Memorandum

Florida Department of Environmental Protection

To: Trina Vielhauer, Bureau of Air Regulation

Through: Al Linero, Special Projects Section

From: David Read, Special Projects Section

Date: October 22, 2009

Subject: Draft Air Permit No. 0550061-001-AC (PSD-FL-406)
Highlands Ethanol, LLC, Cellulosic Ethanol Facility

Attached for your review is a draft air construction permit package for the planned Highlands Ethanol Facility (HEF), which will be located in Highlands County immediately north of State Road 70 and approximately 1.7 miles east-northeast of Brighton, Florida.

The attached Technical Evaluation and Preliminary Determination document provides a detailed description of the project and the rationale for permit issuance.

This project is subject to the rules for the Prevention of Significant Deterioration. Day 90 of the permitting time clock is December 16, 2009. I recommend your approval of the attached draft permit package.

Attachments

TLV/aal/dlr

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

Mr. Charles F. Davis III
Senior Vice President
Highlands Ethanol, LLC
55 Cambridge Parkway, 8th Floor
Cambridge, Massachusetts 02142

Re: Draft Air Permit No. No. 0550061-001-AC (PSD-FL-406)
Highlands Ethanol, LLC
Cellulosic Ethanol Production Facility

Dear Mr. Davis:

On February 16, 2009, you submitted an application for an air construction permit subject to the preconstruction review requirements of Rule 62-212.400, Florida Administrative Code, for the Prevention of Significant Deterioration (PSD) of Air Quality.

The purpose of the project is to construct the new Highlands Ethanol Facility that will be located in Highlands County, north of State Road 70 and approximately 1.7 miles east-northeast of Brighton, Florida.

Enclosed are the following documents: Written Notice of Intent to Issue Air Permit; Public Notice of Intent to Issue Air Permit; Technical Evaluation and Preliminary Determination; and Draft Permit with Appendices.

The Public Notice of Intent to Issue Air Permit is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project. If you have any questions, please contact the Project Engineer, David Read at 850/414-7268.

Sincerely,

Trina L Vielhauer 10/22/09

Trina L. Vielhauer, Chief (Date)
Bureau of Air Regulation

Enclosures

TLV/aal/dlr

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

Highlands Ethanol, LLC
55 Cambridge Parkway, 8th Floor
Cambridge, Massachusetts 02142

Authorized Representative:
Mr. Charles F. Davis III, Sr. Vice President

Draft Permit No. 0550061-001-AC
PSD-FL-406

Highlands Ethanol Facility
Cellulosic Ethanol Production
Highlands County, Florida

Facility Location: Highlands Ethanol, LLC proposes to construct the new Highlands Ethanol Facility, which will be located in Highlands County, north of State Road 70 and approximately 1.7 miles east-northeast of Brighton, Florida.

Project: The project is the construction of a cellulosic ethanol production facility using feedstocks of dedicated energy crops, such as energy cane and forage sorghum. The project is subject to the preconstruction review requirements of Rule 62-212.400, Florida Administrative Code (F.A.C.), Prevention of Significant Deterioration (PSD). A determination of best available control technology (BACT) was required.

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210 and 62-212, F.A.C. The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of the proposed equipment will not adversely impact air quality and that the project will comply with all applicable provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Section 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Permit (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet the requirements of Sections 50.011 and 50.031, F.S. in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Permitting Authority at the address or phone number listed above. Pursuant to Rule 62-110.106(5) and (9), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within 7 days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit and requests for a public meeting for a period of 30 days from the date of publication of the Public Notice. Written comments must be received by the Permitting Authority by close of business (5:00 p.m.) on or before the end of this 30-day period. In addition, if a public meeting is requested within the 30-day comment period and conducted by the Permitting Authority, any oral and written comments received during the public meeting will also be considered by the Permitting Authority. If timely received comments result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241; Fax: 850/245-2303). Petitions filed by the applicant or any of the parties listed below must be filed within 14 days of receipt of this Written Notice of Intent to Issue Air Permit. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of the attached Public Notice or within fourteen 14 days of receipt of this Written Notice of Intent to Issue Air Permit, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within 14 days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of when and how each petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Written Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Written Notice of Intent to Issue Air Permit package (including the Written Notice of Intent to Issue Air Permit, the Public Notice of Intent to Issue Air Permit, the Technical Evaluation and Preliminary Determination and the Draft Permit with Appendices) was sent by electronic mail, or a link to these documents made available electronically on a publicly accessible server, with received receipt requested before the close of business on 10/23/09 to the persons listed below.

Charles F. Davis III, Highlands Ethanol, LLC: chuck.davis@verenium.com
Tim Eves, Verenium Corporation: tim.eves@verenium.com
Joseph Vaccaro, P.E., AMEC: joe.vaccaro@amec.com
Ajaya Satyal, DEP South District Office: ajaya.satyal@dep.state.fl.us
Kathleen Forney, EPA Region 4: forney.kathleen@epamail.epa.gov
Heather Abrams, EPA Region 4: abrams.heather@epa.gov
Chair, Highlands County Board of County Commissioners: bstewart@hcbcc.org
Mitchell Cypress, Chairman, Tribal Council, Seminole Tribe of Florida: mitchellcypress@semtribe.com
Richard Bowers, Jr., President, Seminole Tribe of Florida: richardbowers@semtribe.com
Jim Shore, General Counsel, Seminole Tribe of Florida: c/o amotlow@semtribe.com
Craig Tepper, Director, ERMD, Seminole Tribe of Florida ctepper@semtribe.com
Vickie Gibson, DEP BAR Reading File: victoria.gibson@dep.state.fl.us

Clerk Stamp

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

(Clerk) 10/23/09 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Division of Air Resource Management, Bureau of Air Regulation

Draft Air Permit No. 0550061-001-AC / PSD-FL-406
Highlands Ethanol, LLC, Highlands Ethanol Facility
Highlands County, Florida

Applicant: The applicant for this project is Highlands Ethanol, LLC. The applicant's authorized representative and mailing address is: Charles F. Davis III, Sr. Vice President, Highlands Ethanol, LLC, 55 Cambridge Parkway, 8th Floor, Cambridge, Massachusetts 02142.

Facility Location: Highlands Ethanol, LLC proposes to construct the new Highlands Ethanol Facility (HEF), which will be located in Highlands County, north of State Road 70 and approximately 1.7 miles east-northeast of Brighton, Florida.

Project: The feedstocks for the HEF will be dedicated energy crops, such as energy cane and forage sorghum, grown on adjacent farmland. The cellulose and hemicellulose in the crops will be converted to sugars that will be fermented to produce fuel ethanol. The ethanol will be subsequently denatured with gasoline to produce up to 41.5 million gallons per year of the denatured ethanol product.

The project will be the first large commercial application of a cellulosic ethanol process. Per 403.061(18), F.S., 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.

The HEF will generate its own process steam fuel consisting of biomass (stillage cake) from the fermentation and distillation steps and biogas from the on-site wastewater treatment plant. Natural gas will be used as stabilization fuel in the biomass boiler and as fuel in a backup non-biomass boiler. Ultralow sulfur diesel (ULSD) fuel oil (FO) or propane will be used if natural gas is not available and as fuel in the emergency engines.

Based on the air permit application, the project will result in emissions increases of: 192 tons per year (TPY) of carbon monoxide (CO); 156.5 TPY of nitrogen oxides (NO_X); 33.6 TPY of particulate matter (PM); 33.6 TPY of PM with a mean diameter of 10 micrometers (μm) or less (PM_{10}); 24.7 TPY of PM with a mean diameter of 2.5 μm or less ($PM_{2.5}$); less than 7 TPY of sulfuric acid mist (SAM); 104.1 TPY of sulfur dioxide (SO_2); 71.3 TPY of volatile organic compounds (VOC) and 0.1 TPY of lead (Pb). As defined in Rule 62-210.200, F.A.C., the project results in PSD-significant emissions increases for CO, NO_X, PM, PM_{10}, $PM_{2.5}$, SO_2, and VOC.

The Department reviewed an air quality analysis prepared by the applicant. 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. The table below shows 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 project in micrograms per cubic meter (μg/m³). Nitrogen dioxide (NO_2) is the species of NO_X that is modeled.

Pollutant	Averaging Time	Allowable Increment (μg/m³)	Increment Consumed (μg/m³)	Increment Consumed Percent
NO_2	Annual	25	8	32
PM_{10}	24-hour	30	23	77
	Annual	17	5	29
SO_2	3-hour	512	102	20
	24-hour	91	44	48
	Annual	20	9	45

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

The nearest PSD-Class I area is the Everglades National Park located 154 kilometers from the site. Because of the distance, low emissions and minimal effect by the project alone, a more detailed PSD-Class I multisource air quality analysis was not required.

The Department has concluded that emissions from the project will not cause or contribute to a violation of any state or federal ambient air quality standards.

For each PSD-significant pollutant, the Department is required to determine the Best Available Control Technology (BACT) and evaluate the applicant's Air Quality Analysis regarding ambient impacts due to the project. The Department's preliminary BACT determinations for these pollutants from the key emissions units are based on: fabric filters and good combustion design and practices (PM, PM_{10}, and $PM_{2.5}$); selective catalytic reduction or selective non-catalytic reduction on the biomass boilers (NO_X); good combustion design and practices (CO and VOC); wet scrubbers on the fermentation process, storage tank design, and process equipment leak control (VOC); and limestone injection into the biomass boilers and use of low-sulfur fuels in ancillary equipment (SAM and SO_2).

The details of the Department's BACT determination and the air quality analysis are provided in the Technical Evaluation and Preliminary Determination document available at the following web link:

www.dep.state.fl.us/air/emission/construction/highlands/hightech.pdf

Permitting Authority: Applications for air construction permits are subject to review in accordance with the provisions of Chapter 403, Florida Statutes (F.S.) and Chapters 62-4, 62-210 and 62-212, F.A.C. The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. In addition, electronic copies of these documents are available at the following web link:

www.dep.state.fl.us/Air/emission/construction/highlands.htm

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of the proposed equipment will not adversely impact air quality and that the project will comply with all applicable provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit and requests for a public meeting for a period of 30 days from the date of publication of the Public Notice. Written comments must be received by the Permitting Authority by close of business (5:00 p.m.) on or before the end of this 30-day period. In addition, if a public meeting is requested within the 30-day comment period and conducted by the Permitting Authority, any oral and written comments received during the public meeting will also be considered by the Permitting Authority. If timely received comments result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

(Public Notice to be Published in the Newspaper)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241; Fax: 850/245-2303). Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within 14 days of publication of this Public Notice or receipt of a written notice, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Permitting Authority for notice of agency action may file a petition within 14 days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of when and how each petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Public Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation: Mediation is not available in this proceeding.

(Public Notice to be Published in the Newspaper)

P.E. CERTIFICATION STATEMENT

PERMITTEE

Highlands Ethanol, LLC
55 Cambridge Parkway, 8th Floor
Cambridge, Massachusetts 02142

Draft Permit No. 0550061-001-AC (PSD-FL-406)
Highlands Ethanol Facility (HEF)
Highlands County, Florida

PROJECT DESCRIPTION

The feedstocks for the HEF will be dedicated energy crops such as energy cane and forage sorghum grown on adjacent farmland. The cellulose and hemicellulose in the crops will be converted to sugars that will be fermented to produce fuel ethanol. The ethanol will be subsequently denatured with gasoline to produce up to 41.5 million gallons per year of denatured ethanol product.

The HEF will generate its own process steam fuel consisting of biomass (stillage cake) from the fermentation and distillation steps and biogas from the on-site wastewater treatment plant. Natural gas will be used as stabilization fuel in the biomass boiler and as fuel in a backup non-biomass boiler. Ultralow sulfur diesel fuel oil or propane will be used if natural gas is not available and as fuel in the emergency engines.

This project is subject to the general preconstruction review requirements in Rule 62-212.300, Florida Administrative Code (F.A.C.) and the preconstruction review requirements for major stationary sources specified in Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration. The Department's full review of the project and rationale for issuing the draft permit is provided in the Technical Evaluation and Preliminary Determination.

The Department reviewed an air quality analysis prepared by the applicant. The Department has concluded that emissions from the project will not cause or contribute to a violation of any state or federal ambient air quality standards.

The Department's preliminary Best Available Control Technology determinations for these pollutants from the key emissions units are based on: fabric filters and good combustion design and practices (PM, PM_{10}, and $PM_{2.5}$); selective catalytic reduction or selective non-catalytic reduction on the biomass boilers (NO_X); good combustion design and practices (CO); wet scrubbers on the fermentation process, storage tank design, and process equipment leak control (VOC); and limestone injection into the biomass boilers and low-sulfur fuels in ancillary equipment (SAM and SO_2).

***I HEREBY CERTIFY** that the air pollution control engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify any other aspects of the proposal (including, but not limited to, the electrical, civil, mechanical, structural, hydrological, geological, and meteorological features).*

10/22/09

A. A. Linero, P.E. (Date)
Registration Number 26032

ALVARO A. LINERO
LICENSE
NO. 26032
STATE OF
FLORIDA
PROFESSIONAL ENGINEER

TECHNICAL EVALUATION

&

PRELIMINARY DETERMINATION

APPLICANT

Highlands Ethanol, LLC
55 Cambridge Parkway, 8th Floor
Cambridge, Massachusetts 02142

Highlands Ethanol Facility
ARMS Facility ID No. 0550061

PROJECT

Draft Permit No. PSD-FL-406
Project No. 0550061-001-AC

Cellulosic Ethanol Production

COUNTY

Highlands County, Florida

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Special Projects Section
2600 Blair Stone Road, MS#5505
Tallahassee, Florida 32399-2400

October 23, 2009

1. GENERAL PROJECT INFORMATION

1.1. Facility Description and Location

The Highlands Ethanol Facility (HEF) 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 on the left side of Figure 1. The locations of Brighton and the HEF are shown on the Highlands County map below.

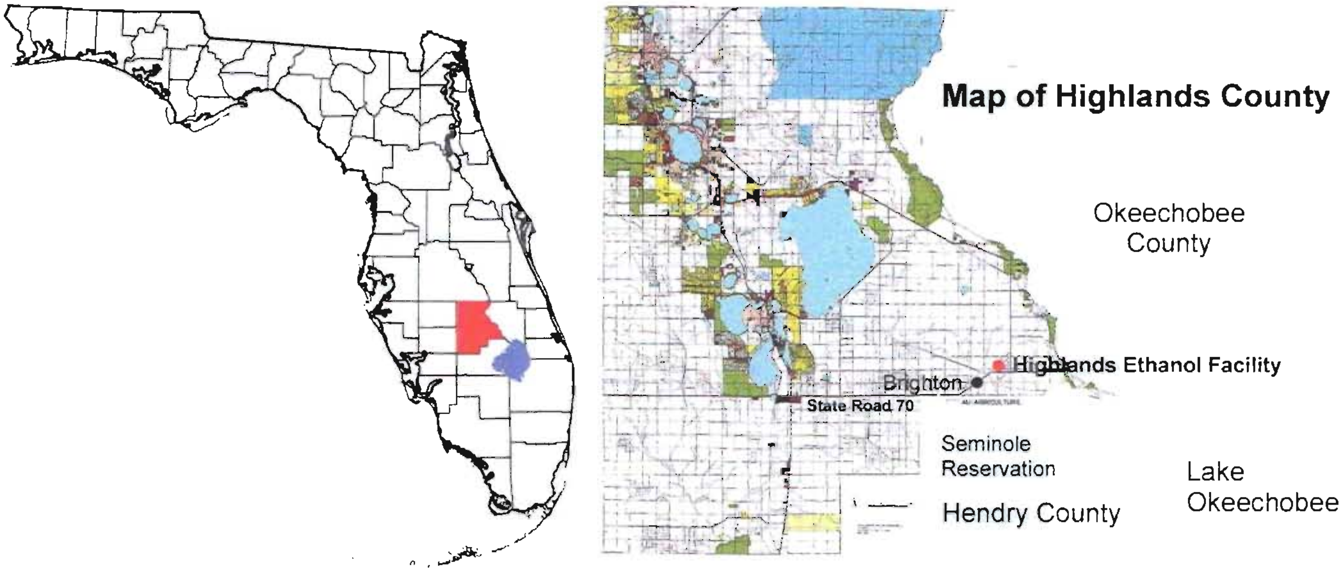

Figure 1 - Highlands County, Florida, Brighton in Highlands County, Proposed Location of HEF.

Highlands County is bounded by the Kissimmee River and Okeechobee County to the east and Hendry County to the south. Lake Okeechobee is located approximately 20 km to the southeast. Most of Highlands County is agricultural. Following are several photographs taken at the proposed site.

Figure 2 - Entrance to Proposed HEF Site, View of the Proposed Site, Adjacent Electric Substation.

Figure 3 - View to East and West along SR 70, Cowpen Operation South of the Proposed Site.

The proposed HEF will be located on property currently owned by Lykes Bros., Inc. The 95.7 acre site is surrounded entirely by Lykes Bros. property, with an easement allowing access to the site from State Route 70. The line between Highlands and Glades Counties is approximately 3 km south of the HEF 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 in the ENP is located 154 km south of the proposed HEF site.

1.2. Process description and the products made

The feedstocks for the facility will be dedicated energy crops, such as energy cane and forage sorghum, grown on adjacent farmland. The cellulose and hemicellulose in the crops will be converted to sugars that will be fermented to produce beer that will be distilled to produce fuel ethanol. The ethanol will be subsequently denatured with gasoline to produce the final ethanol product. Following is a very simplified diagram of the cellulosic ethanol production process excluding the denaturing step. It is also available at the website of Verenium (the parent company of Highlands Ethanol LLC) at the following link: www.verenium.com/cellulosic-ethanol_process.asp

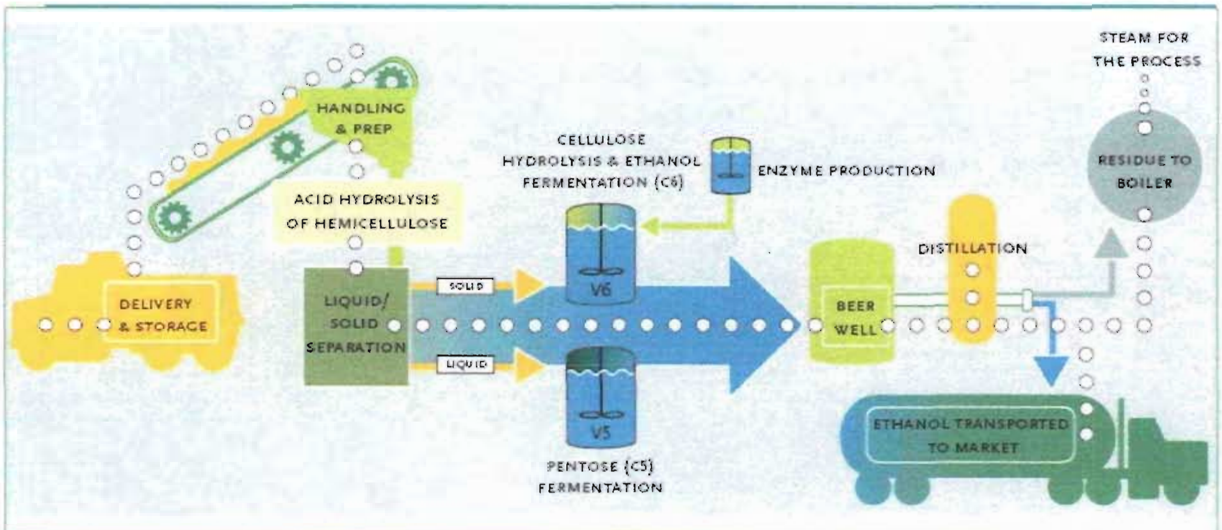

Figure 4 - Simplified Verenium Cellulosic Ethanol Production Process. (Verenium website)

1.3. 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.

1.4. Project Description

Highlands Ethanol LLC submitted an application for an air construction permit 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 proposes to build the first large commercial application of a cellulosic ethanol process. Verenium operates a 0.05 million gallons per year (MGPY) pilot plant in Jennings, Louisiana. A recently constructed 1.4 MGPY demonstration plant in Jennings will be operated to validate and optimize the Verenium process for final commercial scale up.

The feedstocks for the facility will be dedicated energy crops, such as energy cane and forage sorghum, grown on adjacent farmland. The HEF will have a permitted annual capacity 39.4 MGPY of ethanol that will be blended and denatured with gasoline to produce up to 41.5 MGPY of denatured product. The average daily ethanol production capacity is 108,000 gallons per day (gpd) and 118,800 gpd as peak daily capacity. The HEF will generate its own process steam fuel consisting of biomass (stillage cake) from the fermentation and distillation steps and biogas from the on-site wastewater treatment plant. Natural gas (NG-depending on local availability) and ultralow sulfur diesel (ULSD) fuel oil (FO) with a maximum sulfur (S) concentration of 0.0015% or propane will be used as backup fuels. The following table indicates new emissions units (EU) that will be added by this project. Details and a process diagram are provided further below.

Table 1 - Process Steps Comprising the HEF by EU.

EU ID No.	Emissions Unit Description
001	Feedstock delivery, handling and preparation
002	Hydrolysis, liquid/solids separation, neutralization
003	Fermentation, distillation and bacteria/enzyme propagation
004	Solids (stillage and gypsum) separation, dewatering and loadout
005	Denaturing and product storage
006	Product loadout and flare
007	Wastewater treatment system (WWTP), biogas conditioning and flare
008	Bubbling fluidized bed (BFB) combustion biomass-fueled boiler
009	BFB combustion biomass-fueled boiler
010	Backup fossil-fueled boiler primarily fueled by NG, propane or ULSD FO
011	Cooling tower
012	Miscellaneous storage silos
013	Miscellaneous storage tanks
014	Four emergency generators
015	Emergency fire pump engine
016	Facility-wide fugitive VOC equipment leaks

(001) Biomass Delivery and Handling

- Refer to the numbered process steps in the figure below. The facility will be designed to receive 3,600 green tons per day (TPD) of biomass feedstock (001a) for use in ethanol production. Freshly harvested energy cane and forage sorghum from adjacent farmland will be delivered by trucks equipped with a tipper for unloading material. The feedstock will be offloaded to a live bottom bin. The live bottom bin will transfer the feedstock to conveyers, through several washing steps and a screw press prior to the hydrolysis step.
- Prepared (sized and partially dried) supplemental boiler biomass fuel (001b) consisting of tree wood chips, bagasse or energy crop material will be delivered to the plant site in conventional tractor-trailer units or self-unloading trailers with live floors. The trailers will be unloaded to the ground using a hydraulic trailer dump platform and moved using mobile equipment to small storage piles. When required, the material will be reclaimed using a mobile wheel loader, and placed onto the live reclaim area from where it will be conveyed to a scalping screen or shaker screen and then transported to the boiler feed bin and fed into the biomass boilers to supplement stillage from the fermentation step.

(002) Hydrolysis of Hemicellulose, Liquid/Solid Separation and Neutralization

- Steam and a dilute acid solution hydrolyze (002a) the hemicellulose fraction of the biomass feedstock to produce slurry containing cellulose/lignin solids mixed with a liquid fraction containing a variety of pentose (5-carbon) sugars.

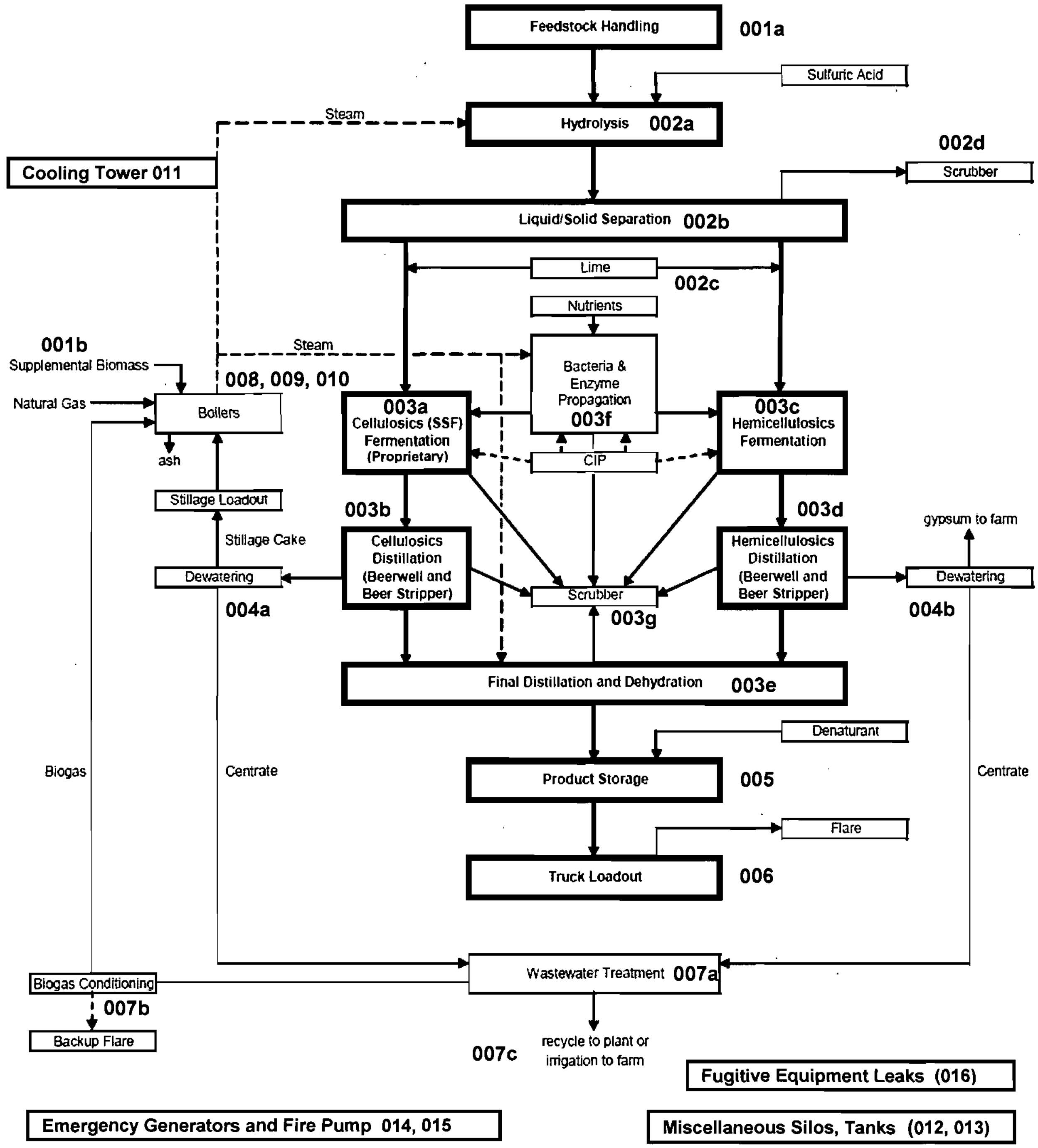

Figure 5 - Cellulosic Ethanol and E95 Production Process Diagram for HEF.

- The liquid pentose sugars are separated (002b) from the fiber solids through mechanical de-watering in a series of screw presses and sent to filtrate tanks to separate liquids and solids.
- The liquid pentose sugars will be neutralized with lime in a neutralization tank (002c). The cellulose/lignin solids stream will be neutralized with lime in a mixer. A vapor capture system will be used to collect the evaporative emissions from each of the enclosed feed tanks and filtrate tanks. The captured emissions will be exhausted to a wet scrubber (002d) dedicated to this step. Scrubbing water will be returned to the neutralization tank as make-up water. Each stream is then stored in a tank until a fermentation vessel becomes available.

(003) Enzymatic Conversion, Fermentation, Distillation and Bacteria/Enzyme Propagation

- The cellulose in the solids' stream will be converted to liquid glucose (six-carbon) sugars using a proprietary enzyme (003a). These sugars will be fermented with an enzyme to produce a dilute ethanol beer. The beer will then be transferred to a stripper that initiates the distillation process (003b).
- The hemicellulosic sugars will be separately fermented (003c) in batch mode with an enzyme to produce dilute ethanol beer. 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 (003d).
- The heads (vapors) from the two beer strippers will be passed to a stripper/rectifier for further distillation (003e) and then a molecular sieve system to remove remaining water (dehydration) from the product.
- Proprietary bacteria and enzymes will be produced on-site (003f). They will be cultured, nourished and propagated under sanitary conditions using a clean-in-place (CIP) system. Nutrients required to produce the enzyme and bacteria will be stored adjacent to the propagation system.
- The vents associated with this equipment will be connected to a wet scrubber (003g) to control volatile organic compounds (VOC). Scrubbing water will be returned to the cellulosic beerwell as make-up water.

Equipment to be used for the fermentation, distillation, and propagation processes include four cellulosic fermentation tanks (003a), four hemicellulosic fermentation tanks (003c), two beerwells (003b and 003d), three cellulosic enzyme propagators (003f), three hemicellulosic enzyme propagators (003f), two beer strippers (003e), a stripper/rectifier (003e), and a molecular sieve system (003e).

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

(004) Solids (stillage and gypsum) separation, dewatering and loadout

- The lignin-rich biomass residue (stillage cake) will be removed from the bottom of the cellulosic beer stripper, partially dewatered, and conveyed to the biomass boilers (004a). Stillage will be generated at a rate of 25 dry tons per hour with moisture content between 35 and 60%. Handling will be performed entirely within a closed system except for the conveyor.
- Gypsum ($CaSO_4$) residue will be removed (004b) from the hemicellulosic beer stripper, dewatered, and conveyed to farms.
- The water fraction from the stillage and gypsum dewatering steps will be conveyed to the wastewater treatment plant (WWTP).

(005) Ethanol, Gasoline Storage and Blending

The purified ethanol and gasoline (denaturant) will be stored in tanks and then blended, resulting in the denatured ethanol product, which will have dedicated storage tanks.

(006) Product Loadout and Flare

The denatured ethanol product will be loaded onto tank trucks at a rate of 600 gallons per minute. Vapors displaced from the trucks will be exhausted to a flare (006). The product loadout flare will have a rated capacity of 9.42 million Btu per hour (mmBtu/hr) to control vapors displaced from the trucks during the loading of denatured ethanol. The trucks are assumed to not be in dedicated ethanol service (i.e., some trucks will have returned from delivering gasoline and gasoline vapors will be displaced).

(007) Wastewater Treatment Plant (WWTP), Biogas Conditioning and Flare

The facility will include a WWTP (007a) to treat process wastewaters and to condition the resulting biogas for use as fuel in the boilers or to flare it (007b) when it cannot be used in the boilers. The effluent from the WWTP will be recycled to the plant or reused for irrigation (007c). The flow through the WWTP will be approximately 1,640 gallons per minute (gpm). The WWTP and associated systems will consist of an equalization basin, clarifiers, anaerobic reactors, aeration basin and sand filters.

(008, 009, 010) Steam Production

Two BFB combustion boilers (008, 009), each with a design heat input capacity of 198 mmBtu/hr, will be used to combust the stillage cake augmented by supplementary biomass, NG and the biogas produced by the anaerobic reactors of the WWTP. ULSD FO or propane will be used at least until NG is locally available.

The facility will include a backup boiler (010) with a design heat input rate of 198 mmBtu/hr and the ability to burn biogas, NG, ULSD FO or propane. The ULSD FO storage tank will have a capacity of 110,000 gallons and will be contained in a concrete dike for spill containment.

(011) Cooling Tower

An induced draft evaporative cooling tower (011) will provide cooling of process water for the project. The tower will be of rectangular mechanical-draft design with six cells. Each cell will be equipped with its own fan and a high efficiency drift eliminator to minimize water drift losses. The recirculating flow rate will be approximately 22,500 gpm. Total dissolved solids in the cooling water are expected to be approximately 2,750 milligrams per liter (mg/l).

(012) Miscellaneous Storage Silos

The facility will include equipment and silos (012) for the handling and storage of dry materials. The materials stored in these silos include enzyme propagation nutrients and pebbled lime for the ethanol process and limestone, sand, urea and ash related to the biomass boilers. These materials will be stored in silos, each of which will be equipped with fabric filters to control emissions during material handling.

(013) Miscellaneous Storage Tanks

The facility will include several liquid chemical storage tanks (013) including fermentation nutrients and reaction chemicals. All of these tanks will be of a vertical fixed roof design except for an anhydrous ammonia (NH_3) storage tank, which will be of a horizontal pressurized design.

(014, 015) Emergency Engines

- Four emergency generators (014), each rated at 2,000 kilowatts (kW), will be installed to provide backup electrical power in the event of a power outage at the facility.
- A backup 360 horsepower (hp) diesel fire pump (015) will also be installed to provide firewater during power outages.

Each of these emission units will fire ULSD FO or propane and will be limited to 500 hours per year of operation during emergencies and 100 hours for maintenance. Each unit will be operated no more than 100 hours per year for testing and maintenance purposes.

(016) Facility-wide Fugitive VOC Equipment Leaks

Fugitive VOC emissions (016) are grouped for the entire process and will be minimized by implementation of a monthly leak detection and repair (LDAR) monitoring program.

1.5. Processing Schedule

February 16, 2009:	Department received the application for an air pollution construction permit;
March 16:	Department requested additional information;
April 17:	Department received additional information (partial response);

April 29:	Department requested additional information regarding truck traffic modeling;
May 22:	Department received additional information regarding biomass handling and storage;
July 21:	Department received additional information regarding truck traffic modeling;
September 17:	Department received additional information clarifying sulfur in fuel, providing a basic leak detection and repair (LDAR) plan, boiler heat input calculation methods and liquid fuel storage tank size; and
October 23:	Department distributed Written Intent to Issue Air Permit 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 Title 40 of the Code of Federal Regulations (CFR). Part 60 identifies New Source Performance Standards (NSPS) for a variety of industrial activities. Part 61 specifies National Emissions Standards for Hazardous Air Pollutant (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: carbon monoxide (CO); nitrogen oxides (NO_X); sulfur dioxide (SO_2); particulate matter (PM); PM with a mean particle diameter of 10 and 2.5 microns or less (PM_{10} and $PM_{2.5}$); 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.

3.2. PSD Applicability for the 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. Therefore, the facility is a major stationary source and the project is subject to a PSD applicability review.

Table 2 is a listing of the applicant's PSD-pollutant emission estimates. As shown in the table, the project is subject to PSD preconstruction review for emissions of: CO, NO_X, $PM/PM_{10}/PM_{2.5}$, SO_2 and VOC.

Table 3 is a list of PSD emissions by operation, i.e. process step. It is clear that the greatest emission source by far is steam production, which accounts for nearly 90% of all PSD-pollutants to be emitted from the HEF. Other meaningful pollutant emissions include: VOC from fermentation and distillation, fugitive VOC from leaks and fugitive particulate emissions from traffic and materials handling.

Table 2 - Summary of the Applicant's PSD Applicability Analysis.

Pollutant	Emissions Increase (TPY)	PSD SER (TPY)	Subject to PSD Review?
CO	192.0	100	Yes
NO_X	156.5	40	Yes
PM/PM_{10}	33.6	25/15	Yes
$PM_{2.5}$	24.7	10	Yes
SAM	< 7	7	No
SO_2	104.1	40	Yes
VOC	71.3	40	Yes
Hg	<< 0.1	0.1	No
Pb	0.1	0.6	No

Table 3 - Breakdown of Emissions by Process Step. (Largest sources are bolded)

Operation	CO	NO_X	PM/PM_{10}	$PM_{2.5}$	SO_2	VOC	HAP
Roadway Fugitives (001)			9.9	1.0			
Liquid/Solid Separation (002)						2.1	
Fermentation/Distillation (003)						18.8	6.4
Stillage Loadout (004)						2.8	
Product/Denaturant Storage (005)						1.7	0.1
Product Loadout (006)	2.3	0.4	0.02	0.02	0.004	5.3	0.4
Wastewater Treatment (007)	0.3	0.1	0.002	0.002	0.001	5.2	
Steam Production (008, 009, 010)	**173.4**	**130.1**	**17.3**	**17.3**	**104.1**	8.7	**9.6**
Cooling Tower (011)			0.7	0.7		4.1	0.2
Miscellaneous Storage Silos (012)			4.7	4.7			
Miscellaneous Storage Tanks (013)						0.0	
Four Emergency Generators (014)	15.6	25.2	0.8	0.8	0.02	2.8	0.1
Emergency Fire Pump Engine (015)	0.5	0.5	0.03	0.03	0.001	0.1	0.004
Fugitive Equipment Leaks (016)				1.0		**19.6**	1.0
Totals (small deviations due to rounding)	192.0	156.5	33.6	24.7	104.1	71.3	17.7

According to the application, the HEF 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). The other meaningful HAP emission is acetaldehyde (C_2H_4O) from the fermentation and distillation step.

4. DEPARTMENT'S PROJECT REVIEW

4.1. Applicable State Regulations

There are no EU presently operating at the project site. The project will establish 16 new EU as described above. Following are some of the key state regulations and a statute that are applicable to the 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 and, in particular, flare pilot flames (EU 006 and 007);
- NSPS Subpart Db – Industrial-Commercial-Institutional Steam Generating Units, which regulates the three boilers (EU 008, 009 and 010);
- NSPS Subpart IIII – Stationary Compression Ignition Internal Combustion Engines (ICE) (EU 014 and 015);
- 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. 005);
- NSPS Subpart VVa – Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry (SOCMI), which regulates EU 002 through 006 and EU 016; and
- NESHAP Subpart ZZZZ – Stationary Reciprocating Internal Combustion Engines (RICE) (EU 014).

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 A – General Provisions (Excluded by reference in Subpart ZZZZ);
- 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 (promulgated but vacated and now under re-evaluation by U.S. EPA).

4.3. Other Requests

By letter dated February 6, 2009, Highlands Ethanol 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, EPA provided a determination that the subject NSPS do not apply to the project because ethanol produced by biological processes is outside the respective scopes.

5. BACT REVIEW

BACT determinations are required for the pollutants that are subject to PSD review, including CO, NO_X, $PM/PM_{10}/PM_{2.5}$, SO_2 and VOC. These determinations are provided in the following sections and are organized and presented by process step.

In the case of $PM_{2.5}$, the Department relies on precursors and surrogates. The rationale is as follows:

On September 16, 1997, EPA revised the national ambient air quality standards (AAQS) for particulate matter, which includes a new AAQS for $PM_{2.5}$. Florida implemented an ambient monitoring program for $PM_{2.5}$. As EPA mentioned in its guidance dated October 23, 1997, there are significant technical difficulties with respect to $PM_{2.5}$ monitoring, emissions estimation and modeling.

This guidance recommended the use of PM_{10} as a surrogate for $PM_{2.5}$ in meeting new source review (NSR) requirements under the Clean Air Act, including the permit programs for PSD. Meeting these measures in the interim will serve as a surrogate approach for reducing $PM_{2.5}$ emissions and protecting air quality. Florida is in the process of revising its State Implementation Plan to address the new $PM_{2.5}$, AAQS, PSD significant emissions rates and ambient air quality impact thresholds for modeling analyses as required by EPA for approved states by 2011. Until state regulations support PSD preconstruction review for $PM_{2.5}$ emissions, the Department will rely on PM_{10} emission limits and $PM_{2.5}$ precursor limits (e.g., SAM, SO_2, VOC, NH_3, and NO_X). This approach goes beyond the minimal EPA guidance memoranda.

5.1. BACT Review for Roadway Emissions and Biomass Handling (EU 001)

PM/PM_{10} Emissions

Discussion. PM/PM_{10} is the only pollution of concern from EU 001. The trucks that will be used to deliver ethanol process biomass and supplemental boiler fuel biomass will generate fugitive dust.

Upon receipt, the process feedstock will be offloaded to a live bottom bin as shown on the left hand side of the following diagram. The feedstock will be transferred from the live bottom bin to conveyors which will pass the feedstock through several washing steps prior to the hydrolysis process.

Figure 6 below is a diagram of the feedstock receiving and handling operation. Because of the feedstock's high moisture content and subsequent washing steps, fugitive emissions are expected to be minimal from this part of the process.

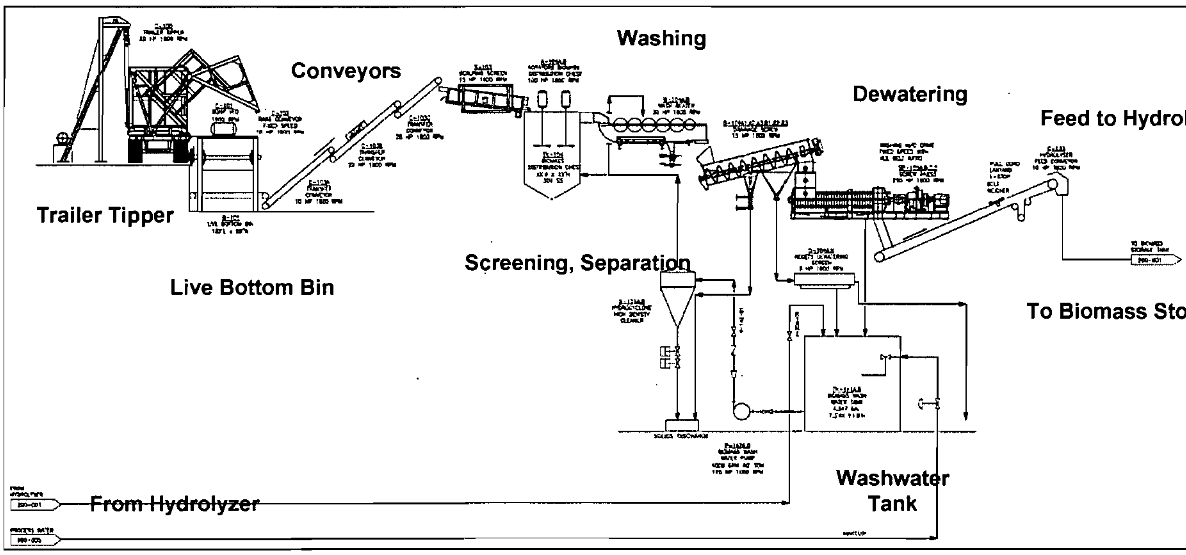

Figure 6 - Ethanol Process Biomass Feedstock Receiving and Handling.

Figure 7 is a diagram of the supplemental fuel receiving and handling operation. Prepared (sized and partially dried) supplemental boiler biomass fuel consisting of tree wood chips, bagasse or energy crop material will be delivered to the plant site in conventional tractor-trailer units or self-unloading trailers with live floors. The trailers will be unloaded to the ground using a hydraulic trailer dump platform and moved using mobile equipment to small storage piles.

When required, the material will be reclaimed using a mobile wheel loader, and placed onto the live reclaim area from which it will be conveyed to a scalping screen or shaker screen and then transported to the boiler feed bin and fed into the biomass boilers to supplement stillage from the fermentation step.

Applicant's Proposal. The only practical measures to control fugitive dust from roads is paving the roads or employing other dust control measures such as wetting and maintaining low vehicle speeds. Initially the applicant proposed to use unpaved roadways in the feedstock delivery area. The applicant now proposes to pave the feedstock loop road and all other roads at HEF. Deliveries of supplemental biomass fuel will also be made using paved roads.

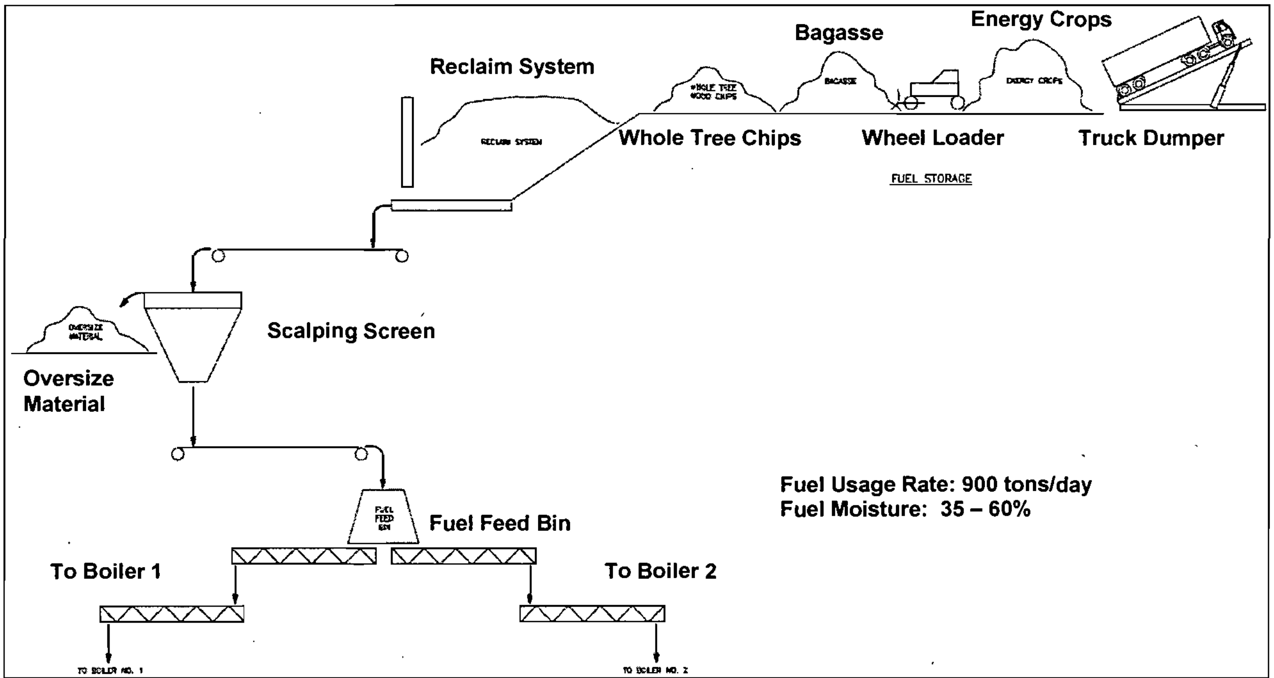

Figure 7 – Supplemental Fuel Receiving and Handling Operation.

As discussed above, the feedstock will be delivered and used on a just-in-time basis and any temporary storage will occur when the trucks are waiting to be unloaded. Supplemental fuel will be used to augment the stillage. The material is moist and will be managed in relatively small piles on gravel surfaces prior to reclaim.

Material transfer points will be enclosed to the extent practical. Conveyer belts will be covered to keep wind and rain away from the material. All conveying will be by mechanical means and no air (such as pneumatic systems) will be used in conveying, thereby reducing potential emission points.

Department's Review. The Department accepts the procedures describes by the applicant as BACT for feedstock and supplemental biomass receiving and handling, with the addition of wetting the roads and gravel areas during dry conditions. In addition, dust collectors must be installed at drop and transfer points in the biomass handling systems and the paved areas must be vacuumed swept weekly.

5.2. BACT Review for Hydrolysis, Liquid/Solid Separation and Neutralization (EU 002)

Discussion. The stream entering liquid/solid separation (002b) from the hydrolyzer (002a) has trace levels of organics that are highly soluble in water such as acetic acid and furfural. They are soluble in water. However, some will evaporate in the process. Estimated emissions from liquid/solid separation after control are estimated at 0.6 lb/hr and 2.1 TPY of VOC.

Applicant's proposal. According to the applicant, wet scrubbing of the highly soluble emissions and thermal oxidation (TO) can provide equivalent levels of control. Highlands Ethanol is proposing to use a wet scrubber to control VOC emissions from the liquid/solid separation process. The applicant estimates control efficiency of 98% to yield the emission estimates given above.

Department's Review. The Department believes that TO can provide even greater control than a scrubber, but reducing emissions by another 1 to 2 TPY would not be cost-effective for this step in the process. The Department accepts the applicant's proposal as BACT for this emissions unit with a technology based limit of 0.106 lb per 1000 gallons of ethanol produced.

5.3. BACT Review for Enzymatic Conversion, Fermentation, Distillation and Bacteria/Enzyme Propagation (EU 003)

Discussion. Ethanol will be the primary VOC emitted from fermentation/distillation and propogation. Other VOC such as acetic acid, lactic acid, and methanol (a HAP) will also be emitted. Emissions after control are estimated at 5.1 lb/hr and 18.8 TPY of VOC and 6.4 TPY of HAP.

Applicant's proposal. Highlands Ethanol proposes to connect the fermentation and distillation vents to a single wet scrubber. According to the applicant, cellulosic ethanol production differs from corn ethanol production in that fermenting organism propagation unit operations are more complex and there is an additional enzyme propagation unit operation. These unit operations require sparging of air into the process and also emit different volatile components than corn ethanol production. The applicant states "Highlands Ethanol has determined that 98 percent control is achievable by wet scrubbing. This is equivalent to the control level required for new facilities in Indiana and is as good as or better than all but three (nearly 90 percent) of the identified (traditional corn-based ethanol) facilities".

Department's Review. The Department believes that TO can provide greater control than a scrubber, but reducing emissions by another 5-15 TPY would not likely be cost-effective for this step in the process. The Department accepts the procedures describes by the applicant as BACT for this emissions unit.

This operation is the heart of the Verenium cellulosic ethanol process. Verenium is an affiliate of Highlands Ethanol and is the process developer. Verenium is conducting research at a pilot plant and a demonstration plant in Jennings, LA.

Based on their expertise and research regarding the differences between corn and cellulosic-based ethanol production, the Department agrees with their conclusion that a wet scrubber is appropriate as BACT for this project with a technology based limit of 0.954 lb per 1000 gallons of ethanol produced. The Department does not conclude here that a wet scrubber is BACT for grain ethanol projects.

The applicant shall also comply with 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".

While the applicant may install a wet scrubber, the Department notes that the applicant will have to comply with the Department's objectionable odor regulation and would have to apply for a permit to install additional control equipment or inject reagents to address objectionable odor problems.

5.4. BACT Review for Stillage Loadout (004)

Discussion. Stillage will be generated at a rate of 25 TPH and will consist primarily of lignin fibers and secondarily of unhydrolyzed cellulose fibers with a moisture content between 35 and 60 percent. Handling will be performed entirely within a closed system except for the conveyor. Based on the consistency and moisture content of the material, PM emissions are expected to be negligible. VOC emissions are estimated at 0.6 lb/hr and 2.8 TPY.

Applicant's proposal. According to the applicant, the VOC occur from the evaporation of trace organics dissolved in the water fraction and maintenance of the material at ambient temperature will reduce the potential for fugitive VOC emissions.

According to the applicant, the only control options for this process would be to capture the emissions and vent them to a wet scrubber or TO. However, the potential uncontrolled VOC emissions from the process are calculated to be only 2.8 tons per year and their capture would not be cost-effective.

Department's Review. The Department concurs with the applicant's proposal to maintain the stillage cake at 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.

5.5. BACT Review for Product and Denaturant (Gasoline) Storage Tanks (005)

Discussion. The facility includes two product shift tanks, two denature ethanol storage tanks, one denaturant tank and one recycle product tank. Ethanol and gasoline vapors will be the primary VOC emitted from these tanks. Emissions after control are estimated at 0.5 lb/hr (1.7 TPY of VOC).

Applicant's proposal. The applicant proposes to design these tanks with internal floating roofs to minimize VOC emissions. The applicant also proposes to incorporate vapor balancing (also called Stage I control) to capture the displaced vapor from the gasoline storage tank and return it to gasoline tanker delivery trucks.

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 product and denaturant tanks and vapor balancing control on the denaturant tank as BACT for this emissions unit.

5.6. BACT Review for Product Loadout including Flare (006)

Discussion. Product will be loaded onto tank trucks at a rate of 600 gallons per minute using submerged fill. Vapors displaced from the trucks will be exhausted to a flare. Ethanol and gasoline vapors will be the primary VOC emitted from this operation. Emissions after control are estimated to be 9.3 TPY of VOC and 5.3 TPY of HAP.

Applicant's proposal. The applicant proposes to divert vapors displaced from the tanker trucks to a flare. The Product Loadout Flare will have a rated capacity of 9.4 MMBtu/hr and will provide 98% control efficiency for VOC emissions during the loading of E95 into trucks.

Department's Review. The available control alternatives for this process include flares and TO. The selection of a flare is appropriate as BACT for this emissions unit.

5.7. BACT Review for WWTP, Biogas Conditioning and Flare (EU 007)

The facility will include a WWTP (007a) to treat process wastewaters and to condition the resulting biogas for use as fuel in the boilers or to flare it (007b) when it cannot be used in the boilers. The effluent from the WWTP will be recycled to the plant or reused for irrigation (007c). The flow through the WWTP will be approximately 1,640 gallons per minute (gpm). The WWTP and associated systems will consist of an equalization basin, clarifiers, anaerobic reactors, aeration basin and sand filters.

Discussion.

The WWTP will have aerobic (007a) and anaerobic (007b) sections. According to the applicant, the WWTP will emit 5.2 TPY of VOC and less than 1 TPY of any other pollutant as indicated in the following table.

Table 4 – Annual Emissions from WWTP including Flare (TPY)

Operation	CO	NO_X	PM/PM_{10}	$PM_{2.5}$	SO_2	VOC
Wastewater Treatment (007)	0.3	0.1	0.002	0.002	0.001	5.2

Most of the emissions will occur as VOC from the aerobic section. Methane (CH_4), VOC, hydrogen sulfide (H_2S) and NH_3 can be emitted from the anaerobic section. However, most of these gases can be recovered and used as biogas fuel in the biomass boilers and in the backup boiler.

Applicant's Proposal.

The applicant proposes as BACT to combust biogas from the anaerobic section in the biomass boilers and install a flare for backup purposes. According to the applicant, combustion of the biogas in the boilers and use of a backup flare will provide a VOC control efficiency of 98%.

The applicant will also enclose the aerobic section equalization tank and primary clarifier to function much as a vertical fixed roof storage tanks. The VOC emissions from these tanks are thereby reduced significantly compared to tanks of open top design.

Department's Review.

The use of the biogas in the biomass boilers will provide BACT level treatment of all pollutants. The biogas will provide approximately 44 mmBtu/hr towards the 396 mmBtu/hr heat input required by the two biomass boilers combined. Combustion of the biogas in the boilers or in the flare will control odor from 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. The storage tank design of the equalization tank and primary clarifier is sufficient to minimize VOC emissions and no further control is necessary. The Department accepts the procedures and equipment describes by the applicant as BACT for this emissions unit

5.8. BACT Review for Biomass-fueled Boilers (EU 008, 009)

NO_X Emissions

Discussion. The biomass fueled boilers are relatively small at 198 mmBtu/hr. If such boilers were used to efficiently produce electricity by burning fossil fuel, each would produce roughly 20 megawatts (MW) of electric power. The size is on par with medium size waste-to-energy or small sugar cane bagasse boilers. The characteristics of the two biomass-fueled boilers are provided in Table 5.

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. Each biomass boiler is expected to emit 65 TPY of NO_X.

Applicant's Proposal for NO_X. The applicant's BACT proposal is 0.075 lb/mmBtu on a 30-day rolling basis and is included in the top row of Table 6. 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.

Table 5 - Characteristics of each Biomass-fueled Boiler

Parameter	Description
Boiler Type	BFB design
Primary Solid Fuel Feed	Stillage and other biomass at maximum rate of 23.6 tons per hour (TPH)
Supplemental Fuel	NG assuming that the Florida Gas Transmission (FGT) expansion is completed in the area. Otherwise will fire ULSD FO or propane
Ash Removal	To ash storage silo and shipment off-site
Heat Input Rate	Nominal 198 mmBtu/hr (maximum 218 mmBtu/hr on a 4-hour basis)
Thermal Efficiency	To be established
Steam Production	100,000 – 130,000 lb/hour (to be determined based on efficiency)
Stack Parameters	6 feet diameter (maximum); 180 feet tall (minimum)
Flue Gas	78,905 actual cubic feet per minute (acfm) at 305 °F and 54,460 dry standard cubic feet per minute (dscfm)
Particulate Control	Fabric filter baghouse greater than 99% efficiency
NO_X Control	Selective non-catalytic reduction (SNCR) based on urea injection in the furnace
SO_2 Control	Dry limestone injection and clean stabilization and backup fuels
VOC and CO Control	Good combustion practices (GCP)

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 boilers and concluded SCR is the top technology. However, the applicant claims:

"Dusty side SCR is not feasible with the fluidized bed combustion (FBC) boiler because of the high particulate matter loading prior to the fabric filter system. In this location, the catalyst is subject to damage from erosion, thermal sintering and fly ash deposition.

"Placement of an SCR system after other air pollution control equipment, termed cold side application, is the only feasible method of incorporating SCR into the FBC boiler system. Cold side applications require flue gas reheat (i.e., fossil fuel is burned to reheat the flue gas) to raise the gas temperature from approximately 270°F to 650°F, the optimum temperature range for effective NO_X reduction across the catalyst bed. Reheating the gas stream also involves heat recovery that adds capital and operating expenses. SCR systems also require reagent storage and management systems and a process control system that monitors reagent usage to minimize ammonia slip."

The applicant calculated the capital costs of SCR at more than $12,000,000 per boiler and the annualized costs at more than $3,000,000 per year per boiler. The cost effectiveness calculated by the applicant is $27,000 per ton of NO_X removed ($/ton). The applicant claims that SCR is not cost-effective.

By electronic communication dated September 17, the application added:

"Highlands Ethanol is proposing to primarily use process stillage solids, which is a new fuel for which there is no current commercial scale operating data available. From laboratory analyses, Highlands Ethanol knows that there can be considerable natural variability in this fuel due to natural variation in the energy crops such as that caused by plant age at harvest and weather conditions. Among the fuel characteristics that are affected by this variability is its nitrogen content, which generally averages from 2 to 3 times (up to 0.49% N) the content of whole tree wood chips.

Table 6 - Emissions in lb/mmBtu – Boilers with Uses or Capacities Similar to Proposed Project

Project Location	CO	VOC	NO_X	PM/PM_{10}	SO_2
HEF, Highlands County, FL BFB - stillage, wood, gas, ULSD FO ~198 mmBtu each (proposed)	**0.10** 30-day GCP	**0.005** stack test GCP	**0.075** 30-day SNCR	**0.01** Stack test fabric filter	**0.06** 30-day BFB limestone
ADAGE, Hamilton County, FL BFB – woody biomass ~760 mmBtu/hr (proposed)	~0.08 12-month GCP	~0.017 stack test GCP	~0.07 12-month SCR	~0.029 stack test fabric filter	~0.045 12-month lime in ducts
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 ≥ 100 mmBtu/hr	0.1 – 0.63 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
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 ≥ 100 < 250 mmBtu/hr	No standard	No standard	0.10-0.20 low/high heat release ULSD	0.03 20% opacity wood basis	0.20
NESHAP Subpart DDDDD[a] large solid fuel category ≥ 100 mmBtu/hr	~0.35 400 ppm @ 3% O_2[b] GCP	No standard	No standard	0.025 stack test	No standard

a. Subpart DDDDD was promulgated and then vacated

b. ppm @ 3% O_2 means parts per million by volume at 3 percent oxygen

"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."

<u>Department's Review.</u> The selection of a BFB boiler (a type of FBC 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."

The Department considers the BFB feature as part of the BACT for the boiler. 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 (ADAGE) that will incorporate SCR in the dusty medium temperature zone is presently under review by the Department as shown in Table 6.

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. When corrected for the smaller boilers at HEF, the figure will be somewhat greater. Most likely the cost-effectiveness is somewhere between the $4,000 figure and the $27,000 value estimated by the applicant. The cost-effectiveness will very likely 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 per boiler) 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. 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 (distillers grain) combustion, let alone cellulosic ethanol stillage combustion. Most grain distillers grain appears to be used as animal feed or fertilizer. Combustion optimization of the cellulosic ethanol stillage is one subject of on-going research at the Verenium pilot and demonstration plants in Jennings, Louisiana.

Based on the foregoing discussion, the Department will set a limit of 0.075 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).

SO_2 Emissions

Discussion. SO_2 is formed from S compounds contained in biomass. According to the application, each biomass boiler is expected to emit 52 TPY of SO_2. According to the application, stillage will comprise up to 12.5 TPH of the 23.6 TPH biomass feed to each BFB boiler. The application states:

"The boiler is designed to burn stillage cake from the distillation process as its primary fuel. The S content of the stillage cake will be a function of the raw materials that are input to the process (energy cane and forage sorghum) and the hydrolysis process which uses sulfuric acid."

Biomass entering the ethanol process (e.g. sorghum) at the HEF will be typically low in S content. A figure of 4.4% S (wet basis) was originally provided in the application (~21 lb/mmBtu) but subsequently corrected to a *maximum* content of 0.08% S (electronic communication dated September 17, 2009). The latter value is included in Table 7 along with heating value, ash and sulfur content of various types of biomass and fossil fuels. The values are on a dry basis except as otherwise noted.

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 5. 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. The stated control efficiency per the application is 85 to 95%.

According to the applicant:

"The S content of the fuel may be variable and is not under the direct control of Highlands Ethanol. Therefore, use of low S fuel is not technically feasible. The only SO_2 emissions control methods that are technically feasible are combustion zone controls (limestone injection) and post-combustion controls (wet scrubber or spray dryer absorber).

Table 7 - Characteristics of Biomass and Fossil Fuels – Heating Value, Ash and S

Fuel Class	Fuel	Gross Heating Value Btu/lb	Ash (%)	S (%)
Bioenergy feedstocks	**HEF stillage**	**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

"Spray dryer absorbers or wet scrubbers are typically understood to provide the highest level of SO_2 control possible in boiler applications. With the BFB 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.

"Highlands Ethanol proposes to utilize limestone injection to control SO_2 emissions from the biomass boilers, which represents the top level of control. Therefore, an analysis of economic, energy, and environmental impacts is not required."

Consequently, the applicant did not provide a cost analysis for further SO_2 reductions.

Department's Review.

In general, the Department disagrees 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 under construction in Wise County, Virginia will also combust coal and 20% biomass in a 585 MW CFB-based power plant. The Virginia project will incorporate limestone injection and 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.

According to Table 6, the new grate boiler at U.S. Sugar at Clewiston fires primarily bagasse, supplemented with low S FO and complies with a SO_2 emission limit of 0.06 lb/mmBtu with no additional sulfur control. Some of the SO_2 is removed in the fly ash without addition of sorbent. The U.S. Sugar bagasse boiler is about 5 times the size of the proposed HEF stillage boilers.

ADAGE proposes a non-BACT, PSD-avoidance limit of 0.045 lb/mmBtu on a 12-month rolling basis from a BFB-based power plant. The ADAGE woody biomass boiler will be about 4 times the size of the proposed stillage biomass boilers to be used at the HEF.

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

For the purpose of further evaluation, the Department will assume that the maximum 0.08% S content stated by the applicant is on a wet basis and that the fuel heat content stated in Table 7 is also on a wet basis. The pre-control SO_2 emission potential is calculated as follows:

(0.08 lb S/100 lb stillage)x(2 lb SO_2/lb S)x(lb stillage/4,200 Btu)x(10^6 Btu/mmBtu) = 0.38 lb SO_2/mmBtu.

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 ULSD FO or NG or propane that contain practically 0% S. Additionally, the applicant will combust as-needed some biomass other than stillage that will be closer in characteristics to the ADAGE and U.S. Sugar fuel sources and lower in S than the HEF stillage.

Co-firing the stillage with varying amounts of clean fossil fuels and other biomass 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 to 0.06 lb/mmBtu (~70% further reduction) is a reasonable expectation goal on a 30-day basis.

To achieve 0.06 lb/mmBtu, the overall control strategy of supplemental combustion of clean fossil fuels, lower S biomass, fuel ash absorption/adsorption and limestone injection must reduce pre-control emissions by approximately 85%.

The Department accepts the HEF 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 boilers are relatively small and will each emit only 52 TPY each; and
- The determination is strictly for a stillage biomass boiler 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 fossil fuels and incorporation of limestone injection. Compliance shall be demonstrated by an SO_2-CEMS.

CO and VOC Emissions

Discussion. VOC and CO are products of incomplete combustion. Refer to Table 6 above for a listing of CO and VOC limits from biomass projects.

Applicant's Proposal. The applicant's BACT proposals are 0.10 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. The applicant also proposes an 8-hour CO limit of 0.2 lb/mmBtu. According to the applicant, each biomass boiler is expected to emit 86.7 TPY of CO and 4.35 TPY 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 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 recently vacated NESHAP Subpart DDDDD would have required compliance with a CO limit of 400 ppm @3% O_2 as a surrogate for organic HAP. This value is roughly equal to 0.35 lb CO/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 initial and annual stack tests.

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

Discussion. PM/PM_{10}/$PM_{2.5}$ 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.

Applicant's Proposal. The applicant's BACT proposal is 0.01 lb/mmBtu for PM/PM_{10} based on fabric filter baghouses. According to the applicant, each biomass boiler is expected to emit 8.7 TPY of PM/PM_{10}. Refer to Table 6 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 boilers, which represents the top level of BACT control and no further analysis is required. The emission rates shown in Table E-12 (incorporated into Table 6 above) range from 0.0125 to 0.8 lb/mmBtu. Highlands Ethanol is proposing a PM/PM_{10} BACT emission limit of 0.01 lb/mmBtu (filterable, based on Method 5), which is more stringent than any of the units listed in the permit database.*"

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} limit at 0.01 lb/mmBtu by fabric filtration. Compliance shall be demonstrated by initial and annual stack tests. A VE standard of 10% will also be established for the biomass boilers. 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;
- The VE limit that directly control the fraction of $PM_{2.5}$, that interferes with light transmission; and
- The Department will establish a NH_3 limit of 10 ppm to minimize direct NH_3 emissions that can form ammoniated compounds in the exhaust stream and in the environment.

The BACT determination for $PM_{2.5}$ is adherence to the BACT determinations for NO_X, SO_2, PM/PM_{10}, VE and the NH_3 slip limit.

5.9. BACT Review for Backup Fossil-fueled Boiler (EU 010)

Discussion. The backup boiler is also rated at 198 mmBtu/hr. It will be fueled by NG and biogas. ULSD FO or propane will be used at least until NG is locally available. The backup boiler will be used only when one of the biomass boilers is not available and is limited to 3,000 hours of operation in any consecutive twelve month period. Therefore, the emissions from the two higher-emitting stillage-fueled boilers represent the total PTE of all three boilers.

If the backup boiler is continuously fired with a combination of NG and ULSD FO (in lieu of a stillage-fueled boiler), its PTE will equal 6.2 TPY of $PM/PM_{10}/PM_{2.5}$, 62.4 TPY of NO_X, 31.8 TPY of CO, 4.8 TPY of SO_2 and 1.3 TPY of VOC. The main difference between NG and ULSD FO is that the PTE NO_X is 30.2 TPY for exclusive use of NG and 62.4 TPY for exclusive use of ULSD FO.

Applicant's Proposal. The applicant's proposals for all of the pollutants in lb/mmBtu from the backup boiler (and biomass boilers) are included in Table 8 with comparison limits from the RBLC survey and other standards.

SO_2 is controlled by specification of NG or other low sulfur fuels. The NG available in Florida generally contains less than 2 grains of S per 100 standard cubic feet (gr/100 SCF). The applicant is specifically proposing ULSD FO with S content equal to or less than 0.0015% (less than NG). These values equate to 0.0056 and 0.0017 lb SO_2/mmBtu for NG and ULSD FO firing, respectively. The characteristics of propane are assumed to be equal to those of NG for the purposes of this discussion.

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

According to the applicant, *"there are 12 auxiliary boiler entries in the database that were listed in permit records as "auxiliary boilers." Two of these boilers have no controls. One of the boilers is controlled with SCR. The remainder are controlled with low NO_X burners, four in conjunction with FGR and three in conjunction with good combustion controls."*

"Proven add-on NO_X control technologies include SCR and SNCR. However, given the fact that the backup boiler will utilize clean fuels and only operate when the biomass boilers are not operational, add-on controls would not be cost effective. Therefore, the base level of control for the backup boiler, low NO_X burners with FGR, is determined to be BACT."

Table 8 - Emissions in lb/mmBtu – Boilers with Uses or Capacities Similar to Proposed Project

Project Location	CO	NO_X	VOC	PM/PM_{10}
HEF, Highlands County NG, propane, ULSD FO ~198 mmBtu/hr	0.035/0.037 (NG/ULSD FO)	0.035/0.072 (NG/ULSD FO)	0.0014/0.0015 (NG/ULSD FO)	0.0071 (ULSD FO) 0.0022 (NG)
Biomass Boilers ~198 mmBtu/hr, stillage[a]	0.10[a]	0.075[a]	0.005[a]	0.01[a]
Recent RBLC Survey	0.035 – 0.08	0.011 – 0.17	0.004 – 0.018	0.0022 – 0.0075
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 Db NG, ULSD $\geq$ 100 mmBtu/hr	No standard	0.20	No standards	
NSPS Subpart Dc NG, ULSD $\geq$ 10, < 100 mmBtu/hr	Record Keeping Required			
NESHAP Subpart DDDDD[b] large solid fuel category $\geq$ 100 mmBtu/hr	400 ppm @3% O_2	No standards		

a. The HEF biomass (stillage) boiler values are included for comparison with those of the backup boiler.

b. For comparison only - Subpart DDDDD was vacated and did not apply to area sources of HAP.

Department's Review. The Department agrees with the applicant's BACT analysis for CO, SO_2, $PM/PM_{10}/PM_{2.5}$ and VOC. The Department agrees that emissions from the backup boiler will be much less than emissions from the biomass boiler and that emissions from the biomass boiler will be avoided when the backup boiler is used.

Although the boiler is for backup use when a biomass boiler is not available, the applicant did not propose to limit the hours of use. The applicant did not conduct a cost-effectiveness evaluation to demonstrate that SCR or SNCR are not cost-effective based on continuous use.

The Department will reduce the allowed hours of operation by 1 hour for every hour that fuel oil is used. This will effectively annual limit NO_X emissions to approximately 30 TPY or the same value as if the unit used NG exclusively. At a PTE of 30 TPY, add-on control equipment will clearly not be cost-effective.

The proposed controls of LNB and FGR to achieve 0.035 and 0.072 lb/mmBtu when burning natural gas and ULSD FO respectively and limited operation is determined to be BACT for NO_X.

5.10. BACT Review for Cooling Tower (EU 011)

Discussion. The 6-cell induced draft evaporative cooling tower will provide cooling of process water for the project. Cooling towers may emit particulate matter 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 0.7 TPY of PM/PM_{10}, 4.1 TPY of VOC and 0.2 TPY of HAP.

Applicant's proposal. The applicant proposes to install 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. Highlands Ethanol proposes to collect a sample of cooling water on a weekly basis and analyze it for VOC. This will enable the early detection of leaking heat exchangers, thereby minimizing VOC emissions.

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

5.11. BACT Review for Miscellaneous Storage Silos (EU 012)

Discussion. The materials stored in these silos include enzyme propagation nutrients and pebbled lime for the ethanol process and limestone, sand, urea and ash related to the biomass boilers. The silos will emit small amounts of PM/PM_{10} estimated at 4.7 TPY total.

Applicant's proposal. The applicant proposes to control PM/PM_{10} emissions from the miscellaneous dry materials storage silos by fabric filter dust collectors achieving a concentration of 0.0005 grains per dry standard cubic foot (gr/dscf).

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

5.12. BACT Review for Miscellaneous Storage Tanks (EU 013)

Discussion. The materials stored in these tanks include aqueous solutions of corn steep, lactose and glucose. 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.

5.13. BACT Review for Emergency Generators (EU 014)

Discussion.

Four emergency generators (014), each rated at 2,000 kilowatts (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 500 hr/yr of operation and 100 hr/yr for testing and maintenance. According to Table 3 above, the emissions from each engine will range from 0.005 TPY of SO_2 to 6.3 TPY of NO_X.

The emergency generators are ICE and RICE. They shall comply with applicable provisions of NSPS Subpart IIII and NESHAP Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the engines meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII.

Applicant's Proposal.

The applicant proposes to use ULSD FO or propane and to comply with the requirements of NSPS Subpart IIII.

Table 9 - Emission Standards for Emergency Generators

Emergency Generator (> 560 kW and ≤ 2,237 kW)	**CO** (g/kWH)[a]	**VOC** (g/kWH)	**NO_X** (g/kWH)	**PM** (g/kWH)	**SO_2**[c] (oil S spec.)
BACT Proposal	3.5	0.64	5.76	0.20	0.0015%
Subpart IIII (2006 and later)	3.5	6.4 (NMHC[b] + NO_X)		0.20	0.0015%

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.
c. Subpart IIII references 40 CFR 80.510, which specifies 0.05% S until October 1, 2010 and 0.0015% S thereafter.

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.

5.14. BACT Review for Emergency Fire Pump Engine (EU 015)

Discussion.

The single 360-horsepower (hp) fire pump engine required for the project will be used sparingly and limited to 500 hr/yr of operation and 100 hr/yr for testing and maintenance. According to Table 3 above, emissions of each PSD-pollutant will be between 0.03 and 0.5 TPY.

This emergency fire pump is an ICE and a RICE. They shall comply with applicable provisions of NSPS Subpart IIII and NESHAP Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the engines meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII.

Applicant's Proposal.

The applicant proposes to use ULSD FO or propane and to comply with the requirements of NSPS Subpart IIII. By complying with Subpart IIII, compliance is attained for Subpart ZZZZ.

Table 10 - Emission Standards for Emergency Fire Pump Engines

Emergency Pumps (≥ 300 hp and < 600 hp)	**VOC** (g/hp-hr)	**NO_X** (g/hp-hr)	**PM** (g/hp-hr)	**CO** (g/hp-hr)	**SO_2**[a] (oil S spec.)
BACT proposal	0.3	2.7	0.15	2.6	0.0015%
Subpart IIII	3.0 ($NMHC+NO_X$)		0.15	2.6	0.0015%

a. g/hp-hr means grams per horsepower-hour.

b. Subpart IIII references 40 CFR 80.510, which specifies 0.05% S until October 1, 2010, after which it specifies 0.0015% S.

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 2009 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 EU.

5.15. BACT Review for VOC Fugitive Equipment Leaks (EU 016)

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 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 requirement 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, 18 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.

The applicant provided the following LDAR program developed pursuant to Subpart VV (the predecessor of Subpart Vva) for the smaller Verenium pilot and demonstration projects in Jennings, LA. The applicant proposes to rely upon the requirements of Subpart VVa and will provide a more comprehensive version for the larger commercial project at the HEF by June 30, 2010.

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 the HEF located in Jennings, Louisiana. 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 the Verenium Biofuels Louisiana Ethanol Facility.

3. REFERENCES
   a. 40 CFR Part 60 Subpart VV (would be Subpart VVa for HEF)
   b. LAC 33: III. 2121 (would include the analogous 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 Louisiana Department of Environmental Quality (LDEQ).

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 comprehensive and, together with the LDAR program, will complement the BACT determinations for each process emission unit that is a source of VOC. The Department accepts the proposal and will include a requirement to submit the details of a site-specific LDAR program pursuant to Subpart VVa by June 30, 2010.

6. HYDROGEN CHLORIDE (HCl) TOTAL HAP EMISSIONS

Discussion.

According to the application, the HEF 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). The applicant estimated 4.8 TPY of HCl from each of the biomass boilers or 9.6 TPY of HCl from the facility. The other meaningful HAP emission is acetaldehyde (C_2H_4O) from the fermentation and distillation step. Total facility HAP emissions are estimated by the applicant at 17.7 TPY.

HCl is formed from chloride (Cl) compounds contained in biomass. The cellulosic biomass to be used at the HEF will be typically low in Cl content as will the stillage derived therefrom.

If HCl PTE is equal to or greater than 10 TPY, then the source would be a major source of HAP and a case-by-case determination of Maximum Achievable Control Technology (MACT) is required. Such a determination would result in emission limitations for HCl and at least several other pollutants or surrogates for those pollutants such as PM-metals or organic HAP.

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. The applicant did not specifically propose measures to control or limit HAP emissions, including HCl.

Department's Review. According to other sources consulted by the Department, untreated woody biomass will contain less than 0.02% 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% moisture. A reasonable assumption is that the stillage will contain less than 0.02% 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. It will be necessary to control HCl emissions by approximately 80%. This should be easily accomplished by the described IDSIS and fabric filter baghouse.

The Department will set a limit of 9.4 TPY of HCl on a 12-month rolling average, rolled monthly. Compliance shall be demonstrated by an HCl-CEMS on each BFB biomass boiler the principle of FTIR and using the procedures described in Performance Specification 15 of Appendix B of 40 CFR part 60. The 12-month limit equates to 2.1 lb/hr HCl. These limits equate to 0.0053 and 0.0048 lb HCl/mmBtu at the nominal heat input rate of 396 mmBtu/hr (2 x 198 mmBtu per boiler) and the maximum heat input rate of 436 mmBtu/hr (2 x 218 mmBtu per boiler), respectively. For each individual boiler, the limits would be 1.05 lb/hr with a nominal heat input limit of 0.0027 lb HCl/mmBtu and a maximum heat input limit of 0.0024 lb HCl/mmBtu.

The applicant can subsequently request an alternative sampling procedure (ASP) from the Department if the applicant is able to find a vendor with a HCl-CEMS operating on a different principle such as NDIR that can demonstrate with a very high degree of confidence that the hourly emissions of HCl are less than or equal to 2.1 lb/hr and less than 9.4 TPY.

GCP in the BFB boiler, use of a non-gasification process, low Cl source biomass and control and measurement of HCl emissions will insure that organic HAP emissions including D/F will be adequately controlled.

6.1. 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 source in a conventional 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 distillers' dried grain with solubles (DDGS) and marketed as animal feed.

DDGS drying is usually accomplished by use of a recuperative TO that destroy 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 HEF is will be comprised largely of unpalatable lignin which will contain much less materials having 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;
- Wet scrubbers to control water-soluble VOC from hydrolysis, fermentation and distillation steps;
- Floating roofs on product storage tanks;
- Flares to control emissions from product loadout and the biogas (if not used as fuel) produced by the anaerobic digestion step in wastewater treatment;
- Use enclosed vessels for the anaerobic digestion step rather than lagoons;
- Maintaining the wet stillage cake from at ambient temperature rather than drying;
- Prompt use of the stillage cake as fuel in the BFB biomass boilers to recover the energy and destroy potential VOC and odor emissions.
- Maintaining only small storage piles of supplemental (wood chips, bagassee, energy crops) to minimize odors;
- Promptly 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;
- As per NSPS 40 CFR 60, Subpart VVa, HEF 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 HEF 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."

The full odor potential will not likely be fully understood by the applicant until further operation is achieved at the demonstration plants in Jennings, LA. However, 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 for no more than 3 days (72 hours);

- HEF 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 June 30, 2010 and will address contingency disposal provisions for stillage that cannot be used in the boilers within 3 days of its generation;
- The OCP shall also include provisions for storing, disposing of or recycling off-specification enzymes and bacteria that could otherwise contribute to objectionable odors.

7. BIOMASS BOILER HEAT INPUT MONITORING

Monitoring of heat input is difficult when using biomass such as cellulosic stillage as fuel as there is there little experience. 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 the following methodology:

<u>Boiler Performance Test</u>: *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% 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.

8. AIR QUALITY IMPACT ANALYSIS

8.1. Introduction

The proposed project will increase emissions of the following PSD-pollutants at levels in excess of the respective SER: $PM/PM_{10}/PM_{2.5}$, SO_2, VOC, CO and NO_X. PM_{10}, SO_2 and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels (SIL) and de minimis monitoring levels defined for them. CO is a criteria pollutant and has only AAQS, significant impact levels and de minimis monitoring levels defined for it. There are no applicable PSD increments, AAQS, significant impact or de minimis monitoring levels for VOC.

VOC and NO_X are ozone precursors and any net increase of 100 TPY or greater of either pollutant requires an ozone ambient air impact analysis including the gathering of preconstruction ambient air quality data. $PM_{2.5}$ is also a criteria pollutant and has national and state AAQS, but is not subject to PSD at this time. $PM_{2.5}$ does not have defined PSD increments (i.e. allowable increases in ambient air concentration), SIL and de minimis monitoring levels.

8.2. Major Stationary Sources Near the Proposed Highlands Ethanol Site

There are few large emission sources in Highlands County. The following tables are lists of the largest stationary sources, by pollutant, in counties adjacent to Lake Okeechobee and including Highlands County. The future emissions from the HEF are also shown.

Table 11 - Largest Sources of NO_X (2008) in Counties Adjacent to Lake Okeechobee.

Owner	Site Name	TPY
Florida Power and Light (FPL)	FPL Martin Plant, Martin County	4,688
FPL	FPL Riviera Plant, Palm Beach County (PBC)	2,245
Indiantown Cogeneration	Indiantown Power Plant, Martin County	2,095
Solid Waste Authority of PBC	North Resource Recovery Facility, PBC	1,401
US Sugar Corporation	Clewiston Mill, Hendry County	886
New Hope Power Company	Okeelanta Cogeneration Plant, PCB	826
Sugar Cane Growers Coop	Sugar Cane Growers Coop, PBC	514
Osceola Farms	Osceola Farms, PBC	392
Tampa Electric Company (TECO)	TECO Phillips Station, Highlands County	353
Florida Gas Transmission (FGT)	FGT Station 20 St. Lucie	308
Verenium/Highlands Ethanol LLC	**HEF, Highlands County**	**156**
Florida Municipal Power Agency	Treasure Coast Energy Center, St. Lucie County	104

Table 12 - Largest Sources of PM/PM_{10} (2008) in Counties Adjacent to Lake Okeechobee.

Owner	Site Name	TPY
FPL	FPL Martin Plant, Martin County	844
Osceola Farms	Osceola Farms, PBC	333
US Sugar Corporation	Clewiston Mill, Hendry County	323
Sugar Cane Growers Coop	Sugar Cane Growers Coop, PBC	257
FPL	FPL Riviera Plant, PBC	173
New Hope Power Company	Okeelanta Cogeneration Plant, PBC	124
Solid Waste Authority (SWA) PBC	North County Resource Recovery Facility, PBC	102
Verenium/Highlands Ethanol LLC	**HEF, Highlands County**	**34**
Okeelanta Corporation	Okeelanta Sugar Refinery, PBC	21
TECO	TECO Phillips Station, Highlands County	10

Table 13 - Largest Sources of SO_2 (2008) in Counties Adjacent to Lake Okeechobee.

Owner	Site Name	TPY
FPL	FPL Martin Plant, Martin County	7,734
FPL	FPL Riviera Plant, PBC	2,643
Indiantown Cogeneration	Indiantown Power Plant, Martin County	2,018
Waste Management	Berman Landfill, Okeechobee County	1,080
Sugar Cane Growers Coop	Sugar Cane Growers Coop, PBC	426
New Hope Power Company	Okeelanta Cogeneration Plant, PBC	250
SWA of PBC	North County Resource Recovery Facility, PBC	248
TECO	TECO Phillips Station, Highlands County	245
U.S. Sugar Corporation	Clewiston Mill, Hendry County	151
Verenium/Highlands Ethanol LLC	**HEF, Highlands County**	**104**
PBC Water Utilities	PBC Water Utilities	72

Table 14 - Largest Sources of CO (2008) in Counties Adjacent to Lake Okeechobee.

Owner	Site Name	TPY
U.S. Sugar Corporation	Clewiston Mill, Hendry County	11,774
Osceola Farms	Osceola Farms, PBC	11,456
Sugar Cane Growers Coop	Sugar Cane Growers Coop, PBC	10,655
New Hope Power Company	Okeelanta Cogeneration Plant, PBC	2,254
FPL	Martin Plant, Martin County	1,451
SWA of PBC	North County Resource Recovery Facility, PBC	772
Southern Gardens Citrus Processing	Southern Gardens Clewiston, Hendry County	622
FPL	Riviera Plant, PBC	443
Louis Dreyfus Citrus	Indiantown Plant, Martin County	370
Waste Management	Berman Landfill, Okeechobee County	250
Verenium/Highlands Ethanol LLC	**HEF, Highlands County**	**192**
Indiantown Cogeneration	Indiantown Power Plant, Martin County	158

Table 15 - Largest Sources of VOC (2008) in Counties Adjacent to Lake Okeechobee.

Owner	Site Name	TPY
Southern Gardens Citrus Processing	Southern Gardens Clewiston, Hendry County	1,066
Osceola Farms	Osceola Farms, PBC	635
Sugar Cane Growers Coop	Sugar Cane Growers Coop, PBC	570
Tropicana Manufacturing	Tropicana Ft. Pierce, St. Lucie County	551
U.S. Sugar Corporation	Clewiston Mill, Hendry County	451
Louis Dreyfus Citrus	Indiantown Plant, Martin County	366
FPL	Martin Plant, Martin County	195
Genpak, LLC	Genpak Plastics, Highlands County	151
S2 Yachts	S2 Yachts, St. Lucie County	98
Verenium/Highlands Ethanol LLC	**HEF, Highlands County**	**71**
FPL	Riviera Plant, PBC	37

The information is from annual operating reports submitted to the Department. The largest stationary sources of air pollution in Highlands County including the future HEF project are small when compared to emissions from industries within some of the nearby counties, including: sugar mills in Hendry and Palm Beach Counties; power plants in Martin and Palm Beach Counties; and several citrus processing plants. They are also small compared with emissions (not shown) from industries in counties to the north such as fertilizer, citrus and power plants in Polk and Osceola Counties.

8.3. Ambient Air Monitoring Surrounding Lake Okeechobee

The Department and the PBC Health Department Local Program operate monitors at seven sites measuring NO_X, SO_2, ozone, PM_{10}, or $PM_{2.5}$ (also called PM_{fine}) in the counties surrounding Lake Okeechobee. The Archbold Biological Station ozone monitor is located in Highlands County. There are PM_{10} and $PM_{2.5}$ monitors in nearby rural Belle Glade, which is the center of the sugar industry. There are ozone and $PM_{2.5}$ monitors in the rural to urban transition area in Royal Palm Beach. The rest are along the east coast in the communities of Riviera Beach, Delray Beach and West Palm Beach (WPB Lantana). Air quality measurements from 2008 at regulatory monitors are summarized in the Table 16 below.

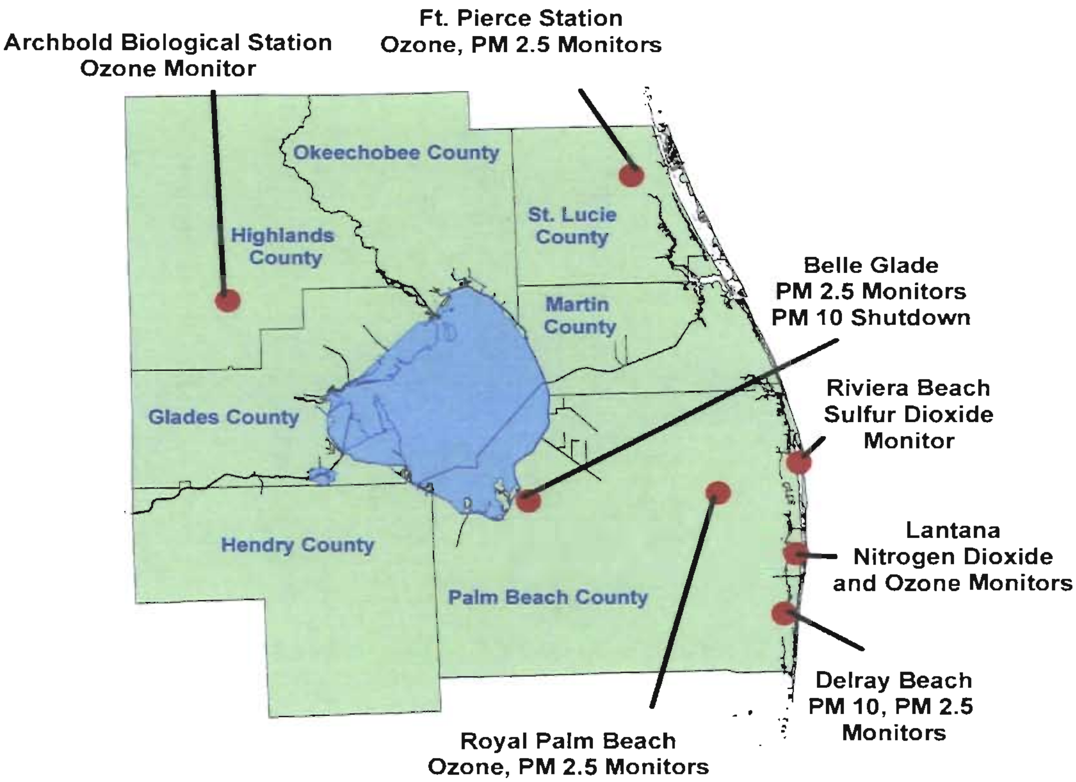

Figure 8 - Air Monitoring Network in Counties Surrounding Lake Okeechobee

8.4. Discussion of Ambient Air Quality in Highlands County - Ozone

On March 27, 2008 the U.S. Environmental Protection Agency (EPA) published a final rule (since vacated) reducing the 8-hour ozone AAQS from 85 to 75 ppb. The average of the annual fourth highest measurements (design value) over the period 2006-2008 is the value that is compared to the stayed ozone AAQS for determining whether an area would have been in attainment. The design values for all counties in Florida are shown in Figure 9 below. For the Highlands monitor, the design value was 73 ppb and Highlands County was in attainment with the since stayed ozone standard.

8.5. Air Quality Impact Analysis

Significant Impact Analysis

SIL are defined for SO_2, CO, PM/PM_{10}, and NO_X. A significant impact analysis (SIA) is performed on each of these pollutants to determine if a project can cause an increase in ground level concentration greater than the SIL for each pollutant.

In order to conduct a SIA, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described below. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SILs for the PSD Class II Area (everywhere except the closest Class I Area, the Everglades National Park).

For the Class II 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 receptor grid consisted of receptors spaced at 25-meter (m) intervals around the facility fence line. The remaining receptors were spaced at 50 m from the property line out to 500 m, 100 m out to 1 km, 200 m out to 2 km, 400 m out to 4 km, 800 m out to 8 km, 1,600 m out to 16 km and 3,200 m out to 32 km from the property line.

Table 16 - Ambient Air Quality Measurements Nearest to the Project Site (2008)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units [a]
PM_{10}	Belle Glade	24-hour	79	49		150 [b]	µg/m^3
		Annual			19	50 [c]	µg/m^3
$PM_{2.5}$	Belle Glade	24-hour	29	20		35 [d]	µg/m^3
		Annual			6	15 [e]	µg/m^3
SO_2	Riviera Beach	3-hour	4	4		500 [f]	ppb
		24-hour	4	4		100 [f]	ppb
		Annual			2	20 [c]	ppb
NO_2	WPB Lantana	Annual			8	53 [c]	ppb
CO	WPB Lantana	1-hour	2	2		35 [f]	ppm
		8-hour	1	1		9 [f]	ppm
Ozone	Highlands Archbold	8-hour	77	77		75 [g]	ppb
		4th highest high			73	75 [g]	ppb

a. Units are in: micrograms per cubic meter (µg/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 24-hour concentrations.
e. Three year average of the weighted annual mean.
f. Not to be exceeded more than once per year.
g. Three year average of the 4th highest daily maximum.

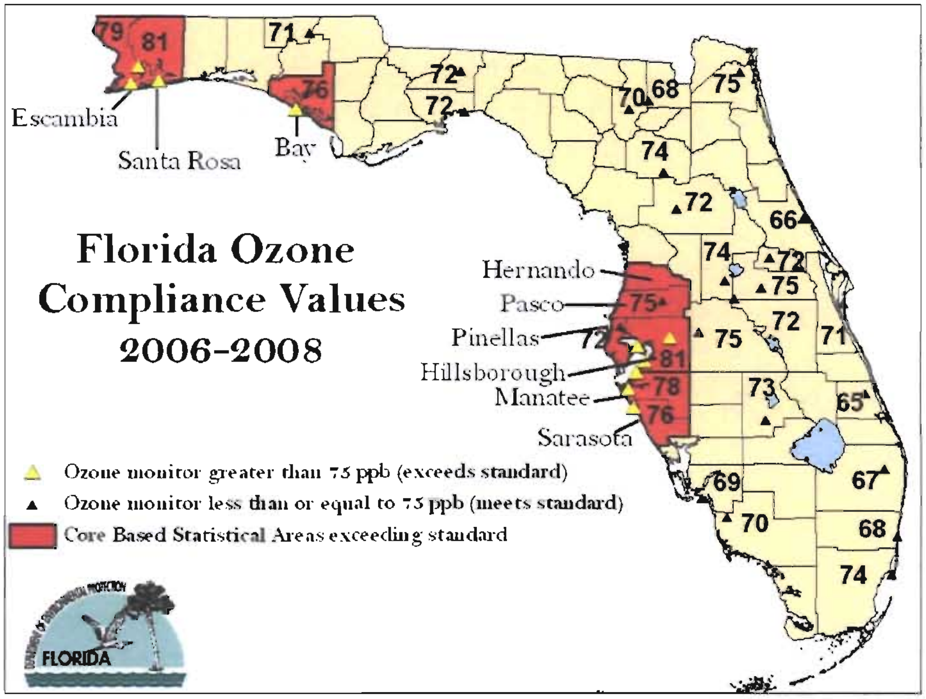

Figure 9. Florida ozone compliance values based on data reported during 2006-2008

If this modeling at worst-load conditions shows ground-level increases less than the SIL, the applicant is exempted from conducting any further modeling. If the modeled concentrations from the project exceed the SIL, 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.

The results of applicant's SO_2, CO, PM/PM_{10} and NO_X air quality SIA for this project are shown below in Table 17. Maximum predicted impacts from all pollutants are greater than the applicable SIL for the Class II area except for CO. These values are tabulated in the table below and compared with existing ambient air quality measurements from the local ambient monitoring network. It is clear that maximum predicted impacts from the project are much less than the respective AAQS.

Table 17 - Maximum Predicted Air Quality Impacts from the HEF for Comparison to the PSD Class II SILs

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	2008 Baseline Concentrations ($\mu g/m^3$)	Ambient Air Standards ($\mu g/m^3$)	Significant Impact?
PM_{10}	Annual	5	1	~20	50	Yes
	24-Hour	23	5	~80	150	Yes
SO_2	Annual	7	1	~5	80	Yes
	24-Hour	43	5	~10	365	Yes
	3-hour	104	25	~10	1300	Yes
NO_2	Annual	4	1	~15	100	Yes
CO	1-hour	138	2,000	~2300	40,000	No
	8-hour	75	500	~1150	10,000	No

For the Class I analysis, 360 receptors were located along a perimeter 50 km away from the property line. While the Everglades National Park (ENP) is 154 km away from the proposed project location, the applicant provided the SIA for 50 km out using Class II SIA (AERMOD) modeling methods to demonstrate that no further Class I analyses should be required based on distance and projected emission rates.

Maximum air quality impacts from the proposed project at a distance of 50 km are summarized in the Table 18. The results of the initial PM/PM_{10}, NO_X and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts are less than the applicable SILs for the Class I area.

Table 18 - Maximum Air Quality Impacts from the Highlands Ethanol Project for Comparison to the PSD Class I SILs

Pollutant	Averaging Time	Max. Predicted Impact at 50 km $\mu g/m^3$)	Class I SIL ($\mu g/m^3$)	Significant Impact?
PM_{10}	Annual	0.004	0.2	No
	24-hour	0.08	0.3	No
NO_2	Annual	0.01	0.1	No
SO_2	Annual	0.005	0.1	No
	24-hour	0.17	0.2	No
	3-hour	0.99	1	No

The National Park Service (NPS) conducted a brief review and advised that it "does not anticipate any significant impacts on resources at the ENP." The NPS did not require any additional modeling or analyses for the proposed project. The conclusion is logical given the distance from the source to the ENP and the low relative and absolute emissions of the source compared with the previously discussed large stationary sources that are more likely to affect the ENP. Additionally, if modeled together (increment expanding and consumptive sources) the overall expansion of increment (improvement) due to regional power plant emissions reductions would overwhelm the small consumption of increment by the HEF. Thus a multisource modeling effort would likely show improvement in air quality.

Notwithstanding the foregoing discussion, for larger projects (such as the FPL Turkey Point Unit 5 or the cancelled Glades coal-fueled project), use of the Class I model CALPUFF is more appropriate.

Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is performed for those pollutants with listed de minimis impact levels. These are levels, which, if exceeded, would require pre-construction ambient monitoring. For this analysis, as was done for the SIA, the applicant used the proposed project's emissions at worst load conditions as inputs to the models. As shown in Table 19 below, the maximum predicted impacts for all pollutants with listed de minimis impact levels were greater than these levels. Therefore, a pre-construction monitoring analysis is required for PM/PM_{10}, and NO_X.

Table 19. Maximum Air Quality Impacts for Comparison to the De Minimis Ambient Impact Levels

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	De Minimis Level ($\mu g/m^3$)	2008 Baseline Concentrations ($\mu g/m^3$)	Impact Greater Than De Minimis?
PM_{10}	24-hour	23	10	~80	Yes
NO_2	Annual	4	14	~15	No
SO_2	24-hour	43	13	~10	Yes
CO	8-hour	75	575	~1150	No

There are no PM_{10} or SO_2 monitors in Highlands County. However, there are particulate monitors on the other side of the lake in Palm Beach County not directly on the coast near larger sources of particulate which are in attainment with the standards. Also, there are monitors located at various sites in Florida near large sources of SO_2. The SO_2 monitor near the FPL Riviera power plant is in attainment with the standards. In 2008, the Riviera facility emitted 2,775 tons of SO_2 compared to the 107 tons expected from the proposed facility. These monitors provide sufficient data to satisfy preconstruction monitoring needs. Given the low emissions from the future predicted Highlands Ethanol operation, preconstruction monitoring at the site would yield little useable information.

Predicted NO_X emissions from the proposed project are above 100 TPY. Therefore, an evaluation for preconstruction monitoring is required for ozone. There is an ozone monitor in Highlands County. This monitor is in attainment with the new ozone standard. The nature of ozone formation from its precursors (NO_X and VOC) and meteorological factors is such that monitoring is focused on regional effects. The single monitor is sufficient to define ozone in Highlands County, whereas some of the coastal counties require more than a single monitor due to differences between shoreline and inland meteorology.

Based on the preceding discussions, the only additional detailed air quality analyses required by the PSD regulations for this project are the following:

- A multi-source AAQS and PSD increment analysis for SO_2, PM_{10} and NO_2 in the Class II area; and
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Models and Meteorological Data Used in the Foregoing Air Quality Analysis

PSD Class II Area: The AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. AERMOD was approved by the EPA in November 2005. The AERMOD modeling system incorporates air dispersion based on planetary boundary layer turbulence structure 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. The stacks associated with this project all satisfied the good engineering practice (GEP) stack height criteria.

The AERMET meteorological data used for this analysis consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service at the Palm Beach International Airport and the Miami International Airport respectively. The 5-year period of meteorological data was from 2001 through 2005. A sensitivity analysis was also completed using surface data from the facility site. The meteorological data used were in accordance with the EPA AERMOD Implementation Guide. The modeling results are the highest concentrations from both sets of AERMET meteorological data.

In reviewing this permit application, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification should EPA revise the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators. A more detailed discussion of the required analyses follows.

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. 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 20 below.

Table 20 - 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?
PM_{10}	24-hour	23	30	No
	Annual	5	17	No
NO_2	Annual	8	25	No
SO_2	3-hour	102	512	No
	24-hour	44	91	No
	Annual	9	20	No

The results of the PSD Class II analysis are conservative. Specifically, the inventory of all increment-consuming sources did not include sources that have expanded increment, i.e. shut down or reduced emissions since the baseline date and potential emissions were used as inputs to the model instead of actual emissions. For example, in the previous ten years FPL Martin Power Plant has expanded increment of NO_X and SO_2 by approximately 5,000 and 2,000 TPY respectively.

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. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The maximum predicted annual and maximum predicted high, second high short term average for the AAQS analysis are summarized in Table 21 below. As shown in this table, emissions from the proposed facility are not expected to significantly cause or contribute to a violation of an AAQS.

Table 21 - Ambient Air Quality Impacts

Pollutant	Averaging Time	Major Sources Impact ($\mu g/m^3$)	Background Conc. 2003- 2007 ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Total Impact Greater Than AAQS?	Florida AAQS ($\mu g/m^3$)
PM_{10}	24-hour	23	42	65	No	150
	Annual	5	20	25	No	50
NO_2	Annual	8	19	27	No	100
SO_2	3-hour	102	11	113	No	1300
	24-hour	44	11	55	No	365
	Annual	9	5	14	No	80

8.6. Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife

The Highlands Ethanol proposed project will not contribute to a violation of the PSD Increment or AAQS. Further, the applicant provided a modeling screening analysis using AERMOD to demonstrate that the proposed project will not have an adverse impact on soils and vegetation. According to the applicant, the modeling results show that impacts from SO_2 and NO_2 are much less than the EPA screening levels.

Growth-Related Impacts Due to the Proposed Project

According to the applicant, the proposed project will provide up to 65 new permanent employees and up to 500 short term employees during the eighteen month construction of the facility. The applicant states that this increase in workers will not significantly impact the air quality in the region since this growth is minimal when compared to the population of Highlands County.

Also according to the applicant, there will be an increase in truck traffic during the construction phase of the project. Once in operation, the applicant anticipates approximately 100 trucks per day, along with additional employee vehicles.

Growth-Related Air Quality Impacts since 1977

The population of Highlands County doubled between 1977 and 2008 from approximately 47,000 to 97,000 but remains relatively small. The applicant provided aerial photos of the area surrounding the proposed facility. Upon review of the historical topographic maps, the applicant determined that the immediate area has remained unchanged since the 1970s and agricultural in nature. With regards to utilities in Highlands County, the small Progress Energy Avon Park Power Plant has been operating since the 1950s and small TECO Phillips Power Plant has been operating since the early 1980s. Highlands County ozone monitoring was initiated in 2001 and has been in attainment throughout its history.

9. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the Draft permit. David Read is the project engineer responsible for reviewing the application and drafting the permit changes. He may be contacted at 850/414-7268 and at david.read@dep.state.fl.us . Debbie Nelson is the meteorologist responsible for reviewing and approving the ambient air quality analyses. She may be contacted at 850/921-9537 and at deborah.nelson@dep.state.fl.us .

DRAFT PERMIT

PERMITTEE

Highlands Ethanol, LLC
55 Cambridge Parkway, 8th Floor
Cambridge, Massachusetts 02142

Authorized Representative:
Mr. Charles F. Davis III, Senior Vice President

Air Permit No. 0550061-001-AC
Expires: December 31, 2012
PSD-FL-406
Highlands Ethanol Facility
Facility ID No. 0550061
Cellulosic Ethanol Production

PROJECT

This is the final air construction permit, which authorizes construction of a cellulosic ethanol production facility using feedstocks of dedicated energy crops, such as energy cane and forage sorghum at the new Highlands Ethanol Facility (HEF), which is an organic chemicals plant categorized under Standard Industrial Classification No. 2869. The new facility will be located in Highlands County north of State Road 70, approximately 1.7 miles east, northeast of Brighton, Florida. The UTM coordinates are Zone 17; 493.2 km East and 3,013.2 km North.

This final permit is organized into the following sections: Section 1 (General Information); Section 2 (Administrative Requirements); Section 3 (Emissions Unit Specific Conditions); and, Section 4 (Appendices). Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations, which are defined in Appendix CF of Section 4 of this permit. As noted in the Final Determination provided with this final permit, only minor changes and clarifications were made to the draft permit.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of: Chapter 403 of the Florida Statutes (F.S.) and Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.). The permittee is authorized to conduct the proposed work in accordance with the conditions of this permit. This project is subject to the general preconstruction review requirements in Rule 62-212.300, F.A.C. and the preconstruction review requirements for major stationary sources in Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality, including a determination of Best Available Control Technology (BACT).

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

Executed in Tallahassee, Florida

(DRAFT)

Joseph Kahn, Director (Date)
Division of Air Resource Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Final Air Permit package (including the Final Determination and Final Permit with Appendices) was sent by electronic mail, or a link to these documents made available electronically on a publicly accessible server, with received receipt requested before the close of business on ______________________________ to the persons listed below.

Charles F. Davis III, Highlands Ethanol, LLC: chuck.davis@verenium.com
Tim Eves, Verenium Corporation: tim.eves@verenium.com
Joseph Vaccaro, P.E., AMEC: joe.vaccaro@amec.com
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Heather Abrams, EPA Region 4: abrams.heather@epa.gov
Chair, Highlands County Board of County Commissioners: bstewart@hcbcc.org
Mitchell Cypress, Chairman, Tribal Council, Seminole Tribe of Florida: mitchellcypress@semtribe.com
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Jim Shore, General Counsel, Seminole Tribe of Florida: c/o amotlow@semtribe.com
Craig Tepper, Director, ERMD, Seminole Tribe of Florida ctepper@semtribe.com
Vickie Gibson, DEP BAR Reading File: victoria.gibson@dep.state.fl.us

Clerk Stamp

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

______________________________ (Clerk) __________ (Date)

PROPOSED PROJECT

The project is the construction of a cellulosic ethanol production facility called the HEF. The feedstocks for the HEF will be dedicated energy crops, such as energy cane and forage sorghum, grown on adjacent farmland. The cellulose and hemicellulose in the crops will be converted to sugars that will be fermented to produce approximately 39.4 million gallons per year (MGPY) of distilled ethanol which will be blended with gas to yield up to 41.5 MGPY of denatured ethanol product. The denatured ethanol product will consist of 2 to 5 percent (%) of gasoline by volume resulting in a blended product called E98 to E95.

The HEF will generate its own fuel to generate process steam consisting of biomass (stillage cake) from the fermentation and distillation steps and biogas from the on-site wastewater treatment plant (WWTP). Natural gas (NG) will also be used as a supplemental fuel depending on local availability. If NG is unavailable, ultralow sulfur distillate (ULSD) fuel oil (FO) with a maximum sulfur (S) concentration of 0.0015% by weight or propane will be used as the supplemental fuel.

This project will consist of the following emissions units (EU).

Facility ID No. 0550061	
EU ID No.	**Emission Unit Description**
001	Feedstock delivery, handling and preparation
002	Hydrolysis of cellulose, liquid/solids separation, neutralization
003	Hydrolysis of hemicellulose, fermentation, distillation and bacteria/enzyme propagation
004	Solids (stillage and gypsum) separation, dewatering and loadout
005	Denaturing and product storage
006	Product loadout and flare
007	Wastewater treatment plant (WWTP), biogas conditioning and flare
008	Fluidized bed combustion biomass-fueled boiler
009	Fluidized bed combustion biomass-fueled boiler
010	Backup fossil-fueled boiler primarily fueled by natural gas, propane or ULSD fuel oil
011	Cooling tower
012	Miscellaneous storage silos
013	Miscellaneous storage tanks
014	Four emergency generators
015	Emergency fire pump engine
016	Facility-wide VOC fugitive equipment leaks

FACILITY REGULATORY CLASSIFICATION

- The facility is not a major source of hazardous air pollutants (HAP).
- The facility does not operate units subject to the acid rain provisions of the Clean Air Act (CAA).
- 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 (PSD), 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.

1. Permitting Authority: The Permitting Authority for this project is the Bureau of Air Regulation in the Division of Air Resource Management of the Department. The mailing address for the Bureau of Air Regulation is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. All documents related to applications for permits to operate an emissions unit shall be submitted to the Air Resource Section of the Department's South District Office at: 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33901-3881.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resource Section of the Department's South District Office at: 2295 Victoria Avenue, Suite 364, Fort Myers, Florida 33901-3881.

3. Appendices: The following Appendices are attached as a part of this permit and must be complied with by the permittee:
   a. Appendix ASME: American Society of Mechanical Engineers (ASME) Form for Abbreviated Efficiency Test;
   b. Appendix BMP: Best Management Practices;
   c. Appendix CC: Common Conditions;
   d. Appendix CEMS: Continuous Emissions Monitoring System (CEMS) Requirements;
   e. Appendix CF: Citation Formats and Glossary of Common Terms;
   f. Appendix CTR: Common Testing Requirements;
   g. Appendix Db: NSPS, Subpart Db – Standards of Performance Small Industrial-Commercial-Institutional Steam Generating Units;
   h. Appendix GC: General Conditions;
   i. Appendix-GP: Identification of General Provisions, Subpart A from NSPS 40 CFR 60 and Subpart A from NESHAP 40 CFR 63;
   j. Appendix IIII: NSPS, Subpart IIII - Stationary Compression Ignition Internal Combustion Engines;
   k. Appendix Kb: NSPS, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels;
   l. Appendix LDAR: Preliminary Leak Detection and Repair (LDAR) Program;
   m. Appendix VVa: NSPS, Subpart VVa – Standards of Performance for Equipment Leaks of VOC in the SOCMI and,
   n. Appendix ZZZZ: NESHAP, Subpart ZZZZ - Stationary Reciprocating Internal Combustion Engines (RICE).

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

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

6. Modifications: No emissions unit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

7. Source Obligation:

   (a) Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit.

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

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

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

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

9. Unconfined Emissions of Particulate Matter: No person shall cause, let, permit, suffer or allow the emissions of unconfined particulate matter from any activity, including vehicular movement; transportation of materials; construction, alteration, demolition or wrecking; or industrially related activities such as loading, unloading, storing or handling; without taking reasonable precautions to prevent such emissions. Any permit issued to a facility with emissions of unconfined particulate matter shall specify the reasonable precautions to be taken by that facility to control the emissions of unconfined particulate matter. Reasonable precautions include the following: a) Paving and maintenance of roads, parking areas and yards; b) Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing; c) Application of asphalt, water, oil, chemicals or other dust suppressants to unpaved roads, yards, open stock piles and similar activities; d) 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 particulate from becoming airborne; e) Landscaping or planting of vegetation; f) Use of hoods, fans, filters, and similar equipment to contain, capture and/or

vent particulate matter; g) Confining abrasive blasting where possible; and, h.) Enclosure or covering of conveyor systems. In determining what constitutes reasonable precautions for a particular facility, the Department shall consider the cost of the control technique or work practice, the environmental impacts of the technique or practice, and the degree of reduction of emissions expected from a particular technique or practice. [Rule 62-296.320(4)(c), F.A.C.]

10. Excess Emissions: Except as required by specific conditions of this permit dealing with excess emissions with regard to individual emission units, the following conditions apply to excess emissions at HEF.
    a. Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
    b. Malfunction: Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.
    c. Department Discretion: Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest.
    d. Department Notification: In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.

    [Rule 62-210.700, F.A.C.]
11. NSPS, Subpart VVa: Emission units associated with the HEF project that can leak volatile organic compounds (VOC) are subject to NSPS Subpart VVa – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry. A requirement of Subpart VVa is the development of a leak detection and repair (LDAR) program. A preliminary LDAR program plan is included as Appendix LDAR in Section IV of this permit. The permittee is required to submit a final LDAR program plan to the Compliance Authority for approval no later than June 30, 2010. The HEF must come into compliance with NSPS, Subpart VVA no later than 180 days after the initial startup of the HEF facility.
    [NSPS, Subpart VVa and Rule 62-4.070, F.A.C. Reasonable Assurance]
12. Equipment Subject to NSPS, Subpart VVa: Equipment such as pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves, line valves and flanges or other connectors in VOC service and any devices or systems subject to NSPS, Subpart VVa and the associated emissions unit must be identified with a listed submitted to the Compliance Authority no later than June 30, 2010. [Rule 62-4.070, F.A.C. Reasonable Assurance]
13. Objectionable Odors Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor. The permittee shall submit an odor control plan (OCP) to the Compliance Authority by June 30, 2010 that addresses the procedures and practices that will be used to control facility wide fugitive odors at HEF including stillage cake storage and disposal (if necessary). In addition, the OCP shall also include provisions for storing, disposing of or recycling off-specification enzymes and bacteria that could otherwise contribute to objectionable odors
    [Rule 62-296.320(2), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]
    {Permitting Note: 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.}

14. Open Burning Prohibited: No person shall ignite, cause to be ignited, or permit to be ignited, any material which will result in any prohibited open burning as regulated by chapter 62-256, F.A.C.; nor shall any person suffer, allow, conduct or maintain any prohibited open burning.
[Rule 62-256.300, F.A.C.]

15. General Visible Emissions Standard:

    a. No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity).

    b. Notwithstanding subparagraph 62-296.320(4)(b)1., F.A.C., above, the owner or operator of an emissions unit subject to the general visible emission standard may request the Department to establish a higher visible emissions standard for that emissions unit. The owner or operator may request that a visible emissions standard be established at that level at which the emissions unit will be able, as indicated by compliance tests, to meet the opacity standard at all times during which the emissions unit is meeting the applicable particulate matter standard. The Department shall establish such a standard, through the permitting process, if it finds that:

        (i.) The emissions unit was in compliance with the applicable particulate emission standard while a compliance test was being conducted but failed to comply with the general visible emissions standard during the test;

        (ii.) The emissions unit and associated air pollution control equipment were operated and maintained in a manner to minimize the opacity emissions during the compliance test; and

        (iii.) The emissions unit and associated air pollution control equipment were incapable of being adjusted or operated in such a manner as to meet the opacity standard.

        (iv.) If the presence of uncombined water is the only reason for failure to meet visible emission standards given in this rule, such failure shall not be a violation of this rule.

    [Rule 62-296.320(4)(b) F.A.C, General Visible Emissions Standard]

A. Biomass Delivery, Handling and Preparation (EU-001)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
001	Biomass delivery, handling and preparation: • Ethanol process biomass: Freshly harvested energy cane and forage sorghum from adjacent farmland is delivered by trucks equipped with a tipper for unloading material. The feedstock is offloaded to a live bottom bin. The live bottom bin transfers the feedstock to conveyers, through several washing steps and a screw press prior to the hydrolysis step. • Supplemental boiler fuel biomass: Prepared (sized and partially dried) tree wood chips, bagasse or energy crop material are delivered to the plant site in conventional tractor-trailer units or self-unloading trailers with live floors. The trailers are unloaded to the ground using a hydraulic operated trailer dump platform and moved using mobile equipment to small storage piles. When required, the material is reclaimed using a mobile wheel loader, and placed onto the live reclaim area from where it is conveyed to a scalping screen or shaker screen and then transported to the boiler feed bin and fed into the biomass boilers to supplement stillage from the fermentation step.

EQUIPMENT

1. Biomass for the Ethanol Process: The permittee is authorized to install the following major pieces of equipment for the delivery, handling and processing of the of the energy cane and forage sorghum used in the ethanol production process:
   - Trailer tipper;
   - Covered rake conveyor;
   - Live bottom bin;
   - Covered transfer conveyors;
   - Scalping screen;
   - Biomass distribution chest;
   - Wash beater;
   - Drainage screw;
   - Screw press;
   - Covered hydrolyser feed conveyor; and,
   - Dust collectors at the drop and transfer points of the primary biomass Delivery, Handling and Preparation System to control fugitive emissions.

   [Application No. 0550061-001-AC and Rule 62-4.070, F.A.C. Reasonable Assurance]

2. Supplemental Biomass Fuel: The permittee is authorized to install the following major pieces of equipment for the delivery, handling and processing of the supplemental biomass fuel for the biomass boilers:
   - Three storage piles west of the ethanol production area for the storage of whole tree chips, bagasse and energy crops;
   - A hydraulic truck dumper adjacent to the storage piles;
   - Covered conveyors to move the supplemental biomass from the reclaim area to the scalping screen;

- A scalping screen to remove oversized biomass material;
- Covered conveyors to move the supplemental biomass from the scalping screen to the fuel feed bin;
- A fuel feed bin and covered conveyors to move the supplemental biomass from the fuel feed bin to the biomass boilers; and,
- Dust collectors at the drop and transfer points of the supplemental biomass Delivery, Handling and Preparation System to control fugitive emissions.

[Application No. 0550061-001-AC and Rule 62-4.070, F.A.C. Reasonable Assurance]

3. Air Pollution Control Equipment: To minimize fugitive particulate matter (PM, $PM_{10}/PM_{2.5}$) henceforth called PM, biomass conveyors shall be enclosed. Dust collectors shall be installed on the conveyor transfer and drop points. The dust collectors shall be designed to obtain an outlet PM loading of 0.005 grains per dry standard cubic foot (DSCF).
[Rule 62-212.400 (BACT), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

PERFORMANCE RESTRICTIONS

4. Roadways: The feedstock roadway loop and plant roadways shall be paved and during dry conditions wetted sufficiently to maintain surface moisture to minimize fugitive dust emissions. Roadways shall be sweep weekly with a vacuum sweeper in good working order to prevent the buildup of dirt and silt on the roadway surfaces. A record of the sweeping shall be kept and made available to the Compliance Authority upon request.
[Application No. 0550061-001-AC; Rule 62-212.400 (BACT), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

5. Gravel Areas: The infield within feedstock roadway loop, the supplemental biomass storage area and other areas of the HEF will have gravel surfaces. To minimize fugitive dust emissions during dry conditions the gravel areas shall be wetted sufficiently to maintain surface moisture.
[Application No. 0550061-001-AC; Rule 62-212.400 (BACT), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

6. Primary Biomass Storage: To control odor, primary biomass shall be delivered to the facility on a just in time basis. Consequently, no primary biomass shall be stored on site. Trucks shall only deliver primary biomass to HEF between 6:00 am to 6:00 pm. Some of the trucks will be parked on the feedstock roadway gravel infield to provide biomass to the ethanol process during the times when trucks are not allowed to deliver biomass to HEF (6:00 pm to 6:00 am).
[Application No. 0550061-001-AC; Rule 62-212.400 (BACT), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

7. Supplemental Biomass Storage: Supplemental biomass consisting of whole tree chips, bagasse and energy crops will be stored on site in three piles located in a small area to the west of the ethanol production area and processed mainly using mobile equipment such as front-end loaders. Each pile will have a foot print of approximately 200 by 100 feet and a height of approximately 20 feet for a volume of roughly 400,000 cubic feet (ft^3). Supplemental biomass shall be used on a first in first out (FIFO) basis to control odors and minimize the chance of spontaneous combustion
[Application No. 0550061-001-AC; Rule 62-212.400 (BACT), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

8. Authorized Biomass: Biomass authorized to be used at the HEF consist of energy cane and forage sorghum for the ethanol process and whole wood chips, bagasse and energy crops for the supplemental fuel for the biomass boilers. Appendix BCP defines the types of biomass that shall be used at the HEF in the ethanol process and as supplemental boiler fuel as well as quality assurance

(Q&A) procedures to ensure the biomass used meets the requirements specified in this permit. [Application No. 0550061-001-AC and Rule 62-4.070, F.A.C. Reasonable Assurance]

9. Restricted Operation: The hours of operation of this emission unit are not limited (8,760 hours per year). [Application No. 0550061-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

10. Visible Emission (VE) Standard: As determined by EPA Method 9, there shall be no VE greater than 5% opacity at drop points, transfer points and dust collector outlets.
[Rule 62-212.400(5)(c), F.A.C.].

11. PM Standard: PM emissions from dust collectors shall not exceed 0.005 grains per dry standard cubic foot (gr/dscf).
[Rules 62-4.070(3); 62-210.200(PTE), F.A.C., and Rule 62-4.070, F.A.C. Reasonable Assurance]

12. Baghouse PM Standard by Opacity Measurement: A visible emission reading of 5% opacity or less may be used to demonstrate compliance with the PM emission standard in **Condition 14** above. A visible emission reading greater than 5% opacity will require the permittee to perform a PM emissions stack test within 60 days to show compliance with the PM standard.
[Application No. 0470016-020-AC; Rules 62-296.603; 62-296.712, F.A.C.; and 40 CFR 60.122(a)(2) and Rule 62-4.070, F.A.C. Reasonable Assurance]

13. Best Management Practices (BMP): A control plan to control PM emissions from biomass delivery, handling and preparation is given in Appendix BMP and shall be followed at all times by the permittee. This plan also addresses measures to minimize the chance of the spontaneous combustion of supplemental biomass storage piles and quality assurance measures for biomass delivered from vendors to the HEF. An example of the procedures to control fugitive PM emission is the wetting of roads and gravel areas during dry periods. As the engineering details of the Biomass Delivery, Handling and Preparation emissions unit becomes finalized, the permittee shall submit an updated BMP plan to the compliance authority by June 30, 2010.
[Rule 62-212.400 (BACT), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

{Permitting Note: PM emissions from the roadways and grounds during operation of the HEF are estimated to be 9.0 and 1.0 tons in any consecutive twelve month period. According to the permittee, no PM emissions will result from biomass delivery, handling and preparation due to the high moisture content of the biomass.} [Application No. 0550061-001-AC]

TESTING AND MONITORING REQUIREMENTS

14. Initial Compliance Tests: The drop points, transfer points and dust collector outlets of the emissions unit shall be tested to demonstrate initial compliance with the emissions standards for opacity given in **Condition 13** above. The initial tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial operation of the unit.
[Rules 62-4.070(3) and 62-297.310(7)(a)1, F.A.C.]

15. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the drop points, transfer points and dust collector outlets of the emissions unit shall be tested to demonstrate compliance with the emissions standards for opacity given in **Condition 13** above.
[Rule 62-297.310(7)(a)4, F.A.C.]

16. Dust Collectors PM Compliance Tests: The initial and annual VE tests in **Conditions 17 and 18** above with regard to the dust collectors shall serve as a surrogate for the PM emissions tests. If the VE emissions standard in **Condition 13** above is not met for the dust collectors, a PM test utilizing EPA Method 5 must be conducted on dust collector stack to show compliance with the PM emissions

standard in **Condition 14** above within 60 days. [Rule 62-297.620(4), F.A.C.]

17. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

18. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
5	Determination of Particulate Emissions. The minimum sample volume shall be 30 dry standard cubic feet.
9	Visual Determination of the Opacity of Emissions from Stationary Sources. The duration of each test shall be 60 minutes.

The above method is described in Appendix A of 40 CFR 60 included as Appendix A of this permit and are adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department.
[Rules 62-204.800 and 62-297.100, F.A.C.; and Appendix A of 40 CFR 60]

RECORDS AND REPORTS

19. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit. For each test run, the report shall also indicate the operating rate. [Rule 62-297.310(8), F.A.C.]

20. Notification, Recordkeeping and Reporting Requirements: The permittee shall maintain records of the amount of biomass feedstock (primary and supplemental) delivered, handled and processed on a daily, monthly and 12 month rolling average basis. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3), F.A.C.]

B. Hydrolysis of Cellulose, Liquid/Solid Separation and Neutralization (EU-002)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
002	Hydrolysis of Cellulose, Liquid/Solid Separation and Neutralization: • Hydrolysis: Steam and a dilute acid solution hydrolyze the hemicellulose fraction of the biomass feedstock to produce a slurry containing cellulose/lignin solids mixed with a liquid fraction containing a variety of sugars. • Liquid/solid separation: The liquid sugars are separated from the fiber solids through mechanical de-watering in a series of screw presses then washed with fresh, recycled, water and sent to filtrate tanks. • Neutralization: The liquid sugars are neutralized with lime in a neutralization tank.

The hydrolyzer system will operate under pressure and will not produce air emissions. The system is equipped with pressure safety valves (PSV), which in turn are ultimately vented to a wet scrubber.

Acid hydrolyzed biomass will be separated into liquid and solid fractions in a 3-stage series of screw presses. An enclosed tank is located at the feed side of each screw press stage (for a total of three feed tanks) and another enclosed tank is located at the filtrate discharge of each screw press stage (for a total of three filtrate tanks). The process will operate at a temperature of approximately 85 to 90 degrees centigrade (°C). The water fraction entering the process will contain trace amounts of dissolved soluble organics that have the potential to volatilize from the water surfaces inside each of the six tanks. Emissions from the liquid/solid separation system_are VOC emissions which will be controlled by a wet scrubber.

EQUIPMENT

1. Hydrolyzer System: The permittee is authorized to construct a hydrolyzer system that will utilize steam and an acid solution to hydrolyze the hemicellulose fraction of the biomass feedstock to generate a slurry that will be separated into liquid and solid streams. [Application No. 0550061-001-AC]
2. Liquid/Solid Separation System: The permittee is authorized to construct the following major components of a acid hydrolyzed biomass liquid/solid separation system:
   a. Three (3) feed tanks;
   b. Three (3) filtrate tanks; and,
   c. Six (6) individual screw presses for a total of three feed to filtrate screw press stages.

   Application No. 0550061-001-AC]
3. Air Pollution Control Equipment: The permittee shall install a wet scrubber to control VOC emissions from the liquid/solid separation system. The wet scrubber shall have a design control efficiency of 98 percent. Emissions from the wet scrubber shall discharge through a stack approximately 20 feet high at a design exit temperature of 77 degrees Fahrenheit (°F).
   [Application No. 0550061-001-AC; Rule 62-212.400 (BACT), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

PERFORMANCE RESTRICTIONS

4. Permitted Capacity: The maximum permitted capacity of the hydrolyzer and liquid/solid separation systems is 3,247 gallons per minute (GPM) of hydrolyzed biomass. The maximum ethanol production rate is 14.8 TPH and in any consecutive twelve month period 129,298 tons which is the equivalent to an ethanol production rate 39.4 MGPY which when blended with gas will equal up to 41.5 MGPY of denatured ethanol product.
   [Application No. 0550061-001-AC; Rule 62-212.400 (BACT), F.A.C.; Rule 62-4.070, F.A.C. Reasonable Assurance and Rule 62-210.200(PTE), F.A.C.]

5. Hours of Operation: The hours of operation of hydrolyzer and liquid/solid separation systems are not limited (8,760 hours per year). [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

6. VOC Standard: The liquid/solid separation system shall not discharge VOC through the wet scrubber stack in excess of 0.6 pounds per hour (lbs/hr) and 0.106 pounds per 1000 gallons of ethanol produced. [Application No. 0550061-001-AC; Rule 62-212.400 (BACT), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

TESTING REQUIREMENTS

7. Initial Compliance Tests: The emissions units' scrubber stack shall be tested to demonstrate initial compliance with the emissions standards for VOC given in **Condition 6** above utilizing EPA Method 25A. The initial tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial operation of the unit. [Rules 62-4.070(3) and 62-297.310(7)(a)1, F.A.C.]
8. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the emissions units' scrubber stack shall be tested to demonstrate compliance with the emissions standards in **Condition 6** above for VOC utilizing EPA Method 25A. [Rule 62-297.310(7)(a)4, F.A.C.]
9. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]
10. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
25A	Method for Determining Gaseous Organic Concentrations (Flame Ionization)

The above methods are described in Appendix A of 40 CFR 60 and are adopted by reference in Rule 62-204.800, F.A.C. No other method may be used unless prior written approval is received from the Department. [Rules 62-204.800 and 62-297.100, F.A.C.; and Appendix A of 40 CFR 60]

MONITORING REQUIREMENTS

11. Wet Scrubber Monitoring Requirements:
    a. Scrubber Operating Parameters: The permittee shall install, calibrate, operate and maintain monitoring devices that continuously measure and record the total pressure drop across the scrubber. If the total pressure drop cannot be measured for the scrubber, then the liquid flow rate and the fan amps shall be measured and recorded for the scrubber. Accuracy of the monitoring devices shall be ± 5% over the operating range.
    b. Scrubber Guarantee: Prior to installation of the scrubber, the permittee shall submit to the Compliance Authority the proposed design information along with a manufacturer's guarantee that the scrubber is capable of meeting the emission limitations established by the VOC BACT determination.

    [Rule 624.070(3), F.A.C.; Rule 62-297.310 and Rule 62-212.400, F.A.C.]

RECORDS AND REPORTS

12. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(8), F.A.C.]

13. Notification, Recordkeeping and Reporting Requirements: The permittee shall maintain records of the amount of biomass feedstock and acid solution used in the hydrolyzer system, the hydrolyzed biomass fed to the liquid/solid separation systems and the amount of ethanol produced on an hourly, monthly and a 12 month average rolling basis. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3), F.A.C.]

C. Fermentation, Distillation and Propagation (EU-003)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
003	Fermentation, distillation and bacteria/enzyme propagation: This emission unit is where the cellulose in the solids stream will be converted to liquid glucose sugars by a proprietary enzyme.

The pentose and glucose sugars will be separately fermented in batch mode to produce dilute ethanol beer. 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 vapors from the two beer strippers will be passed to a stripper/rectifier for further distillation and then a molecular sieve system to remove the remaining water from the product.

EQUIPMENT

1. Fermentation and Propagation System: The permittee is authorized to construct the following major components of a fermentation and propagation system:
   a. Four (4) hemicellulosic fermentation tanks;
   b. Four (4) cellulosic fermentation tanks;
   c. Three (3) hemicellulosic seed propagators;
   d. Three (3) cellulosic enzyme propagators; and,
   e. Three (3) cellulosic seed propagators.
2. Distillation System: The permittee is authorized to construct the following major components of a distillation system:
   a. Two beer strippers;
   b. One stripper/rectifier; and,
   c. One molecular sieve dehydration system.
3. Air Pollution Control Equipment: The permittee shall install a wet scrubber to control VOC emissions from the fermentation and propagation and distillation systems. The wet scrubber shall have a design control efficiency of 98 percent. Emissions from the wet scrubber shall discharge through a stack approximately 24.5 feet high at a design exit temperature of 77 °F.
   [Application No. 0550061-001-AC; Rule 62-212.400 (BACT), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

PERFORMANCE RESTRICTIONS

4. Permitted Capacity: The maximum permitted feed rate into the fermentation, propagation and distillation systems is 14.8 TPH and 129,298 tons in any consecutive twelve month period which is the equivalent to an ethanol production rate 39.42 million gallons.
   [Application No. 0550061-001-AC; Rule 62-212.400 (BACT), F.A.C.; Rule 62-4.070, F.A.C. Reasonable Assurance and Rule 62-210.200(PTE), F.A.C.]
5. Hours of Operation: The hours of operation of the fermentation, propagation and distillation systems are not limited (8,760 hours per year). [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

6. VOC Standard: The fermentation, propagation and distillation systems shall not discharge VOC through the wet scrubber stack in excess of 5.1 lbs/hr and 0.954 pounds per 1000 gallons of ethanol produced.
   [Application No. 0550061-001-AC; Rule 62-212.400 (BACT), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

TESTING REQUIREMENTS

7. Initial Compliance Tests: The emissions unit stack shall be tested to demonstrate initial compliance with the emissions standard for VOC given in **Condition 6** above. The initial tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial operation of the unit. [Rules 62-4.070(3) and 62-297.310(7)(a)1, F.A.C.]
8. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the emissions unit stack shall be tested to demonstrate compliance with the emissions standard for VOC given in **Condition 6** above. [Rule 62-297.310(7)(a)4, F.A.C.]
9. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]
10. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
25A	Method for Determining Gaseous Organic Concentrations (Flame Ionization)

The above methods are described in Appendix A of 40 CFR 60 and are adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800 and 62-297.100, F.A.C.; and Appendix A of 40 CFR 60]

MONITORING REQUIREMENTS

11. Wet Scrubber Monitoring Requirements:
    a. Scrubber Operating Parameters: The permittee shall install, calibrate, operate and maintain monitoring devices that continuously measure and record the total pressure drop across the scrubber. If the total pressure drop cannot be measured for the scrubber, then the liquid flow rate and the fan amps shall be measured and recorded for the scrubber. Accuracy of the monitoring devices shall be ± 5% over the operating range.
    b. Scrubber Guarantee: Prior to installation of the scrubber, the permittee shall submit to the Compliance Authority the proposed design information along with a manufacturer's guarantee that the scrubber is capable of meeting the emission limitations established by the VOC BACT determination.

    [Rule 624.070(3), F.A.C.; Rule 62-297.310 and Rule 62-212.400, F.A.C.]

RECORDS AND REPORTS

12. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(8), F.A.C.]
13. Notification, Recordkeeping and Reporting Requirements: The permittee shall maintain records of the amount of ethanol produced on an hourly, monthly and 12 month rolling average basis along with the feed rate into the fermentation, distillation and propagation systems on an hourly, monthly basis and 12 month rolling average basis. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3), F.A.C.]

D. Stillage Loadout (EU-004)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
004	Solids (stillage and gypsum) separation, dewatering and loadout: • Stillage: The lignin-rich biomass residue (stillage cake) is removed from the bottom of the cellulosic beer stripper, dewatered, and conveyed to the biomass boilers. • Gypsum: Gypsum residue is removed from the bottom of the hemicellulosic beer stripper, dewatered, and conveyed to the biomass boilers. • Centrate: The water fraction from the stillage and gypsum separation steps is conveyed to the WWTP.

Stillage cake will be removed from the bottom of the cellulosic beer stripper in the distillation system, dewatered to remove some of the water fraction, and conveyed to the biomass boilers. Stillage will be generated at a rate of 25 dry TPH with a moisture content of between 35 and 60 percent. Handling will be performed entirely within a closed system except for the conveyor.

EQUIPMENT

1. Stillage Loadout System: The permittee is authorized to construct a stillage loadout system, including a conveyor to take the stillage to the biomass boilers. Handling of the stillage will be entirely within a closed system except for the conveyor which will be covered. [Application No. 0550061-001-AC]

PERFORMANCE RESTRICTIONS

2. Permitted Capacity: The maximum permitted capacity of the stillage loadout systems is 25 TPH of stillage with a maximum of 219,000 tons in any consecutive twelve month period.
[Application No. 0550061-001-AC; Rule 62-4.070, F.A.C. Reasonable Assurance and Rule 62-210.200(PTE), F.A.C.]

3. Restricted Operation: The hours of operation of the stillage loadout system is not limited (8,760 hours per year). [Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

4. Temporary Stillage Storage: If the wet stillage cake cannot be immediately combusted in the BFB biomass boilers it can be temporarily stored on site for no more than 3 days (72 hours) before is must be removed from the site and disposed of. A as part of the OCP, stillage storage and disposal procedures must be submitted to the Compliance Authority no later than June 30, 2010. These procedures must address at a minimum the design of the stillage storage area and how leaching into the ground will be prevented, the procedures that will be used to prevent objectionable odors from the stillage storage area, plans to prevent fugitive PM and VOC emissions and the method(s) of stillage disposal that will be used including off-site transportation.
[Rule 62-4.070, F.A.C., Reasonable Assurance and Rule 62-296.320(2), F.A.C., Objectionable Odors]

EMISSIONS STANDARDS

5. VOC Emissions: Emissions from the stillage loadout system will consist of fugitive VOC. These emissions are not controlled. To minimize VOC emissions the stillage shall be kept at ambient temperature. According to the permittee, due to the high moisture content of the stillage (35 to 60 percent) fugitive PM emissions should be minimal.
[Application No. 0550061-001-AC and Rule 62-4.070, F.A.C. Reasonable Assurance]
{Permitting Note: The permittee estimates that VOC emissions from the stillage loadout system will be 0.6 lbs/hr and 2.8 TPY}

RECORDS AND REPORTS

6. Notification, Recordkeeping and Reporting Requirements: The permittee shall maintain records of the amount of stillage produced and fed to the biomass boilers on an hourly, monthly and 12 month rolling average basis. The stillage temperature at the entry and exit points of the stillage conveyor shall be measured hourly and recorded. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3), F.A.C.]

E. Product Storage (EU-005)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
005	Product Storage: This emissions unit consists of ethanol and gasoline blending that results in the denatured ethanol final product. The resulting denatured product is stored in tanks.

The purified ethanol and gasoline (denaturant) will be stored in tanks and then blended, resulting in a product that contains approximately 95 to 98 percent ethanol and 5 to 2 percent gasoline by volume with the resulting blended product commonly called E95 to E98. The denatured ethanol product will have dedicated storage tanks. This emission unit consists of six tanks that store volatile organic liquids (VOL). These six tanks will be designed with internal floating roofs to minimize VOC emissions.

EQUIPMENT

1. The permittee is authorized to construction the following tanks for product storage:
   a. Product Shift Tanks: The permittee is authorized to construct two nominal 295,317 gallon ethanol product storage tanks with fixed roofs and internal floating roofs to minimize VOC emissions as per 40 CFR 60.110b(a)(2).
   b. Denatured Ethanol Product Storage Tanks: The permittee is authorized to construct two nominal 61,215 gallon denatured ethanol storage tanks with fixed roofs and internal floating roofs to minimize VOC emissions as per 40 CFR 60.110b(a)(2).
   c. Recycle Denatured Product Storage Tank: The permittee is authorized to construct one nominal 61,215 gallon recycle product storage tank with a fixed roof and a internal floating roof to minimize VOC emissions as per 40 CFR 60.110b(a)(2).
   d. Gasoline (Denaturant) Storage Tank: The permittee is authorized to construct one nominal 28,467 gallon gasoline (denaturant) storage tank with a fixed roof and a internal floating roof to minimize VOC emissions as per 40 CFR 60.110b(a)(2).

   [Application No. 0550061-001-AC]

PERFORMANCE RESTRICTIONS

2. Permitted Capacity: The maximum throughput (process) rate of the product storage emissions unit is 39,420,000 gallons of ethanol. For the E95 blended final product, the throughput of gasoline shall be no more than 2,074,737 gallons with a final product production rate of no more than 41,494,737 gallons of E95 in any consecutive twelve month period. For the E98 blended final product, the throughput of gasoline shall be mo more than 804,490 gallons with a final product production rate of no more than 40,224,420 gallons of E98 in any consecutive twelve month period. Ethanol denatured within the E95 to E98 range shall have the allowable amount of gasoline and final denatured product production rate prorated to the appropriate amount in any consecutive twelve month period.
   [Application No. 0550061-001-AC and Rule 62-4.070, F.A.C. Reasonable Assurance]

3. Hours of Operation: The hours of operation of this emissions unit is not restricted (8,760 hours per year).
   [Application No. 0550061-001-AC and Rule 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

4. VOC Standard: Emissions of VOC from the product storage tanks will be controlled by the proper construction of the tanks per 40 CFR 60.110b(a)(2).
   [Application No. 0550061-001-AC; Rule 62-212.400 (BACT), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

   {Permitting Note: The permittee estimated VOC emission from the product storage tanks to be 0.5 lbs/hr and 1.7 TPY}

NSPS SUBPART KB APPLICABILITY

5. VOL Storage Tanks: The six tanks in the product storage emissions unit at the HEF are subject to NSPS Subpart Kb which applies to any storage tank with a capacity greater than or equal to 10,300 gallons that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984. Five of these tanks have a capacity greater than or equal to 40,000 gallons while the gasoline storage tank has a capacity of 28,467 gallons. All six tanks store a liquid with a maximum true vapor pressure greater than 3.5 kilopascals (kPa). Consequently, all six tanks are subject to the General Provisions (40 CFR 60, Subpart A) and the provisions of NSPS 40 CFR 60, Subpart Kb.

RECORDS AND REPORTS

6. Storage Tank Records: The permittee shall keep readily accessible records showing the dimension of the storage tanks and an analysis showing the capacity of the storage tanks. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of the various liquids for the storage tanks for use in the Annual Operating Report. [Rule 62-4.070(3) F.A.C]

7. NSPS Subpart Kb Reporting and Recordkeeping: The owner or operator of each storage vessel as specified in §60.112b(a) shall keep records and furnish reports as required by paragraphs (a), (b), or (c) of §60.115b Reporting and Recordkeeping Requirements. The owner or operator shall keep copies of all reports and records required by§60.115b, except for the record required by (c)(1), for at least 2 years. The record required by (c)(1) will be kept for the life of the control equipment.

F. Product Loadout (EU-006)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
006	Product Loadout: The denatured blended ethanol product from EU-005 product storage tanks will be loaded out to tanker trucks with displaced vapors sent to a product loadout flare for destruction.

The denatured ethanol product will be loaded onto tank trucks at a rate of no more than 600 gallons per minute (GPM). Vapors displaced from the trucks will be exhausted to a flare. The Product Loadout Flare will have a rated capacity of 9.42 million British thermal units per hour (mmBtu/hr) to control vapors displaced from the tanker trucks during the loading of the denatured ethanol product. Vapors displaced from the trucks will be exhausted to a flare with a design control efficiency of 98 percent.

EQUIPMENT

1. Loading Rack: The permittee is authorized to construct at loading rack that is designed to transfer 600 GPM of denatured ethanol product to tanker trucks.
   [Application No. 0550061-001-AC and 62-210.200(PTE), F.A.C.]
2. Flare System: The permittee is required to construct one flare system with a continuous pilot and combustion chambers to destroy displaced vapors during truck loadout. The flare shall be operated with a flame present at all times. The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.
   [Application No. 0550061-001-AC and 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

3. Approximate Capacities: The flare system is designed to combust vapors displaced from the trucks during the loading of the denatured ethanol product. The trucks are assumed to not to be in dedicated denatured ethanol product service (i.e., some trucks will have returned from delivering gasoline and gasoline vapors will be displaced). The product loadout flare will have a rated capacity of 9.42 mmBtu/hr. NG will be used as the fuel for the pilot which has a rated capacity of 0.18 mmBtu/hr. If NG is not available, propane will be used for the pilot until NG becomes available. [Application No. 0550061-0010-AC and Rule 62-210.200(PTE), F.A.C.]
4. Restricted Operation: The flare shall be operated at all times when truck loading operations are taking place. Only E95 to E98 shall only be loaded into the trucks.
   [Application No. 0550061-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]
5. Hours of Operation: Although the hours of operation of the pilot for the flare system is not limited (8,760 hours per year) the flare itself is limited to 1,153 hours per year.
   [Application No. 0550061-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

6. VE Standard: The flare shall 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. [Rules 62-4.070(3), F.A.C.]

TESTING AND MONITORING REQUIREMENTS

7. VE Compliance Tests: The flare system exhaust shall be tested to demonstrate initial compliance with the VE standard given in **Condition 6** above no later than 180 days after initial operation and during each federal fiscal year (October 1st to September 30th) thereafter. EPA Method 22 VE compliance test(s) shall be used to determine the compliance of the flare with the visible emission requirements. The observation period is 2 hours and shall be used according to Method 22. The flare performance test shall be when ethanol is being loaded into trucks that previously held gasoline. [Rule 62-4.070(3), F.A.C.]

8. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

9. Test Methods: Any required stack tests shall be performed in accordance with the following methods:

Method	Description of Method and Comments
EPA 22	Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares 2 Hour Duration

10. Work Practice: Good combustion practices will be utilized at all times to ensure emissions from the flare system are minimized. Therefore, all operators and supervisors shall be properly trained to operate and ensure maintenance of this system in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods for minimizing excess emissions. The flare pilot shall be operated with a flame present at all times. The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame. [Rules 62-4.070(3) F.A.C.]

RECORDS AND REPORTS

11. Records: The permittee shall record in a written log the duration of each flare event and the reason for flaring. If requested by the Compliance Authority, the permittee shall provide a copy of these records or a summary of these records. [Rule 62-4.070(3), F.A.C.]

12. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(8), F.A.C.]

G. Wastewater Treatment Plant, Biogas Conditioning and Flare (EU-007)

This section of the permit addresses the following emissions units.

ID No.	Emission Unit Description
007	Wastewater treatment plant (WWTP), biogas conditioning and flare: The HEF will include a WWTP to treat process wastewaters and to condition the resulting biogas for use as fuel in the biomass and backup boilers or to flare it when it cannot be used in the boilers. The effluent from the WWTP will be reused. The flow through the system will be approximately 1,640 gallons per minute.

EQUIPMENT

1. WWTP: The permittee is authorized to construct a WWTP consisting of the following major pieces of equipment:
   - Equalization Tank;
   - Primary Clarifier;
   - Anaerobic Reactors;
   - Aeration Basin;
   - Secondary Clarifier; and,
   - Four Sand Filters.

   [Application No. 0550061-001-AC]
2. Flare System: The permittee is required to construct one flare system with a continuous pilot and combustion chambers to combust biogas when the biomass boilers are not operational. The flare shall be operated with a flame present at all times. The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.
   [Application No. 0550061-001-AC and 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

3. Approximate WWTP Flare Capacity: The flare system is designed to combust biogas when the biomass and backup boilers are not operating. The WWTP flare will have a rated capacity of 44.03 mmBtu/hr. Natural gas will be used as fuel for the pilot which has a rated capacity of 0.18 mmBtu/hr. If NG is not available, propane will be used for the pilot until NG becomes available.
   [Application No. 0550061-001-AC and Rule 62-210.200(PTE), F.A.C.]
4. Required Operation: The flare shall be operated at all times when all the biogas generated by the WWTP cannot be combusted in the biomass and backup boilers.
   [Application No. 0550061-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]
5. Hours of Operation: The hours of operation of the WWTP flare system is not limited (8,760 hours per year). [Application No. 0550061-001-AC and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]
6. WWTP Flow Rate: The flow through the WWTP will have a maximum design rate of 1,640 gpm.
   [Application No. 0550061-001-AC]

EMISSIONS STANDARDS

7. VE Standard: The flare shall 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. [Rules 62-4.070(3), F.A.C.]

TESTING AND MONITORING REQUIREMENTS

8. VE Compliance Tests: The WWTP flare system exhaust shall be tested to demonstrate initial compliance with the VE standard given in **Condition 7** above no later than 180 days after initial operation and during each federal fiscal year (October 1st to September 30th) thereafter. EPA Method 22 VE compliance test(s) shall be used to determine the compliance of the flare with the visible emission requirements. The observation period is 2 hours and shall be used according to Method 22. The flare performance test shall be when ethanol is being loaded into trucks that previously held gasoline. [Rule 62-4.070(3), F.A.C.]
9. Test Requirements: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]
10. Test Methods: Any required stack tests shall be performed in accordance with the following methods:

Method	Description of Method and Comments
EPA 22	Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares 2 Hour Duration

11. Work Practice: Good combustion practices will be utilized at all times to ensure emissions from the flare system are minimized. Therefore, all operators and supervisors shall be properly trained to operate and ensure maintenance of this system in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods for minimizing excess emissions. The flare pilot shall be operated with a flame present at all times. The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame. [Rules 62-4.070(3) F.A.C.]

RECORDS AND REPORTS

12. Records: The permittee shall record in a written log the duration of each flare event and the reason for flaring. If requested by the Compliance Authority, the permittee shall provide a copy of these records or a summary of these records. [Rule 62-4.070(3), F.A.C.]
13. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(8), F.A.C.]

H. Biomass-Fueled Steam Production (EU-008 and 009)

This section of the permit addresses the following emissions units.

EU ID No. 008 and 009	Emission Unit Description
Description: Each boiler will be a biomass-fueled bubbling fluidized bed (BFB) boiler wherein biomass (solid and gaseous) is combusted within in a bed of hot sand. The heat from the exhaust will be recovered to generate superheated steam to be used in the ethanol production process. *Fuels*: Stillage cake left over from ethanol production and the biogas produced in the anaerobic reactors of the WWTP will be used as fuel in the BFB boilers. In addition, the boilers will be capable of combusting NG for startup and flame stabilization. If pipeline NG is not available when the HEF becomes operational, ULSD FO or propane will be used as a temporary replacement fuel for the natural gas. *Capacity*: The maximum heat input capacity to each boiler is 218 mmBtu per hour (4-hour average) with a design heat input capacity of 198 mmBtu/hr. The steam production capability will be between approximately 100,000 to 125,000 lb/hr. The maximum heat input capacity using fossil fuels to each BFB biomass boiler must be physical constrain to be less than 250 mmBtu/hr so each boiler is not be subject to 40 CFR 60 NSPS, Subpart Da. *Controls*: Efficient combustion of woody biomass in the BFB boilers to minimize formation of PM, NO_X, CO and VOC; use of biomass and clean fossil fuels to minimize HAP formation; use of inherently clean fossil fuels for startup, shutdown and flame (bed) stabilization; Selective Non-Catalytic Reduction (SNCR) with urea injection to destroy NO_X; limestone injection into the BFB boilers to control SO_2 and HCl; and fabric filter baghouses to further control PM and VE, i.e., opacity. *Stack Parameters*: Flue gas from each boiler will discharge to the atmosphere via separate stacks with design heights of 180 feet and diameters of 6 feet. The flue gas exit temperature will be approximately 305 degrees °F with a design volumetric flow rate of 78,905 ACFM. *Continuous emissions and opacity monitoring systems (CEMS, COMS)*: Emissions of CO, NO_X, SO_2, and HCl (one boiler stack) will be monitored and recorded by CEMS. VE (opacity) will be monitored and recorded by COMS on each stack. *Applicability of 40 CFR Subpart Db (NSPS Subpart Db)*: These units are subject to NSPS Subpart Db - Industrial-Commercial-Institutional Steam Generating Units because each has a maximum heat input capacity greater than 100 mmBtu/hr from combusted fuels and is not subject to NSPS Subpart Da because it has a maximum heat input capacity less than 250 mmBtu/hr from combusted fossil fuels. [Application No. 0550061-001-AC]	

{Permitting Note: In accordance with Rule 62-212.400, F.A.C., the Department established permit standards for the biomass-fueled boilers that represent the Best Available Control Technology (BACT) for emissions of NO_X, PM, VOC, SO_2, and CO. The biomass-fueled boilers are subject to the federal New Source Performance Standards (NSPS) in Subpart Db (industrial boilers) of 40 CFR 60, which is adopted by reference in Rule 62-204.800, F.A.C. NSPS Subpart Db for Industrial Boilers is provided in Appendix Db of this permit.}

EQUIPMENT

1. <u>Construction of BFB Biomass-Fueled Boilers</u>: The permittee is authorized to construct two BFB biomass-fueled boilers each with a design heat input rate of 198 mmBtu/hr for steam generation at the HEF. The BFB boilers will include a fluidizing air supply, fossil fuel startup and stabilization burners, overfire air ports, steam drum, superheater, economizer, air heater, ash hoppers, ducts, fuel feeding equipment, air-

cooled condensing unit, air pollution control equipment and other associated equipment. [Application No. 0550061-001-AC]

2. ULSD FO Storage Tank: The permittee is authorized to construct an ULSD FO fixed roof storage tank with a capacity equal to or less than 110,000 gallons. The tank vent will be equipped with an end-line-vacuum breather pressure/vacuum vent valve. The tank will be contained in a concrete dike for spill containment. [Application No. 0550061-001-AC]

   {Permitting Note: The ULSD FO storage tank at HEF is not subject to NSPS Subpart Kb because it is larger or equal to 40,000 gallons (151 cubic meters) and stores a liquid (ULSD FO) with a maximum true vapor pressure less than 3.5 kPa (0.51 pounds per square inch (psi)). Accordingly it is and unregulated emissions unit.}

   [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]

3. Air Pollution Control Equipment: To comply with the emission standards of this permit, the permittee shall install the following air pollution control equipment on each BFB biomass boiler.

   a. Baghouse: The permittee shall design, install, operate and maintain a baghouse to remove PM from the flue gas exhaust and achieve the PM standards specified in this subsection. The baghouse shall have a design control efficiency greater than 99%. The baghouse shall be on line and functioning properly whenever the boiler is in operation.

   b. SNCR System: The permittee shall design, install, operate, and maintain a urea-based SNCR system to reduce NO_X emissions in the flue gas exhaust and achieve the NO_X emissions standards specified in this subsection. The SNCR shall be on line and functioning properly whenever the boiler is in operation.

   c. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

   {Permitting Note: to control emission of SO_2 to the limits specified in this permit, limestone will be injected into the BFB biomass-fueled boilers. Good combustion practices (GCP) will be used to control emissions of CO and VOC to the limits specified in this permit.}

   [Application No. 0550061-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

4. Authorized Fuels: The biomass boilers are authorized to combust as their primary fuels: stillage cake from ethanol production; the biogas produced in the anaerobic reactors of the facility's WWTP; and, supplemental biomass as defined in Appendix BMP. In addition, the boilers are authorized to combust NG for startup and flame stabilization. If pipeline NG is not available when that facility is constructed, the boilers are authorized to combust ULSD FO or propane as a replacement fuel for NG. HEF has estimated the fuel mix to be used in the biomass boilers. This estimate fuel mix is provided below. [Application No. 0550061-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

Stillage Cake	Biogas	Supplemental Biomass	Natural Gas	ULSD Fuel Oil*	Propane*
75%	18%	6%	1%	---	---

* ULSD fuel oil or propane will only be used if natural gas is not available. If used, the percentage amounts would equal natural gas.

5. Boiler Heat Input Rate: The maximum heat input rate from all fuel combinations for each biomass boiler is 218 mmBtu/hr (4 hour average). [Application No. 0550061-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

6. Hours of Operation: The hours of operation for each biomass boiler are not restricted (8,760 hours/year). [Application No. 0550061-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

7. Good Combustion Practices (GCP): The emission standards established by this permit rely on "good combustion practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the steam generating unit and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good combustion practices as well as methods of minimizing excess emissions.
[Rule 62-4.070(3), F.A.C. and 62-212.400(5), F.A.C.]

EMISSIONS STANDARDS

8. Emission Limits: Emissions from each biomass BFB boiler at HEF shall not exceed the following standards. All except hydrogen chloride (HCl) and ammonia (NH_3) are determinations of BACT.

Pollutant	Initial (I) or Annual (A) Test		CEMS/COMS Based Averages	
NO_X [a]	14.9 lb/hr 0.075 lb/mmBtu	(I)	14.9 lb/hr 30 day rolling average	0.075 lb/mmBtu 30 day rolling average
SO_2 [b]	11.9 lb/hr 0.06 lb/mmBtu	(I)	11.9 lb/hr, 30 day rolling average	0.06 lb/mmBtu 30 day rolling average
CO	19.8 lb/hr 0.10 lb/mmBtu	(I)	19.8 lb/hr 30 day rolling average	0.10 lb/mmBtu 30 day rolling average
HCl [c]	1.05 lb/hr 0.0054 lb/mmBtu	(I)	1.05 lb/hr 30 day rolling average	0.0054 lb/mmBtu 30 day rolling average
PM/PM_{10} [d, e]	2.0 lb/hr 0.01 lb/mmBtu	(I,A)	10 percent (%) opacity (6-minute blocks) 20% opacity (one 6-minute block per hour)	
VOC	1.0 lb/hr 0.005 lb/mmBtu	(I,A)	Not applicable	
NH_3 Slip [f]	10 ppmvd @ 7% O_2 1.45 lb/hr	(I,A)	Not applicable	

a. CEMS based NO_X limit in pounds per million Btu heat input (lb/mmBtu) will ensure compliance with NSPS Subpart Db NO_X limit of 0.30 lb NO_X/mmBtu.
b. CEMS based SO_2 limit in lb/mmBtu will ensure compliance with NSPS Subpart Db SO_2 limit of 0.20 lb SO_2/mmBtu.
c. CEMS based mass HCl emission limit insures annual emissions will be less than 10 TPY.
d. Compliance with the PM/PM_{10} mass emission limit insures compliance with the NSPS Subpart Db limit of 0.030 lb PM/mmBtu (filterable PM).
e. During startups, shutdowns and malfunction the following limits apply: 20% opacity (6-minute blocks) except for one 6-minute block per hour of 27%.
f. NH_3 slip in parts per million by dry volume at 7% oxygen (ppmvd @ 7% O_2).

[Application No. 0550061-001-AC; Rule 62-212.400(10) (PSD), Control Technology Review; and 40 CFR 60, Subpart Db]

9. Continuous Monitoring Requirements: The permittee shall install, calibrate, maintain and operate CEMS, a COMS and a diluent monitor to measure and record the emissions of SO_2, NO_X, CO, HCL and opacity from each BFB biomass boiler stack in a manner sufficient to demonstrate continuous compliance with the CEMS-based and COMS-based emission standards in **Conditions 8** above. Each CEMS and COMS shall be installed, calibrated and properly functioning within 60 calendar days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup and prior to the initial performance tests. Within one working day of discovering emissions in excess of a SO_2, NO_X, CO or HCl standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

   a. SO_2 CEMS: - The SO_2 CEMS shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75.

   b. NO_X CEMS: The NO_X CEMS shall be certified, operated, and maintained in accordance with the requirements of 40 CFR Part 75. Recordkeeping and reporting shall be conducted pursuant to Subpart Db in 40 CFR 60 and Subparts F and G in 40 CFR 75.

   c. CO CEMS: The CO CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

   d. HCl CEMS: The HCl CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 15. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the HCl monitor shall be performed using EPA Method 26 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The HCl monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards. The HCl CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 15. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority.

   e. COMS: In accordance with 40 CFR 60.48b(a) the permittee shall install, calibrate, operate and maintain a continuous opacity monitor (COM) to continuously monitor and record opacity from the steam generating unit. The COMS shall be certified pursuant to 40 CFR 60 Appendix B, Performance Specification 1.

   f. Diluent Monitor: The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

   [Rule 62-212.400(10), F.A.C.; Rule 62-210.200(PTE), F.A.C.; Rule 62-4.070(3), F.A.C.; and 40 CFR 60, Subpart Db and Appendices]

STARTUP, SHUTDOWN, AND MALFUNCTION REQUIREMENTS

10. Malfunction Notifications: In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Compliance Authority in accordance with the following. If the permittee is temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall immediately (within one working day) notify the Compliance Authority. Notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its recurrence, and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with Department rules. If requested by the Compliance Authority, the owner or operator shall submit a quarterly written report describing the malfunction. [Rules 62-210.700(6) and 62-4.130, F.A.C.]

11. Emission Limit Compliance and Excess Emission: Because of the long-term nature of all of the NO_X, SO_2, CO and HCl mass emission rate limits and as part of PSD and the associated BACT determination, all emissions data for these pollutants, including periods of startup, shutdown and malfunction, shall be included in any compliance determinations based on CEMS data.
[Rule 62-210.700(4), 62-210.200(PTE); Rule 62-212.400(10) (PSD), Control Technology Review; and Rule 62-4.070(3), F.A.C.]

12. Excess Emissions Allowed – Opacity Requirements: As provided by the authority in Rule 62-210.700(5), F.A.C., the following conditions supersede the provisions in Rule 62-210.700(1), F.A.C.
    a. Opacity: During startup, shutdown and malfunctions, the stack opacity shall not exceed 20% based on a 6-minute block average, except for one 6-minute block per hour that shall not exceed 27% opacity. [Rule 62-210.700(5), 62-210.200(PTE); Rule 62-212.400(10) (PSD), Control Technology Review; and Rule 62-4.070(3), F.A.C.]

TESTING REQUIREMENTS

13. Boiler Performance Test: Within 180 days of first fire on the primary fuels (stillage and biogas with NG 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 (See Appendix ASME of this permit). 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% 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. [Applicant's Request; Rule 62-4.070(3), F.A.C.]

    *{Permitting Note: If NG is not available either propane or ULSD FO may be used for flame stabilization during boiler performance testing. However, once NG becomes available at HEF, the boiler performance test specified in **Condition 14** above must be redone within 30 days with the results submitted to the Compliance Authority no later than 45 days after testing with natural gas was completed.}*

14. Initial and Annual Stack Tests: In accordance with test methods specified in this permit, the biomass boilers shall be tested to demonstrate initial compliance with the emission standards for ammonia slip, CO, NO_X, PM, SO_2, VOC, opacity and HCl. The tests shall be conducted within 60 days after achieving the maximum heat input rate to each boiler, but not later than 180 days after the initial startup of each boiler. Subsequent compliance stack tests for ammonia slip, PM and VOC shall also be conducted during each federal fiscal year (October 1st to September 30th). Tests shall be conducted between 90% and 100% of the maximum heat input rate when firing only the primary fuels. CEMS data for CO, NO_X, SO_2 and HCL along COMS data for opacity shall be reported for each run of the required stack tests for ammonia slip, PM and VOC. The Department may require the permittee to repeat some or all of these initial stack tests after major replacement or major repair of any air pollution control or process equipment.
[Rules 62-212.400(5)(c) and 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

{Permitting Note: All initial tests must be conducted between 90% and 100% of permitted capacity; otherwise, this permit will be modified to reflect the true maximum capacity as constructed.}

Test Methods: Any required stack tests shall be performed in accordance with the following methods.

EPA Method	Description of Method and Comments
CTM-027 320	Measurement of Ammonia Slip *or* Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy
1 - 4	Determination of Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content *{Notes: Methods shall be performed as necessary to support other methods.}*
5	PM
6C	Measurement of SO_2 Emissions (Instrumental)
7E	Measurement of NO_X Emissions (Instrumental)
9	Visual Determination of the Opacity
10B	Measurement of CO Emissions (Instrumental) *{Note: The method shall be based on a continuous sampling train.}*
18	Measurement of Gaseous Organic Compound Emissions (Gas Chromatography) *{Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the THC emissions measured by Method 25A.}*
19	Calculation Method for NO_X, PM, and SO_2 Emission Rates
25	Determination of Total Gaseous Nonmethane Organic Emissions as Carbon
25A	Measurement of Gaseous Organic Concentrations (Flame Ionization)
26	Determination of Hydrogen Chloride (HCl) Emissions from Stationary Sources

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at http://www.epa.gov/ttn/emc/ctm.html . The other methods are specified in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Compliance Authority.
[Rules 62-204.800, F.A.C. and 40 CFR 60, Appendix A]

OTHER MONITORING REQUIREMENTS

15. Steam Parameters: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain continuous monitoring and recording devices for the following parameters: steam temperature (°F), steam pressure (psig) and steam production rate (lb/hour). Records shall be maintained on site and made available upon request.

[Applicant's Request; Rules 62-4.070(3) and 62-212.400(5), F.A.C.]

16. Fuel Flow Meter: A fuel flow meter shall be installed on each BFB biomass boiler to recorded the amount of fossil fuel (NG, ULSD FO or propane) used in each boiler on a hourly, monthly and 12 month rolling average basis. [Rule 62-4.070(3), Reasonable Assurance]

17. Pressure Drop: The permittee shall maintain and calibrate a device which continuously measures and records the pressure drop across each baghouse compartment controlling the PM emissions from each biomass boiler. Pressure drop records shall be maintained on site and made available upon request. [Rule 62-4.070(3), F.A.C. and 40 CFR 63.548(c)(1)]

20. Bag Leak Detection: The permittee shall maintain continuous operation of bag leak detection systems on each biomass boiler baghouse. Baghouse leak detection records shall be kept on site and made available upon request. [Rule 62-4.070(3), F.A.C. and 40 CFR 63.548].

21. SNCR Urea Injection: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a flow meter to measure and record the urea injection rate for the SNCR system for each biomass boiler. The permittee shall document the general range of urea flow rates required to meet the NO_X standard over the range of load conditions by comparing NO_X emissions with urea flow rates. During NO_X CEMS downtimes or malfunctions, the permittee shall operate at a urea flow rate that is consistent with the documented flow rate for the given load condition. Urea injection records shall be maintained on site and made available upon request. [Rules 62-4.070(3) and 62-212.400(5), F.A.C.]

RECORDS AND REPORTS

22. Stack Test Reports: In addition to the information required in Rule 62-297.310(8), F.A.C., each stack test report shall also include the following information: steam production rate (lb/hour), heat input rate (mmBtu/hour), calculated authorized fuels firing rate (tons/hour and cubic feet per minute as appropriate), and emission rates (lb/mmBtu, ppmvd @ 7% oxygen and lb/hr as appropriate). [Rule 62-4.070(3), F.A.C.]

23. Monthly Operations Summary: By the tenth calendar day of each month, the permittee shall record the following parameters for each biomass boiler in a written or electronic log for the previous month of operation: hours of operation, tons of stillage, tons of supplemental biomass and cubic feet of biogas, pounds of steam, total heat input rate and the updated 12-month rolling totals for each of these operating parameters. Cubic feet of NG, cubic feet of propane, or gallons of ULSD FO used shall be recorded in a written or electronic log for the previous month of operation along with the updated 12-month rolling totals for each of these fossil fuels. In addition, the hourly heat input rate to each biomass boiler shall be recorded and reported. The Monthly Operations Summary shall be maintained on site and made available for inspection when requested by the Department. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

24. Quarterly CO, NO_X, SO_2, HCl and Opacity Emissions Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing CO, NO_X, SO_2, HCl and Opacity emissions including periods of startups, shutdowns, malfunctions, and CEMS and COMS systems monitor availability for the previous quarter. If opacity COMS data is excluded from a compliance determination during the quarter due to a startup, shutdown or malfunction, the permittee shall include a description of the malfunction, the actual emissions recorded, and the actions taken to correct the malfunction. See Appendix CTR of this permit for the reporting format. [Rules 62-4.070(3), 62-4.130, and 62-210.400(5)(c), F.A.C.]

I. Backup Fossil-Fueled Steam Production (EU-010)

This section of the permit addresses the following emissions unit.

EU ID No. 010	Emission Unit Description
Description: Backup boiler to be used to generate superheated steam to be used in the ethanol production process when one of the BFB biomass boilers is not available. Use of the backup boiler is limited to 6,000 hours in any consecutive twelve month period. *Fuels*: The backup boiler is primarily fueled by NG and supplemented with biogas. Propane or ULSD FO will be the primary fuel if NG is not available. *Capacity*: The maximum heat input capacity to the backup boiler is 218 mmBtu per hour (4-hour average) with a design heat input capacity of 198 mmBtu/hr. The steam production capability will be between approximately 100,000 to 125,000 pounds per hour (lb/hr). The maximum heat input capacity using fossil fuels to the backup boiler must be physical constrain to be less than 250 mmBtu/hr so the backup boiler is not be subject to 40 CFR 60 NSPS, Subpart Da. *Controls*: Efficient combustion of clean fuels to minimize the emissions of PM, NO_X, CO, VOC and HAP. Efficient combustion and clean fuels to minimize VE. Low NO_X burners and flue gas recirculation (FGR) to further minimize NO_X emissions. *Stack Parameters*: Flue gas from the backup boiler will discharge to the atmosphere via a stack with a design height of 150 feet and a design diameter of 5.56 feet. The flue gas exit temperature will be approximately 350 degrees °F with a design volumetric flow rate of 61,671ACFM. *CEMS*: Emissions of NO_X will be monitored and recorded by CEMS from the backup boiler stack. *Applicability of 40 CFR Subpart Db (NSPS Subpart Db)*: This unit is subject to NSPS Subpart Db - Industrial-Commercial-Institutional Steam Generating Units because it has a maximum heat input capacity greater than 100 mmBtu/hr from the fuels combusted and is not subject to NSPS Subpart Da because it has a maximum heat input capacity less than 250 mmBtu/hr from combusted fossil fuels. [Application No. 0550061-001-AC]	

EQUIPMENT

1. <u>Construction of Natural Gas Fueled Boiler</u>: The permittee is authorized to construct one backup boiler with a design heat input rate of 198 mmBtu/hr for steam generation at the HEF. The backup boiler will include an air supply, low NO_X burners, overfire air ports, FGR, steam drum, superheater, economizer, air heater, ash hoppers, ducts, fuel feeding equipment, air-cooled condensing unit, air pollution control equipment and other associated equipment. [Application No. 0550061-001-AC]

2. <u>Air Pollution Control Equipment</u>: To comply with the emission standards of this permit, the permittee shall install the following air pollution control equipment on the backup boiler.

    a. <u>Low NO_X Burners</u>: The permittee shall design, install, operate and maintain low NO_X burners on the backup boiler to control NO_X from the flue gas exhaust and achieve the NO_X standards specified in this subsection.

    b. <u>Flue Gas Recirculation (FGR)</u>: The permittee shall design, install, operate, and maintain a FGR system on the backup boiler to reduce NO_X emissions in the flue gas exhaust and achieve the NO_X emissions standards specified in this subsection.

{Permitting Note: to control emission of SO_2 to the limits specified in this subsection low sulfur fuels will be used in the backup boiler. Clean fuels and GCP will be used to control emissions of PM, NO_X, CO, VOC and HAP to the limits specified in this subsection. Clean fuels and GCP will also minimize VE.}
[Application No. 0550061-001-AC; Rule 62-212.400(10) (PSD), Control Technology Review; Rule 62-4.070(3), and Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTION

3. Authorized Fuels: The backup boiler is authorized to combust fossil fuels. Specifically, NG is authorized as its primary fuel. If NG is not available when the HEF becomes operational, propane or ULSD FO may be used as the primary fuel. Biogas produced in the anaerobic reactors of the facility's WWTP may be used to supplement the fossil fuels. HEF has estimated the fuel mix to be used in the backup boiler. This estimate fuel mix is provided in the table below.
[Application No. 0550061-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

Stillage Cake	Biogas	Biomass	NG	ULSD FO*	Propane*
0%	18%	0%	82%	---	---

* ULSD FO or propane will only be used if natural gas is not available. If used, the percentage amounts would equal NG.

4. Boiler Heat Input Rate: The maximum heat input rate from all fuel combinations for the backup boiler is 218 mmBtu/hr (4 hour average).
[Application No. 0550061-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]
5. Operational Hours: The hours of operation of the backup boiler is restricted to 6,000 hours in any consecutive twelve month period. In addition, the 6,000 operation hour limit will be reduced by two hours for every hour (2 for 1) that the backup boiler is fired by ULSD FO.
[Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]
6. Backup Boiler Operation: The backup boiler shall only be in operation when one of the biomass boilers is not available due to malfunction, required maintenance or shortage of biomass fuel. Under no circumstance can the backup boiler be in operation for more than 6,000 hours in any consecutive twelve month period.
[Application No. 0550061-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

EMISSIONS STANDARDS

7. Emission Limits: Emissions from the backup boiler at HEF shall not exceed the standards given in the table below. All emission limits are determinations of BACT. Unless otherwise stated, averaging time is the time of the test method.

Pollutant	Initial (I) or Annual (A) Test		CEMS/COMS Based Averages	
NO_X [a]	14.3 lb/hr 0.072 lb/mmBtu	(I)	14.3 lb/hr 30 day rolling average	0.072 lb/mmBtu 30-day rolling average
SO_2 [b]	1.1 lb/hr 0.0056 lb/mmBtu	(I,A)	Not applicable	
CO	7.3 lb/hr 0.037 lb/mmBtu	(I,A)	Not applicable	
PM/PM_{10} [c, d]	1.4 lb/hr	(I,A)	Not applicable	

	0.0071 lb/mmBtu		
VOC	0.3 lb/hr 0.0015 lb/mmBtu	(I,A)	Not applicable
Opacity [c]	10% opacity (6-minute blocks) 20% opacity (one 6-minute block per hour)	(I,A)	Not applicable

a. CEMS based NO_X limit in pounds per million Btu heat input (lb/mmBtu) will ensure compliance with 40 CFR 60, NSPS Subpart Db NO_X limit of 0.30 lb NO_X/mmBtu.

b. Use of low sulfur fossil fuels such as ULSD FO, NG or propane in the backup boiler insures that uncontrolled SO_2 emissions are less than 0.32 lb SO_2/mmBtu. Therefore no specific limit from 40 CFR 60, NSPS Subpart Db applies to the backup boiler.

c. Compliance with the PM/PM_{10} mass emission limit insures compliance with the 40 CFR 60, Subpart Db limit of 0.030 lb PM/mmBtu (filterable PM).

d. During startups, shutdowns and malfunction the following limits apply: 20% opacity (6-minute blocks) except for one 6-minute block per hour of 27%.

e. Opacity limits during normal operation of the backup boiler.

[Application No. 0550061-001-AC; Rule 62-212.400(10) (PSD), Control Technology Review; and 40 CFR 60, Subpart Db]

MONITORING REQUIREMENTS

8. Continuous Monitoring Requirements: The permittee shall install, calibrate, maintain and operate a CEMS and a diluent monitor to measure and record the emissions of NO_X, from the backup boiler stack in a manner sufficient to demonstrate continuous compliance with the CEMS-based emission standard in **Conditions 8** and the table below. The CEMS shall be installed, calibrated and properly functioning within 60 calendar days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup and prior to the initial performance tests. Within one working day of discovering emissions in excess of the NO_X, standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

   a. NO_X CEMS: The NO_X CEMS shall be certified, operated, and maintained in accordance with the requirements of 40 CFR Part 75. Recordkeeping and reporting shall be conducted pursuant to Subpart Db in 40 CFR 60 and Subparts F and G in 40 CFR 75.

   b. Diluent Monitor: The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

   [Rule 62-212.400(10), F.A.C.; Rule 62-210.200(PTE), F.A.C.; Rule 62-4.070(3), F.A.C.; and 40 CFR 60, Subpart Db and Appendices]

STARTUP, SHUTDOWN, AND MALFUNCTION REQUIREMENTS

9. Emission Limit Compliance and Excess Emission: Because of the long-term nature of the NO_X mass emission rate limit and as part of PSD and the associated BACT determination, all emissions data for NO_X, including periods of startup, shutdown and malfunction, shall be included in any compliance determinations based on CEMS data.
   [Rule 62-210.700(4), 62-210.200(PTE); Rule 62-212.400(10) (PSD), Control Technology Review; and Rule 62-4.070(3), F.A.C.]

TESTING REQUIREMENTS

10. Boiler Performance Test: Within 180 days of first fire on the primary fuels (biogas and NG); 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 (See Appendix ASME of this permit). 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 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% 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. [Applicant's Request; Rule 62-4.070(3), F.A.C.]

   *{Permitting Note: If NG is not available either propane or ULSD FO may be used as the primary fuel during boiler performance testing. However, once NG becomes available at HEF, the boiler performance test specified in **Condition 12** above must be redone within 30 days with the results submitted to the Compliance Authority no later than 45 days after testing with natural gas was completed.}*

11. Initial and Annual Stack Tests: In accordance with test methods specified in this permit, the backup boiler shall be tested to demonstrate initial compliance with the emission standards for CO, NO_X, PM, SO_2, VOC and opacity. The tests shall be conducted within 60 days after achieving the maximum heat input rate to the boiler, but not later than 180 days after the initial startup of the boiler. Subsequent compliance stack tests for CO, PM, SO_2, VOC and opacity shall also be conducted during each federal fiscal year (October 1st to September 30th). Tests shall be conducted between 90% and 100% of the maximum heat input rate when firing only the primary fuels. CEMS data for NO_X shall be reported for each run of the required tests for CO, PM, SO_2, VOC and opacity. The Department may require the permittee to repeat some or all of these initial stack tests after major replacement or major repair of any air pollution control or process equipment. [Rules 62-212.400(5)(c) and 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

   {Permitting Note: All initial tests must be conducted between 90% and 100% of permitted capacity; otherwise, this permit will be modified to reflect the true maximum capacity as constructed.}

12. Test Methods: Any required stack tests shall be performed in accordance with the following methods.

EPA Method	Description of Method and Comments
1 - 4	Determination of Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content *{Notes: Methods shall be performed as necessary to support other methods.}*
5	PM
6C	Measurement of SO_2 Emissions (Instrumental)
7E	Measurement of NO_X Emissions (Instrumental)
9	Visual Determination of the Opacity
10B	Measurement of CO Emissions (Instrumental) *{Note: The method shall be based on a continuous sampling train.}*
18	Measurement of Gaseous Organic Compound Emissions (Gas Chromatography) *{Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to*

	deduct emissions of methane and ethane from the THC emissions measured by Method 25A.}
19	Calculation Method for NO_X, PM, and SO_2 Emission Rates
25	Determination of Total Gaseous Nonmethane Organic Emissions as Carbon
25A	Measurement of Gaseous Organic Concentrations (Flame Ionization)

The test methods are specified in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Compliance Authority. [Rules 62-204.800, F.A.C. and 40 CFR 60, Appendix A]

OTHER MONITORING REQUIREMENTS

13. Steam Parameters: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain continuous monitoring and recording devices for the following parameters: steam temperature (°F), steam pressure (psig) and steam production rate (lb/hour). Records shall be maintained on site and made available upon request.
[Applicant's Request; Rules 62-4.070(3) and 62-212.400(5), F.A.C.]

14. Fuel Flow Meter: A fuel flow meter shall be installed on the backup boiler to recorded the amount of fossil fuels (NG, ULSD FO or propane) used in the boiler on a hourly, monthly and 12 month rolling average basis. [Rule 62-4.070(3), Reasonable Assurance]

RECORDS AND REPORTS

15. Stack Test Reports: In addition to the information required in Rule 62-297.310(8), F.A.C., each stack test report shall also include the following information: steam production rate (lb/hour), heat input rate (mmBtu/hour), calculated authorized fuels firing rate (tons/hour and cubic feet per minute as appropriate), and emission rates (lb/mmBtu and ppmvd @ 7% oxygen and lb/hr). [Rule 62-4.070(3), F.A.C.]

16. Monthly Operations Summary: By the tenth calendar day of each month, the permittee shall record the following for each fuel used in the backup boiler in a written or electronic log for the previous month of operation: hours of operation, cubic feet of biogas, cubic feet of natural gas, cubic feet of propane, and gallons of ULSD fuel oil, pounds of steam per month, total heat input rate and the updated 12-month rolling totals for each of these operating parameters. In addition, the hourly heat input rate to the backup boiler shall be recorded and reported. The Monthly Operations Summary shall be maintained on site and made available for inspection when requested by the Department. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

17. Quarterly NO_X Emissions Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing NO_X emissions including periods of startups, shutdowns, malfunctions, and CEMS monitor availability for the previous quarter. See Appendix CTR of this permit for the reporting format.
[Rules 62-4.070(3), 62-4.130, and 62-210.400(5)(c), F.A.C.]

J. Cooling Tower (EU-011)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
011	Six cell mechanical draft cooling tower: An induced draft evaporative cooling tower will provide the cooling of process water for the project.

The cooling tower will be of rectangular mechanical-draft design with six 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 22,500 GPM. Total dissolved solids in the cooling water are expected to be approximately 2,750 milligrams per liter (mg/l).

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one new 6-cell mechanical draft cooling tower with the following design characteristics: a circulating water flow rate of 22,500 GPM; design water temperature of 85 °F; a design air flow rate of 75,398 ACFM; and drift eliminators.
[Application No. 0550061-001-AC; Rule 62-210.200 (PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

2. Hours of Operation: The hours of operation of this emission unit are not limited (8,760 hours per year).
[Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

3. Drift Rate: Within 60 days of commencing operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. [Rule 62-212.400(BACT), F.A.C.]

4. VOC Emissions: VOC emissions can occur from cooling towers used in chemical plants, where the circulating water is used to cool down hydrocarbon process streams. While the process heat exchangers will be designed to prevent contact of the cooling water with the process streams, leaks in the process heat exchangers can occur. The VOCs that would consequently enter the cooling water would ultimately be stripped out by the cooling tower's air flow. Therefore, the permittee shall control VOC emissions by promptly repairing any leaking components in accordance with the approved LDAR plan. The permittee shall collect a sample of cooling water on a weekly basis and analyze it for VOCs to enable the early detection of leaking heat exchangers and thereby minimizing VOC emissions from the cooling tower.
[Application No. 0550061-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance]

   {Permitting Note: These work practice standards are established as BACT for $PM_{10}/PM_{2.5}$ and VOC emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 0.7 tons of PM_{10} and $PM_{2.5}$ per year and 4.1 tons of VOC per year. Actual emissions are expected be lower than these rates.}.

TESTING AND MONITORING REQUIREMENTS

5. VOC Cooling Water Monitoring Plan: A test plan detailing how the cooling tower water shall be monitored for VOC contamination from leaking heat exchangers shall be submitted to the compliance authority for approval no later than 180 days before the HEF becomes operational.
[Application No. 0550061-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance]

6. VOC Water Testing Frequency: Testing of the cooling water shall be conducted weekly unless VOC contamination is found during one of the weekly tests. Then daily testing will be required until the problem is corrected.
   [Application No. 0550061-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance]

7. Notification: The permittee shall notify the Compliance Authority in writing within 24 hours when VOC contamination of the cooling tower water is discovered. Additionally, the permittee shall submit a plan to correct the problem within 7 days for the approval of the Compliance Authority.
   [Application No. 0550061-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance]

RECORDS AND REPORTS

8. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit.
   [Rule 62-297.310(8), F.A.C.]

K. Miscellaneous Storage Silos (EU-012)

This section of the permit addresses the following emissions units.

ID No.	Emission Unit Description
012	Miscellaneous storage silos: Silos to store dry chemicals and agents required for ethanol production at HE, including urea for the SNCR systems on the biomass boilers.

The HEF 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 bacteria, lime for the neutralization of hydrolyzate and cake prior to fermentation, and materials associated with the biomass boilers. Fabric filters baghouses (bin vent filters) will be used to control PM emissions from all the silos. All silos will have stacks with design diameters of 1.5 feet with design flow rates of 2,500 ACFM.

CONSTRUCTION

1. Equipment: The permittee is authorized to construct the following.
   - One lime storage silo with a design stack height of 105 feet.
   - One Solka-Floc® (propagation nutrient) storage silo with a design stack height of 47.5 feet.
   - One soy flour (propagation nutrient) storage silo with a design stack height of 47.5 feet.
   - One ammonium sulfate (propagation nutrient) storage silo with a design stack height of 35.6 feet.
   - One potassium phosphate (propagation nutrient) storage silo with a design stack height of 47.5 feet.
   - One urea (propagation nutrient) storage silo with a design stack height of 35.6 feet.
   - One ash (biomass boilers) storage silo with a design stack height of 34 feet.
   - One sand (fluidized bed for biomass boilers) storage silo with a design stack height of 34 feet.
   - One limestone (fluidized bed for biomass boilers) storage silo with a design stack height of 34 feet.
   - One urea (biomass boilers, SNCR) storage silo with a design stack height of 34 feet.

   [Application No. 0550061-001-AC]

PERFORMANCE RESTRICTION

2. Hours of Operation: The hours of operation of this emission unit are not limited (8,760 hours per year). [Application No. 0550061-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance].

EMISSIONS STANDARDS

3. PM Standard: PM emissions from each baghouse of the silos shall not exceed 0.005 gr/dscf. [Application No. 0550061-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance]

4. VE Standard: VE from the silo baghouses shall not exceed 5% opacity as demonstrated by initial and annual compliance tests. A visible emission reading of 5% opacity or less may be used to establish compliance with the PM emission standard in Specific **Condition 3** above. A visible emission reading greater than 5% opacity will require the permittee to perform a PM emissions stack test within 60 days to show compliance.
   [Application No. 0550061-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance]

TESTING AND MONITORING REQUIREMENTS

5. Initial Compliance Tests: Each silo shall be tested to demonstrate initial compliance with the VE emissions standard specified in **Condition 4** above. The initial test shall be conducted within 180 days after initial operation.
[Application No. 0550061-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance]

6. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each silo shall be tested to demonstrate compliance with the VE emissions standard specified in **Condition 4** above.
[Application No. 0550061-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance]

7. PM Compliance Test: The initial and annual VE tests in **Conditions 5 and 6** above shall serve as a surrogate for the PM emissions tests. If the VE emissions standard in **Condition 4** above is not met, PM tests utilizing EPA Method 5 must be conducted within 60 days on the silo bin vent filters to show compliance with the PM emissions standard in **Condition 3** above.
[Application No. 0550061-001-AC; Rule 62-210.200 (PTE), F.A.C.; Rule 62-212.400(BACT), F.A.C.; and Rule 62-4.070, F.A.C. Reasonable Assurance]

8. Test Requirements: The permittee shall notify the compliance Authority in writing at least 15 days prior to any required tests. Tests shall be conducted in accordance with the applicable requirements specified in Appendix CTR (Common Testing Requirements) of this permit. [Rule 62-297.310(7)(a)9, F.A.C.]

9. Test Methods: Any required stack tests shall be performed in accordance with the following methods.

Method	Description of Method and Comments
EPA 5	Determination of Particulate Emissions. The minimum sample volume shall be 30 dry standard cubic feet.
EPA 9	Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources 60 Minute Test

RECORDS AND REPORTS

10. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit. For each test run, the report shall also indicate the operating rate. [Rule 62-297.310(8), F.A.C.]

L. Miscellaneous Storage Tanks (EU-013)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
013	Miscellaneous Storage Tanks

These miscellaneous tanks consist of tanks to store: (1) ULSD FO; (2) sulfuric acid; (3) ammonia; (4) phosphoric acid; (5) corn steep; (6) lactose; and, (7) glucose.

CONSTRUCTION

1. ULSD FO Storage Tank: The permittee is authorized to construct an ULSD FO fixed roof storage tank with a capacity equal to or less than 110,000 gallons. The tank vent will be equipped with an end-line-vacuum breather pressure/vacuum vent valve. The tank will be contained in a concrete dike for spill containment.
2. Other Storage Tanks: The permittee is authorized to construct tanks to store sulfuric acid, ammonia, phosphoric acid, corn steep, lactose and glucose.
   [Application No. 0550061-001-AC]

NSPS SUBPART Kb APPLICABILITY

3. Non Volatile Organic Liquids (VOL) Storage Tanks: The ULSD FO, sulfuric acid, ammonia, phosphoric acid, corn steep, lactose and glucose storage tanks at HEF do not store VOL. In addition, these storage tanks are larger or equal to 40,000 gallons (151 cubic meters) and store liquids with a maximum true vapor pressure less than 3.5 kPa (0.51 pounds per square inch (psi)). Accordingly, these tanks are unregulated emissions units and are not subject to NSPS 40 CFR 60, Subpart Kb.
   [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]

EMISSIONS AND PERFORMANCE REQUIREMENTS

4. Hours of Operation: The hours of operation of this emissions unit are not restricted (8,760 hours per year).
   [Application No. 0550061-001-AC and Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING AND RECORDS

5. Storage Tank Records: The permittee shall keep readily accessible records showing the dimension of the storage tanks and an analysis showing the capacity of the storage tanks. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of the various liquids for the storage tanks for use in the Annual Operating Report. [Rule 62-4.070(3) F.A.C]
6. Liquid Records: The permittee shall keep readily accessible records showing the maximum true vapor pressure of the liquid stored in a tank not subject to NSPS Subpart Kb. The maximum true vapor pressure shall be less than 3.5 kPa. Compliance with this condition may be demonstrated by using the information from the respective material Safety Data Sheet (MSDS) for the liquid stored in the tank.
   [Rule 62-4.070(3), F.A.C.; Avoidance of 40 CFR 60, Subpart Kb]

M. FOUR EMERGENCY GENERATORS EU-014)

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
014	Four emergency generators each rated at 2,000 kilowatts (kW)

Four emergency generators, each rated at 2,000 kW or 2,682 horsepower (HP), will be installed to provide backup electrical power in the event of a power outage at the facility. The engines will fire ULSD FO or propane and each will be limited to 500 hours per year of operation during emergencies. Each unit will be operated no more than 100 hours per year for testing and maintenance purposes per 40 CFR 60, Subpart IIII. Potential to emit (PTE) emissions are based on an assumed maximum operating time of 500 hr/yr. Each engine will be designed to meet USEPA's emission standards listed in 40 CFR Part 60 Subpart IIII for model year 2009 or later.

EQUIPMENT

1. Emergency Generators: The permittee is authorized to install, operate, and maintain four 2,000 kW emergency generators. [Application No. 0550061-001-AC and Rule 62-210.200 (PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

2. Hours of Operation: Each emergency generator may operate in response to emergency conditions for up to 500 hours per year and 100 non-emergency hours per year for maintenance and testing purposes. [Application No. 0550061-001-AC and Rule 62-210.200 (PTE), F.A.C.]

3. Authorized Fuel: These units shall fire ULSD fuel oil or propane. The ULSD FO shall contain no more than 0.0015% sulfur by weight. [Application No. 0550061-001-AC and Rule 62-210.200 (PTE), F.A.C.]

EMISSION STANDARDS

4. Emissions Limits: Each emergency generator shall comply with the following emission limits and demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII the language of which is given in Appendix IIII. Manufacturer certification can be provided to the Department in lieu of actual stack testing.

Source (model year)	CO (g/KW-hr)	PM (g/KW-hr)	Hydrocarbons (g/KW-hr)	NO_X (g/KW-hr)
Subpart IIII (2006 and later)	3.5	0.20	6.4 (NMHC[a]+NO_X)	

a. NMHC means Non-Methane Hydrocarbons.

[Applicant Request; 40 CFR 60, Subpart IIII and Rule 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

5. Notification, Recordkeeping and Reporting Requirements: The permittee shall adhere to the compliance testing and certification requirements listed in 40 CFR 60.4211 and maintain records demonstrating fuel usage and quality. [Rule 62-212.400 (BACT), F.A.C. and 40 CFR 60.4211]

NSPS APPLICABILITY

6. NSPS Subpart IIII Applicability: These emergency generators are Stationary Compression Ignition Internal Combustion Engines (Stationary ICE) and shall comply with applicable provisions of 40 CFR 60, Subpart IIII, including emission testing or certification. [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines]

NESHAP APPLICABILITY

7. NESHAPS Subpart ZZZZ Applicability: The emergency generators are a Liquid Fueled Reciprocating Internal Combustion Engines (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the generators must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII.
[40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)]

N. EMERGENCY DIESEL-FUELED FIRE PUMP ENGINE (EU-015)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
015	One 360 hp emergency diesel fire pump engine

A backup 360 hp diesel fire pump will also be installed to provide firewater during power outages. This unit will fire ULSD FO or propane and will be limited to 500 hours per year of operation. This unit will be operated no more than 100 hours per year for testing and maintenance purposes per 40 CFR 60, Subpart IIII. The engine will be designed to meet USEPA's emission standards listed in 40 CFR Part 60 Subpart IIII for model year 2009 or later. Potential to emit (PTE) emissions are based on an assumed maximum operating time of 500 hr/yr.

EQUIPMENT

1. Diesel Engine Driven Fire Pump: The permittee is authorized to install, operate, and maintain one diesel engine driven fire pump of approximately 360 hp.
[Application No. 0550061-001-AC and Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

2. Hours of Operation: The fire pump may operate in response to emergency conditions for up to 500 hours per year and 100 non-emergency hours per year for maintenance and testing purposes.
[Application No. 0550061-001-AC and Rule 62-210.200 (PTE), F.A.C.]

3. Authorized Fuel: This unit shall fire ULSD fuel oil or propane. The ULSD fuel oil shall contain no more than 0.0015% sulfur by weight.
[Application No. 0550061-001-AC and Rule 62-210.200 (PTE), F.A.C.]

EMISSION STANDARDS

4. Emissions Limits: The emergency fire pump engine shall comply with the following emission limits and demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII. Manufacturer certification may be provided to the Department in lieu of actual testing.
[40 CFR 60.4211 and Rule 62-4.070(3), F.A.C.]

Model Year	CO (g/hp-hr)	NMHC + NO_X (g/hp-hr)	PM (g/hp-hr)
Subpart IIII (2009 or later)	NA	3.0	0.15

[Application No. 0550061-001-AC and 40 CFR 60, Subpart IIII and Rule 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

5. Notification, Recordkeeping and Reporting Requirements: The permittee shall adhere to the compliance testing and certification requirements listed in 40 CFR 60.4211 and maintain records demonstrating fuel usage and quality. [Rule 62-212.400 (BACT), F.A.C. and 40 CFR 60.4211]

NSPS APPLICABILITY

6. NSPS Subpart IIII Applicability: The fire pump engine is an Emergency Stationary Compression Ignition Internal Combustion Engine (Stationary ICE) and shall comply with applicable provisions of 40 CFR 60, Subpart IIII.
[40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines]

N. EMERGENCY DIESEL-FUELED FIRE PUMP ENGINE (EU-015)

NESHAP APPLICABILITY

7. NESHAPS Subpart ZZZZ Applicability: The fire pump engine is a Liquid Fueled Reciprocating Internal Combustion Engine (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the generators must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII.
[40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)]

O. FACILITY FUGITIVE VOC EMISSION LEAKS (EU-016)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
016	Facility Fugitive VOC Emission Leaks: Fugitive VOC emissions from equipment leaks involved in the ethanol production process.

Total fugitive VOC emissions from equipment leaks were calculated to be 19.6 TPY. To minimized VOC fugitive emissions from the HEF, a monthly leak detection and repair (LDAR) program shall be implemented in accordance with New Source Performance Standard (NSPS) 40 CFR Part 60, Subpart VVa.

NSPS SUBPART VVa

1. Leak Detection and Repair (LDAR) Program: The most practical method of controlling fugitive VOC emissions from HEF is to promptly repair any leaking components. HEF is subject to NSPS 40 CFR 60, Subpart VVa - VOC Equipment Leaks in the Synthetic Chemical Manufacturing Industry (SOCMI), for projects that commence construction or modifications after November 7, 2006. NSPS Subpart VVa requires a LDAR program. HEF must come in to compliance with Subpart VVA, including the LDAR program, no later than 180 days after HEF becomes operational.
[40 CFR 60, Subpart VVa and Rule 62-4.070, F.A.C. Reasonable Assurance]

2. Equipment Subject to NSPS, Subpart VVa: As per **Condition 12** of Section II of this permit, all the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines, and valves of at HEF that are subject to NSPS Subpart VVa must be submitted to the Compliance Authority no later than June 30, 2010.
[Rule 62-212.400 (BACT), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

TESTING AND MONITORING REQUIREMENTS

3. LDAR Program Plan Implementation: As per **Condition 11** of Section II of this permit, the permittee must submit for approval a LDAR program plan no later than June 30, 2010. Once the program plan is approved by the Compliance Authority, the permitted shall implement the program within 180 days of initial startup of the HEF.
[40 CFR 60, Subpart VVa ; Application No. 0550061-001-AC; Rule 62-210.200(PTE), F.A.C. and Rule 62-4.070(3), F.A.C. Reasonable Assurance]

4. Compliance with NSPS VVa: The permittee shall demonstrate compliance with the requirements of §§60.482–1a through 60.482–10a or §60.480a(e) for all equipment subject to NSPS Subpart VVa within 180 days of initial startup of the HEF.
[Application No. 0550061-001-AC; Rule 62-210.200(PTE), F.A.C.; Rule 62-4.070(3), F.A.C. Reasonable Assurance and NSPS, Subpart VVa]

5. Test Methods and Procedures: The permittee shall show the HEF is in compliance with the requirements of NSPS Subpart VVa following the test methods and procedures specified in §60.485a.
[Application No. 0550061-001-AC; Rule 62-210.200(PTE), F.A.C.; Rule 62-4.070(3), F.A.C. Reasonable Assurance and NSPS, Subpart VVa]

SUBPART VVa APPLICABILITY

6. Emission Units Subject to Subpart VVa: The following emission units are subject to the requirements of NSPS 40 CFR Part 60, Subpart VVa and must be addressed in the LDAR program plan.
[Application No. 0550061-001-AC; Rule 62-210.200(PTE), F.A.C.; Rule 62-4.070(3), F.A.C. Reasonable Assurance and NSPS, Subpart VVa]

O. FACILITY FUGITIVE VOC EMISSION LEAKS (EU-016)

Facility ID No. 0550061	
EU ID No.	**Emission Unit Description**
002	Hydrolysis of cellulose, liquid/solids separation, neutralization
003	Hydrolysis of hemicellulose, fermentation, distillation and bacteria/enzyme propagation
004	Solids (stillage and gypsum) separation, dewatering and loadout
005	Denaturing and product storage
006	Product loadout and flare
007	Wastewater treatment plan (WWTP), biogas conditioning and flare
011	Cooling tower

RECORDS AND REPORTS

7. NSPS VVa Recordkeeping Requirements: The permittee shall follow the recordkeeping requirements specified in §§60.486a to show compliance with NSPS Subpart VVa and submitted the records to the Compliance Authority 180 days after the initial startup of the HEF and annually thereafter. [Application No. 0550061-001-AC; Rule 62-210.200(PTE), F.A.C.; Rule 62-4.070(3), F.A.C. Reasonable Assurance and NSPS, Subpart VVa]

SECTION IV. APPENDICES

CONTENTS

AMERICAN SOCIETY OF MECHANICAL ENGINEERS (ASME) FORM FOR ABBREVIATED EFFICIENCY TEST

Below is the form from the American Society of mechanical Engineers (ASME) that shall be used by HEF to calculate the heat input rate (mmBtu/hr) into the biomass BFB boilers (**Specific Condition 14 of Section-H)** and the backup boiler **(Specific Condition 12 of Section I)** of this permit.

SUMMARY SHEET

ASME TEST FORM
FOR ABBREVIATED EFFICIENCY TEST

PTC 4.1-a (1964)

	TEST NO.	BOILER NO.	DATE
OWNER OF PLANT	LOCATION		
TEST CONDUCTED BY	OBJECTIVE OF TEST		DURATION
BOILER, MAKE & TYPE		RATED CAPACITY	
STOKER, TYPE & SIZE			
PULVERIZER, TYPE & SIZE		BURNER, TYPE & SIZE	
FUEL USED MINE	COUNTY	STATE	SIZE AS FIRED

PRESSURES & TEMPERATURES

1	STEAM PRESSURE IN BOILER DRUM	psia	
2	STEAM PRESSURE AT S. H. OUTLET	psia	
3	STEAM PRESSURE AT R. H. INLET	psia	
4	STEAM PRESSURE AT R. H. OUTLET	psia	
5	STEAM TEMPERATURE AT S. H. OUTLET	F	
6	STEAM TEMPERATURE AT R H INLET	F	
7	STEAM TEMPERATURE AT R.H. OUTLET	F	
8	WATER TEMP. ENTERING (ECON.) (BOILER)	F	
9	STEAM QUALITY % MOISTURE OR P. P. M.		
10	AIR TEMP. AROUND BOILER (AMBIENT)	F	
11	TEMP AIR FOR COMBUSTION (This is Reference Temperature) †	F	
12	TEMPERATURE OF FUEL	F	
13	GAS TEMP. LEAVING (Boiler) (Econ.) (Air Htr.)	F	
14	GAS TEMP. ENTERING AH (If conditions to be corrected to guarantee)	F	

UNIT QUANTITIES

15	ENTHALPY OF SAT. LIQUID (TOTAL HEAT)	Btu/lb	
16	ENTHALPY OF (SATURATED) (SUPERHEATED) STM.	Btu/lb	
17	ENTHALPY OF SAT. FEED TO (BOILER) (ECON.)	Btu/lb	
18	ENTHALPY OF REHEATED STEAM R.H. INLET	Btu/lb	
19	ENTHALPY OF REHEATED STEAM R. H. OUTLET	Btu/lb	
20	HEAT ABS/LB OF STEAM (ITEM 16 – ITEM 17)	Btu/lb	
21	HEAT ABS/LB R.H. STEAM (ITEM 19 – ITEM 18)	Btu/lb	
22	DRY REFUSE (ASH PIT + FLY ASH) PER LB AS FIRED FUEL	lb/lb	
23	Btu PER LB IN REFUSE (WEIGHTED AVERAGE)	Btu/lb	
24	CARBON BURNED PER LB AS FIRED FUEL	lb/lb	
25	DRY GAS PER LB AS FIRED FUEL BURNED	lb/lb	

HOURLY QUANTITIES

26	ACTUAL WATER EVAPORATED	lb/hr	
27	REHEAT STEAM FLOW	lb/hr	
28	RATE OF FUEL FIRING (AS FIRED wt)	lb/hr	
29	TOTAL HEAT INPUT $\frac{\text{Item 28} \times \text{Item 41}}{1{,}000}$	kB/hr	
30	HEAT OUTPUT IN BLOW-DOWN WATER	kB/hr	
31	TOTAL HEAT OUTPUT $\frac{(\text{Item 26} \times \text{Item 20}) + (\text{Item 27} \times \text{Item 21}) + \text{Item 30}}{1000}$	kB/hr	

FLUE GAS ANAL. (BOILER) (ECON) (AIR HTR) OUTLET

32	CO_2	% VOL	
33	O_2	% VOL	
34	CO	% VOL	
35	N_2 (BY DIFFERENCE)	% VOL	
36	EXCESS AIR	%	

FUEL DATA

	COAL AS FIRED PROX. ANALYSIS	% wt
37	MOISTURE	
38	VOL MATTER	
39	FIXED CARBON	
40	ASH	
	TOTAL	
41	Btu per lb AS FIRED	
42	ASH SOFT TEMP.* ASTM METHOD	

	COAL OR OIL AS FIRED ULTIMATE ANALYSIS	
43	CARBON	
44	HYDROGEN	
45	OXYGEN	
46	NITROGEN	
47	SULPHUR	
40	ASH	
37	MOISTURE	
	TOTAL	

	COAL PULVERIZATION	
48	GRINDABILITY INDEX*	
49	FINENESS % THRU 50 M*	
50	FINENESS % THRU 200 M*	
64	INPUT-OUTPUT EFFICIENCY OF UNIT %	$\frac{\text{ITEM 31} \times 100}{\text{ITEM 29}}$

	OIL	
51	FLASH POINT F*	
52	Sp. Gravity Deg. API*	
53	VISCOSITY AT SSU* BURNER SSF	
44	TOTAL HYDROGEN % wt	
41	Btu per lb	

	GAS	% VOL
54	CO	
55	CH_4 METHANE	
56	C_2H_2 ACETYLENE	
57	C_2H_4 ETHYLENE	
58	C_2H_6 ETHANE	
59	H_2S	
60	CO_2	
61	H_2 HYDROGEN	
	TOTAL	
	TOTAL HYDROGEN % wt	
62	DENSITY 68 F ATM. PRESS.	
63	Btu PER CU FT	
41	Btu PER LB	

	HEAT LOSS EFFICIENCY	Btu/lb A. F. FUEL	% of A. F. FUEL
65	HEAT LOSS DUE TO DRY GAS		
66	HEAT LOSS DUE TO MOISTURE IN FUEL		
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2		
68	HEAT LOSS DUE TO COMBUST. IN REFUSE		
69	HEAT LOSS DUE TO RADIATION		
70	UNMEASURED LOSSES		
71	TOTAL		
72	EFFICIENCY = (100 – Item 71)		

* Not Required for Efficiency Testing

† For Point of Measurement See Par. 7.2.8.1-PTC 4.1-1964

AMERICAN SOCIETY OF MECHANICAL ENGINEERS (ASME) FORM FOR ABBREVIATED EFFICIENCY TEST

PTC 4.1-b (1964)

CALCULATION SHEET

ASME TEST FORM FOR ABBREVIATED EFFICIENCY TEST

Revised September, 1965

	OWNER OF PLANT	TEST NO.	BOILER NO.	DATE

Item	
30	HEAT OUTPUT IN BOILER BLOW-DOWN WATER = LB OF WATER BLOW-DOWN PER HR x $\left[\frac{\text{ITEM 15} - \text{ITEM 17}}{1000}\right]$ = ... kB/hr
24	*If impractical to weigh refuse, this item can be estimated as follows* DRY REFUSE PER LB OF AS FIRED FUEL = $\frac{\text{\% ASH IN AS FIRED COAL}}{100 - \text{\% COMB. IN REFUSE SAMPLE}}$ CARBON BURNED PER LB AS FIRED FUEL = $\frac{\text{ITEM 43}}{100} - \left[\frac{\text{ITEM 22} \times \text{ITEM 23}}{14{,}500}\right]$ = ... NOTE: IF FLUE DUST & ASH PIT REFUSE DIFFER MATERIALLY IN COMBUSTIBLE CONTENT, THEY SHOULD BE ESTIMATED SEPARATELY. SEE SECTION 7, COMPUTATIONS.
25	DRY GAS PER LB AS FIRED FUEL BURNED = $\frac{11CO_2 + 8O_2 + 7(N_2 + CO)}{3(CO_2 + CO)}$ x (LB CARBON BURNED PER LB AS FIRED FUEL + $\frac{3}{8}$ S) $= \frac{11 \times \text{ITEM 32} + 8 \times \text{ITEM 33} + 7(\text{ITEM 35} + \text{ITEM 34})}{3 \times (\text{ITEM 32} + \text{ITEM 34})} \times \left[\text{ITEM 24} + \frac{\text{ITEM 47}}{267}\right]$ = ...
36	EXCESS AIR † $= 100 \times \frac{O_2 - \frac{CO}{2}}{.2682N_2 - (O_2 - \frac{CO}{2})} = 100 \times \frac{\text{ITEM 33} - \frac{\text{ITEM 34}}{2}}{.2682\,(\text{ITEM 35}) - (\text{ITEM 33} - \frac{\text{ITEM 34}}{2})}$ = ...

	HEAT LOSS EFFICIENCY	Btu/lb AS FIRED FUEL	LOSS/HHV x 100 =	LOSS %
65	HEAT LOSS DUE TO DRY GAS = LB DRY GAS PER LB AS FIRED FUEL x C_p x ($t_{lvg} - t_{air}$) = $\frac{\text{ITEM 25}}{\text{Unit}}$ x 0.24 (ITEM 13) − (ITEM 11) = ...	......	$\frac{65}{41}$ x 100 =	......
66	HEAT LOSS DUE TO MOISTURE IN FUEL = LB H_2O PER LB AS FIRED FUEL x [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = $\frac{\text{ITEM 37}}{100}$ x [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) − (ENTHALPY OF LIQUID AT T ITEM 11)] = ...	......	$\frac{66}{41}$ x 100 =	......
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2 = $9H_2$ x [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = 9 x $\frac{\text{ITEM 44}}{100}$ x [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) − (ENTHALPY OF LIQUID AT T ITEM 11)] = ...	......	$\frac{67}{41}$ x 100 =	......
68	HEAT LOSS DUE TO COMBUSTIBLE IN REFUSE = ITEM 22 x ITEM 23 = ...	......	$\frac{68}{41}$ x 100 =	......
69	HEAT LOSS DUE TO RADIATION* = $\frac{\text{TOTAL BTU RADIATION LOSS PER HR}}{\text{LB AS FIRED FUEL} - \text{ITEM 28}}$	......	$\frac{69}{41}$ x 100 =	......
70	UNMEASURED LOSSES **	......	$\frac{70}{41}$ x 100 =	......
71	TOTAL	......	......	......
	EFFICIENCY = (100 − ITEM 71)	......	......	......

† For rigorous determination of excess air see Appendix 9.2 – PTC 4.1-1964
* If losses are not measured, use ABMA Standard Radiation Loss Chart, Fig. 8, PTC 4.1-1964
** Unmeasured losses listed in PTC 4.1 but not tabulated above may by provided for by assigning a mutually agreed upon value for Item 70.

PRELIMINARY BEST MANAGEMENT PRACTICES (BMP) PLAN FOR MINIMIZATION OF FUGITIVE DUST, PILE MANAGEMENT AND FIRE PREVENTION

The permittee shall comply with this BMP plan and any update hereto.
[Rule 62-4.070, F.A.C. Reasonable Assurance and Rule 62-296.320(4)(c), F.A.C.]

{Permitting Note: The preliminary BMP plan will be updated by HEF as the engineering of the Biomass Receiving, Handling, Storage and Processing emission unit (EU-001) is finalized. The final BMP plan must be submitted to the Compliance Authority no later than 180 days before the HEF facility becomes operational}

Practice	Description
Best Management Practice – Minimization of Fugitive Dust	1) Conveyor systems and associated drop points shall be enclosed or partially enclosed. 2) Drop points to supplemental biomass storage areas shall be designed to minimize the overall exposed (or exposed to atmosphere) drop height. 3) Periodic equipment maintenance shall be performed to maintain conveyor systems and associated drop point integrity. Appropriate plant records shall be maintained on equipment maintenance performed. 4) Dust collector shall be installed at all biomass drop and transfer points. 5) All silos shall be equipped with vent filters. 6) Daily observations of the conveyor systems and associated drop point integrity to identify any equipment abnormalities. 7) Plant personnel shall be trained on identification of warning signs for potential equipment malfunction. 8) Signs shall be posted identifying potential warning signs of equipment malfunction. 9) Procedures shall be established for defining excessive fugitive dust from woody biomass truck unloading operations. Plant personnel shall visually observe truck unloading operations and if excessive fugitive dust is detected appropriate fugitive dust minimization techniques shall be implemented. Plant personnel shall be trained on procedures for defining and minimizing excessive dust from the truck unloading operations. 10) All major roadways at the plant shall be paved. 11) Plant roadways and gravel areas shall be wetted during dry conditions. 12) Mud, dirt or similar debris shall be removed promptly from the paved roads by vacuum sweeping. 13) Plant personnel shall be trained on what constitutes excessive dust on paved roads.
Storage Pile Management	1) Supplemental biomass storage areas shall be managed to avoid excessive wind erosion. 2) A biomass fugitive dust management plan shall be developed and maintained onsite. Plan shall identify warning signs for conditions that could result in excessive fugitive dust formation. Plant personnel shall be trained on what warning signs to look for. 3) Mechanical moving of supplemental biomass by front end loaders and other supporting equipment shall be minimized on high wind event days. 4) Objectionable odor is prohibited with first in first out supplemental biomass utilization implemented to minimize odors. 5) Daily visual observations of the supplemental biomass storage areas shall be performed and if conditions are right for fugitive dust formation, procedures from the fugitive dust plan shall be implemented.
Best Management Practice	1) Contact local fire marshal to develop fire management plan. Plan shall be

– Fire Prevention /Spontaneous Combustion Minimization	maintained. 2) Fire Management plan to include: a) requirement to train onsite personnel to handle incipient fires and training on the identification of potential fire hazards; and, b) install and maintain equipment for plant personnel to handle incipient fires. The local fire department shall be invited to participate in onsite training. 3) Daily observations of the supplemental biomass storage areas shall be performed by plant personnel to identify potential fire hazards. Plant personnel shall be trained on identification of potential fire hazards. 4) Signs shall be posted at the plant, which identify potential fire hazards. 5) Incoming unprocessed supplemental biomass shall be stored in areas with a clearance between each storage area. 6) The reclaiming supplemental biomass shall be done to maximize the removal of older material in order to minimize the stacking of newer material on top of older material. 7) Compaction of supplemental biomass materials in the storage areas shall be minimized.
Best Management Practice – Quality Assurance of Biomass	1) The feedstock for the bubbling fluidized bed (BFB) biomass boilers will consist of energy crops and supplemental biomass (energy crops, wood chips and bagasse) that will be processed in designate areas. The primary biomass will be sent directly to the BFB biomass boilers. The supplemental biomass will be placed in segregated storage areas and when required sent directly to the BFB biomass boilers. 2) The permittee will contract for biomass that specifically meets the definition of energy crops, wood chips and bagasse as identified below: • Energy crops will consist of energy cane and forage sorghums. • Wood chips will consist of clean untreated wood or untreated wood products including clean untreated lumber, tree stumps (whole or chipped), tree limbs (whole or chipped) and slash. This also includes, but is not limited to, wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sander dust, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues. • Bagasse is the residue from the processing of sugar cane and cannot contain any other materials. 3) The biomass feedstock will be delivered to the HEF in vehicles designed to prevent release of fugitive dust. 4) For each shipment of biomass, the permittee shall record the date, quantity and a description of the material received. 5) The permittee shall inspect each shipment of biomass upon receipt for any material not specifically identified in this plan. If the permittee identifies any such material, the material shall be rejected and/or marshaled in specified areas until proper disposal can be arranged. Rejected materials shall be moved off site in a logistically reasonable time period. 6) The permittee shall maintain records of rejected shipments and disposition thereof. Such records shall be made available to the Department upon request.

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at HEF.

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed 2 hours in any 24-hour period unless specifically authorized by the Department for longer duration. Pursuant to Rule 62-210.700(5), F.A.C., the permit subsection may specify more or less stringent requirements for periods of excess emissions. Rule 62-210-700(Excess Emissions), F.A.C., cannot vary or supersede any federal NSPS or NESHAP provision. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permittee shall notify the Compliance Authority in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means 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. [Rules 62-296.320(2) and 62-210.200(Definitions), F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20% opacity. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

RECORDS AND REPORTS

10. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 5 years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]
11. Emissions Computation and Reporting
    a. *Applicability.* This rule sets forth required methodologies to be used by the owner or operator of a facility for computing actual emissions, baseline actual emissions, and net emissions increase, as defined at Rule 62-210.200, F.A.C., and for computing emissions for purposes of the reporting requirements of subsection 62-210.370(3) and paragraph 62-212.300(1)(e), F.A.C., or of any permit condition that requires emissions be computed in accordance with this rule. This rule is not intended to establish methodologies for determining compliance with the emission limitations of any air permit.
    b. *Computation of Emissions.* For any of the purposes set forth in subsection 62-210.370(1), F.A.C., the owner or operator of a facility shall compute emissions in accordance with the requirements set forth in this subsection.
        (1) Basic Approach. The owner or operator shall employ, on a pollutant-specific basis, the most accurate of the approaches set forth below to compute the emissions of a pollutant from an emissions unit; provided, however, that nothing in this rule shall be construed to require installation and operation of any continuous emissions monitoring system (CEMS), continuous parameter monitoring system (CPMS), or predictive emissions monitoring system (PEMS) not otherwise required by rule or permit, nor shall anything in this rule be construed to require performance of any stack testing not otherwise required by rule or permit.
            (a) If the emissions unit is equipped with a CEMS meeting the requirements of paragraph 62-210.370(2)(b), F.A.C., the owner or operator shall use such CEMS to compute the emissions of the pollutant, unless the owner or operator demonstrates to the department that an alternative approach is more accurate because the CEMS represents still-emerging technology.
            (b) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C, but emissions of the pollutant can be computed pursuant to the mass balance methodology of paragraph 62-210.370(2)(c), F.A.C., the owner or operator shall use such methodology, unless the owner or operator demonstrates to the department that an alternative approach is more accurate.
            (c) If a CEMS is not available or does not meet the requirements of paragraph 62-210.370(2)(b), F.A.C., and emissions cannot be computed pursuant to the mass balance methodology, the owner or operator shall use an emission factor meeting the requirements of paragraph 62-210.370(2)(d), F.A.C., unless the owner or operator demonstrates to the department that an alternative approach is more accurate.
        (2) Continuous Emissions Monitoring System (CEMS).
            (a) An owner or operator may use a CEMS to compute emissions of a pollutant for purposes of this rule provided:
                1) The CEMS complies with the applicable certification and quality assurance requirements of 40 CFR Part 60, Appendices B and F, or, for an acid rain unit, the certification and quality assurance requirements of 40 CFR Part 75, all adopted by reference at Rule 62-204.800, F.A.C.; or

2) The owner or operator demonstrates that the CEMS otherwise represents the most accurate means of computing emissions for purposes of this rule.

(b) Stack gas volumetric flow rates used with the CEMS to compute emissions shall be obtained by the most accurate of the following methods as demonstrated by the owner or operator:

1) A calibrated flowmeter that records data on a continuous basis, if available; or

2) The average flow rate of all valid stack tests conducted during a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

(c) The owner or operator may use CEMS data in combination with an appropriate f-factor, heat input data, and any other necessary parameters to compute emissions if such method is demonstrated by the owner or operator to be more accurate than using a stack gas volumetric flow rate as set forth at subparagraph 62-210.370(2)(b)2., F.A.C., above.

(3) Mass Balance Calculations.

(a) An owner or operator may use mass balance calculations to compute emissions of a pollutant for purposes of this rule provided the owner or operator:

1) Demonstrates a means of validating the content of the pollutant that is contained in or created by all materials or fuels used in or at the emissions unit; and

2) Assumes that the emissions unit emits all of the pollutant that is contained in or created by any material or fuel used in or at the emissions unit if it cannot otherwise be accounted for in the process or in the capture and destruction of the pollutant by the unit's air pollution control equipment.

(b) Where the vendor of a raw material or fuel which is used in or at the emissions unit publishes a range of pollutant content from such material or fuel, the owner or operator shall use the highest value of the range to compute the emissions, unless the owner or operator demonstrates using site-specific data that another content within the range is more accurate.

(c) In the case of an emissions unit using coatings or solvents, the owner or operator shall document, through purchase receipts, records and sales receipts, the beginning and ending VOC inventories, the amount of VOC purchased during the computational period, and the amount of VOC disposed of in the liquid phase during such period.

(4) Emission Factors.

(a) An owner or operator may use an emission factor to compute emissions of a pollutant for purposes of this rule provided the emission factor is based on site-specific data such as stack test data, where available, unless the owner or operator demonstrates to the department that an alternative emission factor is more accurate. An owner or operator using site-specific data to derive an emission factor, or set of factors, shall meet the following requirements.

1) If stack test data are used, the emission factor shall be based on the average emissions per unit of input, output, or gas volume, whichever is appropriate, of all valid stack tests conducted during at least a five-year period encompassing the period over which the emissions are being computed, provided all stack tests used shall represent the same operational and physical configuration of the unit.

2) Multiple emission factors shall be used as necessary to account for variations in emission rate associated with variations in the emissions unit's operating rate or operating conditions during the period over which emissions are computed.

3) The owner or operator shall compute emissions by multiplying the appropriate emission factor by the appropriate input, output or gas volume value for the period over which the emissions are computed. The owner or operator shall not compute emissions by converting an emission factor to pounds per hour and then multiplying by hours of operation, unless the owner or operator demonstrates that such computation is the most accurate method available.

(b) If site-specific data are not available to derive an emission factor, the owner or operator may use a published emission factor directly applicable to the process for which emissions are computed. If no directly-applicable emission factor is available, the owner or operator may use a factor based on a similar, but different, process.

(5) Accounting for Emissions During Periods of Missing Data from CEMS, PEMS, or CPMS. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of missing data from CEMS, PEMS, or CPMS using other site-specific data to generate a reasonable estimate of such emissions.

(6) Accounting for Emissions During Periods of Startup and Shutdown. In computing the emissions of a pollutant, the owner or operator shall account for the emissions during periods of startup and shutdown of the emissions unit.

(7) Fugitive Emissions. In computing the emissions of a pollutant from a facility or emissions unit, the owner or operator shall account for the fugitive emissions of the pollutant, to the extent quantifiable, associated with such facility or emissions unit.

(8) Recordkeeping. The owner or operator shall retain a copy of all records used to compute emissions pursuant to this rule for a period of five years from the date on which such emissions information is submitted to the department for any regulatory purpose.

c. *Annual Operating Report for Air Pollutant Emitting Facility*

(1) The Annual Operating Report for Air Pollutant Emitting Facility (DEP Form No. 62-210.900(5)) shall be completed each year for the following facilities:

(a) All Title V sources.

(b) All synthetic non-Title V sources.

(c) All facilities with the potential to emit ten (10) tons per year or more of volatile organic compounds or twenty-five (25) tons per year or more of nitrogen oxides and located in an ozone nonattainment area or ozone air quality maintenance area.

(d) All facilities for which an annual operating report is required by rule or permit.

(2) Notwithstanding paragraph 62-210.370(3)(a), F.A.C., no annual operating report shall be required for any facility operating under an air general permit.

(3) The annual operating report shall be submitted to the appropriate Department of Environmental Protection (DEP) division, district or DEP-approved local air pollution control program office by April 1 of the following year.

(4) Beginning with 2007 annual emissions, emissions shall be computed in accordance with the provisions of subsection 62-210.370(2), F.A.C., for purposes of the annual operating report.

[Rule 62-210.370, F.A.C.]

CONTINUOUS EMISSIONS MONITORING SYSTEM (CEMS) REQUIREMENTS

CEMS OPERATION PLAN

1. CEMS Operation Plan: The owner or operator shall create and implement a facility-wide plan for the proper installation, calibration, maintenance and operation of each CEMS required by this permit. The owner or operator shall submit the CEMS Operation Plan to the Bureau of Air Monitoring and Mobile Sources for approval at least 60 days prior to CEMS installation. The CEMS Operation Plan shall become effective 60 days after submittal or upon its approval. If the CEMS Operation Plan is not approved, the owner or operator shall submit a new or revised plan for approval.

   {Permitting Note: The Department maintains both guidelines for developing a CEMS Operation Plan and example language that can be used as the basis for the facility-wide plan required by this permit. Contact the Emissions Monitoring Section of the Bureau of Air Monitoring and Mobile Sources at (850)488-0114.}

INSTALLATION, PERFORMANCE SPECIFICATIONS AND QUALITY ASSURANCE

2. Timelines:

   a. *New and Existing Emission Units.* For new emission units, the owner or operator shall install each CEMS required by this permit prior to initial startup of the unit. The owner or operator shall conduct the appropriate performance specification for each CEMS within 90 operating days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup.

3. Installation: All CEMS shall be installed such that representative measurements of emissions or process parameters from the facility are obtained. The owner or operator shall locate the CEMS by following the procedures contained in the applicable performance specification of 40 CFR part 60, Appendix B.

4. Span Values and Dual Range Monitors: The owner or operator shall set appropriate span values for the CEMS. The owner or operator shall install dual range monitors if required by and in accordance with the CEMS Operation Plan.

5. Continuous Flow Monitor: For compliance with mass emission rate standards, the owner or operator shall install a continuous flow monitor to determine the stack exhaust flow rate. The flow monitor shall be certified pursuant to 40 CFR part 60, Appendix B, Performance Specification 6.

6. Diluent Monitor: If it is necessary to correct the CEMS output to the oxygen concentrations specified in this permit's emission standards, the owner or operator shall either install an oxygen monitor or install a CO_2 monitor and use an appropriate F-Factor computational approach.

7. Moisture Correction: If necessary, the owner or operator shall determine the moisture content of the exhaust gas and develop an algorithm to enable correction of the monitoring results to a dry basis (0% moisture).

   {Permitting Note: The CEMS Operation Plan will contain additional CEMS-specific details and procedures for installation.}

8. Performance Specifications: The owner or operator shall evaluate the acceptability of each CEMS by conducting the appropriate performance specification, as follows. CEMS determined to be unacceptable shall not be considered installed for purposes of meeting the timelines of this permit.

   a. *CO Monitors:* For CO monitors, the owner or operator shall conduct Performance Specification 4 or 4A of 40 CFR part 60, Appendix B

   b. *NO_X and SO_2 Monitors:* For NO_X and SO_2 monitors, the owner or operator shall conduct Performance Specification 2 of 40 CFR part 60, Appendix B.

   c. *HCl CEMS*: The HCl CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 15. Quality assurance procedures shall conform to the requirements of 40 CFR 60,

Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority.

d. *COMS*: In accordance with 40 CFR 60.48b(a) the permittee shall install, calibrate, operate and maintain a continuous opacity monitor (COM) to continuously monitor and record opacity from the steam generating unit. The COMS shall be certified pursuant to 40 CFR 60 Appendix B, Performance Specification 1.

9. Quality Assurance: The owner or operator shall follow the quality assurance procedures of 40 CFR part 60, Appendix F.

a. *CO Monitors:* The required relative accuracy test audit (RATA) tests shall be performed using EPA Method 10 in Appendix A of 40 CFR part 60 and shall be based on a continuous sampling train.

b. *NO_X Monitors:* The required RATA tests shall be performed using EPA Method 7E in Appendix A of 40 CFR part 60. NO_X shall be expressed "as NO_2."

c. *SO_2 Monitors:* The required RATA tests shall be performed using EPA Method 6C in Appendix A of 40 CFR part 60.

d. *HCl CEMS*: The RATA tests required for the HCl monitor shall be performed using EPA Method 26 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The HCl monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

10. Substituting RATA Tests for Compliance Tests: Data collected during CEMS quality assurance RATA tests can substitute for annual stack tests, and vice versa, at the option of the owner or operator, provided the owner or operator indicates this intent in the submitted test protocol and follows the procedures outlined in the CEMS Operation Plan.

CALCULATION APPROACH

11. CEMS Used for Compliance: Once adherence to the applicable performance specification for each CEMS is demonstrated, the owner or operator shall use the CEMS to demonstrate compliance with the applicable emission standards as specified by this permit.

12. CEMS Data: Each CEMS shall monitor and record emissions during all periods of operation and whenever emissions are being generated, including during episodes of startups, shutdowns, and malfunctions. All data shall be used, except for invalid measurements taken during monitor system breakdowns, repairs, calibration checks, zero adjustments and span adjustments, and except for allowable data exclusions as per Condition 20 of this appendix.

13. Operating Hours and Operating Days: For purposes of this appendix, the following definitions shall apply. An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Unless otherwise specified by this permit, any day with at least one operating hour for an emissions unit is an operating day for that emission unit.

14. Valid Hourly Averages: Each CEMS shall be designed and operated to sample, analyze and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.

a. Hours that are not operating hours are not valid hours.

b. For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data, the 1-hour block average is not valid, and the hour is considered as "monitor unavailable."

15. Calculation Approaches: The owner or operator shall implement the calculation approach specified by this permit for each CEMS, as follows:

    a. *Rolling 30-day Average*: Compliance shall be determined after each operating day by calculating the arithmetic average of all the valid hourly averages from that operating day and the prior 29 operating days.

MONITOR AVAILABILITY

16. Monitor Availability: The quarterly excess emissions report shall identify monitor availability for each quarter in which the unit operated. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter in which the unit operated for more than 760 hours. In the event the applicable availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving the required availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

EXCESS EMISSIONS

17. Definitions:

    a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

    b. *Shutdown* means the cessation of the operation of an emissions unit for any purpose.

    c. *Malfunction* means any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

18. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.

19. Data Exclusion Procedures for SIP Compliance: As per the procedures in this condition and **Specific Condition 12 of Subsection-H** of this permit, limited amounts of COMS emissions data may be excluded from the corresponding compliance demonstration, provided that best operational practices to minimize emissions are adhered to and the duration of data excluded is minimized. The data exclusion procedures of this condition apply only to SIP-based emission limits.

    a. Opacity: During startup, shutdown and malfunctions, the stack opacity shall not exceed 20% based on a 6-minute block average, except for one 6-minute block per hour that shall not exceed 27% opacity.

20. Notification Requirements: The owner or operator shall notify the Compliance Authority within one working day of discovering any emissions that demonstrate noncompliance for a given averaging period. Within one working day of occurrence, the owner or operator shall notify the Compliance Authority of any malfunction resulting in the exclusion of CEMS data. For malfunctions, notification is sufficient for the owner or operator to exclude CEMS data.

ANNUAL EMISSIONS

21. CEMS Used for Calculating Annual Emissions: All valid data, as defined in Condition 12 of this appendix, shall be used when calculating annual emissions.
    a. Annual emissions shall include data collected during startup, shutdown and malfunction periods.
    b. Annual emissions shall include data collected during periods when the emission unit is not operating but emissions are being generated (for example, when firing fuel to warm up a process for some period of time prior to the emission unit's startup).
    c. Annual emissions shall not include data from periods of time where the monitor was functioning properly but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, RATA, calibration gas audit or RAA. These periods of time shall be considered missing data for purposes of calculating annual emissions.
    d. Annual emissions shall not include data from periods of time when emissions are in excess of the calibrated span of the CEMS. These periods of time shall be considered missing data for purposes of calculating annual emissions.
22. Accounting for Missing Data: All valid measurements collected during each hour shall be used to calculate a 1-hour block average. For each hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the owner or operator shall account for emissions during that hour using site-specific data to generate a reasonable estimate of the 1-hour block average.
23. Emissions Calculation: Hourly emissions shall be calculated for each hour as the product of the 1-hour block average and the duration of pollutant emissions during that hour. Annual emissions shall be calculated as the sum of all hourly emissions occurring during the year.

CITATION FORMATS AND GLOSSARY OF COMMON TERMS

CITATION FORMATS

The following illustrate the formats used in the permit to identify applicable requirements from permits and regulations.

Old Permit Numbers

Example: Permit No. AC50-123456 or Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit

"AO" identifies the permit as an Air Operation Permit

"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located

"2222" represents the specific facility ID number for that county

"001"identifies the specific permit project number

"AC" identifies the permit as an air construction permit

"AF" identifies the permit as a minor source federally enforceable state operation permit

"AO" identifies the permit as a minor source air operation permit

"AV" identifies the permit as a major Title V air operation permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the preconstruction review requirements of the Prevention of Significant Deterioration of Air Quality

"FL" means that the permit was issued by the State of Florida

"317" identifies the specific permit project number

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

GLOSSARY OF COMMON TERMS

° F: degrees Fahrenheit

acfm: actual cubic feet per minute

ARMS: Air Resource Management System (Department's database)

BACT: best available control technology

Btu: British thermal units

CAM: compliance assurance monitoring

CEMS: continuous emissions monitoring system

cfm: cubic feet per minute

CFR: Code of Federal Regulations

CO: carbon monoxide

COMS: continuous opacity monitoring system

DEP: Department of Environmental Protection

Department: Department of Environmental Protection

dscfm: dry standard cubic feet per minute

EPA: Environmental Protection Agency

ESP: electrostatic precipitator (control system for reducing particulate matter)

EU: emissions unit

F.A.C.: Florida Administrative Code

F.D.: forced draft

F.S.: Florida Statutes

FGR: flue gas recirculation

F: fluoride

ft^2: square feet

ft^3: cubic feet

gpm: gallons per minute

gr: grains

HAP: hazardous air pollutant

Hg: mercury

I.D.: induced draft

ID: identification

kPa: kilopascals

lb: pound

MACT: maximum achievable technology

MMBtu: million British thermal units

MSDS: material safety data sheets

MW: megawatt

NESHAP: National Emissions Standards for Hazardous Air Pollutants

NO_X: nitrogen oxides

NSPS: New Source Performance Standards

O&M: operation and maintenance

O_2: oxygen

Pb: lead

PM: particulate matter

PM_{10}: particulate matter with a mean aerodynamic diameter of 10 microns or less

PSD: prevention of signifi9cant deterioration

psi: pounds per square inch

PTE: potential to emit

RATA: relative accuracy test audit

SAM: sulfuric acid mist

scf: standard cubic feet

scfm: standard cubic feet per minute

SIC: standard industrial classification code

SNCR: selective non-catalytic reduction (control system used for reducing emissions of nitrogen oxides)

SO_2: sulfur dioxide

TPH: tons per hour

TPY: tons per year

UTM: Universal Transverse Mercator coordinate system

VE: visible emissions

VOC: volatile organic compounds

COMMON TESTING REQUIREMENTS

Unless otherwise specified in the permit, the following testing requirements apply to all emissions units at the HEF.

COMPLIANCE TESTING REQUIREMENTS

1. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. [Rule 62-297.310(2), F.A.C.]

2. Applicable Test Procedures - Opacity Compliance Tests: When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

   a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

   b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

   c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

   [Rule 62-297.310(4), F.A.C.]

3. Determination of Process Variables

   a. *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

   b. *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

   [Rule 62-297.310(5), F.A.C.]

4. Frequency of Compliance Tests: The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

   a. *General Compliance Testing.*

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.
2. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to sub-subparagraph 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   (a) Did not operate; or
   (b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours,
3. During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for visible emissions, if there is an applicable standard.
4. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

b. *Special Compliance Tests.* When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

[Rule 62-297.310(7), F.A.C.]

RECORDS AND REPORTS

5. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report shall provide the following information.
   a. The type, location, and designation of the emissions unit tested.
   b. The facility at which the emissions unit is located.
   c. The owner or operator of the emissions unit.
   d. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
   e. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
   f. The date, starting time and end time of the observation.
   g. The test procedures used.

h. The names of individuals who furnished the process variable data, conducted the test, and prepared the report.

i. The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit plus the test result in the same form and unit of measure.

j. A certification that to the knowledge of the owner or his authorized agent, all data submitted are true and correct. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

NSPS, 40 CFR 60, SUBPART DB – STANDARDS OF PERFORMANCE SMALL INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

{Permitting Note: This is a modified version of NSPS, Subpart Db that retains the information applicable to the ADAGE project. Parts that are critical to the ADGAE project are provided in "Bold" text. To access the full version of NSPS, Subpart Db, follow the link at the end of this appendix.}

Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

Source: 72 FR 32742, June 13, 2007, unless otherwise noted.

§ 60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 100 million British thermal units per hour (MMBtu/hr).

(b) Through (f) are not applicable (NA).

(g) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, the following authorities shall be retained by the Administrator and not transferred to a State.

(1) Section 60.44b(f).

(2) Section 60.44b(g).

(3) Section 60.49b(a)(4).

(h) Through (k) are NA.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009]

§ 60.41b Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see §60.17) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO_2 control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means combustion of fuel in a bed or series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Gaseous fuel means any fuel that is a gas at ISO conditions. This includes, but is not limited to, natural gas and gasified coal (including coke oven gas).

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit (*i.e.* , steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hr) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 70,000 Btu/hr-ft^3.

ISO Conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Low heat release rate means a heat release rate of 70,000 Btu/hr-ft^3 or less.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (lb/mmBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems. For gasified coal or oil that is desulfurized prior to combustion, the *Potential sulfur dioxide emission rate* is the theoretical SO_2 emissions (lb/mmBtu heat input) that would result from combusting fuel in a cleaned state without using any post combustion emission control systems.

Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Very low sulfur oil means for units constructed, reconstructed, or modified after February 28, 2005 and not located in a noncontinental area, oil that contains no more than 0.30 weight percent sulfur or that, when combusted without SO_2 emission control, has a SO_2 emission rate equal to or less than 0.32 lb/mmBtu heat input.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009]

§ 60.42b Standard for sulfur dioxide (SO_2).

(a) through (d) are NA.

(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis.

(f) NA.

(g) Except as provided in paragraph (i) of this section and §60.45b(a), the SO_2 emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) through (j) are NA.

(k)

(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO_2in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO_2emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. For facilities complying with the percent reduction

standard and paragraph (k)(3) of this section, only the heat input supplied to the affected facility from the combustion of coal and oil is counted in paragraph (k) of this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(2) N/A

(3) NA.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009]

§ 60.43b Standard for particulate matter (PM).

(a) through (d) are NA.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum heat input capacity.

(f) **On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that can combust coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.** Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/mmBtu or less are exempt from the opacity standard specified in this paragraph.

(g) The PM and opacity standards apply at all times, except during periods of startup, shutdown, or malfunction.

(h)

(1) **Except as provided in paragraphs (h)(2), (h)(3), (h)(4), (h)(5), and (h)(6) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 0.030 lb/mmBtu heat input,**

(2) NA due to election by applicant to comply with (h)(1) above.

(3) Through (6) are NA.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5084, Jan. 28, 2009]

§ 60.44b Standard for nitrogen oxides (NO_X).

(a) NA except for subsequent reference to the following table:

Fuel/steam generating unit type	Nitrogen oxide emission limits (expressed as NO_2)

	(lb/mmBtu heat input)
(1) Natural gas and distillate oil:	
(i) Low heat release rate	0.10
(ii) High heat release rate	0.20

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of a limit determined by the use of the following formula:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:

E_n= NO_X emission limit (expressed as NO_2), lb/mmBtu;

EL_{go}= Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, lb/mmBtu;

H_{go}= Heat input from combustion of natural gas or distillate oil, mmBtu;

(c) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_X in excess of the emission limit for the coal or oil, or mixtures of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

(d) **On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X in excess of 0.30 lb/mmBtu heat input** unless the affected facility has an annual capacity factor for natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas.

(e) through (g) are NA.

(h) For purposes of paragraph (i) of this section, the NO_X standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j) and (k) are NA.

(l) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction or reconstruction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the following limits:

a. If the affected facility combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels: A limit of 0.20 lb/mmBtu heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas; or

b. If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = \frac{(0.10 \times H_{go}) + (0.20 \times H_r)}{(H_{go} + H_r)}$$

Where:

E_n= NO_X emission limit, (lb/mmBtu);

H_{go}= 30-day heat input from combustion of natural gas or distillate oil; and

H_r= 30-day heat input from combustion of any other fuel.

c. After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of 2.1 lb/MWh gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of §60.48Da(i) of subpart Da of this part, and must monitor emissions according to §60.49Da(c), (k), through (n) of subpart Da of this part.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009]

§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) NA.

(b) In conducting the performance tests required under §60.8, the owner or operator shall use the methods and procedures in appendix A (including fuel certification and sampling) of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) Through (j) NA.

(k) The owner or operator of an affected facility seeking to demonstrate compliance in §§60.42b(d)(4), 60.42b(j), 60.42b(k)(2), and 60.42b(k)(3) (when not burning coal) shall follow the applicable procedures in §60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009]

§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The PM emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NO_X emission standards under §60.44b apply at all times.

(b) Compliance with the PM emission standards under §60.43b shall be determined through perfomance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(c) Compliance with the NO_X emission standards under §60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the PM emission limits and opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

(1) Method 3A or 3B of appendix A–2 of this part is used for gas analysis when applying Method 5 of appendix A–3 of this part or Method 17 of appendix A–6 of this part.

(2) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 of appendix A–6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F).

(iii) NA.

(3) Method 1 of appendix A of this part is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5 of appendix A of this part, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).

(5) For determination of PM emissions, the oxygen (O_2) or CO_2sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section;

(ii) The dry basis F factor; and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for NO_X required under §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring NO_X under §60.48(b).

(1) For the initial compliance test, NO_X from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to

determine compliance with the NO_X emission standards under §60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) NA.

(3) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 250 mmBtu/hr and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the NO_X standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(4) Following the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 250 mmBtu/hr or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_X standards in §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_X emissions data collected pursuant to §60.48b(g)(1) or §60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_X emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

(5) NA.

(f) through (i) are NA.

(j) NA unless applicant elects to install, calibrate and operate a PM-CEMS.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5086, Jan. 28, 2009]

§ 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b) and (f) of this section, the owner or operator of an affected facility subject to the SO_2 standards in §60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO_2 concentrations and either O_2 or CO_2concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the $SO_2$and either O_2or CO_2 concentrations shall both be monitored at the inlet and outlet of the SO_2control device. If the owner or operator has installed and certified SO_2 and O_2or CO_2 CEMS according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

(1) When relative accuracy testing is conducted, SO_2 concentration data and CO_2 (or O_2) data are collected simultaneously; and

(2) In addition to meeting the applicable $SO_2$and CO_2(or O_2) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of

Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(3) The reporting requirements of §60.49b are met. $SO_2$and CO_2(or O_2) data used to meet the requirements of §60.49b shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO_2data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) NA.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average SO_2 emission rates measured by the CEMS required by paragraph (a) of this section and required under §60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under §60.42(b). Each 1-hour average SO_2 emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to §60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) Except as provided for in paragraph (e)(4) of this section, all CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Except as provided for in paragraph (e)(4) of this section, quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the SO_2CEMS at the inlet to the SO_2control device is 125 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO_2control device is 50 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted. Alternatively, SO_2span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(4) As an alternative to meeting the requirements of requirements of paragraphs (e)(1) and (e)(2) of this section, the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(i) For all required $CO_2$and O_2monitors and for $SO_2$and NO_X monitors with span values greater than or equal to 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part.

(ii) For all required $CO_2$and O_2monitors and for $SO_2$and NO_X monitors with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for $SO_2$and NO_X span values less than or equal to 30 ppm; and

(iii) For SO_2, CO_2, and O_2monitoring systems and for NO_X emission rate monitoring systems, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO_2 (regardless of the SO_2 emission level during the RATA), and for NO_X when the average NO_X emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under §60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in §60.49b(r).

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009]

§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. [The rest of this paragraph is NA because the applicant will install a COMS.

(1) through (3) are NA because the applicant will install a COMS.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NO_X standard under §60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring NO_X and O_2 (or CO_2) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a NO_X emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.49b. Data reported to meet the requirements of §60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(c) The CEMS required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(d) The 1-hour average NO_X emission rates measured by the continuous NO_X monitor required by paragraph (b) of this section and required under §60.13(h) shall be expressed in lb/mmBtu heat input and shall be used to calculate the average emission rates under §60.44b. The 1-hour averages shall be calculated using the data points required under §60.13(h)(2).

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a COMS shall be between 60 and 80 percent.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for NO_X is determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, NO_X span values shall be determined as follows:

Fuel	**Span values for NO_X (ppm)**
Natural gas	500
Oil	500
Coal	1,000
Mixtures	500 (x + y) + 1,000z

Where:

x = Fraction of total heat input derived from natural gas;

y = Fraction of total heat input derived from oil; and

z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the NO_X span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (e)(2)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(f) When NO_X emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) through (i) are NA.

(j) NA because applicant will install a COMS.

(k) NA.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5087, Jan. 28, 2009]

§ 60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i);

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired; and

(4) NA because the applicant is not using an emerging technology for SO2 control.

(b) The owner or operator of each affected facility subject to the SO_2, PM, and/or NO_X emission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) NA because the applicant will demonstrate NO_X compliance by use of a CEMS

(d) Except as provided in paragraph (d)(2) of this section, the owner or operator of an affected facility shall record and maintain records as specified in paragraph (d)(1) of this section.

(1) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(2) NA.

(e) NA.

(f) For an affected facility subject to the opacity standard in §60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in §60.48b(a) shall maintain records according to the requirements specified in paragraphs (f)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) NA because the applicant will use a COMS.

(2) NA because the applicant will use a COMS.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NO_X standards under §60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NO_X emission rates (expressed as NO_2) (lb/mmBtu heat input) measured or predicted;

(3) The 30-day average NO_X emission rates (lb/mmBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards in §60.43b(f) or to the operating parameter monitoring requirements in §60.13(i)(1).

(2) Any affected facility that is subject to the NO_X standard of §60.44b, and that:

(i) Combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_X emissions on a continuous basis under §60.48b(g)(1) or steam generating unit operating conditions under §60.48b(g)(2).

(3) For the purpose of §60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under §60.43b(f).

(4) For purposes of §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under §60.46b(e), that exceeds the applicable emission limits in §60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_X under §60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the SO_2 standards under §60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of §60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average SO_2 emission rate (lb/mmBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken; For an exceedance due to maintenance of the SO_2control system covered in paragraph 60.45b(a), the report shall identify the days on which the maintenance was performed and a description of the maintenance;

(3) Each 30-day average percent reduction in SO_2 emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(7) Identification of times when hourly averages have been obtained based on manual sampling methods;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3;

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of §60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average SO_2 emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(5) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(6) Identification of times when hourly averages have been obtained based on manual sampling methods;

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(8) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§60.47b(e)(4)(i) through (e)(4)(iii), each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by §§60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the SO_2standards in §60.42(b) for which the minimum amount of data required in §60.47b(c) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

(1) The number of hourly averages available for outlet emission rates and inlet emission rates;

(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19 of appendix A of this part, section 7;

(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19 of appendix A of this part, section 7; and

(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19 of appendix A of this part, section 7.

(n) NA.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in §60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator a report containing:

(1) The annual capacity factor over the previous 12 months;

(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and

(3) If the affected facility meets the criteria described in §60.44b(j), the results of any NO_X emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NO_X emission test.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in §60.42b or §60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil, natural gas, wood, a mixture of these fuels, or any of these fuels (or a mixture of these fuels) in combination with other fuels that are known to contain an insignificant amount of sulfur in §60.42b(j) or §60.42b(k) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier that certify that the oil meets the definition of distillate oil and gaseous fuel meets the definition of natural gas as defined in §60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition, natural gas, wood, and/or other fuels that are known to contain insignificant amounts of sulfur were combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in §60.42b or §60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) through (u) are NA.

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_X and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) and (y) are NA.

[72 FR 32742, June 13, 2007, as amended at 74 FR 5089, Jan. 28, 2009]

Link to 40 CFR 60, Subpart Db

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.
4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.
6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:
   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

   Reasonable time may depend on the nature of the concern being investigated.
8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:
   a. A description of and cause of non-compliance; and
   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

   The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.
10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
    a. Determination of Best Available Control Technology ( );
    b. Determination of Prevention of Significant Deterioration ( );
    c. Compliance with National Emission Standards for Hazardous Air Pollutants ( ); and
    d. Compliance with New Source Performance Standards (X).
14. The permittee shall comply with the following:
    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
    c. Records of monitoring information shall include:
        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

NSPS Subpart A and NESHAP Subpart A - Identification of General Provisions

NSPS - Subpart A, Identification of General Provisions

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

NESHAP - Subpart A, Identification of General Provisions

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a National Emission Standards for Hazardous Air Pollutants of 40 CFR 63 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 63.1 Applicability.

§ 63.2 Definitions.

§ 63.3 Units and abbreviations.

§ 63.4 Prohibited Activities and Circumvention.

§ 63.5 Preconstruction Review and Notification Requirements.

§ 63.6 Compliance with Standards and Maintenance Requirements.

§ 63.7 Performance Testing Requirements.

§ 63.8 Monitoring Requirements.

§ 63.9 Notification Requirements.

§ 63.10 Recordkeeping and Reporting Requirements.

§ 63.11 Control Device Requirements.

§ 63.12 State Authority and Delegations.

§ 63.13 Addresses of State Air Pollution Control Agencies and EPA Regional Offices.

§ 63.14 Incorporation by Reference.

§ 63.15 Availability of Information and Confidentiality.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

NSPS, SUBPART IIII - STATIONARY COMPRESSION IGNITION INTERNAL COMBUSTION ENGINES

A 1800 kW or less emergency generator (EU ID 004) and two 500 hp or less water pumps (EU-005 and EU-006) are proposed for the ADAGE facility and they are subject to the applicable requirements of 40 CFR 60, Subpart IIII--Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The provisions of this Subpart may be provided in full upon request and are also available at the following link:

Link to Subpart IIII

NSPS, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels

The six tanks in the product storage emissions unit at the HEF are subject to NSPS Subpart Kb which applies to any storage tank with a capacity greater than or equal to 10,300 gallons that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984. Five of these tanks have a capacity greater than or equal to 40,000 gallons while the gasoline storage tank has a capacity of 28,467 gallons. All six tanks store a liquid with a maximum true vapor pressure greater than 3.5 kilopascals (kPa). Consequently, all six tanks are subject to the General Provisions (40 CFR 60, Subpart A) and the provisions of NSPS 40 CFR 60, Subpart Kb.

Link to Subpart Kb

Link to Subpart A

PRELIMINARY LEAK DETECTION AND REPAIR (LDAR) PROGRAM

The applicant provided the following LDAR program developed pursuant to Subpart VV (the predecessor of Subpart VVa for the smaller Verenium pilot and demonstration projects in Jennings, LA. The applicant proposes to rely upon the requirements of Subpart VVa and will provide a more comprehensive version for the larger commercial project at the HEF to the Compliance Authority no later than June 30, 2010.

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 the HEF located in Jennings, Louisiana. 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 the Verenium Biofuels Louisiana Ethanol Facility.

3. REFERENCES

   a. 40 CFR Part 60 Subpart VV (would be Subpart VVa for HEF)

   b. LAC 33: III. 2121 (would include the analogous 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 Louisiana Department of Environmental Quality (LDEQ).

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.

The most practical method of controlling fugitive VOC emissions from HEF is to promptly repair any leaking components. HEF is subject to NSPS 40 CFR 60, Subpart VVa - VOC Equipment Leaks in the Synthetic Chemical Manufacturing Industry (SOCMI), for projects that commence construction or modifications after November 7, 2006. NSPS Subpart VVa requires a LDAR program. HEF must come in to compliance with Subpart VVA, including the LDAR program, no later than 180 days after HEF becomes operational.

SUBPART VVA—STANDARDS OF PERFORMANCE FOR EQUIPMENT LEAKS OF VOC IN THE SYNTHETIC ORGANIC CHEMICALS MANUFACTURING INDUSTRY FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER NOVEMBER 7, 2006

Source: 72 FR 64883, Nov. 16, 2007, unless otherwise noted.

§ 60.480A APPLICABILITY AND DESIGNATION OF AFFECTED FACILITY.

(a)(1) The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.

(2) The group of all equipment (defined in §60.481a) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after November 7, 2006, shall be subject to the requirements of this subpart.

(c) Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d)(1) If an owner or operator applies for one or more of the exemptions in this paragraph, then the owner or operator shall maintain records as required in §60.486a(i).

(2) Any affected facility that has the design capacity to produce less than 1,000 Mg/yr (1,102 ton/yr) of a chemical listed in §60.489 is exempt from §§60.482–1a through 60.482–11a.

(3) If an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, then it is exempt from §§60.482–1a through 60.482–11a.

(4) Any affected facility that produces beverage alcohol is exempt from §§60.482–1a through 60.482–11a.

(5) Any affected facility that has no equipment in volatile organic compounds (VOC) service is exempt from §§60.482–1a through 60.482–11a.

(e) *Alternative means of compliance* —(1) *Option to comply with part 65.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 65, subpart F, to satisfy the requirements of §§60.482–1a through 60.487a for an affected facility. When choosing to comply with 40 CFR part 65, subpart F, the requirements of §§60.485a(d), (e), and (f), and 60.486a(i) and (j) still apply. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(ii) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart F must also comply with §§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(1)(ii) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 65, subpart F, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart F, must comply with 40 CFR part 65, subpart A.

(2) *Part 63, subpart H.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 63, subpart H, to satisfy the requirements of §§60.482–1a through 60.487a for an affected facility. When choosing to comply with 40 CFR part 63, subpart H, the requirements of §60.485a(d), (e), and (f), and §60.486a(i) and (j) still apply.

(ii) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 63, subpart H must also comply with §§60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2)(ii) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 63, subpart H, except that provisions required to be met prior to implementing 40 CFR part 63 still apply. Owners and operators who choose to comply with 40 CFR part 63, subpart H, must comply with 40 CFR part 63, subpart A.

(f) *Stay of standards.* (1) Owners or operators that start a new, reconstructed, or modified affected source prior to November 16, 2007 are not required to comply with the requirements in this paragraph until EPA takes final action to require compliance and publishes a document in the Federal Register.

(i) The definition of "capital expenditure" in §60.481a of this subpart. While the definition of "capital expenditure" is stayed, owners or operators should use the definition found in §60.481 of subpart VV of this part.

(ii) [Reserved]

(2) Owners or operators are not required to comply with the requirements in this paragraph until EPA takes final action to require compliance and publishes a document in the Federal Register.

(i) The definition of "process unit" in §60.481a of this subpart. While the definition of "process unit" is stayed, owners or operators should use the following definition:

Process unit means components assembled to produce, as intermediate or final products, one or more of the chemicals listed in §60.489 of this part. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.

(ii) The method of allocation of shared storage vessels in §60.482–1a(g) of this subpart.

(iii) The standards for connectors in gas/vapor service and in light liquid service in §60.482–11a of this subpart.

[72 FR 64883, Nov. 16, 2007, as amended at 73 FR 31375, June 2, 2008]

§ 60.481A DEFINITIONS.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act (CAA) or in subpart A of part 60, and the following terms shall have the specific meanings given them.

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(a) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$A = Y \times (B \div 100)$;

(2) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log X$, where X is 2006 minus the year of construction; and

(3) The applicable basic annual asset guideline repair allowance, B, is selected from the following table consistent with the applicable subpart:

Table for Determining Applicable Value for B

Subpart applicable to facility	Value of B to be used in equation
VVa	12.5
GGGa	7.0

Closed-loop system means an enclosed system that returns process fluid to the process.

Closed-purge system means a system or combination of systems and portable containers to capture purged liquids. Containers for purged liquids must be covered or closed when not being filled or emptied.

Closed vent system means a system that is not open to the atmosphere and that is composed of hard-piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device or back to a process.

Connector means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation.

Control device means an enclosed combustion device, vapor recovery system, or flare.

Distance piece means an open or enclosed casing through which the piston rod travels, separating the compressor cylinder from the crankcase.

Double block and bleed system means two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.

Duct work means a conveyance system such as those commonly used for heating and ventilation systems. It is often made of sheet metal and often has sections connected by screws or crimping. Hard-piping is not ductwork.

Equipment means each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart.

First attempt at repair means to take action for the purpose of stopping or reducing leakage of organic material to the atmosphere using best practices.

Fuel gas means gases that are combusted to derive useful work or heat.

Fuel gas system means the offsite and onsite piping and flow and pressure control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices or in-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

Hard-piping means pipe or tubing that is manufactured and properly installed using good engineering judgment and standards such as ASME B31.3, Process Piping (available from the American Society of Mechanical Engineers, P.O. Box 2300, Fairfield, NJ 07007–2300).

In gas/vapor service means that the piece of equipment contains process fluid that is in the gaseous state at operating conditions.

In heavy liquid service means that the piece of equipment is not in gas/vapor service or in light liquid service.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in §60.485a(e).

In-situ sampling systems means nonextractive samplers or in-line samplers.

In vacuum service means that equipment is operating at an internal pressure which is at least 5 kilopascals (kPa) (0.7 psia) below ambient pressure.

In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of §60.485a(d) specify how to determine that a piece of equipment is not in VOC service.)

Initial calibration value means the concentration measured during the initial calibration at the beginning of each day required in §60.485a(b)(1), or the most recent calibration if the instrument is recalibrated during the day (i.e., the calibration is adjusted) after a calibration drift assessment.

Liquids dripping means any visible leakage from the seal including spraying, misting, clouding, and ice formation.

Open-ended valve or line means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

Pressure release means the emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.

Process improvement means routine changes made for safety and occupational health requirements, for energy savings, for better utility, for ease of maintenance and operation, for correction of design deficiencies, for bottleneck removal, for changing product requirements, or for environmental control.

Process unit means the components assembled and connected by pipes or ducts to process raw materials and to produce, as intermediate or final products, one or more of the chemicals listed in §60.489. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in §60.482–1a(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart.

Process unit shutdown means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a process unit or part of a process unit consistent with safety constraints and during which repairs can be accomplished. The following are not considered process unit shutdowns:

(1) An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours.

(2) An unscheduled work practice or operational procedure that would stop production from a process unit or part of a process unit for a shorter period of time than would be required to clear the process unit or part of the process unit of materials and start up the unit, and would result in greater emissions than delay of repair of leaking components until the next scheduled process unit shutdown.

(3) The use of spare equipment and technically feasible bypassing of equipment without stopping production.

Quarter means a 3-month period; the first quarter concludes on the last day of the last full month during the 180 days following initial startup.

Repaired means that equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in the applicable sections of this subpart and, except for leaks identified in accordance with §§60.482–2a(b)(2)(ii) and (d)(6)(ii) and (d)(6)(iii), 60.482–3a(f), and 60.482–10a(f)(1)(ii), is re-monitored as specified in §60.485a(b) to verify that emissions from the equipment are below the applicable leak definition.

Replacement cost means the capital needed to purchase all the depreciable components in a facility.

Sampling connection system means an assembly of equipment within a process unit used during periods of representative operation to take samples of the process fluid. Equipment used to take nonroutine grab samples is not considered a sampling connection system.

Sensor means a device that measures a physical quantity or the change in a physical quantity such as temperature, pressure, flow rate, pH, or liquid level.

Storage vessel means a tank or other vessel that is used to store organic liquids that are used in the process as raw material feedstocks, produced as intermediates or final products, or generated as wastes. Storage vessel does not include vessels permanently attached to motor vehicles, such as trucks, railcars, barges or ships.

Synthetic organic chemicals manufacturing industry means the industry that produces, as intermediates or final products, one or more of the chemicals listed in §60.489.

Transfer rack means the collection of loading arms and loading hoses, at a single loading rack, that are used to fill tank trucks and/or railcars with organic liquids.

Volatile organic compounds or VOC means, for the purposes of this subpart, any reactive organic compounds as defined in §60.2 Definitions.

Effective Date Note: At 73 FR 31376, June 2, 2008, in §60.481a, the definitions of "capital expenditure" and "process unit" were stayed until further notice.

§ 60.482-1A STANDARDS: GENERAL.

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §§60.482–1a through 60.482–10a or §60.480a(e) for all equipment within 180 days of initial startup.

(b) Compliance with §§60.482–1a to 60.482–10a will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485a.

(c)(1) An owner or operator may request a determination of equivalence of a means of emission limitation to the requirements of §§60.482–2a, 60.482–3a, 60.482–5a, 60.482–6a, 60.482–7a, 60.482–8a, and 60.482–10a as provided in §60.484a.

(2) If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of §§60.482–2a, 60.482–3a, 60.482–5a, 60.482–6a, 60.482–7a, 60.482–8a, or 60.482–10a, an owner or operator shall comply with the requirements of that determination.

(d) Equipment that is in vacuum service is excluded from the requirements of §§60.482–2a through 60.482–10a if it is identified as required in §60.486a(e)(5).

(e) Equipment that an owner or operator designates as being in VOC service less than 300 hr/yr is excluded from the requirements of §§60.482–2a through 60.482–11a if it is identified as required in §60.486a(e)(6) and it meets any of the conditions specified in paragraphs (e)(1) through (3) of this section.

(1) The equipment is in VOC service only during startup and shutdown, excluding startup and shutdown between batches of the same campaign for a batch process.

(2) The equipment is in VOC service only during process malfunctions or other emergencies.

(3) The equipment is backup equipment that is in VOC service only when the primary equipment is out of service.

(f)(1) If a dedicated batch process unit operates less than 365 days during a year, an owner or operator may monitor to detect leaks from pumps, valves, and open-ended valves or lines at the frequency specified in the following table instead of monitoring as specified in §§60.482–2a, 60.482–7a, and 60.483.2a:

Operating time (percent of hours during year)	Equivalent monitoring frequency time in use		
	Monthly	Quarterly	Semiannually
0 to <25	Quarterly	Annually	Annually.
25 to <50	Quarterly	Semiannually	Annually.
50 to <75	Bimonthly	Three quarters	Semiannually.
75 to 100	Monthly	Quarterly	Semiannually.

(2) Pumps and valves that are shared among two or more batch process units that are subject to this subpart may be monitored at the frequencies specified in paragraph (f)(1) of this section, provided the operating time of all such process units is considered.

(3) The monitoring frequencies specified in paragraph (f)(1) of this section are not requirements for monitoring at specific intervals and can be adjusted to accommodate process operations. An owner or operator may monitor at any time during the specified monitoring period (e.g., month, quarter, year), provided the monitoring is conducted at a reasonable interval after completion of the last monitoring campaign. Reasonable intervals are defined in paragraphs (f)(3)(i) through (iv) of this section.

(i) When monitoring is conducted quarterly, monitoring events must be separated by at least 30 calendar days.

(ii) When monitoring is conducted semiannually (*i.e.* , once every 2 quarters), monitoring events must be separated by at least 60 calendar days.

(iii) When monitoring is conducted in 3 quarters per year, monitoring events must be separated by at least 90 calendar days.

(iv) When monitoring is conducted annually, monitoring events must be separated by at least 120 calendar days.

(g) If the storage vessel is shared with multiple process units, the process unit with the greatest annual amount of stored materials (predominant use) is the process unit the storage vessel is assigned to. If the storage vessel is shared equally among process units, and one of the process units has equipment subject to this subpart, the storage vessel is assigned to that process unit. If the storage vessel is shared equally among process units, none of which have equipment subject to this subpart of this part, the storage vessel is assigned to any process unit subject to subpart VV of this part. If the predominant use of the storage vessel varies from year to year, then the owner or operator must estimate the predominant use initially and reassess every 3 years. The owner or operator must keep records of the information and supporting calculations that show how predominant use is determined. All equipment on the storage vessel must be monitored when in VOC service.

Effective Date Note: At 73 FR 31376, June 2, 2008, in §60.482–1a, paragraph (g) was stayed until further notice.

§ 60.482-2A STANDARDS: PUMPS IN LIGHT LIQUID SERVICE.

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in §60.485a(b), except as provided in §60.482–1a(c) and (f) and paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in §60.482–1a(c) and paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in §60.482–1a(f).

(b)(1) The instrument reading that defines a leak is specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;

(ii) 2,000 ppm or greater for all other pumps.

(2) If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either paragraph (b)(2)(i) or (ii) of this section. This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable.

(i) Monitor the pump within 5 days as specified in §60.485a(b). A leak is detected if the instrument reading measured during monitoring indicates a leak as specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable. The leak shall be repaired using the procedures in paragraph (c) of this section.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in paragraph (c) of this section or by eliminating the visual indications of liquids dripping.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in paragraphs (c)(2)(i) and (ii) of this section, where practicable.

(i) Tightening the packing gland nuts;

(ii) Ensuring that the seal flush is operating at design pressure and temperature.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in paragraphs (d)(1) through (6) of this section are met.

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of §60.482–10a; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4)(i) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(ii) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section prior to the next required inspection.

(A) Monitor the pump within 5 days as specified in §60.485a(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.

(B) Designate the visual indications of liquids dripping as a leak.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm.

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(iii) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.

(6)(i) When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

(ii) A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.

(iii) A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

(e) Any pump that is designated, as described in §60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing;

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in §60.485a(c); and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of §60.482–10a, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

§ 60.482-3A STANDARDS: COMPRESSORS.

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in §60.482–1a(c) and paragraphs (h), (i), and (j) of this section.

(b) Each compressor seal system as required in paragraph (a) of this section shall be:

(1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) Equipped with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of §60.482–10a; or

(3) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(c) The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.

(d) Each barrier fluid system as described in paragraph (a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(e)(1) Each sensor as required in paragraph (d) of this section shall be checked daily or shall be equipped with an audible alarm.

(2) The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(f) If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under paragraph (e)(2) of this section, a leak is detected.

(g)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(h) A compressor is exempt from the requirements of paragraphs (a) and (b) of this section, if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of §60.482–10a, except as provided in paragraph (i) of this section.

(i) Any compressor that is designated, as described in §60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a) through (h) of this section if the compressor:

(1) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in §60.485a(c); and

(2) Is tested for compliance with paragraph (i)(1) of this section initially upon designation, annually, and at other times requested by the Administrator.

(j) Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of §60.14 or §60.15 is exempt from paragraphs (a) through (e) and (h) of this section, provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of paragraphs (a) through (e) and (h) of this section.

§ 60.482-4A STANDARDS: PRESSURE RELIEF DEVICES IN GAS/VAPOR SERVICE.

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in §60.485a(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in §60.482–9a.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in §60.485a(c).

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in §60.482–10a is exempted from the requirements of paragraphs (a) and (b) of this section.

(d)(1) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements in paragraph (d)(2) of this section.

(2) After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in §60.482–9a.

§ 60.482-5A STANDARDS: SAMPLING CONNECTION SYSTEMS.

(a) Each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in §60.482–1a(c) and paragraph (c) of this section.

(b) Each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall comply with the requirements specified in paragraphs (b)(1) through (4) of this section.

(1) Gases displaced during filling of the sample container are not required to be collected or captured.

(2) Containers that are part of a closed-purge system must be covered or closed when not being filled or emptied.

(3) Gases remaining in the tubing or piping between the closed-purge system valve(s) and sample container valve(s) after the valves are closed and the sample container is disconnected are not required to be collected or captured.

(4) Each closed-purge, closed-loop, or closed-vent system shall be designed and operated to meet requirements in either paragraph (b)(4)(i), (ii), (iii), or (iv) of this section.

(i) Return the purged process fluid directly to the process line.

(ii) Collect and recycle the purged process fluid to a process.

(iii) Capture and transport all the purged process fluid to a control device that complies with the requirements of §60.482–10a.

(iv) Collect, store, and transport the purged process fluid to any of the following systems or facilities:

(A) A waste management unit as defined in 40 CFR 63.111, if the waste management unit is subject to and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;

(B) A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266;

(C) A facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR part 261;

(D) A waste management unit subject to and operated in compliance with the treatment requirements of 40 CFR 61.348(a), provided all waste management units that collect, store, or transport the purged process fluid to the treatment unit are subject to and operated in compliance with the management requirements of 40 CFR 61.343 through 40 CFR 61.347; or

(E) A device used to burn off-specification used oil for energy recovery in accordance with 40 CFR part 279, subpart G, provided the purged process fluid is not hazardous waste as defined in 40 CFR part 261.

(c) In-situ sampling systems and sampling systems without purges are exempt from the requirements of paragraphs (a) and (b) of this section.

§ 60.482-6A STANDARDS: OPEN-ENDED VALVES OR LINES.

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in §60.482–1a(c) and paragraphs (d) and (e) of this section.

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) of this section at all other times.

(d) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a), (b), and (c) of this section.

(e) Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

§ 60.482-7A STANDARDS: VALVES IN GAS/VAPOR SERVICE AND IN LIGHT LIQUID SERVICE.

(a)(1) Each valve shall be monitored monthly to detect leaks by the methods specified in §60.485a(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section, §60.482–1a(c) and (f), and §§60.483–1a and 60.483–2a.

(2) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section, §60.482–1a(c), and §§60.483–1a and 60.483–2a.

(i) Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.

(ii) If the existing valves in the process unit are monitored in accordance with §60.483–1a or §60.483–2a, count the new valve as leaking when calculating the percentage of valves leaking as described in §60.483–2a(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

(b) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(c)(1)(i) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(ii) As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in §60.482–9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;

(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts;

(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in §60.486a(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in §60.485a(c), and

(3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in §60.486a(f)(2), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either:

(i) Becomes an affected facility through §60.14 or §60.15 and was constructed on or before January 5, 1981; or

(ii) Has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator.

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

§ 60.482-8A STANDARDS: PUMPS, VALVES, AND CONNECTORS IN HEAVY LIQUID SERVICE AND PRESSURE RELIEF DEVICES IN LIGHT LIQUID OR HEAVY LIQUID SERVICE.

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in §60.485a(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9a.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under §§60.482–2a(c)(2) and 60.482–7a(e).

§ 60.482-9A STANDARDS: DELAY OF REPAIR.

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves and connectors will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with §60.482–10a.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(f) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

§ 60.482-10A STANDARDS: CLOSED VENT SYSTEMS AND CONTROL DEVICES.

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume (ppmv), whichever is less stringent.

(c) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 ppmv, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

(d) Flares used to comply with this subpart shall comply with the requirements of §60.18.

(e) Owners or operators of control devices used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (2) of this section.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (f)(1)(i) and (ii) of this section:

(i) Conduct an initial inspection according to the procedures in §60.485a(b); and

(ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(2) If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:

(i) Conduct an initial inspection according to the procedures in §60.485a(b); and

(ii) Conduct annual inspections according to the procedures in §60.485a(b).

(g) Leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

(1) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(2) Repair shall be completed no later than 15 calendar days after the leak is detected.

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(i) If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (2) of this section:

(1) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1)(i) or (f)(2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (3) of this section:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The process unit within which the closed vent system is located becomes an affected facility through §§60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(l) The owner or operator shall record the information specified in paragraphs (l)(1) through (5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in §60.486a(c).

(4) For each inspection conducted in accordance with §60.485a(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

§ 60.482-11A STANDARDS: CONNECTORS IN GAS/VAPOR SERVICE AND IN LIGHT LIQUID SERVICE.

(a) The owner or operator shall initially monitor all connectors in the process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.

(b) Except as allowed in §60.482–1a(c), §60.482–10a, or as specified in paragraph (e) of this section, the owner or operator shall monitor all connectors in gas and vapor and light liquid service as specified in paragraphs (a) and (b)(3) of this section.

(1) The connectors shall be monitored to detect leaks by the method specified in §60.485a(b) and, as applicable, §60.485a(c).

(2) If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.

(3) The owner or operator shall perform monitoring, subsequent to the initial monitoring required in paragraph (a) of this section, as specified in paragraphs (b)(3)(i) through (iii) of this section, and shall comply with the requirements of paragraphs (b)(3)(iv) and (v) of this section. The required period in which monitoring must be conducted shall be determined from paragraphs (b)(3)(i) through (iii) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (c) of this section.

(i) If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).

(ii) If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.

(iii) If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (b)(3)(iii)(A) of this section and either paragraph (b)(3)(iii)(B) or (b)(3)(iii)(C) of this section, as appropriate.

(A) An owner or operator shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.

(B) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.

(C) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.

(iv) If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.

(v) The owner or operator shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

(c) For use in determining the monitoring frequency, as specified in paragraphs (a) and (b)(3) of this section, the percent leaking connectors as used in paragraphs (a) and (b)(3) of this section shall be calculated by using the following equation:

$\%C_L = C_L / C_t * 100$

Where:

$\%C_L$= Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

C_L= Number of connectors measured at 500 ppm or greater, by the method specified in §60.485a(b).

C_t= Total number of monitored connectors in the process unit or affected facility.

(d) When a leak is detected pursuant to paragraphs (a) and (b) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in §60.482–9a. A first attempt at repair as defined in this subpart shall be made no later than 5 calendar days after the leak is detected.

(e) Any connector that is designated, as described in §60.486a(f)(1), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section if:

(1) The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) and (b) of this section; and

(2) The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (d) of this section if a leak is detected.

(f) *Inaccessible, ceramic, or ceramic-lined connectors* . (1) Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from the recordkeeping and reporting requirements of §§63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:

(i) Buried;

(ii) Insulated in a manner that prevents access to the connector by a monitor probe;

(iii) Obstructed by equipment or piping that prevents access to the connector by a monitor probe;

(iv) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground;

(v) Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or

(vi) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.

(2) If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

(g) Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this subpart. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

Effective Date Note: At 73 FR 31376, June 2, 2008, §60.482–11a was stayed until further notice.

§ 60.483-1A ALTERNATIVE STANDARDS FOR VALVES—ALLOWABLE PERCENTAGE OF VALVES LEAKING.

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in §60.487a(d).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.

(3) If a valve leak is detected, it shall be repaired in accordance with §60.482–7a(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in §60.485a(b).

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

(d) Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent, determined as described in §60.485a(h).

§ 60.483-2A ALTERNATIVE STANDARDS FOR VALVES—SKIP PERIOD LEAK DETECTION AND REPAIR.

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in §60.487(d)a.

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in §60.482–7a.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in §60.482–7a but can again elect to use this section.

(5) The percent of valves leaking shall be determined as described in §60.485a(h).

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

(7) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for a process unit following one of the alternative standards in this section must be monitored in accordance with §60.482–7a(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

§ 60.484A EQUIVALENCE OF MEANS OF EMISSION LIMITATION.

(a) Each owner or operator subject to the provisions of this subpart may apply to the Administrator for determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart.

(b) Determination of equivalence to the equipment, design, and operational requirements of this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for an equivalence determination shall be responsible for collecting and verifying test data to demonstrate equivalence of means of emission limitation.

(2) The Administrator will compare test data for demonstrating equivalence of the means of emission limitation to test data for the equipment, design, and operational requirements.

(3) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) Determination of equivalence to the required work practices in this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate equivalence of an equivalent means of emission limitation.

(2) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.

(3) For each affected facility, for which a determination of equivalence is requested, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for a determination of equivalence shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(5) The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in paragraph (c)(4) of this section.

(6) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

(d) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(e)(1) After a request for determination of equivalence is received, the Administrator will publish a notice in theFederal Registerand provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(2) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in theFederal Register.

(3) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design, or operational standard within the meaning of section 111(h)(1) of the CAA.

(f)(1) Manufacturers of equipment used to control equipment leaks of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of this subpart.

(2) The Administrator will make an equivalence determination according to the provisions of paragraphs (b), (c), (d), and (e) of this section.

§ 60.485A TEST METHODS AND PROCEDURES.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) The owner or operator shall determine compliance with the standards in §§60.482–1a through 60.482–11a, 60.483a, and 60.484a as follows:

(1) Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A–7 of this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.

(2) A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in §60.486a(e)(7). Calculate the average algebraic difference between the three meter readings and the most recent calibration value. Divide this algebraic difference by the initial calibration value and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

(c) The owner or operator shall determine compliance with the no-detectable-emission standards in §§60.482–2a(e), 60.482–3a(i), 60.482–4a, 60.482–7a(f), and 60.482–10a(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) Method 21 of appendix A–7 of this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Procedures that conform to the general methods in ASTM E260–73, 91, or 96, E168–67, 77, or 92, E169–63, 77, or 93 (incorporated by reference—see §60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.

(2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d)(1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F). Standard reference texts or ASTM D2879–83, 96, or 97 (incorporated by reference—see §60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H_2O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) Method 22 of appendix A–7 of this part shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{max} = K_1 + K_2 H_T$$

Where:

V_{max}= Maximum permitted velocity, m/sec (ft/sec).

H_T= Net heating value of the gas being combusted, MJ/scm (Btu/scf).

K_1= 8.706 m/sec (metric units) = 28.56 ft/sec (English units).

K_2= 0.7084 m^4 /(MJ-sec) (metric units) = 0.087 ft^4 /(Btu-sec) (English units).

(4) The net heating value (HT) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

Where:

K = Conversion constant, 1.740 × 10^{-7} (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674 × 10^{-6} [(g-mole)(Btu)/(ppm-scf-kcal)] (English units).

C_i= Concentration of sample component "i," ppm

H_i= net heat of combustion of sample component "i" at 25 °C and 760 mm Hg (77 °F and 14.7 psi), kcal/g-mole.

(5) Method 18 of appendix A–6 of this part or ASTM D6420–99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420–99, and the target concentration is between 150 parts per billion by volume and 100 ppmv) and ASTM D2504–67, 77, or 88 (Reapproved 1993) (incorporated by reference-see §60.17) shall be used to determine the concentration of sample component "i."

(6) ASTM D2382–76 or 88 or D4809–95 (incorporated by reference-see §60.17) shall be used to determine the net heat of combustion of component "i" if published values are not available or cannot be calculated.

(7) Method 2, 2A, 2C, or 2D of appendix A–7 of this part, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

(h) The owner or operator shall determine compliance with §60.483–1a or §60.483–2a as follows:

(1) The percent of valves leaking shall be determined using the following equation:

$\%V_L = (V_L / V_T) * 100$

Where:

$\%V_L$= Percent leaking valves.

V_L= Number of valves found leaking.

V_T= The sum of the total number of valves monitored.

(2) The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.

(3) The number of valves leaking shall include valves for which repair has been delayed.

(4) Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.

(5) If the process unit has been subdivided in accordance with §60.482–7a(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.

(6) The total number of valves monitored does not include a valve monitored to verify repair.

§ 60.486A RECORDKEEPING REQUIREMENTS.

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(3) The owner or operator shall record the information specified in paragraphs (a)(3)(i) through (v) of this section for each monitoring event required by §§60.482–2a, 60.482–3a, 60.482–7a, 60.482–8a, 60.482–11a, and 60.483–2a.

(i) Monitoring instrument identification.

(ii) Operator identification.

(iii) Equipment identification.

(iv) Date of monitoring.

(v) Instrument reading.

(b) When each leak is detected as specified in §§60.482–2a, 60.482–3a, 60.482–7a, 60.482–8a, 60.482–11a, and 60.483–2a, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in §60.482–7a(c) and no leak has been detected during those 2 months.

(3) The identification on a connector may be removed after it has been monitored as specified in §60.482–11a(b)(3)(iv) and no leak has been detected during that monitoring.

(4) The identification on equipment, except on a valve or connector, may be removed after it has been repaired.

(c) When each leak is detected as specified in §§60.482–2a, 60.482–3a, 60.482–7a, 60.482–8a, 60.482–11a, and 60.483–2a, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) Maximum instrument reading measured by Method 21 of appendix A–7 of this part at the time the leak is successfully repaired or determined to be nonrepairable, except when a pump is repaired by eliminating indications of liquids dripping.

(5) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in §60.482–10a shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in §60.482–10a(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(4) Periods when the closed vent systems and control devices required in §§60.482–2a, 60.482–3a, 60.482–4a, and 60.482–5a are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed vent systems and control devices required in §§60.482–2a, 60.482–3a, 60.482–4a, and 60.482–5a.

(e) The following information pertaining to all equipment subject to the requirements in §§60.482–1a to 60.482–11a shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2)(i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§60.482–2a(e), 60.482–3a(i), and 60.482–7a(f).

(ii) The designation of equipment as subject to the requirements of §60.482–2a(e), §60.482–3a(i), or §60.482–7a(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.

(3) A list of equipment identification numbers for pressure relief devices required to comply with §60.482–4a.

(4)(i) The dates of each compliance test as required in §§60.482–2a(e), 60.482–3a(i), 60.482–4a, and 60.482–7a(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment duringeach compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(6) A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with §60.482–1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.

(7) The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.

(8) Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A–7 of this part and §60.485a(b).

(i) Date of calibration and initials of operator performing the calibration.

(ii) Calibration gas cylinder identification, certification date, and certified concentration.

(iii) Instrument scale(s) used.

(iv) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of appendix A–7 of this part.

(v) Results of each calibration drift assessment required by §60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).

(vi) If an owner or operator makes their own calibration gas, a description of the procedure used.

(9) The connector monitoring schedule for each process unit as specified in §60.482–11a(b)(3)(v).

(10) Records of each release from a pressure relief device subject to §60.482–4a.

(f) The following information pertaining to all valves subject to the requirements of §60.482–7a(g) and (h), all pumps subject to the requirements of §60.482–2a(g), and all connectors subject to the requirements of §60.482–11a(e) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

(2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(g) The following information shall be recorded for valves complying with §60.483–2a:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in §§60.482–2a(d)(5) and 60.482–3a(e)(2) and explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for the changes.

(i) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in §60.480a(d):

(1) An analysis demonstrating the design capacity of the affected facility,

(2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(3) An analysis demonstrating that equipment is not in VOC service.

(j) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(k) The provisions of §60.7(b) and (d) do not apply to affected facilities subject to this subpart.

§ 60.487A REPORTING REQUIREMENTS.

(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date.

(b) The initial semiannual report to the Administrator shall include the following information:

(1) Process unit identification.

(2) Number of valves subject to the requirements of §60.482–7a, excluding those valves designated for no detectable emissions under the provisions of §60.482–7a(f).

(3) Number of pumps subject to the requirements of §60.482–2a, excluding those pumps designated for no detectable emissions under the provisions of §60.482–2a(e) and those pumps complying with §60.482–2a(f).

(4) Number of compressors subject to the requirements of §60.482–3a, excluding those compressors designated for no detectable emissions under the provisions of §60.482–3a(i) and those compressors complying with §60.482–3a(h).

(5) Number of connectors subject to the requirements of §60.482–11a.

(c) All semiannual reports to the Administrator shall include the following information, summarized from the information in §60.486a:

(1) Process unit identification.

(2) For each month during the semiannual reporting period,

(i) Number of valves for which leaks were detected as described in §60.482–7a(b) or §60.483–2a,

(ii) Number of valves for which leaks were not repaired as required in §60.482–7a(d)(1),

(iii) Number of pumps for which leaks were detected as described in §60.482–2a(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

(iv) Number of pumps for which leaks were not repaired as required in §60.482–2a(c)(1) and (d)(6),

(v) Number of compressors for which leaks were detected as described in §60.482–3a(f),

(vi) Number of compressors for which leaks were not repaired as required in §60.482–3a(g)(1),

(vii) Number of connectors for which leaks were detected as described in §60.482–11a(b)

(viii) Number of connectors for which leaks were not repaired as required in §60.482–11a(d), and

(ix)–(x) [Reserved]

(xi) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (b) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

(d) An owner or operator electing to comply with the provisions of §§60.483–1a or 60.483–2a shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

(e) An owner or operator shall report the results of all performance tests in accordance with §60.8 of the General Provisions. The provisions of §60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the state.

§ 60.488A RECONSTRUCTION.

For the purposes of this subpart:

(a) The cost of the following frequently replaced components of the facility shall not be considered in calculating either the "fixed capital cost of the new components" or the "fixed capital costs that would be required to construct a comparable new facility" under §60.15: Pump seals, nuts and bolts, rupture disks, and packings.

(b) Under §60.15, the "fixed capital cost of new components" includes the fixed capital cost of all depreciable components (except components specified in §60.488a(a)) which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the applicability date for the appropriate subpart. (See the "Applicability and designation of affected facility" section of the appropriate subpart.) For purposes of this paragraph, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

§ 60.489A LIST OF CHEMICALS PRODUCED BY AFFECTED FACILITIES.

Process units that produce, as intermediates or final products, chemicals listed in §60.489 are covered under this subpart. The applicability date for process units producing one or more of these chemicals is November 8, 2006

NESHAP, Subpart ZZZZ – Stationary Reciprocating Internal Combustion Engines

A 1800 kW or less emergency generator (EU ID 004) and two 500 hp or less water pumps (EU-005 and EU-006) are proposed for the ADAGE facility and they are subject to the requirements of 40 CFR 63, Subpart ZZZZ--National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. The complete provisions of Subpart ZZZZ may be provided in full upon request and are also available beginning at Section 63.6580 at:

Link to Subpart ZZZZ

Livingston, Sylvia

From:	Livingston, Sylvia
Sent:	Friday, October 23, 2009 1:37 PM
To:	'chuck.davis@verenium.com'
Cc:	'tim.eves@verenium.com'; 'joe.vaccaro@amec.com'; Satyal, Ajaya; 'forney.kathleen@epamail.epa.gov'; 'abrams.heather@epa.gov'; 'bstewart@hcbcc.org'; 'mitchellcypress@semtribe.com'; 'richardbowers@semtribe.com'; 'amotlow@semtribe.com'; 'ctepper@semtribe.com'; Gibson, Victoria; Walker, Elizabeth (AIR); Read, David; Linero, Alvaro
Subject:	HIGHLANDS ETHANOL, LLC - Cellulosic Ethanol Facility; 0550061-001-AC/ PSD-FL-406
Attachments:	HIGHINTENT.pdf

Dear Sir/ Madam:

Attached is the official **Notice of Intent to Issue** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Click on the following link to access the permit project documents:

http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0550061.001.AC.D_pdf.zip

Owner/Company Name: HIGHLANDS ETHANOL, LLC
Facility Name: HIGHLANDS ETHANOL
Project Number: 0550061-001-AC/ PSD-FL-406
Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: HIGHLANDS
Processor: David Read

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/eproducts/apds/default.asp .

Permit project documents are addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation

Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
850/921-9506

Livingston, Sylvia

From: Chuck Davis [Charles.Davis@vercipia.com]
Sent: Friday, October 23, 2009 2:39 PM
To: Livingston, Sylvia
Cc: Tim Eves
Subject: RE: HIGHLANDS ETHANOL, LLC - Cellulosic Ethanol Facility; 0550061-001-AC/ PSD-FL-406

Confirmed - We are able to access the documents.

Chuck Davis
Vercipia Biofuels
55 Cambridge Parkway, 8th Floor
Cambridge, MA 02142

P: 617.674.5313 I C: 781.640.0718
chuck.davis@vercipia.com

From: Livingston, Sylvia [mailto:Sylvia.Livingston@dep.state.fl.us]
Sent: Friday, October 23, 2009 1:37 PM
To: chuck.davis@verenium.com
Cc: tim.eves@verenium.com; joe.vaccaro@amec.com; Satyal, Ajaya; forney.kathleen@epamail.epa.gov; abrams.heather@epa.gov; bstewart@hcbcc.org; mitchellcypress@semtribe.com; richardbowers@semtribe.com; amotlow@semtribe.com; ctepper@semtribe.com; Gibson, Victoria; Walker, Elizabeth (AIR); Read, David; Linero, Alvaro
Subject: HIGHLANDS ETHANOL, LLC - Cellulosic Ethanol Facility; 0550061-001-AC/ PSD-FL-406

Dear Sir/ Madam:

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Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

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http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0550061.001.AC.D_pdf.zip

Owner/Company Name: HIGHLANDS ETHANOL, LLC
Facility Name: HIGHLANDS ETHANOL
Project Number: 0550061-001-AC/ PSD-FL-406
Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: HIGHLANDS
Processor: David Read

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/eproducts/apds/default.asp .

Livingston, Sylvia

From: Satyal, Ajaya
Sent: Friday, October 23, 2009 1:43 PM
To: Livingston, Sylvia
Subject: RE: HIGHLANDS ETHANOL, LLC - Cellulosic Ethanol Facility; 0550061-001-AC/ PSD-FL-406

Thanks, Sylvia.

AJ Satyal

From: Livingston, Sylvia
Sent: Friday, October 23, 2009 1:37 PM
To: 'chuck.davis@verenium.com'
Cc: 'tim.eves@verenium.com'; 'joe.vaccaro@amec.com'; Satyal, Ajaya; 'forney.kathleen@epamail.epa.gov'; 'abrams.heather@epa.gov'; 'bstewart@hcbcc.org'; 'mitchellcypress@semtribe.com'; 'richardbowers@semtribe.com'; 'amotlow@semtribe.com'; 'ctepper@semtribe.com'; Gibson, Victoria; Walker, Elizabeth (AIR); Read, David; Linero, Alvaro
Subject: HIGHLANDS ETHANOL, LLC - Cellulosic Ethanol Facility; 0550061-001-AC/ PSD-FL-406

Dear Sir/ Madam:

Attached is the official **Notice of Intent to Issue** for the project referenced below. Click on the link displayed below to access the permit project documents and send a "reply" message verifying receipt of the document(s) provided in the link; this may be done by selecting "Reply" on the menu bar of your e-mail software, noting that you can view the documents, and then selecting "Send".

Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0550061.001.AC.D_pdf.zip

Owner/Company Name: HIGHLANDS ETHANOL, LLC
Facility Name: HIGHLANDS ETHANOL
Project Number: 0550061-001-AC/ PSD-FL-406
Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: HIGHLANDS
Processor: David Read

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Access these documents by clicking on the link provided above, or search for other project documents using the "*Air Permit Documents Search*" website at http://www.dep.state.fl.us/air/eproducts/apds/default.asp .

Permit project documents are addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation

Livingston, Sylvia

From: Linero, Alvaro
Sent: Sunday, October 25, 2009 12:34 PM
To: Livingston, Sylvia
Subject: RE: HIGHLANDS ETHANOL, LLC - Cellulosic Ethanol Facility; 0550061-001-AC/ PSD-FL-406

Thanks Sylvia:

Mr. Moses Osceola apparently received his and he)along with Mr. Bowers are the key people on both the Tribal Council and the Tribal government.

With copies to their Environmental person (Mr. Tepper) and the Tribes legal representative (Jim Shore's office), I think they have been sufficiently informed.

Thanks.

Al.

-----Original Message-----
From: Livingston, Sylvia
Sent: Fri 10/23/2009 1:39 PM
To: Linero, Alvaro
Cc:
Subject: FW: HIGHLANDS ETHANOL, LLC - Cellulosic Ethanol Facility; 0550061-001-AC/ PSD-FL-406

Al

Richard Bowers email was returned as undeliverable.

Sylvia Livingston

Bureau of Air Regulation

Division of Air Resource Management (DARM)

850/921-9506

sylvia.livingston@dep.state.fl.us

From: System Administrator
Sent: Friday, October 23, 2009 1:37 PM
To: Livingston, Sylvia
Subject: Undeliverable:HIGHLANDS ETHANOL, LLC - Cellulosic Ethanol Facility+ADs- 0550061-001-AC/ PSD-FL-406

Your message did not reach some or all of the intended recipients.

Subject: HIGHLANDS ETHANOL, LLC - Cellulosic Ethanol Facility; 0550061-001-AC/ PSD-FL-406

Sent: 10/23/2009 1:37 PM

The following recipient(s) cannot be reached:

richardbowers@semtribe.com on 10/23/2009 1:37 PM

There was a SMTP communication problem with the recipient's email server. Please contact your system administrator.

<tlhexsprot2.floridadep.net #5.5.0 smtp;550 Invalid recipient <richardbowers@semtribe.com> (#5.1.1)>