both boilers, which will allow BPH flexibility in determining the best use of natural gas over a 12-month period. The applicant requested a natural gas limit of 1,065 MMscf/year.

Department's Review. The Department agrees that by limiting the use of natural gas in the two boilers at BPH, it is possible to become a synthetic minor source with regard to non-biogenic GHG emission. A synthetic minor source would not require a GHG BACT determination. However, the Department will stipulate a natural gas limit based on the volume of natural gas used on a yearly basis instead of a yearly heat input limit. Natural gas volume measured by flow meters installed on each boiler will provide more reasonable assurance that the 75,000 TPY threshold is not exceeded by not requiring the conversion to

heat input. Based on a natural gas higher heating value (HHV) heat content of 1,020 MMBtu/MMscf, the combined natural gas used by the biomass and peaking boilers shall not exceed 1,085 MMscf/yr in any consecutive 12 month period. In addition, the emergency equipment will be limited to 100 hours of operation per year to limit fossil fuel usage and thereby non-biogenic GHG emissions.

10. AIR QUALITY IMPACT ANALYSIS

10.1. Introduction

The proposed project will include emissions of the following PSD-pollutants at levels in excess of the respective PSD significant emission rates: $PM_{10}/PM_{2.5}$, SO_2, CO, VOC, and NO_X. For these pollutants the applicant must provide a demonstration using approved air quality models that project emissions will not cause or contribute to a violation of an ambient air quality standard (AAQS) or PSD increment for the pollutants as applicable. Of these pollutants, PM_{10}, $PM_{2.5}$, SO_2, CO, and NO_X (as NO_2) have defined national and state AAQS, and the pollutants PM_{10}, SO_2, and NO_2 have defined PSD increments. In addition, significant impact levels (SILs) and de minimis monitoring levels are defined for these pollutants and are used to determine the scope of the modeling analysis and the need for additional ambient air monitoring data.

10.2. Major Stationary Sources Near the Proposed Project

To provide some perspective on the relative scale of the proposed project, Tables 12 through 16 list the largest stationary sources, by pollutant, in and around Highlands County.

Table 12 - Largest Sources of SO_2 (2011) Nearest to the Project Site (TPY).

Owner/Company Name	Site Name	County	Emissions
Indiantown Cogen	Indiantown Cogen Plant	Martin	1,566
FP&L	Martin Power Plant	Martin	599
Tampa Electric Company	Phillips Station	Highlands	338*
Okeechobee Landfill	Berman Road Landfill	Okeechobee	294
US Sugar Corp	Clewiston Mill and Refinery	Hendry	148
BP Biofuels – Highlands	**BP Biofuels – Highlands**	**Highlands**	**73 (proposed)**

Table 13 - Largest Sources of NO_X (2011) Nearest to the Project Site (TPY).

Owner/Company Name	Site Name	County	Emission
FP&L	Martin Power Plant	Martin	2,582
Indiantown Cogen	Indiantown Cogen Plant	Martin	1,254
US Sugar Corp	Clewiston Mill and Refinery	Hendry	853
Tampa Electric Company	Phillips Station	Highlands	442*
BP Biofuels – Highlands	**BP Biofuels – Highlands**	**Highlands**	**136 (proposed)**

Table 14 - Largest Sources of CO (2011) Nearest to the Project Site (TPY).

Owner/Company Name	Site Name	County	Emission
US Sugar Corp	Clewiston Mill and Refinery	Hendry	12,829
FP&L	Martin Power Plant	Martin	1,331
Southern Gardens Citrus Processing	Southern Gardens Citrus Processing	Hendry	382
Louis Dreyfus Citrus	Louis Dreyfus Citrus/ Indiantown	Martin	287
BP Biofuels – Highlands	**BP Biofuels – Highlands**	**Highlands**	**147 (proposed)**
Okeechobee Landfill	Berman Road Landfill	Okeechobee	106
Indiantown Cogen	Indiantown Cogen Plant	Martin	94

Table 15 - Largest Sources of PM_{10} (2011) Nearest to the Project Site (TPY).

Owner/Company Name	Site Name	County	Emission
US Sugar Corp	Clewiston Mill and Refinery	Hendry	275
FP&L	Martin Power Plant	Martin	239
Bay State Milling	Bay State Milling	Martin	71
BP Biofuels – Highlands	**BP Biofuels – Highlands**	**Highlands**	**21**
Southern Gardens Citrus Processing	Southern Gardens Citrus Processing	Hendry	20

Table 16 - Largest Sources of VOC (2011) Nearest to the Project Site (TPY).

Owner/Company Name	Site Name	County	Emissions
US Sugar Corp	Clewiston Mill and Refinery	Hendry	1,809
Louis Dreyfus Citrus	Louis Dreyfus Citrus/ Indiantown	Martin	284
Southern Gardens Citrus Processing	Southern Gardens Citrus Processing	Hendry	221
Genpak	Genpak	Highlands	151
FP&L	Martin Power Plant	Martin	132
BP Biofuels – Highlands	**BP Biofuels – Highlands**	**Highlands**	**64.6**

To further illustrate the major emission sources nearest to this proposed project, refer to Figure 15. All major facilities within a 60 km radius of the proposed project are shown.

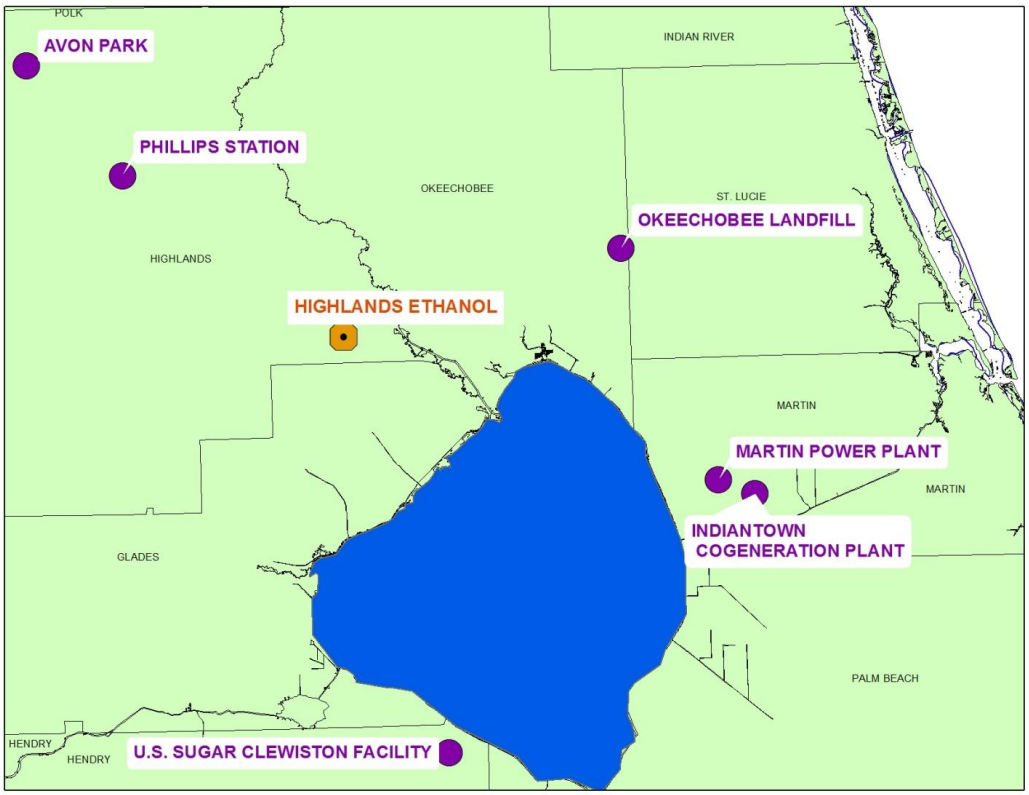

Figure 15 - Major Pollution Sources Nearest to the BP Biofuels – Highlands Project.

10.3. SO_2 and NO_X Emission Trends

There are regional efforts underway through the Federal Acid Rain Program and the Clean Air Interstate Rule (CAIR) to reduce emissions of NO_X and SO_2. Regional SO_2 emissions from existing power plants in the Southeast U.S. in 2007 and 2011 are listed in Table 17.

Table 17 - SO_2 Emission from Power Plants in the Southeast in 2007 and 2011 in TPY.

State	2007	2011	Δ Since 2007 (%)
Alabama	447,189	179,250	267,939 (60%)
Florida	**317,582**	**91,380**	**226,202 (71%)**
Georgia	635,484	186,860	448,624 (71%)
Kentucky	379,837	246,396	133,441 (35%)
Mississippi	69,796	43,211	26,585 (38%)
North Carolina	370,826	73,507	297,319 (80%)
South Carolina	172,726	66,167	106,559 (62%)
Tennessee	237,231	120,325	116,906 (49%)
Total	**2,630,671**	**1,007,096**	**1,623,575 (62%)**

SO_2 emissions from power plants in the Southeast U.S. during 2011 were reduced by more than 1,600,000 tons/year and 62 percent referenced to emissions in 2007. SO_2 emissions from power plants in Florida during 2011 declined by more than 226,000 tons/year and 71 percent.

Regional NO_X emissions from existing power plants in the Southeast U.S. in 2007 and 2011 are listed in Table 18.

Table 18 - NO_X Emission from Power Plants in the Southeast in 2007 and 2011 (TPY).

State	2007	2011	Δ Since 2007 (%)
Alabama	122,374	61,398	60,976 (50%)
Florida	**184,171**	**54,748**	**129,423 (70%)**
Georgia	107,471	54,823	52,648 (49%)
Kentucky	174,840	92,051	82,789 (47%)
Mississippi	48,546	25,078	23,468 (48%)
North Carolina	59,417	41,348	18,069 (4%)
South Carolina	46,062	23,262	17,229 (30%)
Tennessee	102,886	26,838	76,048 (74%)
Total	**845,767**	**379,546**	**396,690 (45%)**

NO_X emissions from power plants in the Southeast U.S. during 2011 were reduced by nearly 400,000 tons/year and 45 percent referenced to emissions in 2007.

The Department graphed gross electrical generation and the SO_2 and NO_X emission trends during the period 1998-2011 from power plants in Florida that report their emissions to the EPA Clean Air Markets database. The results are summarized in Figure 16. By comparison with the overwhelming downtrend of regional and local emissions of SO_2 and NO_X, the emission increases from the Highlands Facility are very low.

During the period 1998-2011 there was a *decrease* of 89 percent (818,159 TPY to 24,700 TPY) in SO_2 emissions from the FP&L fossil fleet in peninsular Florida. Similarly there was a *decrease* of 84 percent (335,647 TPY to 54,748 TPY) in NO_X emissions. For comparison purposes, the future project will emit 73 TPY of SO_2 and 136 TPY of NO_X.

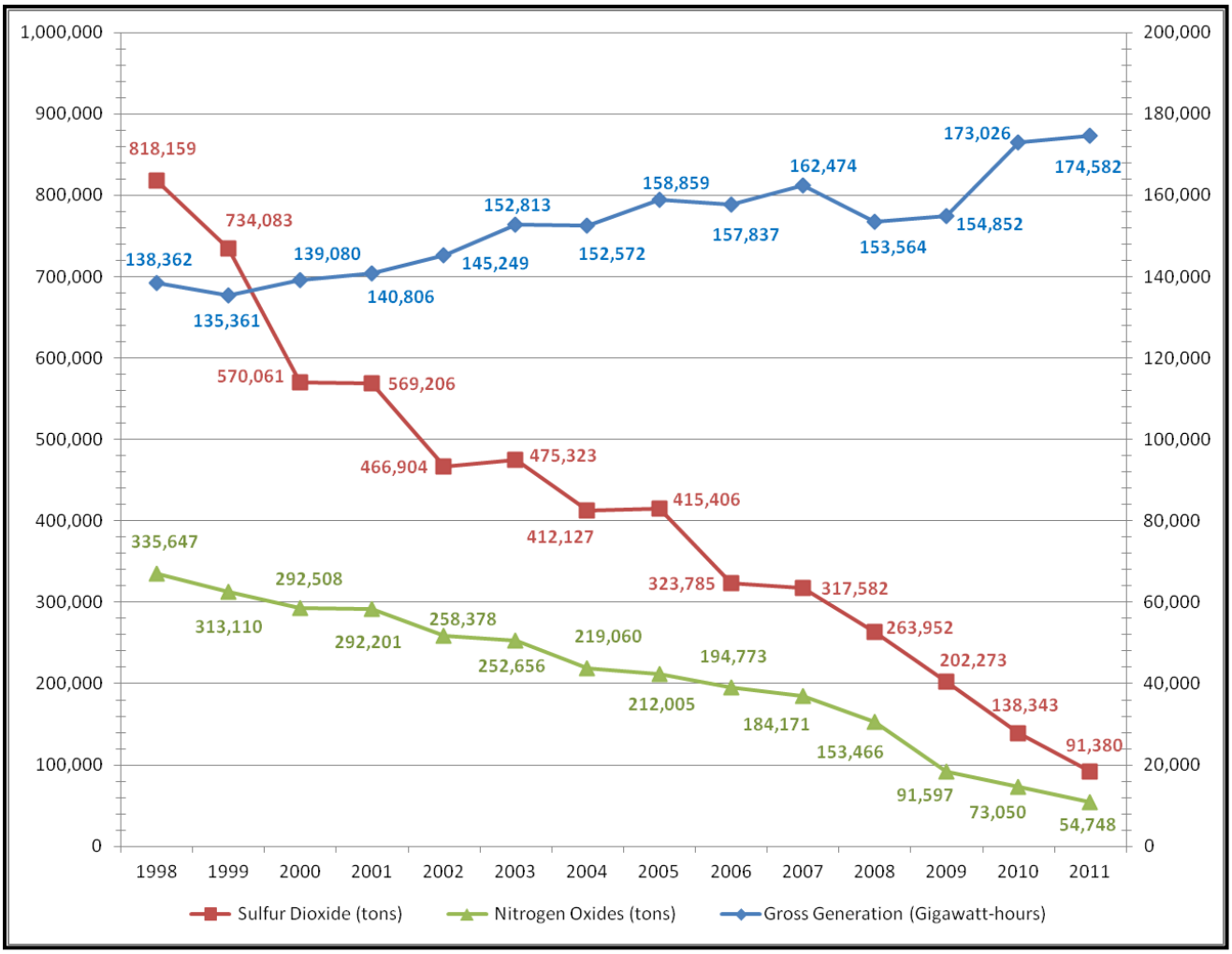

Figure 16 – Gross Electric Generation and SO_2, NO_X Emissions from Florida Acid Rain Units, 1998-2011

The contribution of 73 TPY of SO_2 and 136 TPY of NO_X from the proposed project will not affect the general, overwhelming and continuing downward trend in $PM_{2.5}$ precursors. Similarly, it will not have an appreciable effect on local or regional $PM_{2.5}$ concentrations.

10.4. Ambient Air Monitoring Surrounding Proposed Facility

The State ambient air monitoring network operated by the Department and its partners (local air pollution control programs) includes monitors in counties containing over 90 percent of the States' population. As Figure 17 and 18 indicate, the ambient air monitoring sites are concentrated in areas of high population density, along the coasts and near major highways in the interior portion of the state.

These monitors are used to estimate the existing air quality in the area of the proposed facility. The monitors chosen (see Table 19) are most representative of the proposed site due to their close proximity.

The ambient air measurements listed above are values that do not contain 'exceptional events'. An 'exceptional event' is defined by EPA in accordance with 40 CFR 50.14 as an event that affects air quality, is not reasonably controlled or preventable, is an event caused by human activity that is unlikely to recur at a particular location or natural event. Such events include complex wildfires, driven by prolonged drought conditions and other large-scale meteorological patterns. The department has evaluated several $PM_{2.5}$ episodes and found that they occur in conjunction with certain meteorological conditions, combined with very high SO_2 emissions and sulfate deposition.

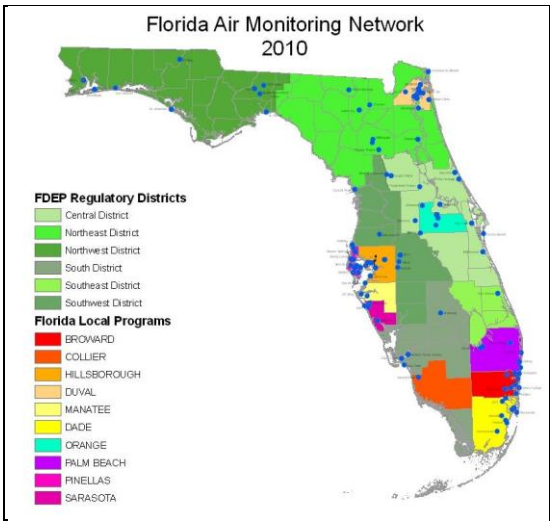

Figure 17 – Air Monitoring Network.

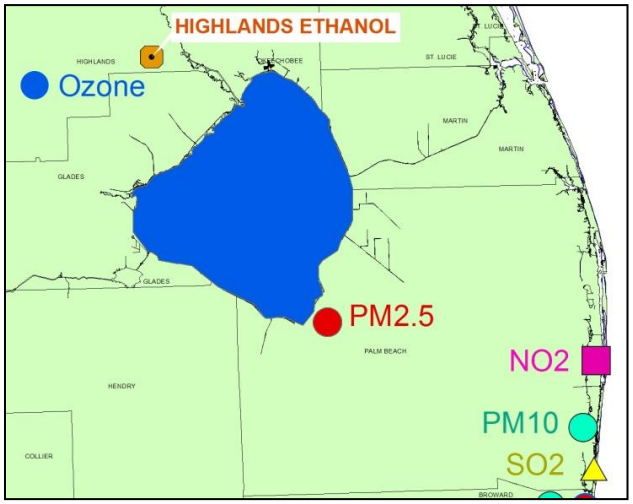

Figure 18 – Monitors Closest to Project Site.

Table 19 - Ambient Air Quality Measurements Nearest to the Project Site (2008-2010 or 2009-2011).

Pollutant	Location (Site Number)	Averaging Period	Ambient Concentration			
			Compliance Period	Value	Standard	Units [a]
PM_{10}	Delray Beach (0992005)	24-hour [b]	2010	40	150	$\mu g/m^3$
		Annual [c]	2010	17.5	50	$\mu g/m^3$
$PM_{2.5}$	Belle Glade (0990008)	24-hour [d]	2009-2011	14	35	$\mu g/m^3$
		Annual [e]	2009-2011	6.3	15	$\mu g/m^3$
SO_2	Riviera Beach (0993004)	1-hour [i]	2009-2010	6	75	ppb
		3-hour [f]	2010	15.7	1300	$\mu g/m^3$
		24-hour [f]	2010	7.9	260	$\mu g/m^3$
		Annual [c]	2008-2010	3.1	60	$\mu g/m^3$
NO_2	Lantana (0990020)	Annual [c]	2011	4.1	53	ppb
		1-hour [h]	2009-2011	40	100	ppb
CO	Broward Co (0110010)	1-hour [f]	2011	2.1	35	ppm
		8-hour [g]	2011	1.4	9	ppm
Ozone	Highlands Co (0550003)	8-hour [g]	2011	0.064	0.075	ppm

a. Units are in: micrograms per cubic meter ($\mu g/m^3$); parts per billion (ppb); or parts per million (ppm).
b. Not to be exceeded on more than an average of one day per year over a three-year period.
c. Arithmetic mean.
d. Three year average of the 98th percentile of maximum daily 24-hour concentrations.
e. Three year average of the arithmetic annual means.
f. Not to be exceeded more than once per year.
g. Three year average of the annual 4th highest daily 8-hour maximum.
h. Three-year average of the annual 98th percentile maximum daily 1-hour value
i. Three-year average of the annual 99th percentile maximum daily 1-hour value

10.5. Existing Ambient Air Quality Near Project Site – $PM_{2.5}$ and Ozone

Ozone is a key indicator of the overall state of regional air quality. It is not emitted directly from combustion processes. Rather it is formed from VOC and NO_X emitted primarily from regional industrial and transportation sources. VOC is also emitted from authorized agricultural fires, natural drought-related fires and natural emissions from vegetation. These two precursors participate in photochemical reactions that occur on an area-wide basis and are highly dependent on meteorological factors.

Ozone limits and measurements in Table 19 are summarized on three year blocks, rolled annually. The reported ozone value was calculated by taking the maximum 8-hour readings recorded each day during the three years. The fourth highest of the recorded maxima were identified for each year and then the average of those three values was reported as the compliance value given in Table 19 and Figure 19.

$PM_{2.5}$ (also known as PM_{fine}) is another key indicator of the overall state of regional air quality. Some $PM_{2.5}$ is directly emitted as a product of combustion from transportation and industrial sources as well as fires. Much of it consists of particulate nitrates and sulfates formed through chemical reactions between gaseous precursors such as SO_2 and NO_X from combustion sources and ammonia (NH_3) naturally present in the air or added by other industrial sources.

$PM_{2.5}$ limits and measurements are summarized on three-year blocks, rolled annually. The reported 24-hour compliance value for $PM_{2.5}$ is 14 μg/m^3 as indicated in Table 19 for the Belle Glade site, and was calculated by taking the average 24-hour readings recorded each day during the three years (2009-2011). The value for each year that exceeds 98 percent of all daily measurements within each given year was identified and then the average of those three numbers was reported as the 24-hour compliance value and compared with the standard of 35 μg/m^3.

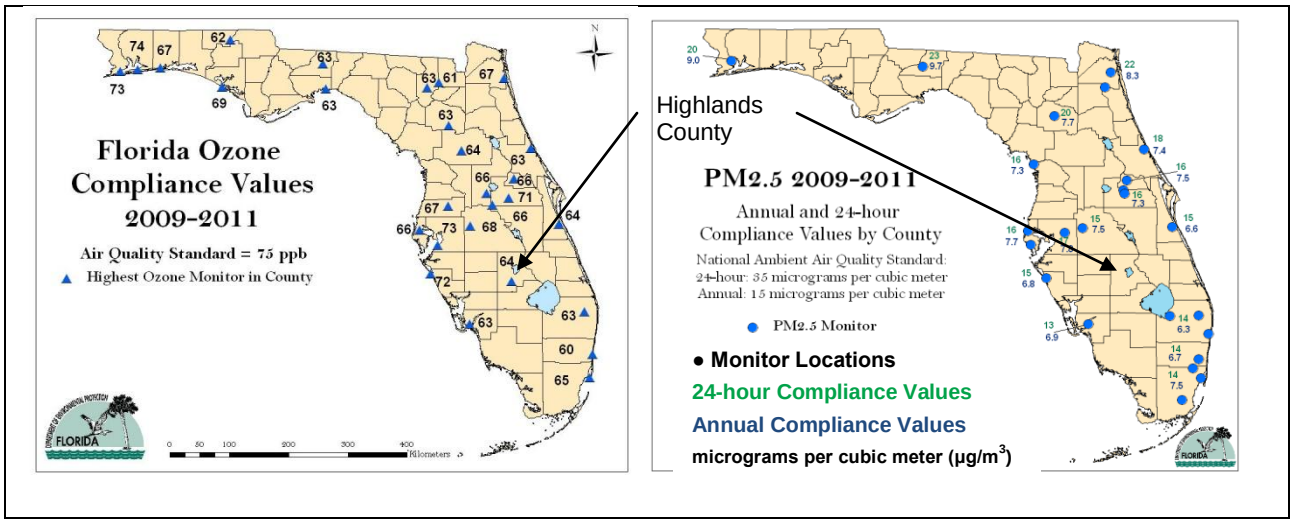

Figure 19 – Florida Ozone Compliance Values **Figure 20 – Florida $PM_{2.5}$ Compliance Values**

The simple average of all $PM_{2.5}$ measurements within each three years (2009-2011) was also calculated and then the mean of the three averages (6.3 μg/m^3) was reported as the annual compliance value and compared with the standard of 15 μg/m^3. Comparisons of the 24-hour and annual $PM_{2.5}$ compliance values for the Belle Glade station are shown in Figure 20 along with compliance values for the rest of the state.

The results indicate that Highlands County is in attainment with the applicable ozone and $PM_{2.5}$ AAQS. The results compiled from Highlands County (ozone) and Palm Beach County ($PM_{2.5}$) shown in Figures 19 and 20 suggest that Highlands County is in attainment for both pollutants.

10.6. Ambient $PM_{2.5}$ Trends in South Florida

The overall reduction in $PM_{2.5}$ precursor emissions from stationary sources and the transportation sources (due to use of cleaner fuels) has contributed to the clear decline in ambient $PM_{2.5}$ levels in South Florida during the same period as shown in Figure 21. Basically the pronounced reductions in Miami are consistent with the mentioned reductions in emissions from stationary and transportation sources. By and large, the values in Belle Glade (within the rural sugar cane growing area) have been the lowest. However, they have been more resistant to further declines most likely due to the nature of the sugar industry which is based on periodic burning followed by harvesting of sugar cane.

10.7. Air Quality Impact Analysis

10.7.1. Significant Impact Analysis

Significant Impact Levels (SILs) are defined for CO, PM_{10}, $PM_{2.5}$, NO_X, Pb and SO_2. A significant impact analysis is performed on each of these pollutants and applicable averaging periods to determine if a project causes an increase in modeled ground level concentrations greater than the SILs for each pollutant.

In conducting a significant impact analysis, the applicant used the proposed project's worst-case (as determined by a load screening analysis) short-term emissions as inputs to a dispersion model. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SIL for the PSD Class II Areas.

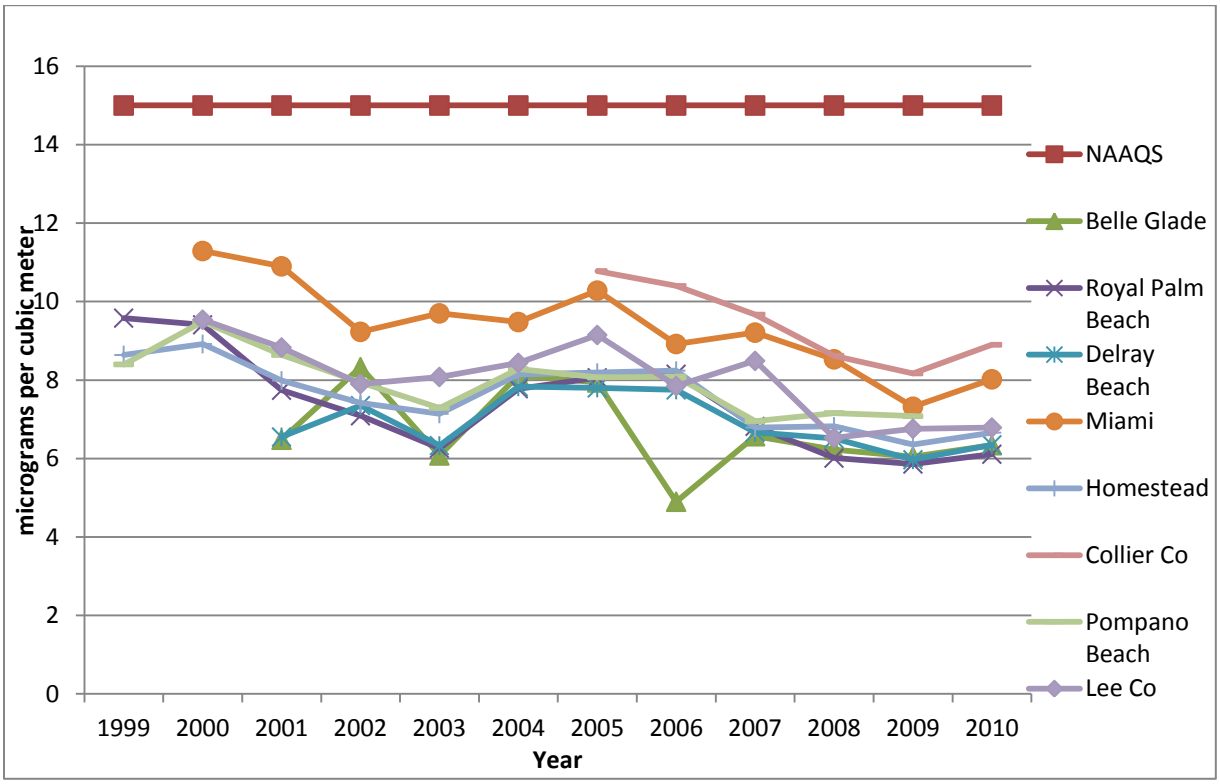

Figure 21 - South Florida Annual Average $PM_{2.5}$ Trends (1999 – 2010).

If the modeling for a particular pollutant/averaging period shows predicted ground-level impacts less than the corresponding SIL, it is assumed that the project will have minimal impact on air quality for that pollutant/averaging period and the applicant is not required to conduct any further modeling for that pollutant/averaging period. If the modeled concentrations of a pollutant emitted by the project exceed one or more SILs, then additional modeling, including emissions from all major facilities or projects in the region (multi-source modeling), is required to determine the proposed project's impacts compared to the AAQS and PSD increments for those pollutants and averaging periods.

For the Class II SIL analysis, a combination of fence line, near-field and far-field receptors were chosen for predicting maximum concentrations in the vicinity of the project. The fence line receptors consisted of discrete Cartesian receptors spaced at 25-meter intervals around the facility fence line. The remaining receptor grids consisted of densely spaced Cartesian receptors at 50 meters apart extending out to 500 meters, 100-meters apart extending out to1 km, 200 meter spacing was placed out to 2 km, 400 meters out to 4 kilometers, 800 meters out to 8 km, 1,600 meters out to 16 km, and 3,200 meters out to 32 km from the project site. The grid has a total coverage of 64 km, covering portions of Highlands, Glades, Okeechobee, Martin, and Palm Beach Counties. Results from the Class II SIL analysis are shown in Table 20.

Table 20 - Maximum Predicted Air Quality Impacts from the Proposed Project for Comparison to the PSD Class II SIL

Pollutant	Averaging Time	Max Predicted Impact [a] ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Ambient Air Standards ($\mu g/m^3$)	Significant Impact?	Max Distance of Sig. Impact (km)
PM_{10}	Annual 24-Hour	1.7 13.7	1 5	50 150	Yes Yes	1.1
$PM_{2.5}$	Annual 24-Hour	1.5 9.6	0.3 [d] 1.2 [d]	15 35	Yes Yes	3.0
SO_2	Annual 24-Hour 3-hour 1-hour	2.8 43.0 106.4 55.9	1 5 25 7.9 [b]	60 260 1300 196	Yes Yes Yes Yes	8.4
NO_2 [c]	Annual 1-Hour	3.1 61.6	1 7.6 [b]	100 189	Yes Yes	5.5
CO	1-hour 8-hour	416 243	2,000 500	40,000 10,000	No No	N/A
Pb	3-month	0.003	0.1	0.15	No	N/A

a. Results based on the maximum impacts of either the boiler and truck flare operation or the biogas flare and truck flare operation.
b. Assumes 100 percent conversion of NO_X to NO_2, i.e., the tier 1 modeling approach.

For Class I SIL analysis, the CALPUFF dispersion model was used, which is the preferred model for analyses covering distances greater than 50 km. The applicant modeled impacts on both the Everglades National Park (ENP) and the Chassahowitzka Wilderness Area (CWA), which are 154 km and 216 km from the project site, respectively. The analysis was performed by using receptor grids provided by the Federal Land Manager, which include 901 receptors across the ENP and 37 receptors across the CWA. The results of the applicant's significant impact analyses are shown below in Tables 21 and 22.

The Class I results are all well below the SIL. Therefore, a Class I Increment Analysis is not required and no further Class I modeling is necessary.

For the Class II results, predicted maximum concentrations for CO and Pb for all averaging periods are less than SILs. Thus, the project is predicted to comply with the ambient air quality standards and increments for these pollutants and averaging periods. No interactive source modeling is required for these pollutants. However, predicted maximum concentrations for SO_2, PM_{10}, $PM_{2.5}$, and NO_2 are greater than SILs. Consequently, interactive modeling is required for these pollutants. The significant impact areas for each were identified and are as follows: SO_2 8.4 km; PM_{10} 1.1 km; $PM_{2.5}$ 3.0 km; and NO_2 5.5 km.

Table 21 - Maximum Predicted Air Quality Impacts from the Proposed Project for Comparison to the PSD Class I SIL at the Everglades National Park

Pollutant	Averaging Time	Max Predicted Impact [a] ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact?	Max Distance of Sig. Impact (km)
PM_{10}	Annual 24-Hour	0.0004 0.009	0.2 0.3	No No	N/A
$PM_{2.5}$	Annual 24-Hour	0.0004 0.009	0.06 0.07	No No	N/A
SO_2	Annual 24-Hour 3-hour	0.001 0.02 0.06	0.1 0.2 1.0	No No No	N/A
NO_2 [c]	Annual	0.001	0.1	No	N/A

a. Results based on the maximum impacts of either the boiler and truck flare operation or the biogas flare and truck flare operation.
b. Assumes 100 percent conversion of NO_X to NO_2, i.e., the tier 1 modeling approach.

Table 22 - Maximum Predicted Air Quality Impacts from the Proposed Project for Comparison to the PSD Class I SIL at the Chassahowitzka Wilderness Area

Pollutant	Averaging Time	Max Predicted Impact [a] ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact?	Max Distance of Sig. Impact (km)
PM_{10}	Annual 24-Hour	0.0004 0.01	0.2 0.3	No No	N/A
$PM_{2.5}$	Annual 24-Hour	0.0004 0.004	0.06 0.07	No No	N/A
SO_2	Annual 24-Hour 3-hour	0.001 0.01 0.05	0.1 0.2 1.0	No No No	N/A
NO_2 [c]	Annual	0.001	0.1	No	N/A

a. Results based on the maximum impacts of either the boiler and truck flare operation or the biogas flare and truck flare operation.
b. Assumes 100 percent conversion of NO_X to NO_2, i.e., the tier 1 modeling approach.

10.7.2. Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is performed for those pollutants with listed significant monitoring concentrations (de minimus levels). These are levels, which, if exceeded, would potentially require pre-construction ambient monitoring. As shown in Table 23 below, the maximum predicted impacts due to the proposed project are predicted to be below the PSD de minimis concentration levels for Pb, NO_2, and CO, but above the de minimis concentration levels for SO_2, PM_{10}, and $PM_{2.5}$.

Because the predicted maximum $PM_{2.5}$, $PM_{10,}$ and SO_2 concentrations are greater than the de minimis levels, a pre-construction ambient monitoring analysis is required for all three pollutants as part of the application. Readily available ambient monitoring data can be used to assess pre-construction air quality if: (1) the existing monitoring locations are in areas that are representative of the project area; (2) the data are of sufficient quality, and (3) the data are current.

Table 23 – Maximum Air Quality Impacts for Comparison to De Minimis Concentration Levels.

Pollutant	Averaging Time	Max Predicted Impact (µg/m^3)	De Minimis Level (µg/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	13.7	10	Yes
$PM_{2.5}$	24-hour	9.6	4	Yes
NO_2	Annual	3.1	14	No
SO_2	24-hour	43	13	Yes
CO	8-hour	243	575	No
Pb	3-month	0.002[a]	0.1	No
a. Modeled Pb based on a 1 month average, yielding a more conservative comparison to the 3-month SMC				

The ambient monitors described previously satisfy the pre-construction monitoring criteria. The monitors are in areas representative of preconstruction conditions in Highlands County and of sufficient quality to be used to identify background air quality for interactive modeling. All of the data were collected from 2008 through 2010, satisfying the requirement that the data be current. Therefore, the three criteria established for using existing air quality measurements have been satisfied..

10.7.3. Models, Emissions Data, and Meteorological Data Used in the AAQS and PSD Increments Analysis

The EPA-approved AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. The AERMOD modeling system incorporates air dispersion based on planetary boundary layer turbulence and scaling concepts, including the treatment of both surface and elevated sources, and both simple and complex terrain. AERMOD contains two input data processors, AERMET and AERMAP. AERMAP is the terrain processor and AERMET is the meteorological data processor.

A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction specific downwash parameters were used for all sources for which downwash was considered.

Emissions data for nearby sources used in the modeling analysis were obtained from the DEP ARMS database, DEP permit files, and recent PSD permit reviews. Emissions data for the new proposed facility were derived from the proposed maximum permit limits imposed on the facility for each pollutant and the load screening analysis.

The AERMET meteorological data used for this analysis consisted of a concurrent 5-year period of hourly surface weather observations from the Palm Beach International Airport (PBI) in West Palm Beach and, twice-daily upper air soundings from the National Weather Service in Miami, respectively. The 5-year period of meteorological data is from 2006 through 2010. The location of the proposed facility is 115 km northwest of West Palm Beach and 185 km northwest of Miami.

10.7.4. Multi-source PSD Class II Increment Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration. A PSD increment analysis was required for PM_{10}, SO_2, $PM_{2.5}$, and NO_X. The maximum predicted annual and maximum predicted high, second high short-term average PSD Class II area impacts from this project and other increment-consuming sources in the vicinity of the proposed facility are shown in Table 24 below.

Table 24 - PSD Class II Increment Analysis.

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Impact Greater Than Allowable Increment?	Percentage of Increment Consumed
PM_{10}	24-hour	10.8	30	No	36 percent
	Annual	1.7	17	No	10 percent
SO_2	3-hour	96.5	512	No	19 percent
	24-hour	43.4	91	No	48 percent
	Annual	4.4	20	No	22 percent
$PM_{2.5}$	24-hour	8.3	9	No	92 percent
	Annual	1.6	4	No	40 percent
NO_X	Annual	4.5	25	No	18 percent

10.7.5. AAQS Analysis

For pollutants subject to an AAQS review, the total impact on ambient air quality is obtained by adding a "background" concentration to the maximum modeled concentration of the proposed project in conjunction with sources in the SIA. This "background" concentration is based on existing monitoring data for each pollutant and representative of the area of the proposed source. This background is intended to account for sources of a particular pollutant that are not explicitly modeled. Since no attempt is typically made to subtract out the impacts due to the explicitly modeled sources on these monitored values, there is some amount of double-counting reflected in the total concentration (modeled + background) used to compare with the appropriate AAQS.

An evaluation of the emission inventories for background sources considered in the PSD application for the project was performed to determine whether the method used to eliminate background sources from the NAAQS compliance modeling demonstration was reasonable. All background sources within the significant impact area of the project were included in the modeling demonstration.

For facilities within 50 km of the SIA, the “20D” screening process was applied to exclude insignificant sources. In this process, regional sources whose potential emissions were less than 20 times the distance to the edge of the SIA were eliminated because they are presumed to have negligible contributions to receptors in the SIA. Regional sources located within close proximity to each other (2 km) were evaluated cumulatively in the 20D analysis to determine whether the combined “source” was still appropriate to exclude. After applying the 20D rule, the applicant was left with six sources to be included in the cumulative modeling assessment. Of these six sources, four are electric generating stations and the remaining two are US Sugar in Clewiston and the Okeechobee Landfill.

The sources that are explicitly modeled include the subject facility and nearby sources that are judged to potentially have a significant interaction with the proposed facility. The appropriate calculations for the modeled and background values are different for each pollutant, but generally follow the form for compliance with the AAQS. Table 25 shows the results of this analysis. As shown in the below table, emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS.

Based on the results of the air quality modeling analysis, the operation of the proposed facility will not cause or contribute to a violation of an ambient air quality standard or maximum allowable concentration increase (PSD increment).

Table 25 - Ambient Air Quality Impacts.

Pollutant	Averaging Time	Major Sources Impact ($\mu g/m^3$)	Background Conc. ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Total Impact Greater Than AAQS?	AAQS ($\mu g/m^3$)
PM_{10}	24-hour	9.7	40	49.70	No	150
	Annual	1.5	18	19.7	No	50
$PM_{2.5}$	24-hour	9.5	14	23.5	No	35
	Annual	1.6	6	7.68	No	15
SO_2	1-hour	133.8	16	149.8	No	195
	3-hour	96.5	16	112.5	No	1300
	24-hour	43.4	8	51.4	No	365
	Annual	4.4	3	7.4	No	80
NO_2	1-hour	92.7	75	167.7	No	188
	Annual	4.5	8	12.5	No	100

10.7.6. Ozone Modeling

Projects with VOC and NO_X emissions greater than 100 TPY are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The applicant estimated annual potential VOC and NO_X emissions from the project to be 68 and 136 TPY respectively.

Readily available ambient monitoring data can be used to assess pre-construction ozone air quality if: (1) the existing monitoring locations are in areas that are representative of the project area; (2) the data are of sufficient quality; and (3) the data are current.

The ozone monitoring data at Sebring is only 26 km west of the proposed project and satisfies the pre-construction monitoring criteria. The monitor is in an area representative of preconstruction conditions and the data are of sufficient quality for the purposes of identifying background values at the BP Biofuels – Highlands site. All of the data were collected from 2008 through 2010, satisfying the requirement that the data be current. Therefore, the three criteria established for using existing air quality measurements have been satisfied.

Ozone site-specific modeling is not typically completed for single source permitting because of its complexity. Ozone is a secondarily formed pollutant that is known to be caused by the regional emissions of VOC and NO_X in combination with meteorological parameters (temperature, rainfall, solar insolation, etc.).

To conclusively prove whether or not 136 TPY of NO_X will not cause or contribute to a violation, a very sophisticated and expensive model would need to be run for the entire region. The key inputs to the model would be traffic, power plants throughout the region, other industrial sources, and meteorology. As previously discussed, the NO_X emission reductions in South Florida from FP&L projects alone have declined by nearly 80,000 TPY. The effects of the proposed project on ozone would not be measurable considering the overwhelming effects of the FP&L reductions and the climatological variability. The uncertainty in any regional ozone model would be greater than the contribution from this project.

10.8. Additional Impacts Analysis

10.8.1. General Description with Regard to Growth and Air Quality Impacts

BP Biofuels – Highlands estimates that 200 new employees will be hired at the farm and the facility, which will increase permanent jobs within the community. There will be additional short-term local

employment during the 18 to 24 month construction phase of the proposed project. Short-term employment is estimated at 600 to 800 workers.

10.8.2. Growth-Related Impacts Due to the Proposed Project

During the anticipated construction period associated with the proposed project, the construction jobs will be filled by the local area workers, as well as workers currently located outside Highlands County. While supplemental, short-term labor is likely to relocate into the Highlands County area during the construction phase of the proposed project, BP Biofuels – Highlands anticipates the influx of temporary workers during the construction phase will have minimal effect on the environment, but will have a positive effect on the local economy.

For daily operation and maintenance of the proposed project, BP Biofuels – Highlands anticipates that the required full time staff will be mostly comprised of current or future Highlands County area residents, and the project could result in a small increase in residential housing demand.

During the construction phase of the project, there will be a temporary increase in truck traffic. Once in operation, it is anticipated that approximately

100 vehicles per day will access the site from public roads. These include 60 employee vehicles, 26 delivery trucks, and 14 product trucks.

The resulting increase in indirect employment is not anticipated to significantly impact the air quality of the area because the increase represents a small fraction of the population of Highlands County. Thus, construction and operation of the proposed project will have a positive impact on the work force in Highlands County and the surrounding areas, but its net impact on the environment and to residential resource consumption is expected to be minimal.

Because much of the growth from the project will be filled by a relatively small number of new local labor and resources, the proposed project does not anticipate any significant corresponding commercial growth. Because the commercial and industrial growth resulting from the project is anticipated to be minimal, air quality impacts resulting from such commercial and industrial growth are expected to be minimal in the immediate area and its adjacent communities.

10.8.3. Impact on Soils, Vegetation, and Wildlife

Ambient air quality screening levels are provided for soils and vegetation in USEPA guidance. Table 26 below compares the predicted concentration for those compounds that have predicted concentrations greater than their SIL for which there are relevant screening levels. EPA has not published screening values for $PM_{2.5}$.

Table 26 – Soils and Vegetation Screening Modeling.

Parameter	Averaging Period	AERMOD Predicted Concentration (ug.m3)	USEPA Screening Level (ug/m3)
SO_2	1-hour	56	917
	3-hour	106	786
	Annual	3	18
NO_2	4-hour	50	3760
	8-hour	45	3760
	1-month	8	564
	Annual	3	94

The predicted concentrations for SO_2 and NO_2 are less than the screening levels, thereby demonstrating that impacts to soils and vegetation will be negligible.

10.8.4. Class I Area Impacts- Air Quality Related Values (AQRV)

An AQRV analysis was conducted to assess the potential risk to AQRV at the Everglades National Park (ENP), due to the proposed emissions from the proposed facility. Everglades National Park is the closest Class I area to the proposed project and is located 154 km to the southeast.

In October 2010, the Federal Land Managers (FLMs), consisting of the National Park Service, U.S. Forest Service, and U.S. Fish and Wildlife Service, issued the Federal Land Managers' Air Quality Related Values Work Group (FLAG), Phase I Report- Revised (2010). Based on the report, the FLMs recommended initial screening criteria that would exempt a source from AQRV impact review based on a source's annual emissions and distance from a Class I areas. The FLMs will consider a source located greater than 50 km from a Class I area to have negligible impacts with respect to Class I AQRVs if its total SO_2, NO_X, PM_{10}, and H_2SO_4 annual emissions (in TPY based on 24-hour maximum allowable emissions), divided by the distance (km) from the Class I area (Q/D) is 10 or less. The FLMs would not request any further Class I AQRV impact analyses from such sources.

With Q as 229 TPY and D as 154 km, Q/D (917.4 / 147) Q/D is equal to 1.5. This result is well below the FLM criteria of 10. As a result, an AQRV impact analyses is not necessary.

11. CONCLUSION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution control regulations as conditioned by the Draft Permit.