Memorandum

Florida Department of Environmental Protection

To: Jeff Koerner

Through: Greg DeAngelo & A.A. Linero

8/11

From: David Read

Date: August 11, 2011

Subject: DEP File No. 0550063-001-AC (PSD-FL-416)
Highlands EnviroFuels (HEF), LLC
Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

Attached for your review is a Draft Air Construction Permit package for the construction of the HEF Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant which will be located south of Lake Placid in Highlands County, 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 (PSD).

According to the application, construction of the HEF facility will occur over approximately 12 to 18 months. Through a third party independent consultant, HEF conducted a comprehensive, in-depth economic impact study for the project on the local Highlands County economy.

The study report indicates that a one-time construction phase will generate nearly 1,400 new jobs, $39 million in household income, and $47 million of Gross Domestic Product (GDP) for Highlands County. The study also indicates that the permanent impact derived from the ongoing annual operation of the ethanol plant will account for $51 million in annual GDP, $44 million in annual household income, and will generate 60 direct jobs, 470 indirect jobs, and 210 induced jobs, for a total of 740 new jobs, throughout Highlands County.

We received the application on June 1, 2011. Today is Day 71 on the 90-day clock and also Day 71 since receipt of the application (irrespective of completeness). This represents very prompt action for a Draft PSD permit.

Attachments

JK/gd/aal/dlr

P.E. CERTIFICATION STATEMENT

PERMITTEE

Highlands EnviroFuels (HEF), LLC
10027 Water Works Lane
Riverview, Florida 33578
Authorized Representative: Mr. Bradley Krohn
President and Managing Member

DEP File No. 0550063-001-AC
(PSD-FL-416)
Sugar Cane and Sweet Sorghum to Ethanol
Advanced Biorefinery
Highlands County, Florida

PROJECT DESCRIPTION

The project involves the construction of a 36 million gallons per year Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant. The sugar cane and sweet sorghum will be grown on adjacent and surrounding farmland. The cane and sorghum juice will be squeezed from the stalks, fermented, distilled and blended to make a range of ethanol/gasoline products. The leftover stalk fiber (sugar cane and sweet sorghum bagasse) along with supplemental wood (energy crops, wood chips and vegetative debris) will be used as fuel in a biomass boiler to make process steam and up to 30 megawatts (MW, gross) of electricity. Natural gas will be used for boiler startup, flame stabilization and shutdown and also in the event of a disruption in the biomass supply. The project is subject to the preconstruction review requirements of Rule 62-212.400, Florida Administrative Code (F.A.C.) for the Prevention of Significant Deterioration (PSD) of Air Quality requiring a Best Available Control Technology (BACT) determination.

The project will result in PSD-significant emissions increases for: NO_X, CO, SO_2, VOC, PM and PM_{10}. The controls to meet the BACT determinations for these pollutants consist of an electrostatic precipitator (ESP) on the boiler to control PM/PM_{10}; good combustion practices (GCP) in a stoker (grate) boiler to control NO_X, CO and VOC; a dry sorbent injection system (DSIS) on the boiler to control SO_2, SAM and acid gas HAP such as hydrogen chloride (HCl) and hydrogen fluoride (HF); a non-selective catalytic reduction (SNCR) system on the boiler to control NO_X; an oxidation catalyst (Ox-cat) on the boiler to control CO, VOC and organic HAP; and wet scrubbers on the ethanol production process, good storage tank design, and process equipment leak detection to control VOC and HAP. Emission control measures for NO_X, SO_2 and VOC will also minimize the formation of $PM_{2.5}$. Clean fuels (natural gas and ultra low sulfur distillate fuel oil) and GCP will be used in emergency equipment to control NO_X, CO, VOC, PM and SO_2 emissions. Reasonable precautions and best management practices will be implemented to minimize fugitive dust and to ensure the biomass used at the HEF facility comports to the allowable types defined for the project.

Continuous emissions monitoring systems will be required for SO_2, NO_X, CO and HCl. A continuous opacity monitoring system will be required for visible emissions.

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 required controls ensure that the project will not be a major source of HAP.

The details are provided in the public notice package available at:

www.dep.state.fl.us/air/emission/bioenergy/highlands_envirofuels_llc.htm

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 Chapters 62-4 and 62-204 through 62-297, F.A.C.. 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, geologica, and meteorological features).*

8/8/2011

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

ALVARO A. LINERO
LICENSE
NO. 26032
aal 8/8
STATE OF FLORIDA
PROFESSIONAL ENGINEER

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

Rick Scott
Governor

Jennifer Carroll
Lt. Governor

Herschel T. Vinyard Jr.
Secretary

Sent by Electronic Mail – Received Receipt Requested

BKrohn@usenvirofuels.com
Mr. Bradley Krohn
President and Managing Member
Highlands EnviroFuels (HEF), LLC
10027 Water Works Lane
Riverview, Florida 33578

Re: DEP File No. 0550063-001-AC (PSD-FL-416)
Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

Dear Mr. Krohn:

On June 2, 2011 you submitted an application for an air construction permit subject to the preconstruction review requirements of Rule 62-212.400, Florida Administrative Code (F.A.C.), for the Prevention of Significant Deterioration (PSD) of Air Quality.

The project is the construction of a Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant that will be located south of Lake Placid in Highlands County, 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 a 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 Alvaro Linero, P.E. at 850/717-9076 or David Read at 850/717-9075.

Sincerely,

8-11-11

Jeffery F. Koerner, Program Administrator
Office of Permitting and Compliance
Division of Air Resource Management

(Date)

Enclosures

JK/gd/aal/dlr

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

Highlands EnviroFuels (HEF), LLC
10027 Water Works Lane
Riverview, Florida 33578
Authorized Representative: Mr. Bradley Krohn
President and Managing Member

DEP File No. 0550063-001-AC (PSD-FL-416)
Sugarcane/Sweet Sorghum-to-Ethanol Advanced
Biorefinery and Cogeneration Plant
Highlands County, Florida

Facility Location: The HEF facility will be located approximately 0.5 mile south-southwest of the intersection of U.S. Highway 27 and State Road (SR) 70, south of Lake Placid, in Highlands County, Florida.

Project: The project involves the construction of a 36 million gallons per year Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant utilizing cane and sorghum grown on adjacent and surrounding farmland. The cane and sorghum juice will be squeezed from the stalks, fermented, distilled and blended to make a range of ethanol/gasoline products. The leftover stalk fiber (sugarcane and sweet sorghum bagasse) along with supplemental biomass consisting of fuel crops, wood chips and vegetative debris will be used as fuel in a biomass boiler to make process steam and up to 30 megawatts (MW, gross) of electricity with 20 MW for sale to the grid. Natural gas will be used for boiler startup, flame stabilization and shutdown and also in the event of a disruption in the biomass supply. The project is subject to the preconstruction review requirements of Rule 62-212.400, Florida Administrative Code (F.A.C.) for the Prevention of Significant Deterioration of Air Quality requiring a best available control technology determination.

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 Office of Permitting and Compliance is the Permitting Authority responsible for making a permit determination for this project. The Office of Permitting and Compliance 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 Office of Permitting and Compliance phone number is 850/717-9000.

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 the 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 (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

8-11-11

Jeffery F. Koerner, Program Administrator
Office of Permitting and Compliance
Division of Air Resource Management
(Date)

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 was made available electronically on a publicly assessable server, with received receipt requested before close of business on 8-11-11 to the persons listed below.

Bradley Krohn, HEF: BKrohn@usenvirofuels.com
Ajaya Saytal, DEP SD: ajaya.satyal@dep.state.fl.us
Heather Abrams, EPA Region 4: abrams.heather@epa.gov
Dee Morse, NPS: dee_morse@nps.gov
David Buff, P.E. Golder and Associates: dbuff@golder.com
John Holbrook, Mayor, Lake Placid: john_holbrook@mylakeplacid.org
Rick Helms, Highlands County: rhelms@hcbcc.org
Jim Shore, Esq., General Counsel, Seminole Tribe of Florida: c/o amotlow@semtribe.com
Craig Tepper, Director, ERMD, Seminole Tribe of Florida: ctepper@semtribe.com
Barbara Friday, DEP OPC: barbara.friday@dep.state.fl.us
Lynn Scearce, OPC Reading File: lynn.scearce@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.

8-11-11

(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection (Department)
Division of Air Resource Management, Office of Permitting and Compliance

DEP File No. 0550063-001-AC (PSD-FL-416)
Highlands EnviroFuels, LLC
Highlands County, Florida

Applicant: The applicant for this project is Highlands EnviroFuels (HEF), LLC. The applicant's authorized representative and mailing address are: Bradley Krohn, President and Managing Member, 10027 Water Works Lane, Riverview, Florida 33578.

Facility Location: The HEF facility will be located approximately 0.5 mile south-southwest of the intersection of U.S. Highway 27 and State Road 70, south of Lake Placid, in Highlands County, Florida.

Project: The project involves the construction of a 36 million gallons per year Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant utilizing cane and sorghum grown on adjacent farmland. The cane and sorghum juice will be squeezed from the stalks, fermented, distilled and blended to make a range of ethanol/gasoline products. The leftover stalk fiber (sugarcane and sweet sorghum bagasse) along with supplemental biomass consisting of fuel crops, wood chips and vegetative debris will be used as fuel in a biomass boiler to make process steam and up to 30 megawatts (MW, gross) of electricity with 20 MW for sale to the grid. Natural gas will be used for boiler startup, flame stabilization and shutdown and also in the event of a disruption in the biomass supply. The project is subject to the preconstruction review requirements of Rule 62-212.400, Florida Administrative Code (F.A.C.) for the Prevention of Significant Deterioration (PSD) of Air Quality requiring a best available control technology (BACT) determination.

The project will result in emissions increases of 559.8 tons per year (TPY) of carbon monoxide (CO); 194.2 TPY of nitrogen oxides (NO_X); 36.9 TPY of particulate matter (PM); 30.6 TPY of PM with a mean diameter of 10 micrometers (µm) or less (PM_{10}); 19.5 TPY of PM with a mean diameter of 2.5 µm or less ($PM_{2.5}$); 6.8 TPY of sulfuric acid mist (SAM); 109.3 TPY of sulfur dioxide (SO_2); 136.6 TPY of volatile organic compounds (VOC); 0.2 TPY of lead (Pb); 1.1 TPY of fluoride (F); 9.0 TPY of hydrogen chloride (HCl); and less than 25 TPY of hazardous air pollutants (HAP).

The project will result in PSD-significant emissions increases for: NO_X, CO, SO_2, VOC, PM and PM_{10}. The controls to meet the BACT determinations for these pollutants consist of an electrostatic precipitator (ESP) on the boiler to control $PM/PM_{10}/PM_{2.5}$; good combustion practices (GCP) in a stoker (grate) boiler to control NO_X, CO and VOC; a dry sorbent injection system (DSIS) on the boiler to control SO_2, SAM and acid gas HAP such as HCl and hydrogen fluoride (HF); a non-selective catalytic reduction (SNCR) system on the boiler to control NO_X; an oxidation catalyst (Ox-cat) on the boiler to control CO, VOC and organic HAP; and liquid scrubbers on the ethanol production process, good storage tank design, and process equipment leak detection to control VOC and HAP. Emission control measures for NO_X, SO_2 and VOC will also minimize the formation of $PM_{2.5}$. Clean fuels (natural gas and ultra low sulfur distillate fuel oil) and GCP will be used in emergency equipment to control NO_X, CO, VOC, PM and SO_2 emissions.

Reasonable precautions and best management practices will be implemented to minimize fugitive dust and to ensure the biomass used at the HEF facility comports to the allowable types defined for the project.

Continuous emissions monitoring systems will be required for SO_2, NO_X, CO and HCl. A continuous opacity monitoring system will be required for visible emissions.

According to the application, the HEF project will emit less than 10 TPY of any single HAP and less than 25 TPY of all HAP combined and thus is an area source of HAP. The boiler is therefore subject to 40 Code of Federal regulations (CFR) 63, Subpart JJJJJJ - National Emission Standards for Hazardous Air Pollutants (NESHAP) for Area Sources: Industrial, Commercial and Institutional Boilers. Conditions were included in the permit to give the Department reasonable assurance that the HEF facility will be an area source of HAP.

(Public Notice to be Published in the Newspaper)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed HEF project are greater than the modeling significant impact levels applicable to areas in the vicinity of the project (i.e. PSD Class II Areas) for the pollutants SO_2 (1-hour and 24-hour averages), nitrogen dioxide (NO_2) (1-hour average) and PM_{10} (24-hour and annual averages). Therefore, multi-source PSD increment consumption modeling was required for SO_2 (24-hour average) and PM_{10} (24-hour and annual averages), but not for SO_2 or NO_2 1-hour because no increments exist for those averaging periods. The nearest PSD-Class I area is the Everglades National Park (ENP) that straddles Monroe, Collier and Miami-Dade Counties. The nearest boundary point in the ENP is located 147 km south of the proposed HEF site and is the only Class I area that is located within 200 kilometers of the proposed project. The maximum predicted project impacts in the Class I ENP are less than the applicable modeling significant impact levels for all pollutants. 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 results of the Class II multi-source increment consumption modeling are shown in the table below.

Pollutant Averaging Time	Class II PSD Increment Consumed ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Percent Increment Consumed (%)
SO_2, 24-hour	27.9	91	31
PM_{10}, 24-hour	9.6	30	32
PM_{10}, Annual	2.4	17	14

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment.

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/bioenergy/highlands_envirofuels_llc.htm

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 Office of Permitting and Compliance is the Permitting Authority responsible for making a permit determination for this project. The Office of Permitting and Compliance 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 Office of Permitting and Compliance phone number is 850/717-9000.

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 the 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 link provided 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.

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 (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)

TECHNICAL EVALUATION

&

PRELIMINARY DETERMINATION

APPLICANT

Highlands EnviroFuels, LLC
10027 Water Works Lane
Riverview, FL 33578

PROJECT

Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant
ARMS Facility ID No. 0550063

DEP File No. 0550063-001-AC (PSD-FL-416)

COUNTY

Highlands County, Florida

PERMITTING AUTHORITY

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

August 11, 2011

1. APPLICATION INFORMATION

1.1. Applicant Name and Address

Highlands EnviroFuels, LLC (HEF)
10027 Water Works Lane
Riverview, FL 33578

Authorized Representative: Dr. Bradley Krohn, President

1.2. Key Dates

- June 2, 2011 Received a Prevention of Significant Deterioration (PSD) air construction permit application from HEF.
- June 14 Department met with HEF and Golder Associates to discuss application.
- June 28 Department received additional information from HEF.
- July 1 EPA announced issuance of a final rule that defers, for a period of three years, greenhouse gas (GHG) permitting requirements for carbon dioxide (CO_2) emissions from biomass-fired and other biogenic sources.
- August 11 Department issued Draft Permit decision for HEF and posted documents.

1.3. Facility Location

The HEF facility will be located approximately 0.5 miles southwest of the intersection of U.S. Highway 27 and State Road (SR) SR 70, south of Lake Placid in Highlands County. The UTM coordinates are Zone 17; 466.407 kilometers (km) East and 3,009.015 km North. The locations of Highlands County and the proposed site are shown in Figures 1 and 2.

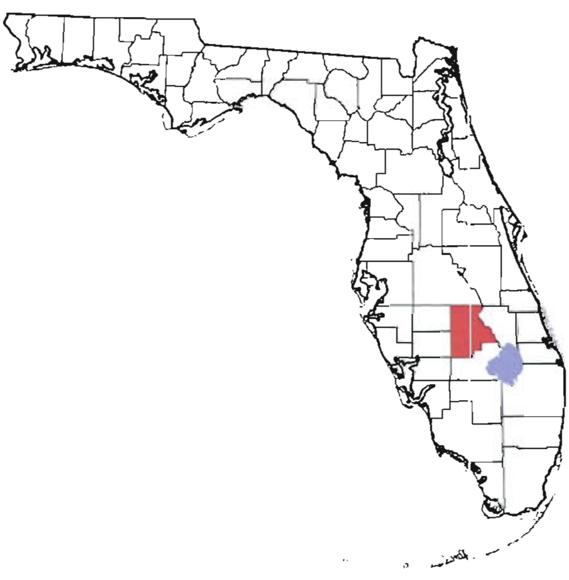

Figure 1 - Highlands County, Florida

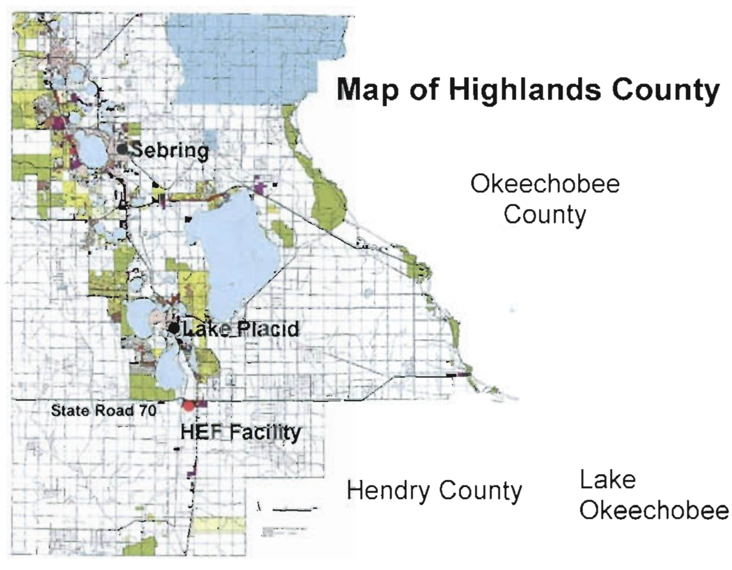

Figure 2 - Proposed Location of HEF Facility

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 36 km to the southeast. The proposed HEF facility will be located on 75 acres of citrus farmland immediately south of an east-west spur of the CSX Railroad as shown in Figure 3.

Sugarcane and sweet sorghum (cane) for the proposed HEF facility will be grown on nearby farms comprising about 30,000 to 36,000 acres. Figures 4 is a photograph taken on SR 70 near the entrance of an adjacent (inactive) industrial park located north of the HEF site. Figure 5 was taken from U.S. Highway 27 that runs in a north-south direction approximately 0.5 miles east of the site.

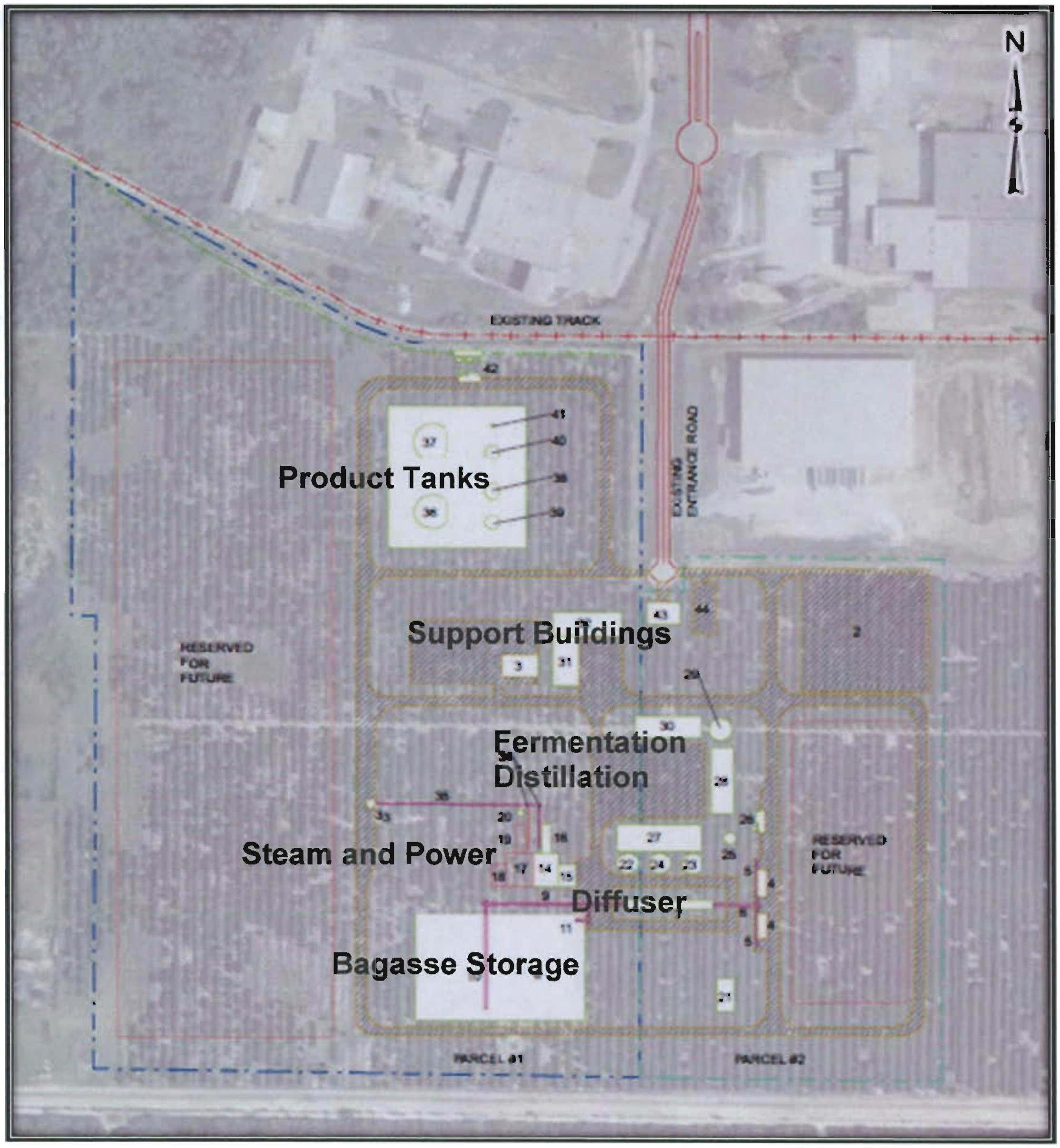

Figure 3 – Preliminary Layout of Future HEF Facility

Figure 4 – Road from SR 70 towards HEF Site

Figure 5 – View from U.S. 27 towards HEF Site

The nearest 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 approximately 147 km south of the proposed HEF site.

1.4. Project Description

The applicant proposes to construct a sugarcane and sweet sorghum-to-ethanol advanced biorefinery with a maximum annual ethanol (C_2H_5OH) production rate of 36 million gallons per year (MGPY). The cane (i.e. the sugarcane and sorghum) will be grown on nearby farmland. The juice will be squeezed from the feedstock stalks, fermented, distilled and blended to make a range of ethanol/gasoline products, including E-85 (an 85/15 ethanol/gasoline blend). The leftover stalk fiber (bagasse) will be combusted in a cogeneration biomass boiler to make process steam and up to 30 megawatts (MW, gross) of electricity. In addition to bagasse, HEF will use supplemental biomass consisting of energy crops, wood chips and vegetative debris. Natural gas will be used for startup shutdown and flame stabilization and during a disruption in the biomass supply.

The HEF process is akin to conventional sugar production practiced in South Florida, except that the juice is fermented and distilled to produce ethanol rather than evaporated and refined to produce sugar.

The main process steps are:

- Cane and other biomass receiving, handling and feeding;
- Juice extraction and evaporation;
- Ethanol production (including fermentation, distillation and dehydration);
- Product storage, blending and loadout; and
- Steam and electrical production.

Table 1 indicates the emissions units (EU) associated with this project. Figure 6, provided by HEF, is a simplified process flow diagram for the project with only the key EU indicated.

Table 1 - Process Steps Comprising the HEF by EU.

EU ID No.	Emissions Unit Description
001	Feedstock and Biomass Material Handling and Preparation
002	Biomass Boiler
003	Cooling Towers
004	Ethanol Production Process
005	Product Loadout and Flare
006	Storage Tanks
007	Miscellaneous Storage Silos
008	Emergency Equipment
009	Facility-Wide Fugitive Volatile Organic Compounds (VOC) Equipment Leaks

2. PROCESS DESCRIPTION

2.1. __(E.U. 001) Feedstock and Biomass Material Handling and Preparation__

Cane receiving. Refer to Figure 6. Harvested cane stalks in the form of 6 to 12 inch billets will arrive via trucks or rail from nearby agricultural fields to the production facility. The trucks and railcars will be weighed on a weighing bridge as they enter the unloading area. The cane in the trucks is then transferred to the feed table via a tipping trailer. Railcars will be bottom dumped into a feed hopper, which feeds the feed table. The feed table is equipped with chains that convey the cane billets toward the main conveyor that feeds the juice extraction system.

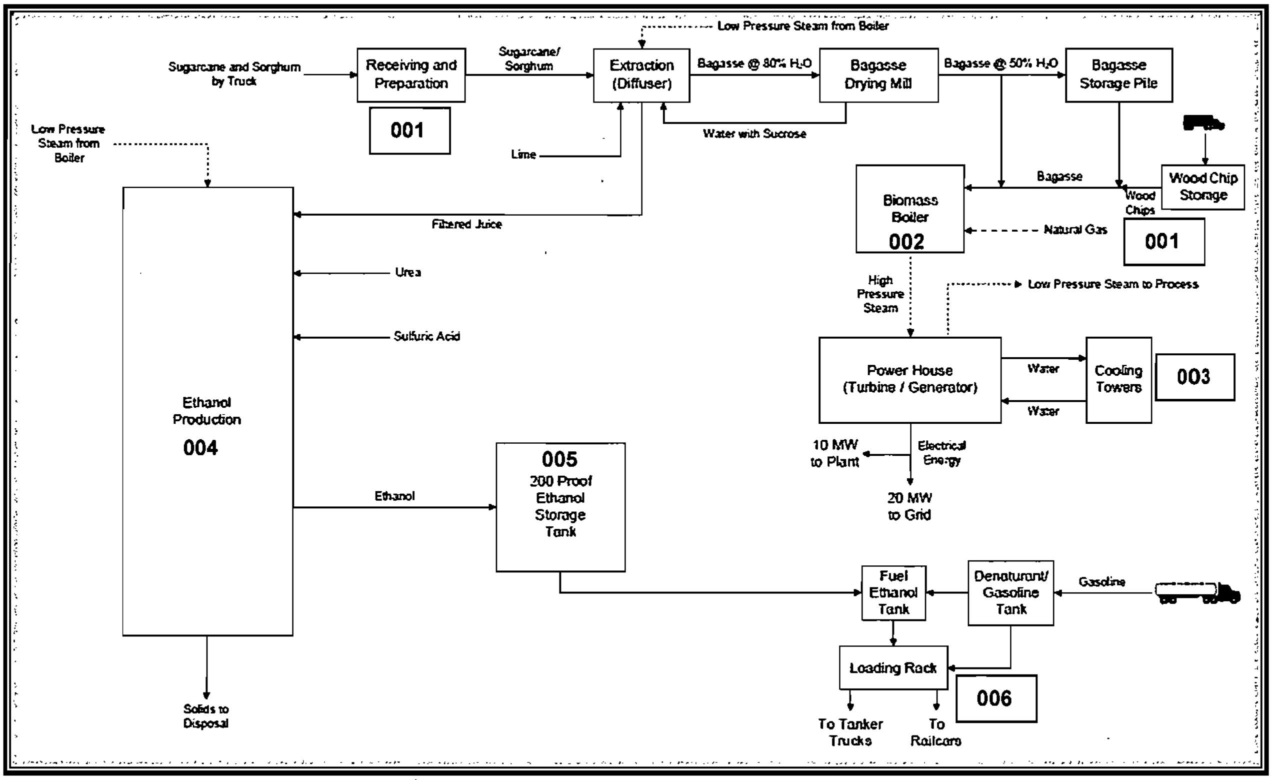

Figure 6 – Simplified Diagram of HEF Sugarcane and Sorghum to Ethanol and Power Facility

Supplemental boiler fuel receiving. Energy crops, wood chips and vegetative debris will be received from local suppliers.

Sorghum cutting, shredding and conveyance. The cane passes through several sets of revolving cane knives and one heavy-duty shredder. From the shredder, the cane passes to a high-speed belt carrier then to the diffuser feed carrier. Any excess cane is returned to the high-speed belt conveyor via the excess sorghum carrier and a chute.

The diffuser consists of a horizontal slat-type conveyor with a fixed bottom consisting of perforated screens. Beneath the screens, several semi-cylindrical transversal juice receivers will be installed. Imbibition water is fed into the juice trough and falls onto the shredded cane mat, percolates through the fibers, passes across the screen, and is collected in the last juice receiver.

As the sorghum moves across the diffuser it is progressively washed of its sucrose content. The wash water is circulated in a countercurrent manner such that it is progressively concentrated in sucrose in the direction of the incoming shredded cane.

The washed and shredded cane (now bagasse) is pressed in a roller system to approximately 50 percent (%) moisture and is then transferred to the biomass boiler. The juice is pumped to a juice screen which separates fine particles prior to evaporation. The fine particles are recycled to the diffuser. The pH of the filtered juice is adjusted and the product is stored in the juice storage tank.

2.2. (E.U. 002) Biomass Boiler Steam and Power Production

The project will employ one biomass grate stoker boiler with a maximum capacity of 504.3 million Btu per hour (mmBtu/hr on a 4-hr basis) and 485.5 mmBtu/hr on a 24-hr basis. The boiler primary fuel will be sugarcane bagasse and sweet sorghum bagasse. Biomass consisting of energy crops, wood chips and vegetative debris will be used as a supplemental boiler fuel. Natural gas will be used as a startup, shutdown and flame stabilization fuel and during a disruption in the biomass supply.

A simplified process flow diagram for the steam and power operations including proposed pollution control equipment is shown in Figure 7.

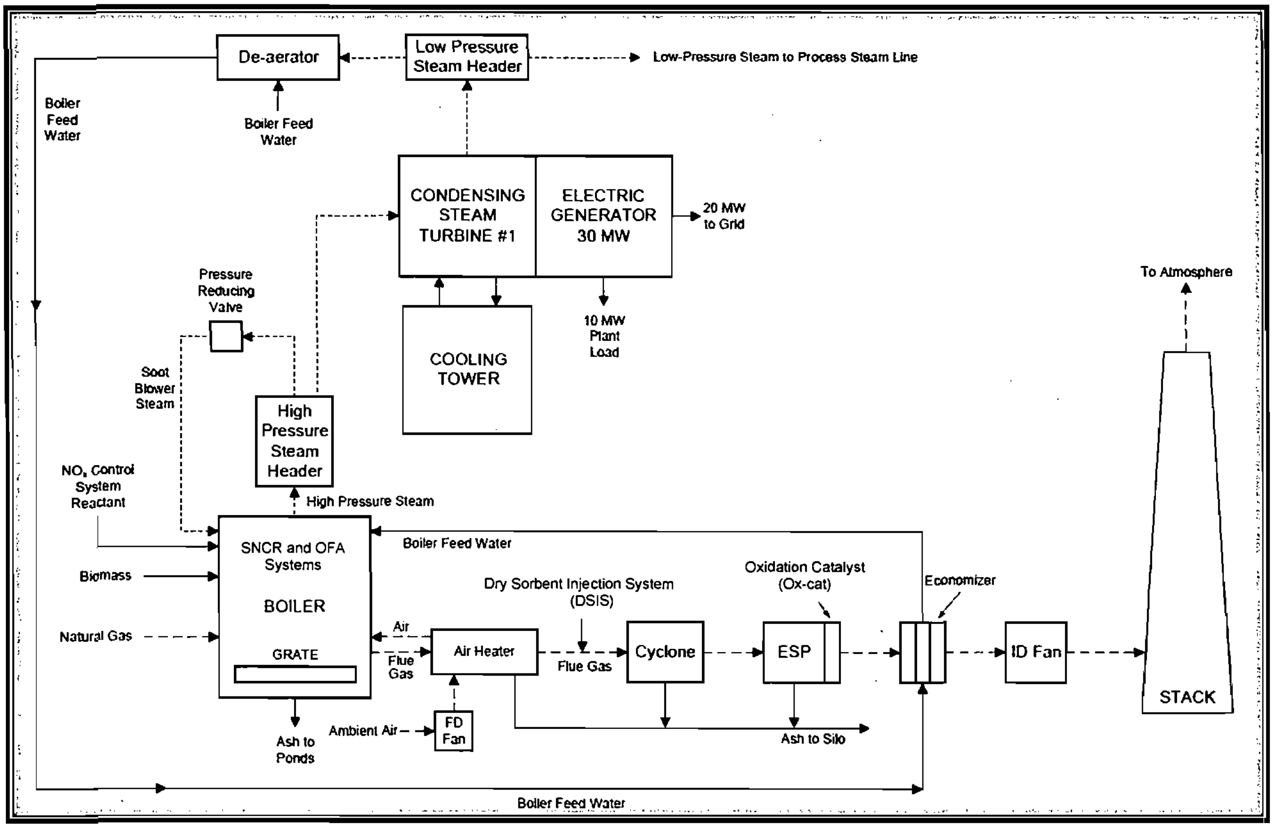

Figure 7 – Simplified Diagram of Applicant's Proposed HEF Steam and Electricity Production Cycles

The proposed pollution control systems as described by the applicant include:

- Selective non-catalytic reduction (SNCR) based on urea $[(NH_2)_2CO]$ or ammonia (NH_3) injection and a high performance overfire air (OFA) system for minimizing emissions of nitrogen oxides (NO_X);
- Low-NO_X burners (LNB) for firing natural gas;
- Mechanical collectors and an electrostatic precipitator (ESP) will be used for control of particulate matter (PM) and metals emissions;
- Use of very low-sulfur fuels and a dry sorbent injection system (DSIS) to control emissions of sulfur dioxide (SO_2) and other acid gases;
- Use of clean biomass and natural gas will also control emissions of mercury (Hg) and lead (Pb);
- The modern OFA system will also control emissions of carbon monoxide (CO) and volatile organic compounds (VOC);
- Oxidation catalyst (Ox-cat) will be used to provide further CO and VOC control as well as control of organic hazardous air pollutants (HAP).

For reference, control of PM also accomplishes control of PM with a diameter less than 10 micrometers (PM_{10}). Control/minimization of PM/PM_{10}, NO_X, SO_2, VOC and sulfuric acid mist (SAM – H_2SO_4) emissions will also control PM with an aerodynamic diameter less than 2.5 micrometers ($PM_{2.5}$). Measures such as OFA and LNB fall into the category of good combustion practices (GCP).

2.3. (E.U. 003) Cooling Towers

The proposed HEF facility will utilize up to three mechanical draft cooling towers. The cooling towers will be used for the cooling of miscellaneous machinery, the condensing set and the process equipment used in ethanol production at the HEF facility. The design parameters for the cooling towers are: one cell with a stack height of 35 feet, a combined circulating water flow rate of 34,000 gallons per minute (gpm), a temperature of 77 °F and a design drift rate of 0.001%. Cooling tower make up water will be primarily a suitable recycled process water stream. Cooling tower blowdown will be treated to remove accumulated dissolved solids and then reused for cooling tower makeup.

2.4. (E.U. 004) Ethanol Process

The ethanol process is shown in Figure 8 and consists of juice extraction, evaporation, fermentation, distillation and dehydration. The process description is paraphrased from the application.

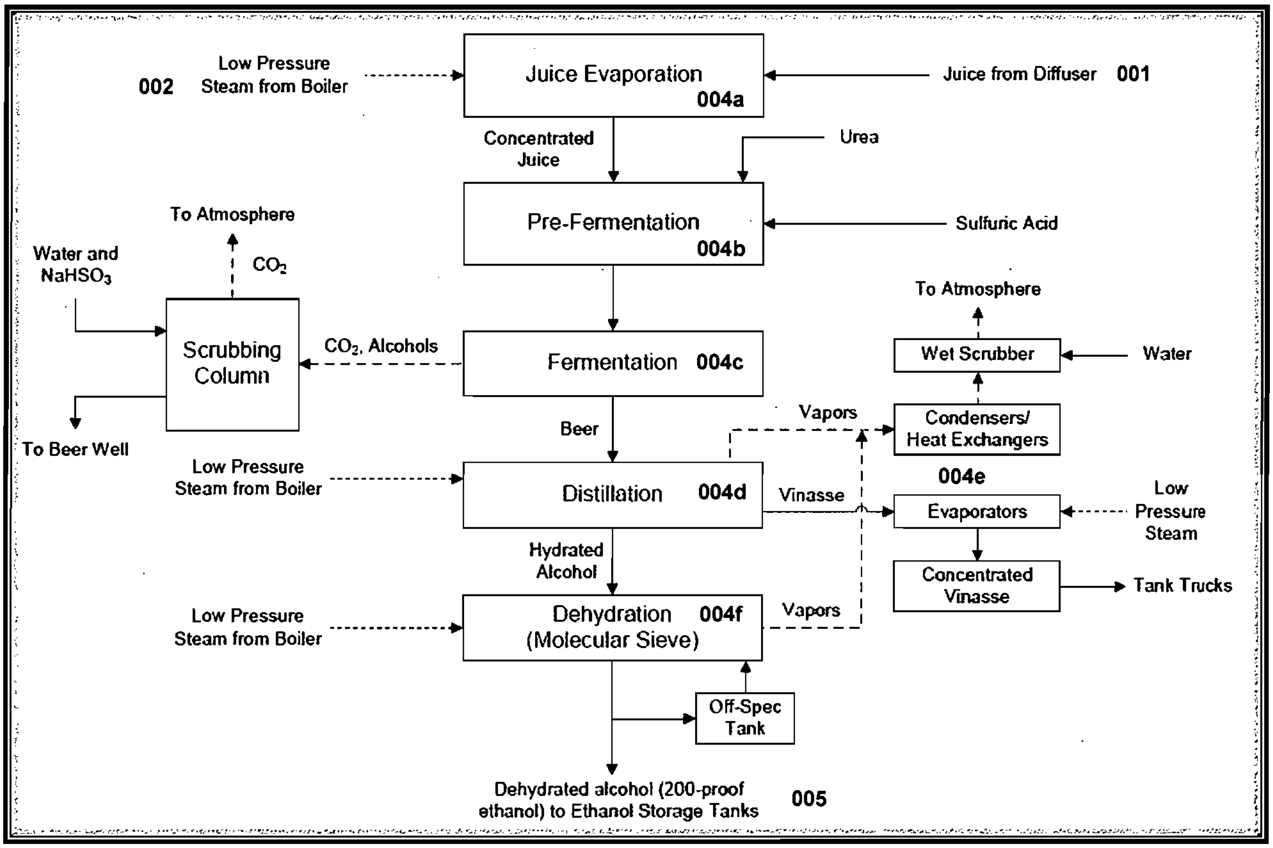

Figure 8 – Simplified Diagram of the HEF Sugarcane and Sorghum to Ethanol Production Process

Juice Evaporation (004a). The evaporation process concentrates the sucrose juices extracted in the diffuser. The extracted juice is pumped from the juice storage tank to a five-effect multiple-effect evaporator, where the juice is concentrated from 14% to 22% total solids. The concentrated juice is stored in the concentrated juice storage tank. The steam condensate is recovered and returned to the boiler feed water system. The condensed vapor condensate is collected and is then pumped to the diffuser as imbibition water for juice extraction.

Pre-fermentation (004b). Concentrated juice from the concentrated juice storage tank is first cooled using the beer feed to distillation followed by a trim heater using cooling water. The cooled, concentrated juice along with the yeast and urea (added as a nutrient) are fed to an agitated pre-fermenter. The pre-fermenter serves as a yeast propagator and initially acclimates the yeast to the fermentation conditions. Sulfuric acid is used to adjust the pH. The pre-fermenter continuously recirculates the ferment through a heat exchanger to keep the temperature in the optimum range for fermentation.

Fermentation (004c). During fermentation, sugars contained in the concentrated juice are transformed to ethyl alcohol, carbon dioxide (CO_2) and various secondary products. Secondary products include other alcohols, aldehydes, glycerin, etc. There are a total of four agitated fermenters in series, each having controlled temperature and controlled additions of urea and yeast to maintain optimum fermentation conditions. The ferment is continuously transferred from the pre-fermenter to the first fermenter based on level. Flow is maintained from one fermenter to another based on level.

The product of fermentation, called "beer," is a weak ethanol solution and contains the residue of fermentation components. The beer is pumped to a holding tank, designated as the beer well. The alcohol concentration in the clean beer is generally 8%. Solid substances include yeast, bacteria, non-fermentable solids, mineral salts, albuminoidal substances and other miscellaneous substances. Dissolved gases include CO_2 and SO_2.

The off-gases from the fermentation vessels are collected and sent to a packed scrubbing column, called the CO_2 scrubber. The CO_2 scrubber uses water, fortified with sodium bisulfite ($NaHSO_3$), to remove water soluble components, such as ethanol, and to chemically remove acetaldehyde. The off-gases, which are composed primarily of CO_2 with minor traces of ethanol and other organic compounds, are released to the atmosphere. The CO_2 scrubber effluent is sent to the stripper column for removal of ethanol and related compounds.

The following equipment will be used in steps 004b and 004c: rotary screens; juice evaporator; clean and foul condensate tanks; a sulfuric acid tank; a urea tank; yeast mixing tank; pre-fermenter; pre-fermenter cooler; fermenters; fermenter coolers; beer well tank; beer/sucrose heat exchanger; and CO_2 scrubbing column.

Distillation (004d). From the beer storage, the beer is sent to a pre-heater and then to a beer/stillage heat exchanger. The gas removed in the degassing column is cooled, scrubbed in the distillation scrubber and then released to atmosphere. The beer column overhead is transferred in the vapor phase to the rectifier column.

The alcohol stream is increased to 91% by weight ethanol concentration in the rectifier column. Rectifier overhead vapor is sent to the molecular sieve units to further remove water to less than 0.7% by weight in the ethanol product. Propanol and fusel oils are removed from the lower section of the rectifier column and combined with the 91% ethanol vapor which goes to the molecular sieves.

Rectifier bottoms are sent to a stripper column to strip remaining traces of ethanol from the rectifier bottoms. The bottoms from the stripper column are comprised of almost pure water, and are reused in the process. The stripper column overhead vapor is sent back to the rectifying column.

The following equipment will be used in step 004d: beer distillation column; degassing column; degassing condenser; stripping column; rectification column; heat exchangers; fusel oil decanter; hydrated alcohol tank; CO_2 washing column; and scrubber water degasser.

Vinasse Evaporation (004e). The beer column bottom stillage, called vinasse, is cooled using the incoming beer as the heat sink and sent to storage. From the storage, the vinasse is evaporated to 40% solids using a combination of several waste heat sources and live steam in three sets of multiple effect evaporators. The concentrated vinasse is stored and then loaded onto trucks for shipment to be utilized for animal feed.

Vinasse evaporator vapor condensates will normally be less than 3,000 parts per million (ppm) chemical oxygen demand (COD) with 70 pounds per hour (lb/hr) dissolved solids, 26 lb/hr alcohol and 44 lb/hr liquid fermentation byproducts. The condensed vinasse vapor condensate stream will be processed as necessary for reuse as cooling tower make-up.

The zeolite beds must be regenerated periodically by vacuum. The molecular sieve bed being regenerated is first isolated from the incoming hydrated ethanol steam and the inlet of this bed is valved to a regeneration condenser. A purge stream consisting of a portion of the dehydrated product from the on-line molecular sieve is fed into the outlet of the regenerating molecular sieve. The non-condensable vapors from the regeneration condenser are removed via a two-stage steam ejector or a liquid ring vacuum pump. The cooled non-condensable vapors are then fed to the distillation vent scrubber. The condensed liquid from the regeneration condenser is reclaimed by sending it back to the rectifier column.

The following equipment will be used in step 004e: multiple effect evaporators; raw and concentrated vinasse storage vessels; and a load out system.

Dehydration (004f): The final stage in the ethanol production process is dehydration. Hydrated alcohol from the distillation process, at about 96% by volume alcohol, undergoes dehydration with a molecular sieve to produce ethanol at 99.3% by weight purity. The process is performed in a continuous operation where the hydrated alcohol is superheated by steam in a shell and tube heat exchanger to ensure that the ethanol stream is always in the vapor phase as it passes through molecular sieve zeolite beds. The final ethanol product is condensed, cooled, and sent to the 200-proof storage tank.

The following equipment will be used in step 004f: hydrated alcohol heater; zeolite absorber (molecular sieve); condensers and coolers; filter; dehydrated alcohol holding tank; and tie-in to CO_2 washing column.

Air Pollution Control Equipment. Two wet scrubbers will be used in the ethanol production area to control emissions of ethanol, other VOC and organic HAP. One will be incorporated into the fermentation step (with $NaHSO_4$) and the other will be incorporated into the distillation and dehydration steps. According to the applicant, the two scrubbers will have ethanol/VOC removal efficiencies of 98%.

2.5. (E.U. 005) Volatile Organic Liquid Storage Tanks: Denaturant/Gasoline, Alcohol, Blends

The facility will contain several volatile organic liquids (VOL) organic storage tanks for ethanol, second grade alcohol, denaturant/gasoline and blending tanks. The following tanks will be controlled by internal floating roofs and are subject to Title 40 of the Code of Federal Regulations (CFR), Part 60, Subpart Kb (40 CFR 60, Subpart Kb):

- One fuel ethanol storage tank with a capacity of 1,000,000 gallons (gal);
- One 200 proof ethanol storage tank with a capacity of 100,000 gal;
- One off-specification (off-spec) tank with a capacity of 100,000; and
- One denaturant/gasoline tank with a capacity of 100,000 gal.

The following tanks are not subject to 40 CFR 60, Subpart Kb and will have a vertical fixed roof (VFR):

- One corrosion inhibitor tank with a capacity of 2,500 gal.

The facility will include several liquid chemical storage tanks to store sulfuric acid, phosphoric acid and ammonia or urea. All of these tanks will be of a VFR design except for an anhydrous NH_3 storage tank, which will be of a horizontal pressurized design.

2.6. (E.U. 006) Truck and Rail Loadout and Flare

Loading racks will be used to load out denatured fuel ethanol from the product storage tank to trucks and railcars. In-line blending for gasoline and ethanol to produce a denatured product may also take place at the loading rack. One loading rack will be provided for trucks, and one for railcars. The maximum truck loading rate of each rack will be 600 gpm. During ethanol loadout, ethanol and gasoline vapors can be generated. The vapors are sent to the loading racks flare for destruction. The loading racks and the flare will be permitted to operate up to 3,120 hr/yr. A truck loading rack will be used to load ethanol and ethanol blends from the product storage tank to trucks. The product loadout flare will have a rated capacity of 9.8 mmBtu/hr to control VOC vapors displaced from the trucks during the loading of denatured ethanol product.

2.7. (E.U. 007) Miscellaneous Materials Storage Silos

Materials storage silos will be installed to store material for the DSIS and to store ash, as well as lime for the water treatment system. Each silo will be controlled by a baghouse or a bin vent filter.

2.8. (E.U. 008) Emergency Equipment

There will be one diesel or natural gas-fired electric generator of 2,000 kilowatt (kW) capacity, for purposes of supplying electric power to the facility during a black start or a power failure. The generator will be limited to 500 hr/yr of operation during emergencies and 100 hr/yr for maintenance and testing. There will be one diesel or natural gas-fueled 600 horsepower (hp) diesel fire pump will also be installed to provide firewater during emergencies. This engine will be limited to 500 hr/yr of operation during emergencies and 100 hr/yr for maintenance and testing.

2.9. (E.U. 009) Facility-wide Fugitive VOC Equipment Leaks

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

2.10. Project Emissions

Tabulations of project emissions are given and discussed in conjunction with major source review applicability in Sections 3.3, 3.4 and 3.5 below.

3. APPLICABLE REGULATIONS

3.1. State Regulations

This project is subject to the applicable environmental laws specified in Chapter 403 of the Florida Statutes (F.S.). The F.S. authorize the Department of Environmental Protection (Department) 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. and summarized in Table 2.

Table 2 - Applicable Rules from the F.A.C.

F.A.C. Rule	Description
62-4	Permits
62-204	Air Pollution Control – General Provisions
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Stationary Sources – Preconstruction Review
62-213	Operation Permits for Major Sources (Title V) of Air Pollution
62-214	Requirements for Sources Subject to the Federal (Title IV) Acid Rain Program
62-296	Stationary Sources – Emission Standards
62-297	Stationary Sources – Emissions Monitoring

3.2. Federal Regulations

The U.S. Environmental Protection Agency (EPA) establishes air quality regulations in 40 CFR Part 60 that identifies New Source Performance Standards (NSPS) for a variety of industrial activities. 40 CFR Part 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP). 40 CFR Part 63 specifies NESHAP provisions based on the Maximum Achievable Control Technology (MACT) for given source categories.

Federal regulations adopted by reference are given in Rule 62-204.800, F.A.C. State regulations approved by EPA are given in 40 CFR Part 52, Subpart K – Florida, also known as the State Implementation Plan (SIP) for Florida.

3.3. PSD Major Stationary Source Applicability Determination

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 (PTE) 250 tons per year (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. The planned HEF facility is a major stationary source because it is: *"A chemical processing plant which emits, or has the PTE, 100 TPY or more of any PSD pollutant."*

According to EPA rules at 40 CFR 52.21(b)(1)(iii)(*t*), *"the term chemical processing plant shall not include ethanol production facilities that produce ethanol by natural fermentation included in NAICS codes 325193 or 312140."* Thus EPA regulations would consider HEF to be a major stationary source if it emits or has the potential to emit 250 TPY or more of any PSD pollutant. On July 27, 2011 the Department held a workshop for the purpose of initiating rulemaking to revise Rule 62-210.200(189) consistent with the federal definition. See link to Ethanol Rule Project .

PSD pollutants include: CO; NO_X; SO_2; PM; PM_{10}; VOC; Pb; Fluorides (F); SAM; total reduced sulfur (TRS), including H_2S; municipal waste combustor (MWC) organics measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans (D/F); MWC metals measured as PM; MWC acid gases measured as SO_2 and hydrogen chloride (HCl); and 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, (Definitions) F.A.C. Emissions of PSD pollutants from the project exceeding these SER are considered "significant" and 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 given in Table 3.

Table 3 – List of SER by PSD-Pollutant [1, 4]

Pollutant	SER (TPY)	Pollutant	SER (TPY)
CO	100	NO_X	40
PM/PM_{10} [2]	25/15	Ozone (VOC) [3]	40
Ozone (NO_X) [3]	40	SAM	7
SO_2	40	F	3
Pb	0.6	TRS	10
H_2S	10	Hg	0.1

1. Excluding those defined exclusively for MWC and MSW landfills.
2. PM with a diameter less than 2.5 micrometers ($PM_{2.5}$) is also a PSD pollutant, but an SER has not yet been defined in the Department's rules. It is regulated by its precursors and surrogates (e.g. PM/PM_{10} NH_3, SO_2 and NO_X).
3. Ozone (O_3) is regulated by its precursors (VOC and NO_X).
4. There is a federal SER of 75,000 TPY for Greenhouse Gases (GHG) as carbon dioxide equivalent (CO_2e) that has not been incorporated into Department rules. However, the applicability to the CO_2 component of GHG emissions from bioenergy and biogenic stationary sources was recently deferred by EPA until the second half of 2014. Refer to: Link to Final CO2 PSD Deferral .

$PM_{2.5}$ is also a Federal PSD pollutant and the Department is in the process of adopting a SER of 10 TPY. Refer to Link to $PM_{2.5}$ Rule . Until the rule is finalized, projects in Florida are not subject to a SER for $PM_{2.5}$.

Table 4 summarizes the applicant's estimates of key PSD pollutants from the proposed HEF project. The project will result in emissions of NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, SAM, VOC, Pb and Hg. It is clear that the greatest emission source by far is the boiler, which accounts for more than 85% of all PSD-pollutants to be emitted from the HEF facility. The facility will also emit approximately 32.3 TPY of NH_3 (not a PSD-pollutant) largely due to injection of urea to control NO_X emissions.

In summary, the HEF project will emit at least 100 TPY of at least three PSD pollutants (SO_2, NO_X and VOC) and at least 250 TPY of CO. Emissions of the following PSD air pollutants as proposed by the applicant will exceed their respective SER: NO_X, PM/PM_{10}, SO_2, CO, SAM, and VOC. Therefore, the HEF project will be subject to the Department's PSD rules including PSD ambient air modeling and a requirement for a best available control technology (BACT) determination for the cited pollutants. $PM_{2.5}$ will be addressed by the BACT evaluations for its precursors and surrogates [e.g. NO_X, SO_2 and VOC].

For reference, the applicant has requested a federally enforceable limit on natural gas consumption to insure that the project will not trigger the 75,000 TPY CO_2e SER for GHG even after exclusion of the CO_2 component of bioenergy/biogenic emissions from bagasse use in the boiler.

3.4. Major Source of Air Pollution (Title V Source) Determination

As defined in Rule 62-210.200(188), F.A.C., a Title V source is an emissions unit or group of emissions units that directly emits, or has a PTE of, 100 TPY or more of any regulated air pollutant.

Table 4 – Applicant's Estimated PTE of Key PSD Pollutants (in TPY) for the SER Facility[1]

Operation/EU	CO	NO_X	PM/PM_{10} [1]	$PM_{2.5}$ [1]	SO_2	SAM	VOC	Hg[3]	Pb
Biomass Material Handling (001)			7.9/1.8	0.3					
Boiler (002)	552.9	184.3	27.6/27.6	18.0	200.4	9.8	31.3	0.025	0.18
Cooling Towers (003)			0.37/0.19	0.19			0		
Ethanol Production (004)							87.6		
Storage Tanks (005)							3.9		
Product Loadout and Flare (006)	5.64	1.04	0.052	0.052	0.009		7.0		
Miscellaneous Storage Silos (007)			0.85	0.85			0		
Emergency Equipment (008)	1.29	8.84	0.087	0.087	0.0063		0.26		
Fugitive Equipment Leaks (009)							6.5		
Totals	559.8	194.2	36.9/30.6	19.5	200.4	9.8	136.6	0.025	0.18
SER	100	40	25/15	(10) [2]	40	7	40	0.1	0.6
PSD Applies? (Yes/No)	Yes	Yes	Yes	No [2]	Yes	Yes	Yes	No	No

1. Estimates based on filterable (front-half sampling train) material and do not include condensable (back-half) material.
2. PSD would apply based on the federal SER (reference 40 CFR 52.21) of 10 TPY for $PM_{2.5}$ or 40 TPY of its surrogates (NO_X or SO_2). PSD does not apply per the present Department rules incorporated into the federal rules at 40 CFR 52, Subpart K.
3. Uncontrolled estimate equals 50 pounds Hg per year (lb/yr). Applicant expects much lower emissions.

The Major (Title V) Source of Air Pollution definition also includes, any emissions unit or group of emissions units that (except for radionuclides) emits or has the PTE of, in the aggregate, 10 tons TPY or more of any one HAP, 25 TPY or more of any combination of HAP, or any lesser quantity of a HAP as established through EPA rulemaking. Specific HAP are defined/listed in Rule 62-210.200(155), F.A.C.

The emissions estimates given in Table 4 are sufficient to conclude that the HEF facility will be a Title V source based on emissions of regulated air pollutants regardless of HAP emissions.

3.5. HAP Major Source Non-Applicability Determination

As defined in 40 CFR 63, Subpart A, adopted and referenced in Rule 62-204.800(11)(d)1, F.A.C., and per Rule 62-210.200(188 – Major Source of Air Pollution), F.A.C., a major source of HAP means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the PTE of, considering controls, in the aggregate, 10 TPY or more of any HAP or 25 TPY or more of any combination of HAP, unless the Administrator establishes a lesser quantity, or in the case of radionuclides, different criteria from those specified in this sentence. See Subpart A .

Pursuant to Rule 62-210.200 (188), F.A.C., if a facility is a major source of HAP it will also be a Title V source. Table 5 is a summary of the applicant's estimate of HAP from the key emission categories at the HEF facility. The main source of HAP is the boiler. The greatest single HAP emitted from the biomass boiler is HCl at 6.85 TPY followed by chlorine (Cl_2) at 3.03, formaldehyde at 2.69 TPY and benzene at 2.17 TPY. The other key HAP emission (> 1 TPY) is acetaldehyde from the ethanol process at 2.87 TPY.

According to the applicant's estimate, the facility (boiler and other processes) does not constitute a major source. If the facility emissions equal or exceed the 10 or 25 TPY HAP thresholds, then the ethanol process will be subject to a number of promulgated NESHAP including 40 CFR 63, Subpart FFFF – NESHAP: Miscellaneous Organic Chemical Manufacturing, adopted and incorporated as Rule 62-204.800(11)(d)63., F.A.C. See Subpart FFFF .

If the facility emissions were to equal or exceed the 10 or 25 TPY HAP thresholds, then the boiler would ultimately be subject to the Boiler NESHAP pursuant to 40 CFR 63, Subpart DDDDD, which was revised on March 21, 2011. See Revision to Subpart DDDDD . The rule (for which implementation has been delayed) includes very stringent PM limits as well as specific limits for Hg, HCl and D/F.

Table 5 – Applicant's Estimated PTE of HAP from the HEF Project in TPY

Pollutant	HCl	HF	Cl_2	Key Metal HAP [1]	Key Organic HAP [2,3]	Other HAP	Total
Boiler	6.85	0.04	3.03	1.05	7.11	0.18	18.26
Ethanol Process					4.24		4.24
Other Sources						0.67 [4]	0.67
Total	6.85	0.04	3.03	1.05	11.35	0.85	23.17

1. Key metal HAP for the boiler consist of chromium (Cr), lead (Pb), manganese (Mn) and nickel (Ni).
2. Key organic HAP for the boiler consist of acetaldehyde (C_2H_4O), acrolein (C_3H_4O), benzene (C_6H_6), Bis(2-ethylhexyl) phthalate ($C_{24}H_{38}O_4$), formaldehyde (CH_2O), styrene (C_8H_8), toluene (C_7H_8) and polycyclic aromatic hydrocarbon/polycyclic organic matter (PAH/POM).
3. Key Organic HAP for the ethanol process consists of: acetaldehyde (C_2H_4O), acrolein (C_3H_4O), formaldehyde (CH_2O) and methanol (CH_4O).
4. This includes all HAP for all other sources such as fugitive emissions from equipment leaks and tanks.

On May 18, 2011 EPA delayed the effective date of Subpart DDDDD until proceedings for judicial review of this rule are completed or the EPA completes its reconsideration of this rule, whichever is earlier. See Delay of Subpart DDDDD .

The Department will include sufficient conditions in the permit to provide reasonable assurance that the project will not be a major source of HAP and therefore not subject to Subpart DDDDD.

3.6. Review of other Key Regulatory Provisions for Applicability to Project

Following is a summary of the applicability of key regulatory provisions to the HEF project.

Chapter 62-4, F.A.C. www.dep.state.fl.us/air/rules/fac/62-4.pdf

Rule 62-4.070(1), F.A.C., Standards for Issuing or Denying Permits; Issuance; Denial.

This rule applies to all permitting decisions:

- A permit shall be issued to the applicant upon such conditions as the Department may direct, only if the applicant affirmatively provides the Department with reasonable assurance based on plans, test results, installation of pollution control equipment, or other information, that the construction, expansion, modification, operation, or activity of the installation will not discharge, emit, or cause pollution in contravention of Department standards or rules.

Chapter 62-17, F.A.C. www.dep.state.fl.us/siting/files/rules_statutes/pps_rule.pdf

- The HEF project is not subject to certification pursuant to the power plant siting provisions of this rule because it will produce less than 75 MW of power.

Chapter 62-204, F.A.C. www.dep.state.fl.us/air/rules/fac/62-204.pdf

Rule 62-204.220(1), F.A.C., Ambient Air Quality Protection.

This rule applies to all air permitting decisions.

- The Department shall not issue an air permit authorizing a person to build, erect, construct, or implant any new emissions unit; operate, modify, or rebuild any existing emissions unit; or by any other means release or take action which would result in the release of an air pollutant into the atmosphere which would cause or contribute to a violation of an ambient air quality standard established under Rule 62-204.240, F.A.C.

Rule 62-204.240, F.A.C., Ambient Air Quality Standards.

This rule applies to all air permitting decisions.

- Refer to list of pollutants and ambient air quality standards provided therein and discussed in the Ambient Air Quality Section of this evaluation.

Rule 62-204.800(8), F.A.C., 40 CFR 60, NSPS.

The following provisions incorporated into Rule 62-204.800(8), F.A.C. adopted from 40 CFR 60 and incorporated into this rule apply to this project:

- 40 CFR 60, Subpart A – General Provisions which regulates all EU that are subject to a NSPS standard and, in particular, flare pilot flames (EU 005);
- 40 CFR 60, Subpart Db – Industrial-Commercial-Institutional Steam Generating Units (EU 002);
- 40 CFR 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 (EU 006);
- 40 CFR 60, Subpart IIII – Stationary Compression Ignition Internal Combustion Engines (ICE) (EU 008); and
- 40 CFR 60, Subpart VVa – VOC Equipment Leaks from SOCMI Processes (EU 002, 003,004, 005, 006, 007 and 009).

The boiler (EU 002) will combust a fuel feed stream containing approximately 10% (much less than 30%) of materials (e.g. vegetative waste) that could be construed to be municipal solid waste (MSW). Therefore the HEF is exempt from the following rule:

- 40 CFR 60, Subpart Eb – Large Municipal Solid Waste Combustors for Which Construction is Commenced After September 20, 1984 or for Which Modification or Reconstruction is Commenced After June 19, 1996.

By letter dated March 26, 2009, EPA provided a determination to the Department that the following NSPS do not apply to the Vercipia Ethanol project (and by extension to the HEF) that processes ethanol produced by biological processes:

- 40 CFR 60 Subpart NNN – VOC Emissions from SOCMI Distillation Operations; and
- 40 CFR 60 Subpart RRR – VOC Emissions from SOCMI Reactor Processes.

Rule 62-204.800(11), F.A.C., 40 CFR 63, NESHAP.

The following provisions incorporated into Rule 62-204.800(11), F.A.C. adopted from 40 CFR 63 and incorporated into this rule apply to this project:

- 40 CFR 63, Subpart A – General Provisions (to the extent explicitly identified within each applicable 40 CFR 63 standard);
- 40 CFR 63, Subpart JJJJJJ – Industrial, Commercial, and Institutional Boilers Area Sources; and

- 40 CFR 63, Subpart ZZZZ – Stationary Reciprocating Internal Combustion Engines (RICE). This subpart requires all affected area source units to meet the applicable emission standards of 40 CFR 60, Subpart IIII. 40 CFR 63, Subpart A is explicitly excluded when applying this standard.

The following provisions incorporated into Rule 62-204.800(11), F.A.C. adopted from 40 CFR 63 and incorporated into this rule do not apply to this project because after applicant-proposed and Department-required controls it is not a major source of HAP:

- 40 CFR 63, Subpart B – Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act (CAA) Sections, Sections 112(g) and 112(j);
- 40 CFR 63, Subpart DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters (applicable to major sources of HAP); and
- 40 CFR 63, Subpart FFFF – Miscellaneous Organic Chemical Manufacturing (and by reference Subparts H , Q, SS, TT, UU, WW, and GGG).

Chapter 62-210, F.A.C. www.dep.state.fl.us/air/rules/fac/62-210.pdf

62-210.200, F.A.C., Definitions.

- The project is a Title V or "Major Source" of air pollution because the PTE of at least one regulated pollutant will exceed 100 TPY.
- The project is not a major source of HAP because it will not emit or have PTE of 10 TPY or more of any one HAP or 25 TPY or more of any combination of HAP.
- The project is classified as a "Major Stationary Source" (PSD-source) because it emits 100 TPY or more of a PSD pollutant and is (until completion of ongoing Department rulemaking) one of the 28 facility categories listed in the definition with the PSD applicability threshold of 100 TPY.

Rule 62-210.300, F.A.C., Permits Required.

- Unless exempted, the owner or operator of any facility or emissions unit which emits or can reasonably be expected to emit any air pollutant shall obtain appropriate authorization (i.e. a permit) from the Department prior to undertaking any activity at the facility or emissions unit for which such authorization is required.

Rule 62-210.350, F.A.C. Public Notice and Comment.

- A notice of proposed agency action on permit application, where the proposed agency action is to issue the permit, shall be published by any applicant.
- The rule details additional public notice requirements for emissions units subject to PSD. Examples include: the location and nature of the project; whether BACT has been determined; PSD increment consumption; and notification to the public of the opportunity to submit comments or request a public hearing (meeting).

Rule 62-210.700, F.A.C., Excess Emissions.

This rule applies to all air permitting decisions. Only the key provisions potentially affecting this project are listed.

- 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 two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
- 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.

- 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.

Chapter 62-212, F.A.C. www.dep.state.fl.us/air/rules/fac/62-212.pdf

Rule 62-212.300, F.A.C., General Preconstruction Review Requirements.

- This rule generally applies to the construction or modification of air pollutant emitting facilities in those parts of the state in which the state ambient air quality standards are being met.

Rule 62-212.400, F.A.C., PSD.

- The rule applies because the project is a major stationary (PSD) source.

Chapter 62-213, F.A.C. www.dep.state.fl.us/air/rules/fac/62-213.pdf

- Because the facility is a Title V source, the applicant will be required to apply for and obtain a Title V operation permit in the future.

Chapter 62-214, F.A.C. www.dep.state.fl.us/air/rules/fac/62-214.pdf

- The applicant asserts that the planned facility is a cogeneration plant and not subject to the Acid Rain Program (ARP) because it will provide 219,000 MW-hours or less of actual electric output on an annual basis to any utility power distribution system for sale on a gross basis. However, if in any three calendar year period, such unit sells to a utility power distribution system an annual average of more than one-third of its potential electrical output capacity and more than 219,000 MW-hours of actual electric output, that unit shall be an affected unit, subject to the requirements of the ARP.

Chapter 62-296, F.A.C. www.dep.state.fl.us/air/rules/fac/62-296.pdf

Rule 62-296.320, F.A.C., General Pollutant Emission Limitation Standards.

- This rule prohibits the discharge of air pollutants which cause or contribute to an objectionable odor;
- This rule specifies a visible emissions standard of 20 percent (%) opacity; and
- The rule prohibits emissions of unconfined PM provisions without taking reasonable precautions to prevent such emissions.

Rules 62-296.401, F.A.C., Incinerators

- The facility will combust primarily cane bagasse, which is clearly fuel and not a waste in this industry. Only the wood chips and vegetative debris (which will comprise no more than approximately 10% of the fuel) could be construed to be waste. The Department's definition of "incinerator" at Rule 62-210.200(160), F.A.C. is "a combustion apparatus designed for the ignition and burning of solid, semi-solid, liquid or gaseous combustible wastes". The furnace is not specifically designed to burn wastes though it is capable of burning some waste as supplementary fuel. The Department concludes that neither he term the term "incinerator" nor the incinerator rule applies to this project. Furthermore, this rule contains less stringent requirements than the applicable NSPS, NESHAP and case-by-case BACT.

Rule 62-296.416, F.A.C., Waste-to-Energy (WTE) Facilities

- This rule does not apply because per Rule 62-210.200(327), F.A.C., the term "WTE facility" does not include facilities that primarily burn fuels other than solid waste, even if the facility also burns some solid waste as a fuel supplement. The term also does not include facilities that burn vegetative, agricultural, or silvicultural wastes, bagasse, clean dry wood, methane or other landfill gas, wood fuel derived from construction or demolition debris, or waste tires, alone or in combination with fossil fuel. The facility will typically burn 90% (or more) fuels "other than solid waste".

Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 mmBtu/hr Heat Input

- This rule applies only to the extent that fossil fuel is burned in the boiler. The fossil fuel heat input capability of the boiler will be less than 250 mmBtu/hr. This provision requires compliance with applicable NSPS requirements for visible emissions, PM, NO_X and SO_2 (e.g., NSPS Subpart Db requirements).

Rule 62-296.410, F.A.C., Carbonaceous Fuel Burning Equipment.

- Cane bagasse is carbonaceous fuel when directly combusted and this rule requires that the carbonaceous component of fuel combustion comply with a PM standard of 0.2 lb/mmBtu. Visible emissions are limited to 30% opacity except that 40% opacity is permissible for not more than 2 minutes in any hour.

Rule 62-296.470, F.A.C., Implementation of Federal Clean Air Interstate Rule (CAIR).

- The HEF facility is not subject to CAIR. On July 6, 2011, EPA announced, but has not yet published in the Federal Register a rule known as the Cross-State Air Pollution Rule (CSAPR) that will replace CAIR. The HEF facility is not subject to the Cross-State Air Pollution Rule (CSAPR), because its biomass boiler is a cogeneration unit that will sell less than 219,000 megawatt hours (MWh) per year of electricity to the grid. Details are available at the following link: Pre-publication CSAPR .

4. BACT REVIEW

Based on the applicant's emission estimates, BACT determinations are required for the pollutants that are subject to PSD review, including CO, NO_X, PM/PM_{10}, SO_2, SAM and VOC. These determinations are provided in the following sections and are organized and presented by process step. A BACT determination for $PM_{2.5}$ is not required because the Department has not yet adopted a SER for $PM_{2.5}$ and identified it as a PSD-pollutant.

Even without a SIP requirement and without approved test methods or accounting requirements, the Department nevertheless relies on precursors and surrogates to minimize direct emissions and subsequent formation of $PM_{2.5}$ per the rationale given below.

On September 16, 1997, EPA revised the NAAQS for particulate matter, which includes a new NAAQS 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 CAA, 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 SIP to address the new $PM_{2.5}$, NAAQS, PSD SER 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, and NO_X).

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.

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

PM/PM_{10} Emissions

Discussion. PM/PM_{10} represent the only pollution of concern from EU 001. Refer to the description of EU 001 in Section 2.1 above. The trucks that will be used to deliver sweet sorghum feedstock and supplemental boiler fuel biomass along with the biomass handling and processing itself will generate fugitive dust.

Figure 9 below is a diagram of the bagasse and supplemental boiler biomass feed system. Because of the biomass high moisture content, fugitive emissions are expected to be minimal from this part of the process.

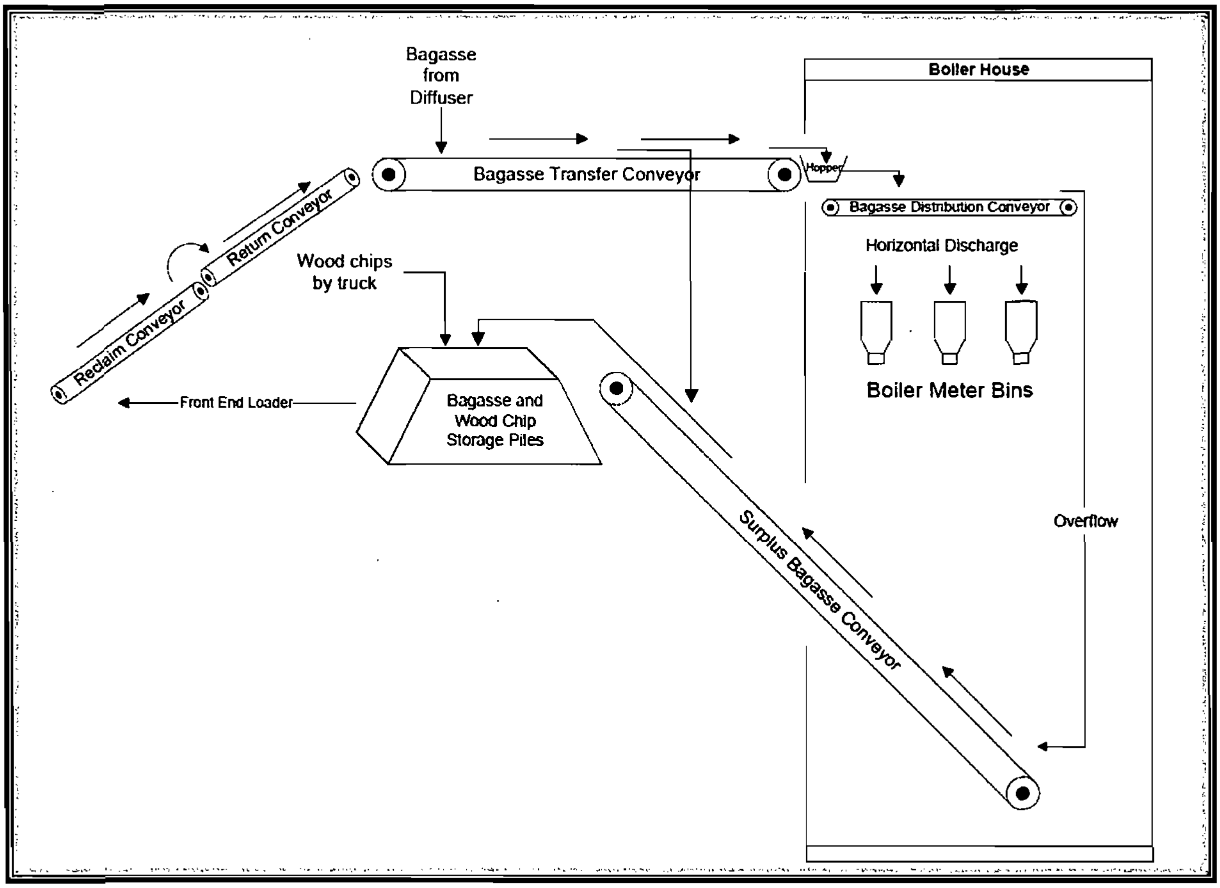

Figure 9 - Boiler Biomass Feed System

PCL XL error

Subsystem: USERSTREAM

Error: MissingData

Operator: ReadImage

Position: 435102

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TECHNICAL EVALUATION

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PRELIMINARY DETERMINATION

APPLICANT

Highlands EnviroFuels, LLC
10027 Water Works Lane
Riverview, FL 33578

PROJECT

Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant
ARMS Facility ID No. 0550063

DEP File No. 0550063-001-AC (PSD-FL-416)

COUNTY

Highlands County, Florida

PERMITTING AUTHORITY

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

August 11, 2011

1. APPLICATION INFORMATION

1.1. Applicant Name and Address

Highlands EnviroFuels, LLC (HEF)
10027 Water Works Lane
Riverview, FL 33578

Authorized Representative: Dr. Bradley Krohn, President

1.2. Key Dates

- June 2, 2011 — Received a Prevention of Significant Deterioration (PSD) air construction permit application from HEF.
- June 14 — Department met with HEF and Golder Associated to discuss application.
- June 28 — Department received additional information from HEF.
- July 1 — EPA announced issuance of a final rule that defers, for a period of three years, greenhouse gas (GHG) permitting requirements for carbon dioxide (CO_2) emissions from biomass-fired and other biogenic sources.
- August 11 — Department issued Draft Permit decision for HEF and posted documents.

1.3. Facility Location

The HEF facility will be located approximately 0.5 miles southwest of the intersection of U.S. Highway 27 and State Road (SR) SR 70, south of Lake Placid in Highlands County. The UTM coordinates are Zone 17; 466.407 kilometers (km) East and 3,009.015 km North. The locations of Highlands County and the proposed site are shown in Figures 1 and 2.

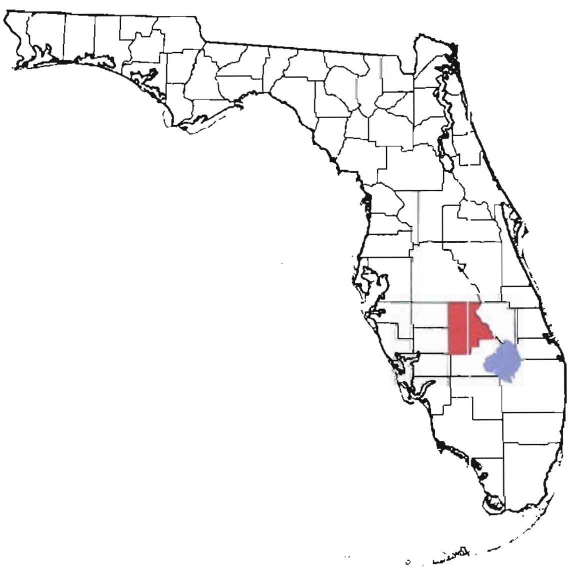


Figure 1 - Highlands County, Florida

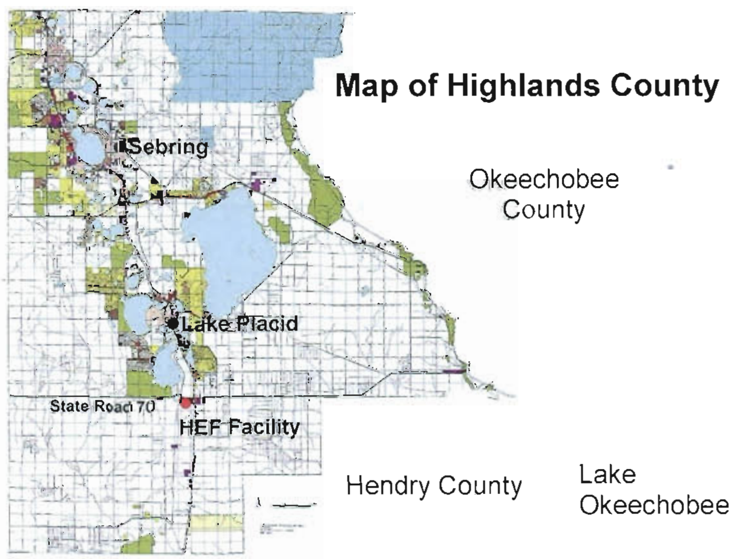


Figure 2 - Proposed Location of HEF Facility

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 36 km to the southeast. The proposed HEF facility will be located on 75 acres of citrus farmland immediately south of an east-west spur of the CSX Railroad as shown in Figure 3.

Sugarcane and sweet sorghum (cane) for the proposed HEF facility will be grown on nearby farms comprising about 30,000 to 36,000 acres. Figures 4 is a photograph taken on SR 70 near the entrance of an adjacent (inactive) industrial park located north of the HEF site. Figure 5 was taken from U.S. Highway 27 that runs in a north-south direction approximately 0.5 miles east of the site.

Figure 3 – Preliminary Layout of Future HEF Facility

Figure 4 – Road from SR 70 towards HEF Site

Figure 5 – View from U.S. 27 towards HEF Site

The nearest 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 approximately 147 km south of the proposed HEF site.

1.4. Project Description

The applicant proposes to construct a sugarcane and sweet sorghum-to-ethanol advanced biorefinery with a maximum annual ethanol (C_2H_5OH) production rate of 36 million gallons per year (MGPY). The cane (i.e. the sugarcane and sorghum) will be grown on nearby farmland. The juice will be squeezed from the feedstock stalks, fermented, distilled and blended to make a range of ethanol/gasoline products, including E-85 (an 85/15 ethanol/gasoline blend). The leftover stalk fiber (bagasse) will be combusted in a cogeneration biomass boiler to make process steam and up to 30 megawatts (MW, gross) of electricity. In addition to bagasse, HEF will use supplemental biomass consisting of energy crops, wood chips and vegetative debris. Natural gas will be used for startup shutdown and flame stabilization and during a disruption in the biomass supply.

The HEF process is akin to conventional sugar production practiced in South Florida, except that the juice is fermented and distilled to produce ethanol rather than evaporated and refined to produce sugar.

The main process steps are:

- Cane and other biomass receiving, handling and feeding;
- Juice extraction and evaporation;
- Ethanol production (including fermentation, distillation and dehydration);
- Product storage, blending and loadout; and
- Steam and electrical production.

Table 1 indicates the emissions units (EU) associated with this project. Figure 6, provided by HEF, is a simplified process flow diagram for the project with only the key EU indicated.

Table 1 - Process Steps Comprising the HEF by EU.

EU ID No.	Emissions Unit Description
001	Feedstock and Biomass Material Handling and Preparation
002	Biomass Boiler
003	Cooling Towers
004	Ethanol Production Process
005	Product Loadout and Flare
006	Storage Tanks
007	Miscellaneous Storage Silos
008	Emergency Equipment
009	Facility-Wide Fugitive Volatile Organic Compounds (VOC) Equipment Leaks

2. PROCESS DESCRIPTION

2.1. <u>(E.U. 001) Feedstock and Biomass Material Handling and Preparation</u>

Cane receiving. Refer to Figure 6. Harvested cane stalks in the form of 6 to 12 inch billets will arrive via trucks or rail from nearby agricultural fields to the production facility. The trucks and railcars will be weighed on a weighing bridge as they enter the unloading area. The cane in the trucks is then transferred to the feed table via a tipping trailer. Railcars will be bottom dumped into a feed hopper, which feeds the feed table. The feed table is equipped with chains that convey the cane billets toward the main conveyor that feeds the juice extraction system.

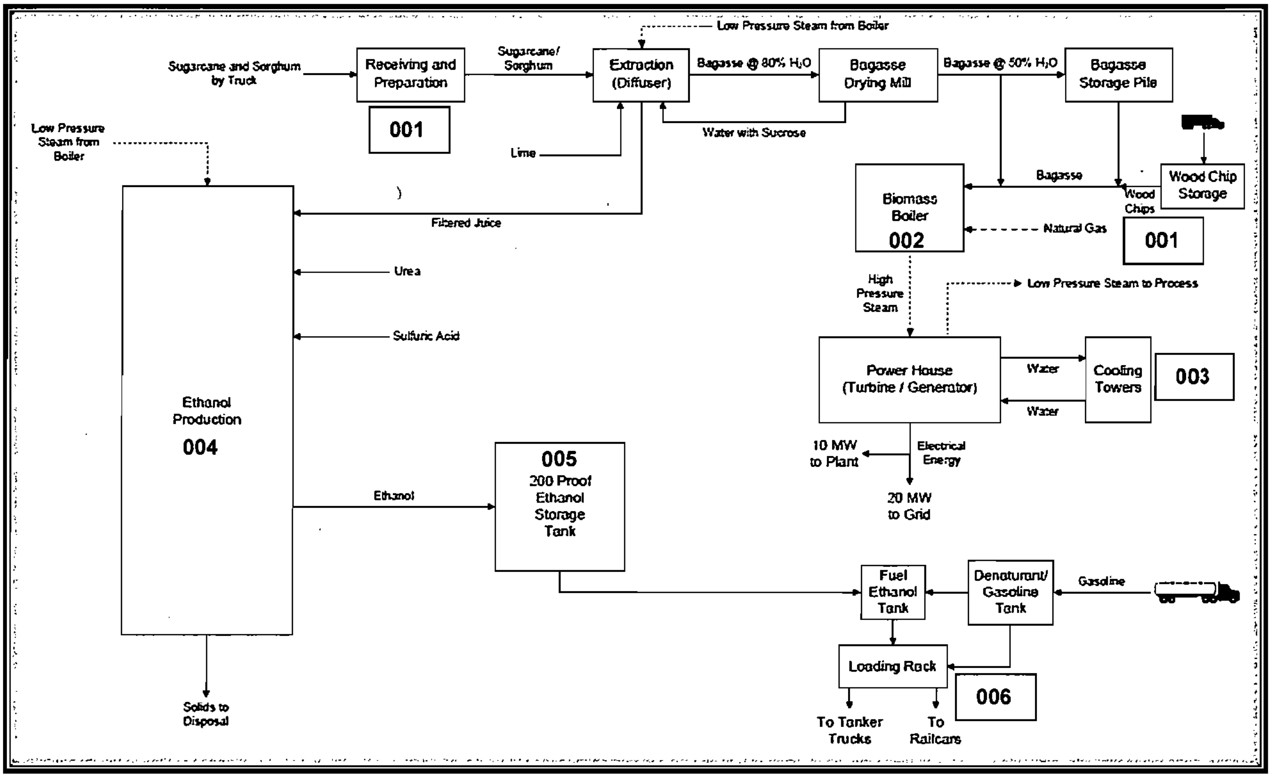


Figure 6 – Simplified Diagram of HEF Sugarcane and Sorghum to Ethanol and Power Facility

Supplemental boiler fuel receiving. Energy crops, wood chips and vegetative debris will be received from local suppliers.

Sorghum cutting, shredding and conveyance. The cane passes through several sets of revolving cane knives and one heavy-duty shredder. From the shredder, the cane passes to a high-speed belt carrier then to the diffuser feed carrier. Any excess cane is returned to the high-speed belt conveyor via the excess sorghum carrier and a chute.

The diffuser consists of a horizontal slat-type conveyor with a fixed bottom consisting of perforated screens. Beneath the screens, several semi-cylindrical transversal juice receivers will be installed. Imbibition water is fed into the juice trough and falls onto the shredded cane mat, percolates through the fibers, passes across the screen, and is collected in the last juice receiver.

As the sorghum moves across the diffuser it is progressively washed of its sucrose content. The wash water is circulated in a countercurrent manner such that it is progressively concentrated in sucrose in the direction of the incoming shredded cane.

The washed and shredded cane (now bagasse) is pressed in a roller system to approximately 50 percent (%) moisture and is then transferred to the biomass boiler. The juice is pumped to a juice screen which separates fine particles prior to evaporation. The fine particles are recycled to the diffuser. The pH of the filtered juice is adjusted and the product is stored in the juice storage tank.

2.2. (E.U. 002) Biomass Boiler Steam and Power Production

The project will employ one biomass grate stoker boiler with a maximum capacity of 504.3 million Btu per hour (mmBtu/hr on a 4-hr basis) and 485.5 mmBtu/hr on a 24-hr basis. The boiler primary fuel will be sugarcane bagasse and sweet sorghum bagasse. Biomass consisting of energy crops, wood chips and vegetative debris will be used as a supplemental boiler fuel. Natural gas will be used as a startup, shutdown and flame stabilization fuel and during a disruption in the biomass supply.

A simplified process flow diagram for the steam and power operations including proposed pollution control equipment is shown in Figure 7.

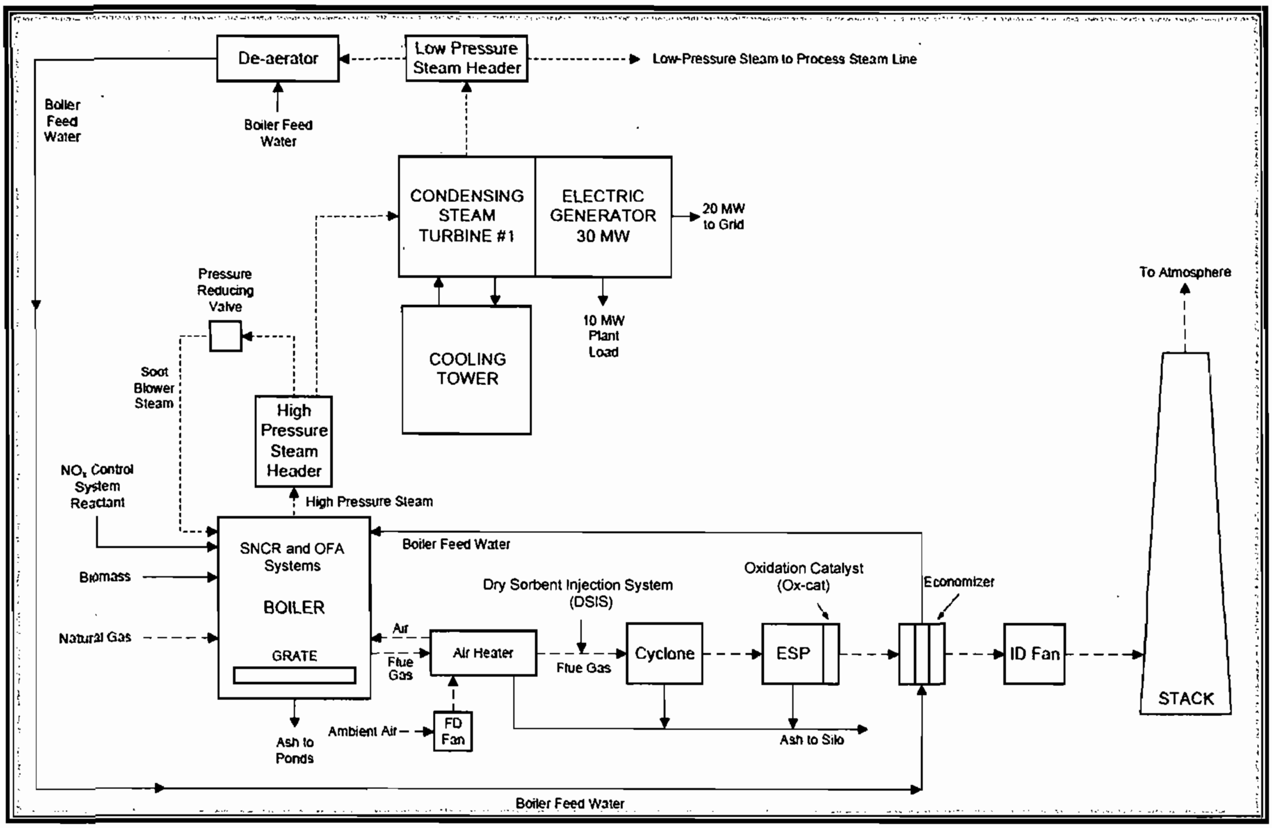


Figure 7 – Simplified Diagram of Applicant's Proposed HEF Steam and Electricity Production Cycles

The proposed pollution control systems as described by the applicant include:

- Selective non-catalytic reduction (SNCR) based on urea [$(NH_2)_2CO$] or ammonia (NH_3) injection and a high performance overfire air (OFA) system for minimizing emissions of nitrogen oxides (NO_X);
- Low-NO_X burners (LNB) for firing natural gas;
- Mechanical collectors and an electrostatic precipitator (ESP) will be used for control of particulate matter (PM) and metals emissions;
- Use of very low-sulfur fuels and a dry sorbent injection system (DSIS) to control emissions of sulfur dioxide (SO_2) and other acid gases;
- Use of clean biomass and natural gas will also control emissions of mercury (Hg) and lead (Pb);
- The modern OFA system will also control emissions of carbon monoxide (CO) and volatile organic compounds (VOC);
- Oxidation catalyst (Ox-cat) will be used to provide further CO and VOC control as well as control of organic hazardous air pollutants (HAP).

For reference, control of PM also accomplishes control of PM with a diameter less than 10 micrometers (PM_{10}). Control/minimization of PM/PM_{10}, NO_X, SO_2, VOC and sulfuric acid mist (SAM – H_2SO_4) emissions will also control PM with an aerodynamic diameter less than 2.5 micrometers ($PM_{2.5}$). Measures such as OFA and LNB fall into the category of good combustion practices (GCP).

2.3. (E.U. 003) Cooling Towers

The proposed HEF facility will utilize up to three mechanical draft cooling towers. The cooling towers will be used for the cooling of miscellaneous machinery, the condensing set and the process equipment used in ethanol production at the HEF facility. The design parameters for the cooling towers are: one cell with a stack height of 35 feet, a combined circulating water flow rate of 34,000 gallons per minute (gpm), a temperature of 77 °F and a design drift rate of 0.001%. Cooling tower make up water will be primarily a suitable recycled process water stream. Cooling tower blowdown will be treated to remove accumulated dissolved solids and then reused for cooling tower makeup.

2.4. (E.U. 004) Ethanol Process

The ethanol process is shown in Figure 8 and consists of juice extraction, evaporation, fermentation, distillation and dehydration. The process description is paraphrased from the application.

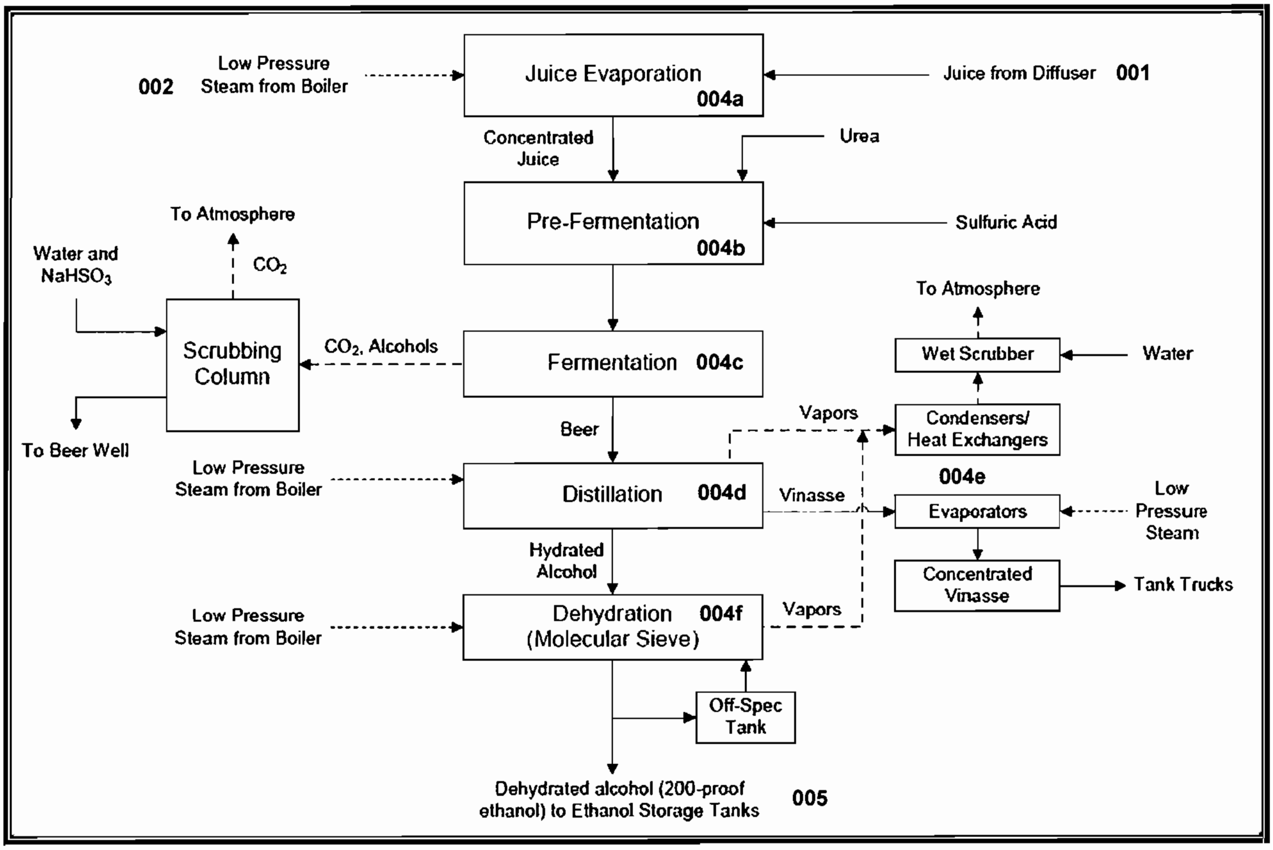


Figure 8 – Simplified Diagram of the HEF Sugarcane and Sorghum to Ethanol Production Process

Juice Evaporation (004a). The evaporation process concentrates the sucrose juices extracted in the diffuser. The extracted juice is pumped from the juice storage tank to a five-effect multiple-effect evaporator, where the juice is concentrated from 14% to 22% total solids. The concentrated juice is stored in the concentrated juice storage tank. The steam condensate is recovered and returned to the boiler feed water system. The condensed vapor condensate is collected and is then pumped to the diffuser as imbibition water for juice extraction.

Pre-fermentation (004b). Concentrated juice from the concentrated juice storage tank is first cooled using the beer feed to distillation followed by a trim heater using cooling water. The cooled, concentrated juice along with the yeast and urea (added as a nutrient) are fed to an agitated pre-fermenter. The pre-fermenter serves as a yeast propagator and initially acclimates the yeast to the fermentation conditions. Sulfuric acid is used to adjust the pH. The pre-fermenter continuously recirculates the ferment through a heat exchanger to keep the temperature in the optimum range for fermentation.

Fermentation (004c). During fermentation, sugars contained in the concentrated juice are transformed to ethyl alcohol, carbon dioxide (CO_2) and various secondary products. Secondary products include other alcohols, aldehydes, glycerin, etc. There are a total of four agitated fermenters in series, each having controlled temperature and controlled additions of urea and yeast to maintain optimum fermentation conditions. The ferment is continuously transferred from the pre-fermenter to the first fermenter based on level. Flow is maintained from one fermenter to another based on level.

The product of fermentation, called "beer," is a weak ethanol solution and contains the residue of fermentation components. The beer is pumped to a holding tank, designated as the beer well. The alcohol concentration in the clean beer is generally 8%. Solid substances include yeast, bacteria, non-fermentable solids, mineral salts, albuminoidal substances and other miscellaneous substances. Dissolved gases include CO_2 and SO_2.

The off-gases from the fermentation vessels are collected and sent to a packed scrubbing column, called the CO_2 scrubber. The CO_2 scrubber uses water, fortified with sodium bisulfite ($NaHSO_3$), to remove water soluble components, such as ethanol, and to chemically remove acetaldehyde. The off-gases, which are composed primarily of CO_2 with minor traces of ethanol and other organic compounds, are released to the atmosphere. The CO_2 scrubber effluent is sent to the stripper column for removal of ethanol and related compounds.

The following equipment will be used in steps 004b and 004c: rotary screens; juice evaporator; clean and foul condensate tanks; a sulfuric acid tank; a urea tank; yeast mixing tank; pre-fermenter; pre-fermenter cooler; fermenters; fermenter coolers; beer well tank; beer/sucrose heat exchanger; and CO_2 scrubbing column.

Distillation (004d). From the beer storage, the beer is sent to a pre-heater and then to a beer/stillage heat exchanger. The gas removed in the degassing column is cooled, scrubbed in the distillation scrubber and then released to atmosphere. The beer column overhead is transferred in the vapor phase to the rectifier column.

The alcohol stream is increased to 91% by weight ethanol concentration in the rectifier column. Rectifier overhead vapor is sent to the molecular sieve units to further remove water to less than 0.7% by weight in the ethanol product. Propanol and fusel oils are removed from the lower section of the rectifier column and combined with the 91% ethanol vapor which goes to the molecular sieves.

Rectifier bottoms are sent to a stripper column to strip remaining traces of ethanol from the rectifier bottoms. The bottoms from the stripper column are comprised of almost pure water, and are reused in the process. The stripper column overhead vapor is sent back to the rectifying column.

The following equipment will be used in step 004d: beer distillation column; degassing column; degassing condenser; stripping column; rectification column; heat exchangers; fusel oil decanter; hydrated alcohol tank; CO_2 washing column; and scrubber water degasser.

Vinasse Evaporation (004e). The beer column bottom stillage, called vinasse, is cooled using the incoming beer as the heat sink and sent to storage. From the storage, the vinasse is evaporated to 40% solids using a combination of several waste heat sources and live steam in three sets of multiple effect evaporators. The concentrated vinasse is stored and then loaded onto trucks for shipment to be utilized for animal feed.

Vinasse evaporator vapor condensates will normally be less than 3,000 parts per million (ppm) chemical oxygen demand (COD) with 70 pounds per hour (lb/hr) dissolved solids, 26 lb/hr alcohol and 44 lb/hr liquid fermentation byproducts. The condensed vinasse vapor condensate stream will be processed as necessary for reuse as cooling tower make-up.

The zeolite beds must be regenerated periodically by vacuum. The molecular sieve bed being regenerated is first isolated from the incoming hydrated ethanol steam and the inlet of this bed is valved to a regeneration condenser. A purge stream consisting of a portion of the dehydrated product from the on-line molecular sieve is fed into the outlet of the regenerating molecular sieve. The non-condensable vapors from the regeneration condenser are removed via a two-stage steam ejector or a liquid ring vacuum pump. The cooled non-condensable vapors are then fed to the distillation vent scrubber. The condensed liquid from the regeneration condenser is reclaimed by sending it back to the rectifier column.

The following equipment will be used in step 004e: multiple effect evaporators; raw and concentrated vinasse storage vessels; and a load out system.

Dehydration (004f): The final stage in the ethanol production process is dehydration. Hydrated alcohol from the distillation process, at about 96% by volume alcohol, undergoes dehydration with a molecular sieve to produce ethanol at 99.3% by weight purity. The process is performed in a continuous operation where the hydrated alcohol is superheated by steam in a shell and tube heat exchanger to ensure that the ethanol stream is always in the vapor phase as it passes through molecular sieve zeolite beds. The final ethanol product is condensed, cooled, and sent to the 200-proof storage tank.

The following equipment will be used in step 004f: hydrated alcohol heater; zeolite absorber (molecular sieve); condensers and coolers; filter; dehydrated alcohol holding tank; and tie-in to CO_2 washing column.

Air Pollution Control Equipment. Two wet scrubbers will be used in the ethanol production area to control emissions of ethanol, other VOC and organic HAP. One will be incorporated into the fermentation step (with $NaHSO_4$) and the other will be incorporated into the distillation and dehydration steps. According to the applicant, the two scrubbers will have ethanol/VOC removal efficiencies of 98%.

2.5. (E.U. 005) Volatile Organic Liquid Storage Tanks: Denaturant/Gasoline, Alcohol, Blends

The facility will contain several volatile organic liquids (VOL) organic storage tanks for ethanol, second grade alcohol, denaturant/gasoline and blending tanks. The following tanks will be controlled by internal floating roofs and are subject to Title 40 of the Code of Federal Regulations (CFR), Part 60, Subpart Kb (40 CFR 60, Subpart Kb):

- One fuel ethanol storage tank with a capacity of 1,000,000 gallons (gal);
- One 200 proof ethanol storage tank with a capacity of 100,000 gal;
- One off-specification (off-spec) tank with a capacity of 100,000; and
- One denaturant/gasoline tank with a capacity of 100,000 gal.

The following tanks are not subject to 40 CFR 60, Subpart Kb and will have a vertical fixed roof (VFR):

- One corrosion inhibitor tank with a capacity of 2,500 gal.

The facility will include several liquid chemical storage tanks to store sulfuric acid, phosphoric acid and ammonia or urea. All of these tanks will be of a VFR design except for an anhydrous NH_3 storage tank, which will be of a horizontal pressurized design.

2.6. (E.U. 006) Truck and Rail Loadout and Flare

Loading racks will be used to load out denatured fuel ethanol from the product storage tank to trucks and railcars. In-line blending for gasoline and ethanol to produce a denatured product may also take place at the loading rack. One loading rack will be provided for trucks, and one for railcars. The maximum truck loading rate of each rack will be 600 gpm. During ethanol loadout, ethanol and gasoline vapors can be generated. The vapors are sent to the loading racks flare for destruction. The loading racks and the flare will be permitted to operate up to 3,120 hr/yr. A truck loading rack will be used to load ethanol and ethanol blends from the product storage tank to trucks. The product loadout flare will have a rated capacity of 9.8 mmBtu/hr to control VOC vapors displaced from the trucks during the loading of denatured ethanol product.

2.7. (E.U. 007) Miscellaneous Materials Storage Silos

Materials storage silos will be installed to store material for the DSIS and to store ash, as well as lime for the water treatment system. Each silo will be controlled by a baghouse or a bin vent filter.

2.8. (E.U. 008) Emergency Equipment

There will be one diesel or natural gas-fired electric generator of 2,000 kilowatt (kW) capacity, for purposes of supplying electric power to the facility during a black start or a power failure. The generator will be limited to 500 hr/yr of operation during emergencies and 100 hr/yr for maintenance and testing. There will be one diesel or natural gas-fueled 600 horsepower (hp) diesel fire pump will also be installed to provide firewater during emergencies. This engine will be limited to 500 hr/yr of operation during emergencies and 100 hr/yr for maintenance and testing.

2.9. (E.U. 009) Facility-wide Fugitive VOC Equipment Leaks

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

2.10. Project Emissions

Tabulations of project emissions are given and discussed in conjunction with major source review applicability in Sections 3.3, 3.4 and 3.5 below.

3. APPLICABLE REGULATIONS

3.1. State Regulations

This project is subject to the applicable environmental laws specified in Chapter 403 of the Florida Statutes (F.S.). The F.S. authorize the Department of Environmental Protection (Department) 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. and summarized in Table 2.

Table 2 - Applicable Rules from the F.A.C.

F.A.C. Rule	Description
62-4	Permits
62-204	Air Pollution Control – General Provisions
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Stationary Sources – Preconstruction Review
62-213	Operation Permits for Major Sources (Title V) of Air Pollution
62-214	Requirements for Sources Subject to the Federal (Title IV) Acid Rain Program
62-296	Stationary Sources – Emission Standards
62-297	Stationary Sources – Emissions Monitoring

3.2. Federal Regulations

The U.S. Environmental Protection Agency (EPA) establishes air quality regulations in 40 CFR Part 60 that identifies New Source Performance Standards (NSPS) for a variety of industrial activities. 40 CFR Part 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP). 40 CFR Part 63 specifies NESHAP provisions based on the Maximum Achievable Control Technology (MACT) for given source categories.

Federal regulations adopted by reference are given in Rule 62-204.800, F.A.C. State regulations approved by EPA are given in 40 CFR Part 52, Subpart K – Florida, also known as the State Implementation Plan (SIP) for Florida.

3.3. PSD Major Stationary Source Applicability Determination

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 (PTE) 250 tons per year (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. The planned HEF facility is a major stationary source because it is: *"A chemical processing plant which emits, or has the PTE, 100 TPY or more of any PSD pollutant."*

According to EPA rules at 40 CFR 52.21(b)(1)(iii)(*t*), *"the term chemical processing plant shall not include ethanol production facilities that produce ethanol by natural fermentation included in NAICS codes 325193 or 312140."* Thus EPA regulations would consider HEF to be a major stationary source if it emits or has the potential to emit 250 TPY or more of any PSD pollutant. On July 27, 2011 the Department held a workshop for the purpose of initiating rulemaking to revise Rule 62-210.200(189) consistent with the federal definition. See link to Ethanol Rule Project .

PSD pollutants include: CO; NO_X; SO_2; PM; PM_{10}; VOC; Pb; Fluorides (F); SAM; total reduced sulfur (TRS), including H_2S; municipal waste combustor (MWC) organics measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans (D/F); MWC metals measured as PM; MWC acid gases measured as SO_2 and hydrogen chloride (HCl); and 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, (Definitions) F.A.C. Emissions of PSD pollutants from the project exceeding these SER are considered "significant" and 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 given in Table 3.

Table 3 – List of SER by PSD-Pollutant [1, 4]

Pollutant	SER (TPY)	Pollutant	SER (TPY)
CO	100	NO_X	40
PM/PM_{10} [2]	25/15	Ozone (VOC) [3]	40
Ozone (NO_X) [3]	40	SAM	7
SO_2	40	F	3
Pb	0.6	TRS	10
H_2S	10	Hg	0.1

1. Excluding those defined exclusively for MWC and MSW landfills.
2. PM with a diameter less than 2.5 micrometers ($PM_{2.5}$) is also a PSD pollutant, but an SER has not yet been defined in the Department's rules. It is regulated by its precursors and surrogates (e.g. PM/PM_{10} NH_3, SO_2 and NO_X).
3. Ozone (O_3) is regulated by its precursors (VOC and NO_X).
4. There is a federal SER of 75,000 TPY for Greenhouse Gases (GHG) as carbon dioxide equivalent (CO_2e) that has not been incorporated into Department rules. However, the applicability to the CO_2 component of GHG emissions from bioenergy and biogenic stationary sources was recently deferred by EPA until the second half of 2014. Refer to: Link to Final CO2 PSD Deferral .

$PM_{2.5}$ is also a Federal PSD pollutant and the Department is in the process of adopting a SER of 10 TPY. Refer to Link to $PM_{2.5}$ Rule . Until the rule is finalized, projects in Florida are not subject to a SER for $PM_{2.5}$.

Table 4 summarizes the applicant's estimates of key PSD pollutants from the proposed HEF project. The project will result in emissions of NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, SAM, VOC, Pb and Hg. It is clear that the greatest emission source by far is the boiler, which accounts for more than 85% of all PSD-pollutants to be emitted from the HEF facility. The facility will also emit approximately 32.3 TPY of NH_3 (not a PSD-pollutant) largely due to injection of urea to control NO_X emissions.

Table 4 – Applicant's Estimated PTE of Key PSD Pollutants (in TPY) for the SER Facility[1]

Operation/EU	CO	NO_X	PM/PM_{10} [1]	$PM_{2.5}$ [1]	SO_2 [4]	SAM[5]	VOC	Hg[3]	Pb
Biomass Material Handling (001)			7.9/1.8	0.3					
Boiler (002)	552.9	184.3	27.6/27.6	18.0	200.4	9.8	31.3	0.025	0.18
Cooling Towers (003)			0.37/0.19	0.19			0		
Ethanol Production (004)							87.6		
Storage Tanks (005)							3.9		
Product Loadout and Flare (006)	5.64	1.04	0.052	0.052	0.009		7.0		
Miscellaneous Storage Silos (007)			0.85	0.85			0		
Emergency Equipment (008)	1.29	8.84	0.087	0.087	0.0063		0.26		
Fugitive Equipment Leaks (009)							6.5		
Totals	559.8	194.2	36.9/30.6	19.5	200.4[4]	9.8[5]	136.6	0.025 [3]	0.18
SER	100	40	25/15	(10) [2]	40	7	40	0.1	0.6
PSD Applies? (Yes/No)	Yes	Yes	Yes	No [2]	Yes	Yes	Yes	No	No

1. Estimates based on filterable (front-half sampling train) material and do not include condensable (back-half) material.
2. PSD would apply based on the federal SER (reference 40 CFR 52.21) of 10 TPY for $PM_{2.5}$ or 40 TPY of its surrogates (NO_X or SO_2). PSD does not apply per the present Department rules incorporated into the federal rules at 40 CFR 52, Subpart K.
3. Uncontrolled estimate equals 50 pounds Hg per year (lb/yr). Applicant expects much lower emissions.
4. SO_2 emissions will be approximately 109.3 TPY pursuant to the Department Draft BACT determination.
5. SAM emissions will be approximately 6.8 TPY pursuant to enforceable limit in Draft permit that avoids PSD.

In summary, the HEF project will emit at least 100 TPY of at least three PSD pollutants (SO_2, NO_X and VOC) and at least 250 TPY of CO. Emissions of the following PSD air pollutants as proposed by the applicant will exceed their respective SER: NO_X, PM/PM_{10}, SO_2, CO, SAM, and VOC. Therefore, the HEF project will be subject to the Department's PSD rules including PSD ambient air modeling and a requirement for a best available control technology (BACT) determination for the cited pollutants. $PM_{2.5}$ will be addressed by the BACT evaluations for its precursors and surrogates [e.g. NO_X, SO_2 and VOC].

For reference, the applicant has requested a federally enforceable limit on natural gas consumption to insure that the project will not trigger the 75,000 TPY CO_2e SER for GHG even after exclusion of the CO_2 component of bioenergy/biogenic emissions from bagasse use in the boiler.

3.4. Major Source of Air Pollution (Title V Source) Determination

As defined in Rule 62-210.200(188), F.A.C., a Title V source is an emissions unit or group of emissions units that directly emits, or has a PTE of, 100 TPY or more of any regulated air pollutant. The Major (Title V) Source of Air Pollution definition also includes, any emissions unit or group of emissions units that (except for radionuclides) emits or has the PTE of, in the aggregate, 10 tons TPY or more of any one HAP, 25 TPY or more of any combination of HAP, or any lesser quantity of a HAP as established through EPA rulemaking. Specific HAP are defined/listed in Rule 62-210.200(155), F.A.C.

The emissions estimates given in Table 4 are sufficient to conclude that the HEF facility will be a Title V source based on emissions of regulated air pollutants regardless of HAP emissions.

3.5. HAP Major Source Non-Applicability Determination

As defined in 40 CFR 63, Subpart A, adopted and referenced in Rule 62-204.800(11)(d)1, F.A.C., and per Rule 62-210.200(188 – Major Source of Air Pollution), F.A.C., a major source of HAP means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the PTE of, considering controls, in the aggregate, 10 TPY or more of any HAP or 25 TPY or more of any combination of HAP, unless the Administrator establishes a lesser quantity, or in the case of radionuclides, different criteria from those specified in this sentence. See Subpart A .

Pursuant to Rule 62-210.200 (188), F.A.C., if a facility is a major source of HAP it will also be a Title V source. Table 5 is a summary of the applicant's estimate of HAP from the key emission categories at the HEF facility. The main source of HAP is the boiler. The greatest single HAP emitted from the biomass boiler is HCl at 6.85 TPY followed by chlorine (Cl_2) at 3.03, formaldehyde at 2.69 TPY and benzene at 2.17 TPY. The other key HAP emission (> 1 TPY) is acetaldehyde from the ethanol process at 2.87 TPY.

According to the applicant's estimate, the facility (boiler and other processes) does not constitute a major source. If the facility emissions equal or exceed the 10 or 25 TPY HAP thresholds, then the ethanol process will be subject to a number of promulgated NESHAP including 40 CFR 63, Subpart FFFF – NESHAP: Miscellaneous Organic Chemical Manufacturing, adopted and incorporated as Rule 62-204.800(11)(d)63., F.A.C. See Subpart FFFF .

If the facility emissions were to equal or exceed the 10 or 25 TPY HAP thresholds, then the boiler would ultimately be subject to the Boiler NESHAP pursuant to 40 CFR 63, Subpart DDDDD, which was revised on March 21, 2011. See Revision to Subpart DDDDD . The rule (for which implementation has been delayed) includes very stringent PM limits as well as specific limits for Hg, HCl and D/F.

Table 5 – Applicant's Initial Estimates of PTE of HAP from the HEF Project in TPY

Pollutant	HCl	HF	Cl_2	Key Metal HAP [1]	Key Organic HAP [2,3]	Other HAP	Total
Boiler	6.85	0.04	3.03	1.05	7.11	0.18	18.26
Ethanol Process					4.24		4.24
Other Sources						0.67 [4]	0.67
Total	6.85	0.04	3.03	1.05	11.35	0.85	23.17

1. Key metal HAP for the boiler consist of chromium (Cr), lead (Pb), manganese (Mn) and nickel (Ni).
2. Key organic HAP for the boiler consist of acetaldehyde (C_2H_4O), acrolein (C_3H_4O), benzene (C_6H_6), Bis(2-ethylhexyl) phthalate ($C_{24}H_{38}O_4$), formaldehyde (CH_2O), styrene (C_8H_8), toluene (C_7H_8) and polycyclic aromatic hydrocarbon/polycyclic organic matter (PAH/POM).
3. Key Organic HAP for the ethanol process consists of: acetaldehyde (C_2H_4O), acrolein (C_3H_4O), formaldehyde (CH_2O) and methanol (CH_4O).
4. This includes all HAP for all other sources such as fugitive emissions from equipment leaks and tanks.

On May 18, 2011 EPA delayed the effective date of Subpart DDDDD until proceedings for judicial review of this rule are completed or the EPA completes its reconsideration of this rule, whichever is earlier. See Delay of Subpart DDDDD .

The Department will include sufficient conditions in the permit to provide reasonable assurance that the project will not be a major source of HAP and therefore not subject to Subpart DDDDD.

3.6. Review of other Key Regulatory Provisions for Applicability to Project

Following is a summary of the applicability of key regulatory provisions to the HEF project.

Chapter 62-4, F.A.C. www.dep.state.fl.us/air/rules/fac/62-4.pdf

Rule 62-4.070(1), F.A.C., Standards for Issuing or Denying Permits; Issuance; Denial.

This rule applies to all permitting decisions:

- A permit shall be issued to the applicant upon such conditions as the Department may direct, only if the applicant affirmatively provides the Department with reasonable assurance based on plans, test results, installation of pollution control equipment, or other information, that the construction, expansion, modification, operation, or activity of the installation will not discharge, emit, or cause pollution in contravention of Department standards or rules.

Chapter 62-17, F.A.C. www.dep.state.fl.us/siting/files/rules_statutes/pps_rule.pdf

- The HEF project is not subject to certification pursuant to the power plant siting provisions of this rule because it will produce less than 75 MW of power.

Chapter 62-204, F.A.C. www.dep.state.fl.us/air/rules/fac/62-204.pdf

Rule 62-204.220(1), F.A.C., Ambient Air Quality Protection.

This rule applies to all air permitting decisions.

- The Department shall not issue an air permit authorizing a person to build, erect, construct, or implant any new emissions unit; operate, modify, or rebuild any existing emissions unit; or by any other means release or take action which would result in the release of an air pollutant into the atmosphere which would cause or contribute to a violation of an ambient air quality standard established under Rule 62-204.240, F.A.C.

Rule 62-204.240, F.A.C., Ambient Air Quality Standards.

This rule applies to all air permitting decisions.

- Refer to list of pollutants and ambient air quality standards provided therein and discussed in the Ambient Air Quality Section of this evaluation.

Rule 62-204.800(8), F.A.C., 40 CFR 60, NSPS.

The following provisions incorporated into Rule 62-204.800(8), F.A.C. adopted from 40 CFR 60 and incorporated into this rule apply to this project:

- 40 CFR 60, Subpart A – General Provisions which regulates all EU that are subject to a NSPS standard and, in particular, flare pilot flames (EU 005);
- 40 CFR 60, Subpart Db – Industrial-Commercial-Institutional Steam Generating Units (EU 002);
- 40 CFR 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 (EU 006);
- 40 CFR 60, Subpart IIII – Stationary Compression Ignition Internal Combustion Engines (ICE) (EU 008); and
- 40 CFR 60, Subpart VVa – VOC Equipment Leaks from SOCMI Processes (EU 002, 003,004, 005, 006, 007 and 009).

The boiler (EU 002) will combust a fuel feed stream containing approximately 10% (much less than 30%) of materials (e.g. vegetative waste) that could be construed to be municipal solid waste (MSW). Therefore the HEF is exempt from the following rule:

- 40 CFR 60, Subpart Eb – Large Municipal Solid Waste Combustors for Which Construction is Commenced After September 20, 1984 or for Which Modification or Reconstruction is Commenced After June 19, 1996.

By letter dated March 26, 2009, EPA provided a determination to the Department that the following NSPS do not apply to the Vercipia Ethanol project (and by extension to the HEF) that processes ethanol produced by biological processes:

- 40 CFR 60 Subpart NNN – VOC Emissions from SOCMI Distillation Operations; and
- 40 CFR 60 Subpart RRR – VOC Emissions from SOCMI Reactor Processes.

Rule 62-204.800(11), F.A.C., 40 CFR 63, NESHAP.

The following provisions incorporated into Rule 62-204.800(11), F.A.C. adopted from 40 CFR 63 and incorporated into this rule apply to this project:

- 40 CFR 63, Subpart A – General Provisions (to the extent explicitly identified within each applicable 40 CFR 63 standard);
- 40 CFR 63, Subpart JJJJJ – Industrial, Commercial, and Institutional Boilers Area Sources; and

- 40 CFR 63, Subpart ZZZZ – Stationary Reciprocating Internal Combustion Engines (RICE). This subpart requires all affected area source units to meet the applicable emission standards of 40 CFR 60, Subpart IIII. 40 CFR 63, Subpart A is explicitly excluded when applying this standard.

The following provisions incorporated into Rule 62-204.800(11), F.A.C. adopted from 40 CFR 63 and incorporated into this rule do not apply to this project because after applicant-proposed and Department-required controls it is not a major source of HAP:

- 40 CFR 63, Subpart B – Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act (CAA) Sections, Sections 112(g) and 112(j);
- 40 CFR 63, Subpart DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters (applicable to major sources of HAP); and
- 40 CFR 63, Subpart FFFF – Miscellaneous Organic Chemical Manufacturing (and by reference Subparts H , Q, SS, TT, UU, WW, and GGG).

Chapter 62-210, F.A.C. www.dep.state.fl.us/air/rules/fac/62-210.pdf

62-210.200, F.A.C., Definitions.

- The project is a Title V or "Major Source" of air pollution because the PTE of at least one regulated pollutant will exceed 100 TPY.
- The project is not a major source of HAP because it will not emit or have PTE of 10 TPY or more of any one HAP or 25 TPY or more of any combination of HAP.
- The project is classified as a "Major Stationary Source" (PSD-source) because it emits 100 TPY or more of a PSD pollutant and is (until completion of ongoing Department rulemaking) one of the 28 facility categories listed in the definition with the PSD applicability threshold of 100 TPY.

Rule 62-210.300, F.A.C., Permits Required.

- Unless exempted, the owner or operator of any facility or emissions unit which emits or can reasonably be expected to emit any air pollutant shall obtain appropriate authorization (i.e. a permit) from the Department prior to undertaking any activity at the facility or emissions unit for which such authorization is required.

Rule 62-210.350, F.A.C. Public Notice and Comment.

- A notice of proposed agency action on permit application, where the proposed agency action is to issue the permit, shall be published by any applicant.
- The rule details additional public notice requirements for emissions units subject to PSD. Examples include: the location and nature of the project; whether BACT has been determined; PSD increment consumption; and notification to the public of the opportunity to submit comments or request a public hearing (meeting).

Rule 62-210.700, F.A.C., Excess Emissions.

This rule applies to all air permitting decisions. Only the key provisions potentially affecting this project are listed.

- 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 two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
- 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.

- 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.

Chapter 62-212, F.A.C. www.dep.state.fl.us/air/rules/fac/62-212.pdf

Rule 62-212.300, F.A.C., General Preconstruction Review Requirements.

- This rule generally applies to the construction or modification of air pollutant emitting facilities in those parts of the state in which the state ambient air quality standards are being met.

Rule 62-212.400, F.A.C., PSD.

- The rule applies because the project is a major stationary (PSD) source.

Chapter 62-213, F.A.C. www.dep.state.fl.us/air/rules/fac/62-213.pdf

- Because the facility is a Title V source, the applicant will be required to apply for and obtain a Title V operation permit in the future.

Chapter 62-214, F.A.C. www.dep.state.fl.us/air/rules/fac/62-214.pdf

- The applicant asserts that the planned facility is a cogeneration plant and not subject to the Acid Rain Program (ARP) because it will provide 219,000 MW-hours or less of actual electric output on an annual basis to any utility power distribution system for sale on a gross basis. However, if in any three calendar year period, such unit sells to a utility power distribution system an annual average of more than one-third of its potential electrical output capacity and more than 219,000 MW-hours of actual electric output, that unit shall be an affected unit, subject to the requirements of the ARP.

Chapter 62-296, F.A.C. www.dep.state.fl.us/air/rules/fac/62-296.pdf

Rule 62-296.320, F.A.C., General Pollutant Emission Limitation Standards.

- This rule prohibits the discharge of air pollutants which cause or contribute to an objectionable odor;
- This rule specifies a visible emissions standard of 20 percent (%) opacity; and
- The rule prohibits emissions of unconfined PM provisions without taking reasonable precautions to prevent such emissions.

Rules 62-296.401, F.A.C., Incinerators

- The facility will combust primarily cane bagasse, which is clearly fuel and not a waste in this industry. Only the wood chips and vegetative debris (which will comprise no more than approximately 10% of the fuel) could be construed to be waste. The Department's definition of "incinerator" at Rule 62-210.200(160), F.A.C. is "a combustion apparatus designed for the ignition and burning of solid, semi-solid, liquid or gaseous combustible wastes". The furnace is not specifically designed to burn wastes though it is capable of burning some waste as supplementary fuel. The Department concludes that neither he term the term "incinerator" nor the incinerator rule applies to this project. Furthermore, this rule contains less stringent requirements than the applicable NSPS, NESHAP and case-by-case BACT.

Rule 62-296.416, F.A.C., Waste-to-Energy (WTE) Facilities

- This rule does not apply because per Rule 62-210.200(327), F.A.C., the term "WTE facility" does not include facilities that primarily burn fuels other than solid waste, even if the facility also burns some solid waste as a fuel supplement. The term also does not include facilities that burn vegetative, agricultural, or silvicultural wastes, bagasse, clean dry wood, methane or other landfill gas, wood fuel derived from construction or demolition debris, or waste tires, alone or in combination with fossil fuel. The facility will typically burn 90% (or more) fuels "other than solid waste".

Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 mmBtu/hr Heat Input

- This rule applies only to the extent that fossil fuel is burned in the boiler. The fossil fuel heat input capability of the boiler will be less than 250 mmBtu/hr. This provision requires compliance with applicable NSPS requirements for visible emissions, PM, NO_X and SO_2 (e.g., NSPS Subpart Db requirements).

Rule 62-296.410, F.A.C., Carbonaceous Fuel Burning Equipment.

- Cane bagasse is carbonaceous fuel when directly combusted and this rule requires that the carbonaceous component of fuel combustion comply with a PM standard of 0.2 lb/mmBtu. Visible emissions are limited to 30% opacity except that 40% opacity is permissible for not more than 2 minutes in any hour.

Rule 62-296.470, F.A.C., Implementation of Federal Clean Air Interstate Rule (CAIR).

- The HEF facility is not subject to CAIR. On July 6, 2011, EPA announced, but has not yet published in the Federal Register a rule known as the Cross-State Air Pollution Rule (CSAPR) that will replace CAIR. The HEF facility is not subject to the Cross-State Air Pollution Rule (CSAPR), because its biomass boiler is a cogeneration unit that will sell less than 219,000 megawatt hours (MWh) per year of electricity to the grid. Details are available at the following link: Pre-publication CSAPR .

4. BACT REVIEW

Based on the applicant's emission estimates, BACT determinations are required for the pollutants that are subject to PSD review, including CO, NO_X, PM/PM_{10}, SO_2, SAM and VOC. These determinations are provided in the following sections and are organized and presented by process step. A BACT determination for $PM_{2.5}$ is not required because the Department has not yet adopted a SER for $PM_{2.5}$ and identified it as a PSD-pollutant.

Even without a SIP requirement and without approved test methods or accounting requirements, the Department nevertheless relies on precursors and surrogates to minimize direct emissions and subsequent formation of $PM_{2.5}$ per the rationale given below.

On September 16, 1997, EPA revised the NAAQS for particulate matter, which includes a new NAAQS 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 CAA, 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 SIP to address the new $PM_{2.5}$, NAAQS, PSD SER 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, and NO_X).

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.

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

PM/PM_{10} Emissions

Discussion. PM/PM_{10} represent the only pollution of concern from EU 001. Refer to the description of EU 001 in Section 2.1 above. The trucks that will be used to deliver sweet sorghum feedstock and supplemental boiler fuel biomass along with the biomass handling and processing itself will generate fugitive dust.

Figure 9 below is a diagram of the bagasse and supplemental boiler biomass feed system. Because of the biomass high moisture content, fugitive emissions are expected to be minimal from this part of the process.

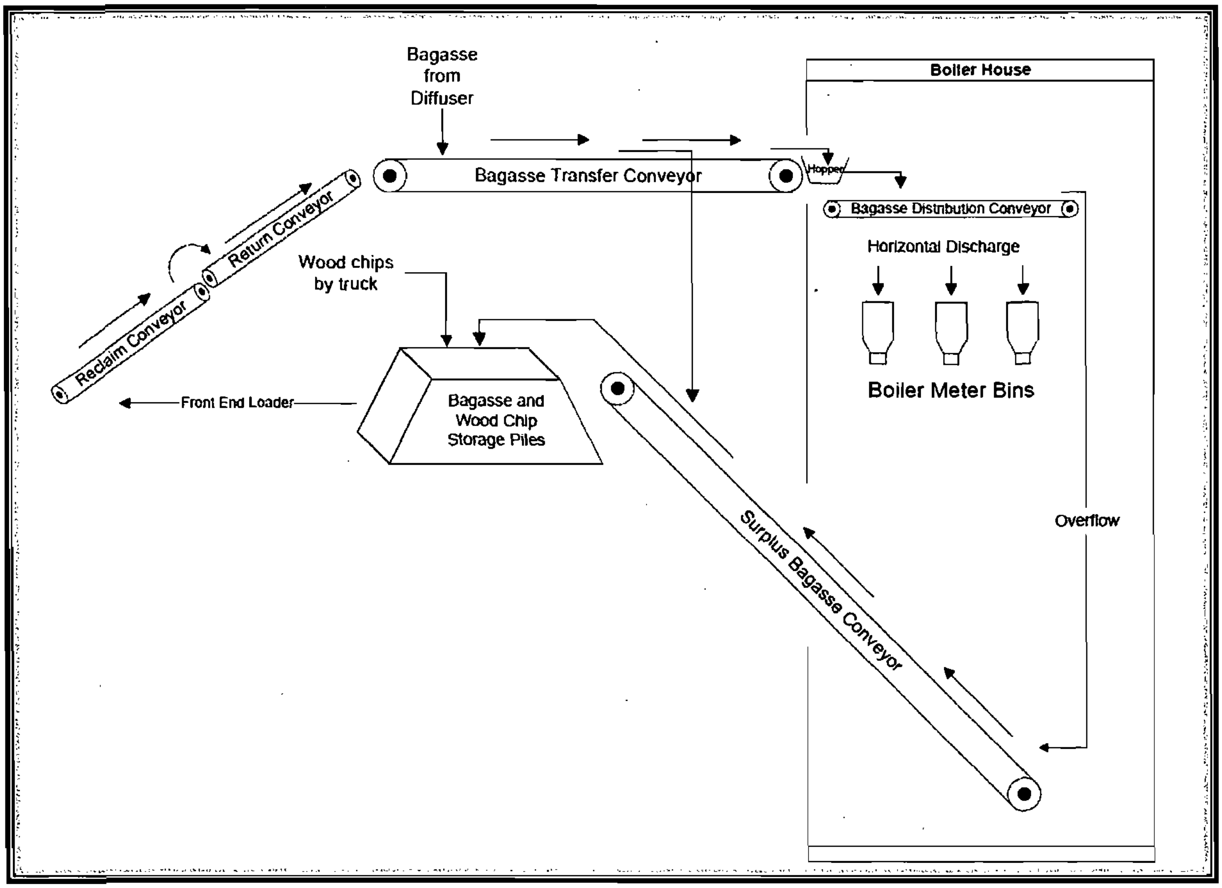


Figure 9 - Boiler Biomass Feed System

The boiler biomass (bagasse and supplemental) will be stored in piles located in the biomass yard in the southwestern quadrant of the HEF site as shown in Figure 3. When required, the material will be reclaimed using a mobile front 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 boiler.

Applicant's Proposal. HEF proposes to utilize reasonable precautions and a best management practices (BMP) plan approved by the Department for controlling fugitive dust emissions from this emission unit. These precautions include the following: enclosing conveyors (e.g. that the conveyance belt for the biomass is totally enclosed from above thus preventing wind from causing fugitive dust emissions with the bottom of conveyance belt accessible for maintenance and repairs) and material drop points, shredders and screens wherever practical; contouring storage piles to minimize wind erosion; utilizing water sprays on storage piles as needed; paving all main plant access roads; sweeping and watering of paved surfaces as needed to remove dust; and utilizing water sprays on ash material from the boiler, as necessary.

Department's Review. The Department accepts the procedures described by the applicant as BACT for sweet sorghum feedstock and supplemental biomass receiving and handling, with the addition of wetting the gravel areas, as necessary, during dry conditions. In addition, where practical, dust collectors must be installed at drop and transfer points in the biomass handling systems and the paved areas must be vacuumed swept as needed to prevent fugitive dust emissions.

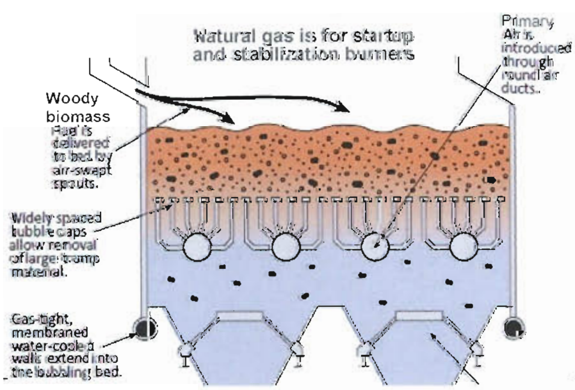
4.2. BACT Review for Biomass-Fueled Boiler (EU 002)

NO_X Emissions

NO_X Formation and Primary Control.

NO_X formation in the boiler may occur by three different mechanisms: 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; and prompt NO_X is formed in the proximity of the flame front as intermediate combustion products.

Bubbling Fluidized bed (BFB) Boiler Principles. The applicant proposes to install a grate stoker boiler and not a BFB boiler. However, it is useful to discuss the alternative design of a BFB boiler due to its inherently lower emission characteristics. Details of the bed portion of a Babcock and Wilcox (B&W) BFB are provided in Figure 10. Figure 11 is an internal diagram for the typical furnace configuration of a HYBEX BFB biomass boiler such as offered by METSO Power.



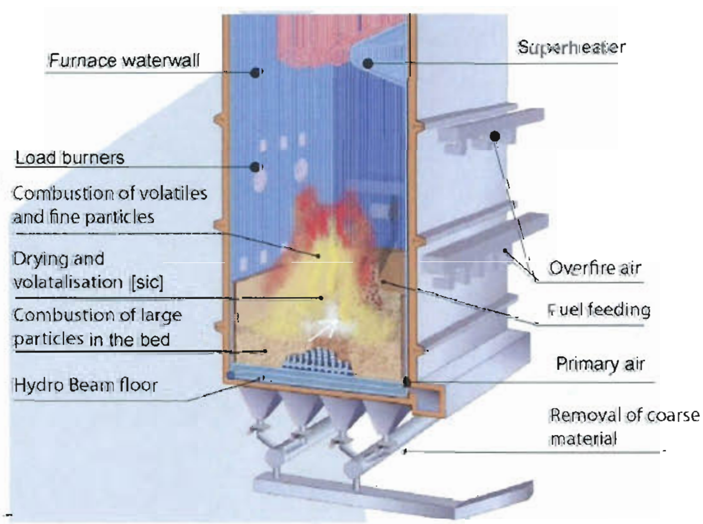


Figure 10 – Bed Description for B&W BFB Boiler **Figure 11 – Typical METSO HYBEX BFB Boiler**

BFB boiler beds are typically maintained at temperatures on the order of 1,350 to 1,700 degrees Fahrenheit (°F). This minimizes thermal NO_X formation but not fuel NO_X formation. The furnace temperature is higher above the fluidized bed where the OFA is introduced but not high enough to form thermal NO_X.

Combustion within the BFB bed occurs under reducing (O_2 starved) conditions provided by the primary air. The fuel in the bed undergoes drying, and partial combustion. Following is the Department's theoretical and simplified explanation of the manner by which combustion proceeds, focusing on the formation and destruction of NO_X. The process involves literally hundreds of steps or reactions expressed as the simplified and unbalanced equations (Eq.) below.

Equation 1. The fuel immediately above and within the bed is heated and pyrolyzed releasing hydrocarbon radicals (CHi*). These, in turn, catalytically or otherwise react with NO to form hydrogen cyanide (HCN) according to:

$$CHi^* + NO \rightarrow HCN + ...$$ Eq. 1

Where:

i = 1, 2, 3

Equation 2. HCN in turn destroys more NO_X in the reducing environment according to:

$$HCN + NO \rightarrow N_2 + CO + CO_2 + H_2O + ...$$ Eq. 2

Equation 3. Ammonia-like radicals (NHi*) are also released during pyrolysis. Under reducing conditions these radicals destroy NO according to:

$$NHi^* + NO \rightarrow N_2 + ...$$ Eq. 3

This mechanism suppresses formation of NO by the pyrolyzed fuel nitrogen and recruits that nitrogen to combat NO_X in reactions that at first glance look much like SCR or selective non-catalytic reduction (SNCR) discussed further below.

Reactions 2 and 3 can be catalytically enhanced based on the presence of various species within such an environment. Also, they can be accelerated by attaining a relatively high temperature within the reducing atmosphere but well below that which would promote thermal NO_X formation. Other reactions involving CO or hydrogen (H_2) also destroy NO_X in this reducing atmosphere and can be to varying degrees catalytically enhanced. Additional volatile and char combustion occurs in the higher temperature free board region above the bed. CharC denotes char carbon and CharN denotes char nitrogen.

Equation 4 and 5. Under the reducing conditions, even the char can assist on NO_X destruction as follows:

$$CharC + NO \rightarrow N_2 + CO + CO_2 + ...$$ Eq. 4

$$CharN + O_2 \rightarrow N_2 + O_2 + ...$$ Eq. 5

Eventually the NO_X destruction reactions will proceed much more slowly and some of the remaining fuel nitrogen forms additional NO_X.

Equations 6, 7, 8 and 9. In the presence of the progressively oxidizing environment effected by the two OFA levels, NO_X formation rather than destruction predominates.

$$NH_3 + O_2 \rightarrow NO + ...$$ Eq. 6

$$HCN + O_2 \rightarrow NO + ...$$ Eq. 7

$$CharC + O_2 \rightarrow NO + ...$$ Eq. 8

$$CharN + O_2 \rightarrow NO + ...$$ Eq. 9

The management of NO_X formation and destruction involves promotion of Eq. 1 through 5 to form N_2 before the inevitable and progressive addition of OFA causes Eq. 6 through 9 to dominate. This can be accomplished to the greatest degree by delaying and then adding the OFA in stages.

It was previously mentioned that peak flame temperatures will increase when lower moisture content biomass fuels are combusted and during low load boiler operations. During these periods, flue gas recirculation (FGR) will be employed to lower the peak flame temperatures thus avoiding the tendency to form thermal NO_X.

The NO_X formation and destruction considerations must also be coupled with CO, PM and VOC management in a combined strategy that constitutes GCP.

Stoker Principles. Modern stoker units for biomass firing are normally mechanical rotating grates or water/air-cooled vibrating grates depending on the fuel moisture content. Fuel is typically introduced into the boiler through multiple fuel chutes. Preheated combustion air is supplied under the grate as well as above via an OFA system. Depending on the fuel moisture content, the combustion air is pre-heated to 350 to 650 °F. The furnace temperature is greater than experienced in a BFB boiler and thus it is possible to form both fuel and thermal NO_X.

Due to high shaft velocities in the lower furnace and the manner by which fuel is spread or thrown onto the grate, some unburned fuel (carbonaceous ash) is carried out of the furnace. In order to recover the energy value of this carbonaceous ash, stoker-fired boilers typically include a re-injection system that recycles the carbonaceous ash back into the furnace.

Because of the hot particle carryover and possible effects on fabric filters, ESP technology is usually incorporated into wood biomass stoker technology projects. A mechanical dust collector is also typically installed to prevent heavy (possibly abrasive) particle carryover from reaching the ESP.

Figure 12 includes a diagram of a Detroit Hydro-Grate and a typical stoker-based process schematic. Sized fuel is metered to a series of distribution devices which spread it uniformly over the stoker grate surface. Fine particles of fuel are rapidly burned in suspension assisted by OFA. Coarser, heavier fuel particles are spread evenly on the grate forming a thin, fast-burning fuel bed.

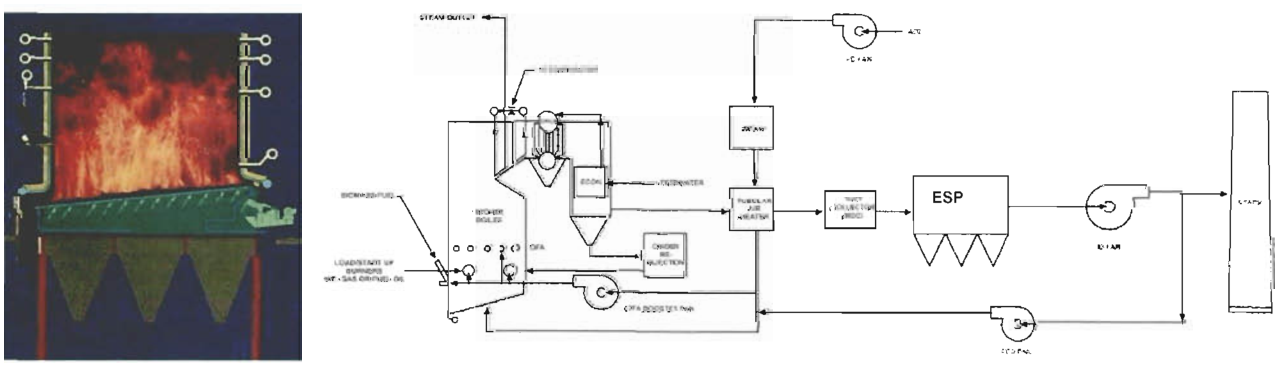


Figure 12 – Detroit Hydro-Grate and Typical Stoker-based Process Schematic

The Detroit Hydro-Grate stoker includes an automatic ash discharge system and water-cooled grates. The higher combustion air temperature needed to burn high moisture fuel can be maintained without damaging the grates. Following are additional details and opinions provided by B&W when comparing the emission characteristics of a typical stoker furnace with a BFB.[1]

[1] Brochure - Bubbling Fluidized Bed or Stoker — Which is the Right Choice for Your Renewable Energy Project?

[In a stoker boiler] "The combustion zone temperature is typically neither measured nor controlled and can range from 2,200 to over 3000 °F. The BFB bed temperature is both measured and controlled to an optimum temperature of approximately 1500 °F.

"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." B&W further adds:

"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."

According to a previous applicant (Southeast Renewals Fuels), "the spreader stoker technology results in inherently higher uncontrolled NO_X emissions compared to the fluidized bed boiler".[2] The Department agrees with the stated B&W and HEF opinions for comparisons between BFB boilers and late 20th century stoker boiler. By incorporating modern developments in GCP or through add-on controls, a stoker can achieve similarly low emissions compared with a BFB boiler.

In response to the Department's aggressive NO_X requirement for the Hillsborough County Waste-to-Energy (WTE) Facility Unit 4 in 2006, Covanta and its affiliate (Martin GmbH) embarked on an effort to improve the profile of the Martin Grate stoker design by employing advanced GCP concepts. They call their designs low NO_X (LN™) and very low NO_X (VLN™)[3].

Basically, all of the NO_X formation and destruction phenomena described for the BFB boiler in Eq. 1 through 9 exist for the stoker to varying degrees. The technology, known as VLN™, employs combustion system design, which in addition to conventional primary and secondary air streams, also features a new internal stream of gas called "VLN™ gas," which is drawn from the combustor and re-injected into the furnace. The gas flow distribution between the primary and secondary air, as well as the VLN™ gas, is controlled to yield the optimal flue gas composition and furnace temperature profile to minimize NO_X formation and optimize combustion.

Figure 13 is a simplified diagram of the VLN™ process. Figure 14 demonstrates that operation of the VLN™ system reduces NO_X concentration by roughly half.

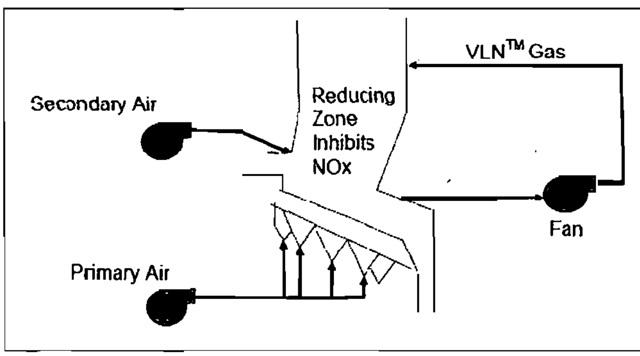


Figure 13 – Diagram of the VLN™ Process

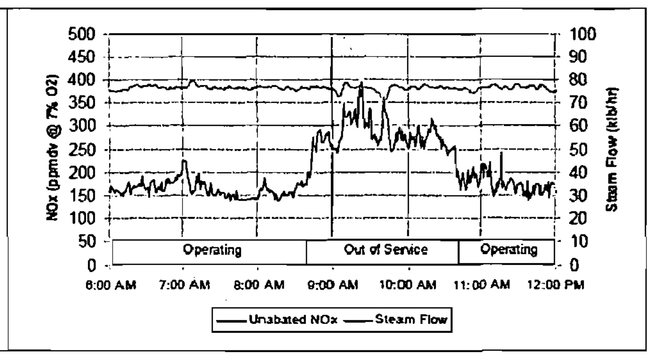


Figure 14 – Operation with/without/with VLN™ System

2 Letter. SRF to FDEP. Southeast Renewable Fuels, LLC, Response to Letter dated August 6, 2010. www.dep.state.fl.us/Air/emission/bioenergy/southern_renewables/serf_add_info_082410.pdf. August 24, 2010.

3 Covanta and Martin GmbH. New Process for Achieving Very Low NO_X. Proceedings of the 17th Annual North American Waste-to-Energy Conference. May 2009.

There are numerous other approaches which are marketed under names like Mobotec, EcoJet, EcoTube, Prizm, etc. that incorporate innovations such that emissions from stokers can be minimized by modern GCP and then achieve very low emissions with add-on controls. Given advances in GCP and add-on controls (discussed below) since the 1990s, the stoker emissions profile must be treated similarly to those of BFB boilers.

HEF has proposed to build a stoker boiler but with volatilization, drying and partial combustion occurring above the grate in a manner analogous to that shown in the BFB diagram in Figure 11.

Add-on NO_X Control. Until recently, add-on controls NO_X were uncommon for biomass boilers. Initial add-on NO_X controls consisted of SNCR whereby NH_3 or urea is injected at a point in the process characterized by a suitable temperature window between about 1,500 and 1,900 °F depending on residence time, turbulence, oxygen content, and a number of other factors specific to the given gas stream. The reaction products are N_2 and water vapor (H_2O). SNCR destroys NO_X by a multi-step process as which is simplified in the equations below.

Equation 10. NH_3 reacts with available hydroxyl radicals (OH*) to form amine radicals (NH_2*) and water per the following theoretical equation:

$$NH_3 + OH^* \rightarrow NH_2{}^* + H_2O \qquad \text{Eq. 10}$$

Equation 11. Amine radicals combine with NO to form nitrogen and water as follows:

$$NH_2{}^* + NO \rightarrow N_2 + H_2O \qquad \text{Eq. 11}$$

Equation 12. The two steps are typically expressed as a single "global reaction".

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \qquad \text{Eq. 12}$$

Similar simplified reactions describe the destruction of NO_2, which is present in much less concentrations than NO. One drawback with SNCR is that some of the NH_3 can be converted to NO_X and excessive NH_3 injection is occasionally required to effect good reduction. Excess NH_3 (called slip) can combine with chloride and sulfate species in the exhaust and cause visible emissions. Additionally good CO control is necessary when employing SNCR due to interference with the reaction as described.

Equation 13. CO competes with NH_3 for available OH radicals needed to effect Eq. 10.

$$CO + OH^* \rightarrow CO_2 + H^* \qquad \text{Eq. 13}$$

In the case of SCR technology, the NH_3 is injected in the presence of catalyst and at a lower temperature than encountered in the furnace. The reactions are more complete and efficient and NH_3 slip is minimized.

In most Florida coal-fueled power plants (e.g. Stanton Energy Center, Progress Energy Crystal River, St. John River Power Park, Tampa Electric Big Bend and others), the SCR unit is located in a dusty environment ahead of other pollution control equipment. Notwithstanding the severe atmosphere, NO_X reduction on the order of 90% is achieved at some of the most recent installations. According to EPA, there are online SCR systems on about 123 gigawatts (GW) of coal steam units.[4] The Department estimates that this equates to 300 coal-fueled units each of 400 MW capacity or nearly 5,000 HEF-sized (30 MW) units.

Refer to Figure 15 below that describes the air pollution control systems for a proposed woody biomass power plant called the Gainesville Renewable Energy Center (GREC). Recently, a number of SCR systems have been specified or actually installed on biomass boilers. The catalyst for the BFB-based GREC project will be located in the clean-side, medium temperature zone after all other air pollution control equipment and before the air preheaters and no reheat of exhaust gases is required.

4 Electronic Communication. William Maxwell, EPA Energy Strategies Group. SCR Count on Coal Utilities.

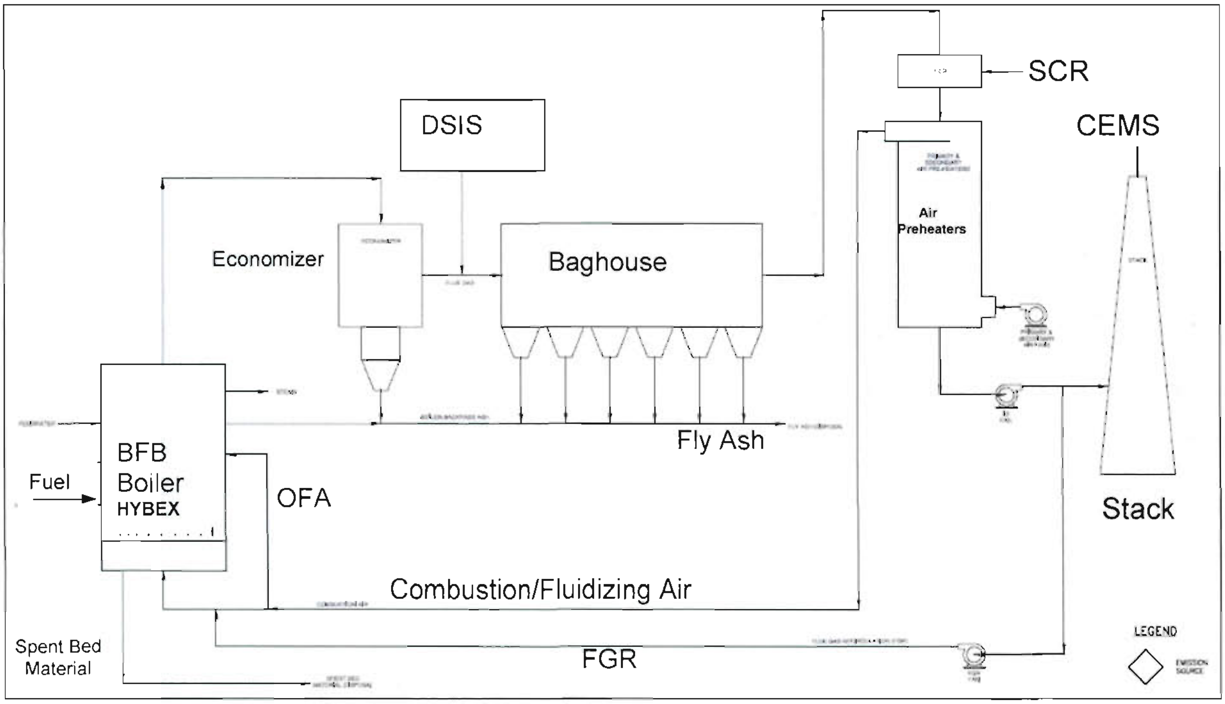


Figure 15 – Gainesville Renewable Energy Center (GREC) BFB Pollution Control Technologies

For conventional or historical installations with the particulate control equipment located in a relatively low temperature regime after the air preheater, exhaust gas reheat may or may not be necessary in order to incorporate SCR on the clean side. In the example shown in Figure 16, reheat is incorporated into the clean-side SCR system at an existing 36 MW poultry litter and feathers-to-energy facility in Holland.

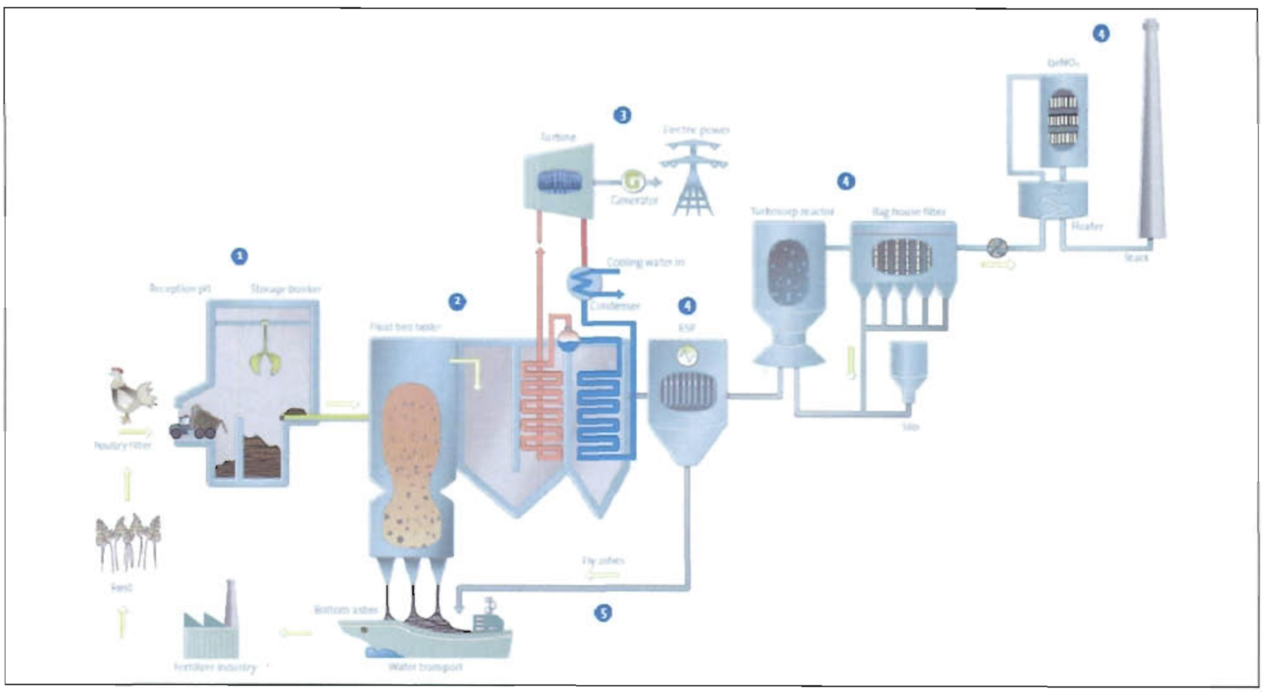


Figure 16 – Basic Process and Air Pollution Control Equipment Diagram for Moerdijk BFB Boiler

Refer to Figure 17.[5] A variation of clean-side SCR called regenerative SCR (RSCR) was developed by Babcock Power, Inc. (BPI) for the purpose of optimizing the efficiency and reducing the cost of such reheat. Ox-cat is usually part of the RSCR package.

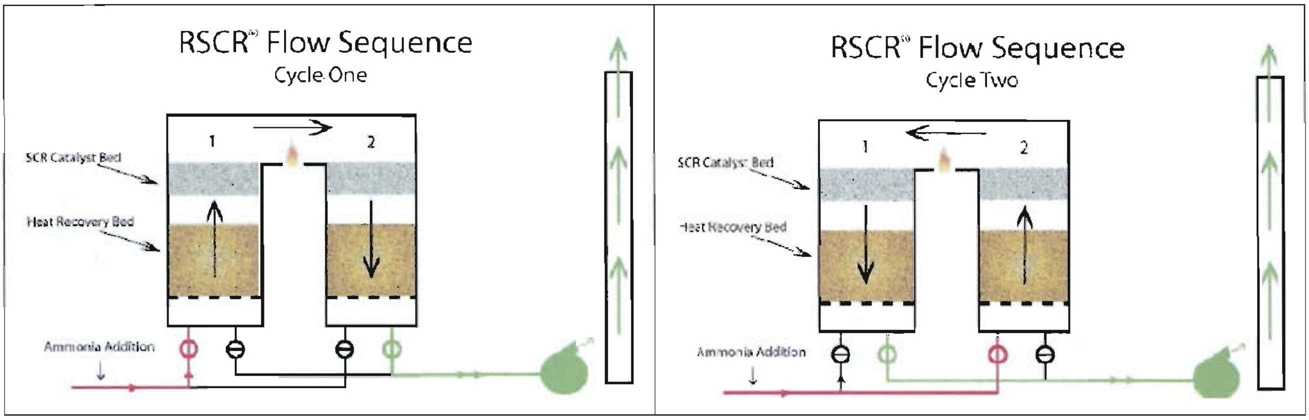


Figure 17 - Principle of RSCR incorporating Duct Burner and Thermal Media (Ox-cat not shown).

Basically a relatively cool exhaust stream is heated by passing through preheated thermal media (Cycle 1) called a heat recovery bed before passing through the SCR catalyst at a moderate temperature. The exhaust gas is then slightly heated by a gas-fueled duct burner. The higher heat of the exhaust gas is then imparted to a second thermal media bed. Eventually the second bed reaches a greater temperature than the first and the flow through the RSCR unit is reversed as shown in Cycle 2.

Basically, the RSCR unit is a heat engine that operates at a moderate temperature while using and expelling low temperature exhaust gas. Thermodynamic losses to the environment are minimized by their arrangement. According to BPI, the RSCR system results in a net increase (system inlet to system outlet) of only 7 °F compared with 50 to 75 °F for more typical heat exchanger arrangements.

One practical benefit of a cool SCR arrangement such as RSCR is that the air preheater shown in Figure 15 can be located right after the economizer. This reduces the actual temperature and volumetric flow rate of gas through the control equipment. RSCR systems have been retrofitted downstream of PM control devices at four existing biomass power plants in Maine (Boralex Stratton and Boralex Fort Fairfield) and New Hampshire (Whitefield Power and Bridgewater Power).[6]

RSCR was also installed at a facility in Vermont (McNeil Burlington).[7] In addition to retrofits, RSCR has been specified for several proposed biomass and WTE projects including the small (38 MW) Palmer Energy biomass project in Massachusetts and the larger Fairfield WTE facility in Maryland.[8, 9] RSCR is often the benchmark against which costs and controls for new projects are weighed.

Despite perceptions to the contrary, application of SCR downstream of a low temperature PM control device do not necessarily require reheating of the exhaust gases prior to the SCR unit. CRI Catalyst (Shell Group) has for years provided low temperature SCR catalyst for use in combustion sources at chemical and refining plants as well as gas turbines and WTE plants.[10]

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5 Presentation to FDEP. RSCR NO_X/CO Control Technology. Babcock Power, Inc. June 2009.

6 Paper. Donovan and Holtzman. Biomass Power Plant Permitting Trends in the Northeast – Lessons Learned. Paper # 271, Air & Waste Management Association 101st Annual Conference & Exhibition, June 2008.

7 Press Announcement. www.babcockpower.com/?p=465 . Babcock Power RSCR® Reduces Vermont Air Emissions. April 21, 2009.

8 Public Notice. www.mass.gov/dep/public/hearings/predcahn_en.htm . Massachusetts Department of Environmental Protection. November 2009.

9 Fact Sheet. www.mde.state.md.us/assets/document/Air/MDE_OC_EA_facility_factsheet.pdf . Energy Answers, International WTE project. Published by the Maryland Department of the Environment. July 2010.

10 CRI Web Link. www.cricatalyst.com/products/environmental/noxreduction.aspx .

In addition to CRI, Haldor Topsoe (HT) supplies low temperature SCR catalyst without requirement for exhaust gas reheating.[11] CRI claims the SCR catalyst as an effective system to reduce dioxin and furan (D/F).[12]

Control of D/F is corroborated in the literature as well as destruction of VOC.[13, 14] SCR was installed at the Algonquin Power WTE in Ontario for the dual purpose of NO_X and D/F reduction. A paper prepared by the government and the operator states:[15]

"In evaluating the technology options, it was suggested that the operating costs for SNCR would be lower than for SCR. However, the SCR system had the potential advantage of dioxin and furan destruction. Thermal oxidation of PCDD/F in the presence of a catalyst produces water, carbon dioxide (CO_2) and HCl. Therefore, SCR was the chosen technology after the evaluation of pollution control options was complete".

According to a report prepared for the Canadian Council of Ministers of the Environment (CCME), *"during commissioning testing (of the SCR system) in November 2001 the facility recorded three D/F emission concentration values well below the Environment Canada Level of Quantification (LOQ) of 32 picograms toxic equivalent (TEQ) per normal cubic meter at 11% oxygen (pg TEQ/Nm^3) @11% O_2".*[16] This equates to 0.045 nanograms (ng) TEQ/Nm^3 @7% O_2. For reference, subsequent installation of activated carbon further reduced D/F at Algonquin by at least another order of magnitude.

The Department conducted a BACT determination for NO_X and D/F at the Palm Beach Renewable Energy facility and required SCR to control both pollutants.

The possibility of low temperature SCR without reheat has been confirmed by the Department's inquiries regarding the operation of at least two of the RSCR installations in New England. According to discussions with the operator at Whitefield Power, NH, the duct burners are not actually used although the NO_X limit is continuously achieved.[17] Operators at the Bridgewater Power, NH facility has made the same determination and this finding has been documented in a permit modification that provides for a lower minimum operating temperature for the RSCR system. The rationale is as follows:

"Since permit issuance, Bridgewater has found that at times of optimal boiler efficiency, the inlet temperature to the RSCR can be as low as 315 degrees F. This results in a corresponding bed temperature of the same value. At 315 degrees F, the outlet NO_X emission rate from the RSCR remains below the desired 0.075 lb/mmBtu and all other criteria pollutants remain below permit limits. In addition, no new pollutants are emitted from the Boiler. As a result of this, Bridgewater has requested that the temperature range be changed from 350 to 650 degrees F to 315 to 650 degrees F."[18]

The manufacturer of the NO_X catalyst used at the mentioned RSCR facilities is Cormetech. Note that the ox-cat is also effective at lower temperatures than previously believed by some operators and agencies.

<u>Applicant's Proposal for NO_X.</u> Refer to Table 6. The applicant's BACT proposal is 0.10 lb/mmBtu on a 30-day rolling basis based on selection of a stoker boiler and incorporation of GCP and SNCR.

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[11] Baviro Roosendaal Web Link. www.baviro.nl/SCR_nl.html .

[12] Paper. Tang, H.S. The Shell Dioxin Destruction System. Solid & Hazardous Waste Management Conference, Singapore, February 2003. www.cricatalyst.com/products/pdfs/sporeconference.pdf

[13] E.g. Tzimas, E., and Peteves, S.D. NO_X and Dioxin Emissions from Waste Incineration Plants. Joint Research Center, European Commission. Circa 2001.

[14] E.g. Leibacher, U., Bellin, C., and Linero, A. High Dust SCR Solutions. International Cement Review. December 2006. www.cementeriadimonselice.it/pdf/HD_SCR_solutions.pdf

[15] Paper. A Case Study of the SCR System at the Algonquin Power WTE Facility. Annual NA WTE Conference. NAWTEC 16-1903. 2008. www.seas.columbia.edu/earth/wtert/sofos/nawtec/nawtec16/nawtec16-1903.pdf

[16] Report. Review of Dioxins and Furans from Incineration in Support of a Canada-wide Standard Review. CCME Project #390-2007. December 15, 2006. www.ccme.ca/assets/pdf/1395_d_f_review_chandler_e.pdf

[17] Telecom. Heron, T., Florida DEP and York, D., Whitefield Power. August 2, 2010.

[18] Permit Amendment. Bridgewater Power Company. Temporary Permit TP-B-0533. Issued September 12, 2007. www2.des.state.nh.us/OneStopPub/Air/3300900021FY08-0501TypeSummary.pdf

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

Project Location	CO	VOC	NO_X	PM/PM_{10} [f,c]	SO_2
HEF, Highlands County [h] ethanol and power grate stoker - cane bagasse, energy crops, wood chips, vegetative debris 504/486 (4/24-hr) mmBtu/hr (2011)	**0.30** 30-day GCP + Ox-cat	**0.017** stack test GCP + Ox-cat	**0.10** 30-day SNCR	**0.015 (f)** stack test ESP	**0.11**[h] 12-month DSIS
SRF, Hendry County Ethanol and Power, BFB or grate Sorghum bagasse, wood, biogas, VLSD fuel oil, propane, yard waste < 30%. 488 mmBtu/hr (2010)	0.10 (grate) 0.10 (BFB) 30-day GCP or Ox-cat	0.010 (grate) 0.010 (BFB) stack test GCP or Oxcat	0.10 (grate) 0.08 (BFB) 30-day SNCR or SCR	0.015 (f) (grate) 0.015 (f) (BFB) stack test ESP	0.060 30-day DSIS
Vercipia, Highlands County, FL *BFB - stillage, wood, gas, ULSD FO* ~198 mmBtu each (2010)	0.10 30-day GCP	0.005 stack test GCP	0.075 30-day SNCR	0.01 (f) Stack test fabric filter	0.060 30-day BFB limestone
Palmer Renewable, MA grate stoker boiler – woody biomass 509 mmBtu/hr (draft 2009)	0.070 4-hour Ox-cat	0.010 stack test Ox-cat	0.060 1-hour RSCR	0.012, 0.02 (f, f+c) stack test fabric filter	0.02 1-hour dry scrubber
Aspen, Lufkin, Angelina Co., TX grate boiler – woody biomass ~692 mmBtu/hr (2009)	0.075 30-day Ox-cat	0.010 stack test Ox-cat	0.075 30-day SCR	0.012 (f) stack test ESP	0.025 stack test sorbent in ducts
Lindale, Smith Co., TX grate stoker boiler – woody biomass ~684 mmBtu/hr (2009)	0.31 30-day GCP	0.017 stack test GCP	0.15 30-day SNCR	0.02, 0.026 (f, f+c) stack test fabric filter	0.025 30-day low sulfur fuel
FBE, Manatee County, FL grate stoker boiler – woody biomass ~757 mmBtu/hr (2010)	~0.0295 (eq) [e] 12-month Ox-cat	~0.003 (eq) stack test Ox-cat	~0.020 (eq) 12-month SCR	0.01 (f) stack test ESP	~0.016 12-month sorbent in ducts
ADAGE, Hamilton County, FL BFB – woody biomass ~758 mmBtu/hr (2010)	~0.074 (eq) 12-month GCP	~0.017 (eq) stack test GCP	~0.070 (eq) 12-month SCR	0.029 (f+c) stack test fabric filter	~0.045 (eq) 12-month sorbent in ducts
GREC, Alachua County, FL BFB – woody biomass 1,358 mmBtu/hr (2010)	0.12/0.08 [a] 30-day GCP	~0.010/0.009 [a] stack test GCP	0.070 24-hour SCR	0.015, 0.042 (f, f+c) stack test fabric filter	~0.029 24-hour sorbent in ducts
Yellow Pine, Ft. Gaines, GA BFB - woody biomass, tires 1529 mmBtu/hr (2010)	0.15 30-day GCP	0.02 stack test GCP	0.10 30-day SNCR	0.018 (f+c) stack test fabric filter	0.14 30-day dry scrubber
U.S. Sugar (USS) Clewiston, FL grate stoker boiler - bagasse ~1,000 mmBtu/hr (2003)	0.38 12-month GCP	0.05 Stack test GCP	0.14 30-day SNCR	0.026 (f) stack test fabric filter	0.06 30-day no control
NSPS Subpart Db Propane, wood, ULSD fuel oil ≤250 mmBtu/hr	No standard	No standard	~0.020	0.030 (f) or 20% opacity [b]	~0.020
40 CFR 63, Subpart DDDDD (major)	~1.57 (eq)	No standard	No standard	0.0011 (f)	No standard
40 CFR 63, Subpart JJJJJ (area)	No Standard	No standard	No standard	0.03 (f)	No standard

a. The lower CO and VOC values for the Gainesville Renewable Energy Center (GREC) apply after one year of operation.
b. 20% opacity except for one 6 minute period per hour of 27% opacity.
c. "c" denotes condensable fraction.
d. The high Subpart DDDDD CO values are for the hybrid suspension grate category. Rule also includes Hg, HCl, D/F limits.
e. "eq" values in lb/mmBtu denote cases where the enforceable limits are actually in other units such as ppm, lb/hr or TPY.
f. "f" denotes filterable fraction.
g. Subpart JJJJJ includes only a PM limit and no Hg, HCl, D/F limits.
h. Limits proposed by HEF. All were accepted except for SO_2, which will be limited to 0.06 lb/mmBtu on a 30-day basis.

One of the key statements in support of their proposal is the claim that "lending institutions are not willing to lend significant amounts of capital for unproven (presumably SCR) technology configurations".

Department's Review. According to its definition, BACT is based on the technology the "Department determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques)".

The use of a BFB boiler versus stoker boiler involves just variations within the same production process which in the present case is combustion of biomass in a furnace to produce steam and electric power. Furthermore the key feature of the stoker grate designs for bagasse stokers is drying, volatilization and partial combustion in suspension (prior to falling on the grate). The suspension feature is clearly part of the BFB design as shown in Figure 11 above.

Consideration of a BFB boiler versus a grate stoker with suspension drying, volatilization and partial combustion (combustion technique) is within the scope of a BACT definition and review. BACT also includes treatment techniques and a combination of such techniques can improve the emission profile of a stoker to a level where is equals that of a BFB boiler. Therefore it is allowable to specify a BFB boiler as the basis of BACT emission limits while allowing installation of a stoker boiler.

The Department accepts the applicant's BACT proposal for this project of 0.10 lb NO_X/mmBtu (30-day average) on the basis of incorporating GCP and SNCR in a stoker boiler. Compliance will be demonstrated by a NO_X-Continuous Emission Monitoring System (CEMS). Inclusion of Ox-cat to control CO, VOC and HAP will provide flexibility to achieve the NO_X BACT by GCP and SNCR. The Department does not reject BFB and SCR and these remain options for consideration in future projects.

The Department has determined lower BACT values for certain other projects in Florida. However the applicant's latest proposal for the present project is adequate for a state PSD BACT determination given that the emissions are likely to be controlled (after installation of Ox-cat as discussed below) to levels less than the federal PSD SER of 250 TPY for this particular industry (ethanol production facilities that produce ethanol by natural fermentation).

SO_2 and SAM Emissions

SO_2 is primarily formed from S compounds contained in biomass. SAM is formed by further oxidation of SO_2 to sulfur trioxide (SO_3) prior to exiting the process. SO_3 readily combines with water vapor (H_2O) available in flue gas to form SAM. According to the application, the biomass boiler is expected to emit approximately 200 TPY of SO_2 and 10 TPY of SAM.

According to the applicant, biomass entering the ethanol process (e.g. sugarcane and sweet sorghum bagasse) at HEF will be typically low in S content. Values of 0.12% and 0.22% S (dry basis) were provided as design values for sugarcane and sweet sorghum respectively. The contribution from natural gas is negligible (<0.002%) compared with bagasse.

Applicant's Proposal for SO_2 and SAM:

The applicant's proposed SO_2 BACT limit for the bagasse boiler for biomass firing is 0.11 lb/mmBtu on a 12-month rolling average. According to the applicant, this limit is somewhat higher than other bagasse boilers (i.e., 0.06 lb/mmBtu), but this is due to the potentially higher sulfur content of sweet sorghum bagasse.

The proposed BACT limit for SO_2 is based on: the DSIS using sodium bicarbonate (SBC or $NaHCO_3$) or a proprietary chemical; the low sulfur content of bagasse, wood, and natural gas; and some inherent SO_2 removal via fly ash collected in the ESP. According to the applicant, the inherent control (i.e. without DSIS) via the fly ash and ESP is estimated to be at least 75%.

The applicant did not propose a specific BACT limit for SAM but proposes the SO_2 controls discussed above for control of SAM.

Department's BACT Determination for SO_2. The proposed value of 0.11 lb/mmBtu on a 12-month basis, rolled monthly is high compared with all of the other projects listed in Table 6. For example, the two sorghum-to-ethanol projects listed in the table are each limited to 0.060 lb/mmBtu. The SRF project, e.g., will use *more* sorghum than intended by HEF thus contradicting the claim that the *"somewhat higher (limit) ...... is due to the potentially higher sulfur content of sweet sorghum bagasse (vs. sugarcane)"*.

U.S. Sugar Unit 8 burns sugarcane bagasse in a grate boiler, is equipped with an ESP and has no add-on SO_2 control such as a DSIS. Unit 8 was limited to and achieves less than 0.06 lb SO_2/mmBtu based on annual testing. Similarly, the New Hope Power Okeelanta facility permitted in the early 1990's has three grate boilers that burn sugarcane bagasse and woody wastes. These are also equipped with ESP and no add-on control equipment for SO_2. All of the New Hope Okeelanta boilers achieve less than 0.060 lb SO_2/mmBtu on a 30-day basis as measured by SO_2-CEMS. The following figure contains the 30-operating day rolling values for the three units over the past year. Flat zones are periods when a unit or CEMS is down.

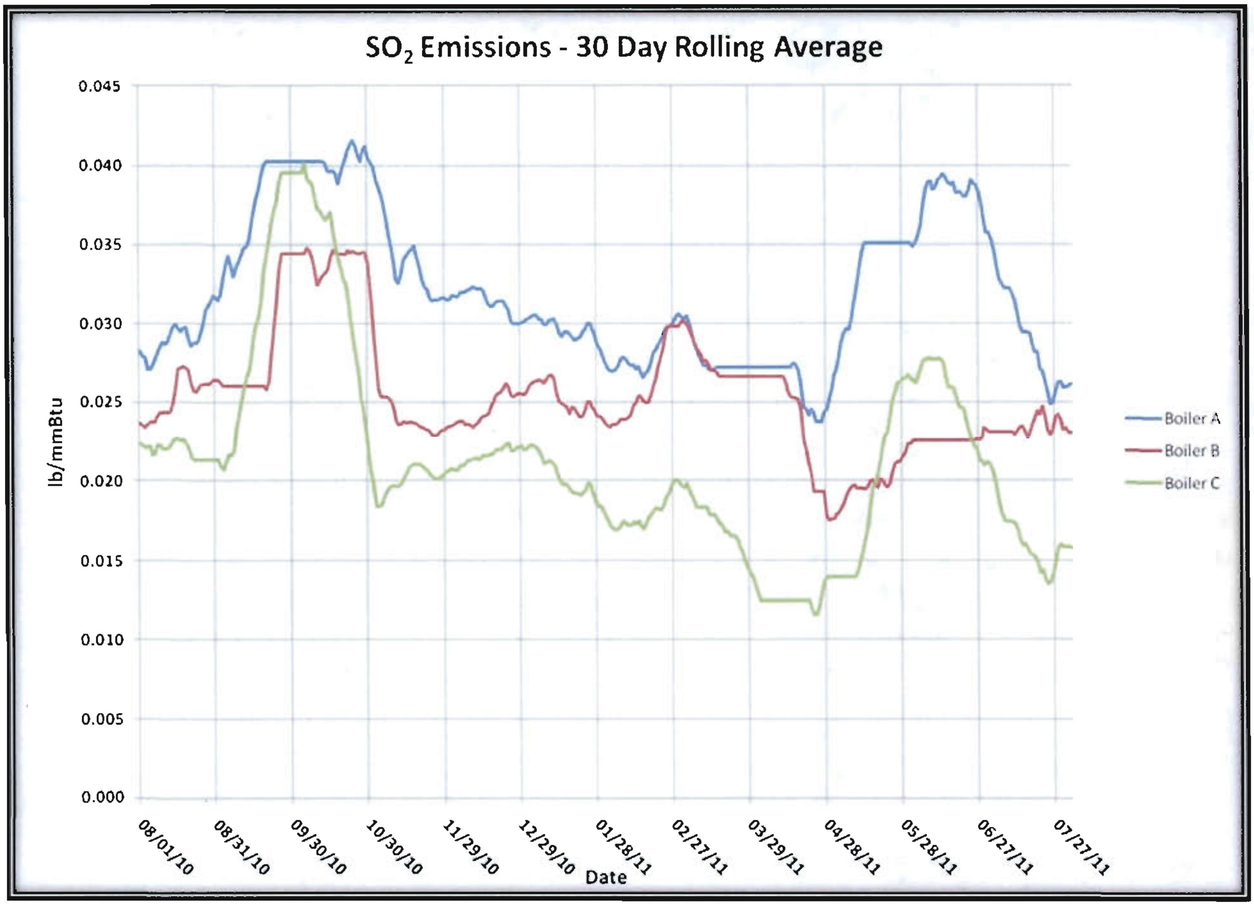

Figure 18 – SO_2 Emissions on a 30-Operating Day Basis at Okeelanta Units 1, 2 and 3

According to the University of Florida study cited by the applicant as a source of chloride (Cl) content, washed sorghum bagasse had a content of only 0.01% S. It is reasonable, given the presence of the DSIS, to expect HEF to comfortably achieve a value of 0.06 lb/mmBtu on a 30-day basis like U.S. Sugar Unit 8, Okeelanta Units 1, 2 and 3 as well as the proposed Vercipia and SRF projects. Also given the expectation by the applicant that a reduction of 95% in HCl emissions will be achieved by use of the DSIS, it is also reasonable to expect a relatively high efficiency for SO_2 as well.

The Department will set the BACT limit at 0.060 lb SO_2/mmBtu on a 30-operating day basis as measured by SO_2-CEMS. The control technology (low sulfur biomass, partial control via fly ash and the ESP, and the DSIS) proposed by HEF is acceptable. In addition to $NaHCO_3$, the permit will also indicate slaked lime [$Ca(OH)_2$], trona [$Na_3(CO_3)(HCO_3)\bullet 2H_2O$] or other proprietary solid chemicals as possible sorbents for use in the DSIS.

Department's non-BACT determination for SAM.

Generally speaking, the DSIS will be as efficient in removing SAM as it is in removing HCl and more efficient in removing SAM than in removing SO_2. The following consolidated table is reproduced from a very recent paper on DSIS when used as a multi-pollutant control technique in conjunction with types of PM control devices to meet the boiler and utility MACT rules. [19]

Table 7 Pollutant Removal with DSIS in an ESP or a Pulsed Jet Fabric Filter Baghouse (PJFFB)

Pollutant	Typical % Removal		Sorbent	Comments
	ESP[1]	PJFFB[2]		
SO_2	70+	80+	Milled SBC Milled trona	If higher removal rates required, sorbent loading to ESP (or PJFFB) must be evaluated as well as PM loading leaving ESP (if selected).
HCl	90+	95+	Milled SBC Milled trona Unmilled trona Hydrated lime	High removal achieved when combined with SO_2 control.
SAM	90+	95+	Unmilled trona, Hydrated lime	Unmilled reagent is typical – SBC could be used, but significantly more expensive

1. Depends upon system residence time, hot or cold ESP, flue gas temperature, sorbent, sorbent coverage and sorbent particle size/reactivity.
2. Depends upon system residence time, flue gas temperature, sorbent, sorbent coverage and sorbent particle size/reactivity.

The SNCR system will require excess NH_3 to achieve the targeted NO_X removal efficiency of approximately 60% and will convert some of the SAM to ammoniated sulfates.

The Department will set a value equivalent to 0.0037 lb SAM/mmBtu (equal to 6.82 TPY) to insure PSD is not triggered. This value is equal to the limit recently set for the SRF project. The strict SO_2 BACT limit and the SO_2-CEMS together with initial and annual SAM tests will provide reasonable assurance of continuous compliance.

CO and VOC Emissions

Discussion. Refer to the previous descriptions of the BFB boiler and stoker boiler operation. CO and VOC (including organic HAP) are products of incomplete combustion. Combustion in the lower furnace occurs in substoichiometric conditions. Also, there often exist localized substoichiometric pockets or cells even if overall excess oxygen conditions are maintained in the lower furnace.

A great deal of CO is evolved as well as VOC (including hydrocarbon radicals and other species). The CO, hydrocarbon radicals and reduced nitrogen compounds (as previously mentioned) participate in reactions that assist in primary NO_X control.

Sufficient OFA, temperature and turbulence is necessary to complete the burnout of CO, fine char and VOC. Clearly throttling NO_X formation by staging combustion using the OFA ports affects CO and VOC formation in the furnace. Basically, the manner by which the boiler is operated (e.g. favoring NO_X over CO/VOC control) is part of an overall source emission strategy that considers the emissions limits and costs of add-on controls.

19 Campobenedetto, E.J. and Silva, A.A., Babcock and Wilcox. Low Cost Multi-Pollutant Control Solution Demonstrations .Air & Waste Management Association Annual Conference. June 21, 2011.

This fact can be appreciated in Figure 19 from a B&W publication that demonstrates the modeled relative effects upon CO when switching to a low NO_X control strategy. Under the low NO_X strategy (newly designed air system including higher OFA ports) moderate levels of CO (and presumably VOC) persist at greater heights within the furnace compared with the previous combustion strategy.

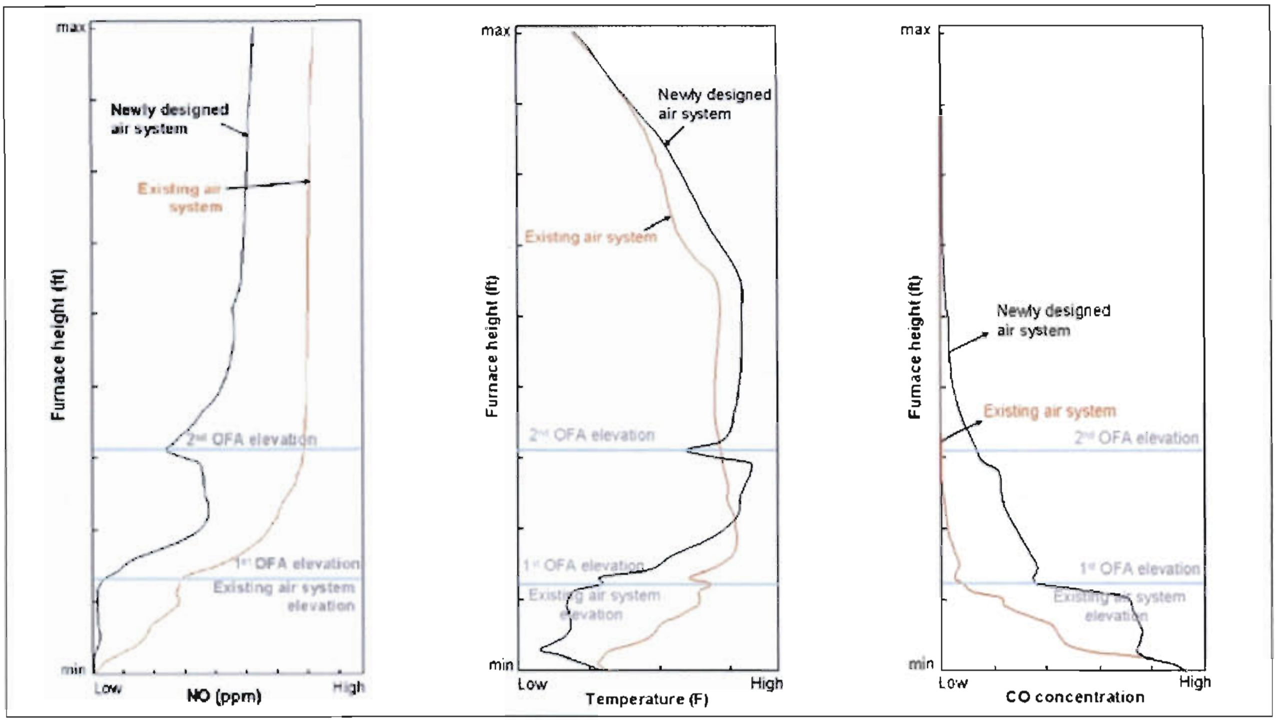

Figure 19 - Modeled NO_X, Temperature and CO a BFB Boiler after Switching to Low NO_X strategy.

According to the article, *"in favor of achieving low NO_X emissions, higher CO values were accepted in the Precision Jet air system. However, these CO emissions were well within the acceptable range to meet state and federal requirements".*[20]

If GCP are geared primarily to control NO_X (such as in the example above) then there is less freedom when also controlling CO and VOC by the same GCP. If GCP as discussed above are not sufficient to achieve low CO and VOC emissions, an oxidation catalyst (Ox-cat) is an option. As in the case of SCR catalyst, the preferred location of an Ox-cat system is after the PM control device (e.g. ESP).

Refer to Figure 20. The information in the curves suggests that Ox-cat is effective for CO removal at temperatures as low as 300 °F.[21] Moreover, Ox-cat is even more effective in destroying formaldehyde (CH_2O - the HAP emitted in the greatest amount from the HEF boiler) than its effectiveness in destroying CO. Ox-cat is also effective in destroying D/F. Furans will oxidize quite easily. Dioxins will also be oxidized, but an accurate prediction of reduction is difficult to provide since its measurement is very specialized and expensive.[22]

<u>Applicant's Proposal for CO and VOC</u>.

The applicant's BACT proposal is 0.30 lb CO/mmBtu (30-day) and 0.010 lb VOC/mmBtu for by GCP within a hybrid suspension grate stoker. The applicant proposes a modern OFA combustion design and controls for boiler CO controls.

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[20] Dessam et al, B&W. Use of Numerical Modeling for Designing a Biomass-fired BFB Boiler Air System for Low NO_X Emissions. 2009 Power-Gen International Conference. Las Vegas December 2009.

[21] Brochures. Süd-Chemie and Johnson-Matthey.

[22] Electronic Communication. Pope, M., Süd-Chemie to Linero, A., Florida DEP. Application of Ox-cat to Crop Biomass CO Emissions. August 9, 2010.

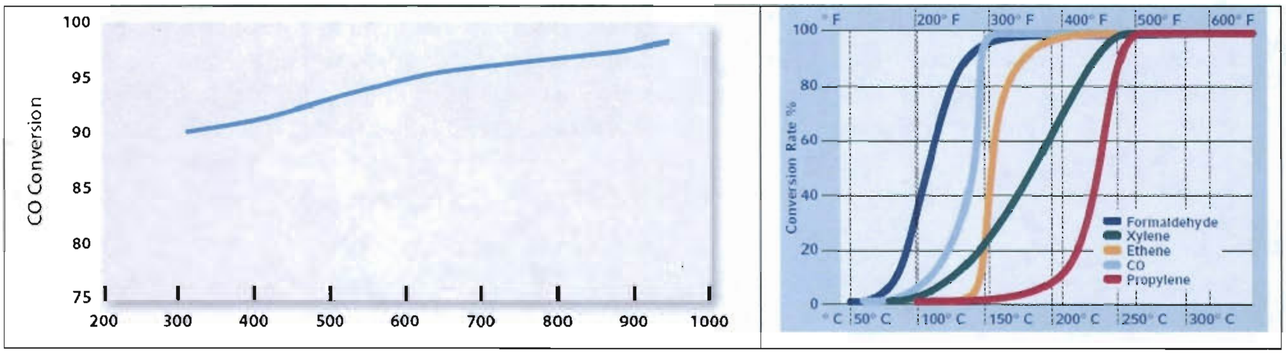


Figure 20 - Ox-cat Performance vs. Temperature (°F) Ox-cat Performance vs. Temperature (°C)

An enhanced OFA system (i.e. beyond the proposed modern OFA system) was evaluated and according to the applicant is not cost-effective at $3,400 per ton of CO removed and $3.1 million in capital costs.

According to the applicant, Ox-cat would reduce CO and VOC emissions by an estimated 60 percent, from 584.3 TPY to 239.6 TPY, for a 345 TPY reduction. The cost effectiveness of oxidation catalyst for CO and VOC control is $1,044 per ton of (CO + VOC) reduced. The cost of oxidation catalyst is therefore comparatively low.

According to the applicant, catalyst vendors are not willing to guarantee the catalyst for more than one year of operation. One key supplier (Süd-Chemie) provided the following assessment to HEF regarding their product:[23]

"Our recent wood gas installations have been operational (24/7) for over 3 years now with annual water wash cleaning. Generally we expect a full rejuvenation (chemical) will be needed within 3 - 4 years on these applications. On this application the flue gas derived from sugar cane waste at an ethanol plant is not in our realm of experience. Consequently, while we have absolute confidence in our catalyst coating, the potential of catalyst masking agents and poisons within the gas are unknown. The agents and poisons would reduce the life and performance of the catalyst. Of course this affects all catalysts in the same way.

"At this point we could not realistically guarantee performance beyond 12 months (8760 hours) and even then the presence of unknowns could reduce this further. Consequently the emissions level would need to be adjusted for this fuel type."

Department's Review. A comparison of the proposed CO and VOC values for the HEF project with other biomass projects is given in Table 6 above. With an SNCR system it is necessary to simultaneously pursue a furnace low NO_X strategy using GCP such that CO and VOC emissions can substantially increase. With SNCR (without SCR), the Department concludes that Ox-cat would be cost-effective to reduce CO and VOC emissions as concluded by the applicant (see discussion above).

By destroying organic HAP such as CH_2O, Ox-cat would provide further reasonable assurance that the facility is an area source of HAP as discussed in Section 3.5 above and yield BACT level CO and VOC emissions.

Department's BACT Determinations for CO and VOC. Treatment by installation of Ox-cat can improve the emission profile of a stoker to a level that is equal or (as shown for FBE) superior to a BFB boiler without Ox-cat. Notably, the CO and VOC limits specified in Table 6 for FBE, Aspen (Lufkin) and Palmer Renewable as a group (stoker boilers) are competitive with the limits for GREC, ADAGE and Highlands Ethanol (BFB boilers).

[23] Letter. Pope, M., Süd-Chemie to Landers, L., PPC Industries. Application of Ox-cat to flue gas from sugarcane waste. June 22, 2011.

The Department has determined that BACT for this project is the requirement to install Ox-cat with a final permit CO and VOC limits to be set in the future. It is very likely that such an installation will reduce emissions of CO to the point that it is not a major stationary (PSD) source by the present federal regulations and the pending state rule. The initial permit limits will be 0.30 lb CO/mmBtu (30-day average) and 0.017 lb VOC/mmBtu. Although several projects listed in Table 6 have lower CO and VOC limits, the applicant's updated proposal is adequate given that the emissions are will actually be controlled to a level less than the federal PSD threshold of 250 TPY for this particular industry.

The Ox-cat system will be installed and tested for a 24 month test period to determine if catalyst poisoning occurs due to the bagasse fuels. At the end of the 24 month test period, a test report will be submitted to the Compliance Authority and the Department. The report will include:

- Daily averages of boiler operating parameters to include heat input, steam generation, fuel mixtures (cane bagasse, sorghum bagasse, supplemental biomass fuel and natural gas) and corresponding weights of each biomass and mmscf of natural gas burned as fuel used including each supplemental fuel (energy crops, wood chips and vegetative debris);
- Daily NO_X and CO CEMS data in lb/mmBtu and lb/hr, daily HCl CEMS data in lb/hr and lb/mmBtu, all HAP and VOC stack test results from both the boiler stack and ethanol process scrubber stacks in lb/mmBtu and lb/hr, all maintenance actions performed on the Ox-cat system; and
- If necessary, a recommendation for the Ox-cat system removal with supporting justification or any requested permit modification to allow the continued use of the Ox-cat system.

Based on all the data (boiler parameters, pollutant and HAP emissions and maintenance actions) in the test report, the Department will either adjust the CO and VOC emission limits downward to reflect the actual CO and VOC emission rates or allow removal of the Ox-cat system. If the Ox-cat system is removed, the CO emission limit will remain 0.30 lb/mmBtu on a 30 day rolling average basis and the VOC limit will remain at 0.017 lb/mmBtu.

Compliance with the CO limit shall be demonstrated by a CO-CEMS. Initial and annual VOC compliance tests will be required.

While the supplier and applicant have expressed some doubts regarding the lifetime of the catalyst, the Department notes that the biomass fired will be fairly consistent and there should be few unknown or unexpected species that will get past the ESP and poison the catalyst.

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

<u>Discussion</u>. 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.

The most well-known controls include cyclones, electrostatic precipitators (ESP), fabric filters and wet scrubbers. Supplementary controls include strategies such as minimization of $PM_{2.5}$ and VE precursors by limiting SO_2, NO_X, NH_3, VOC and chlorides.

The most effective types of direct PM control equipment applied to biomass boilers are fabric filters and ESP. Fabric filters, where technically feasible, are the preferred PM control device because they provide better control for fine PM.

<u>Applicant's Proposal for PM/PM_{10}/$PM_{2.5}$ and VE Limits.</u> The applicant's BACT proposal for PM/PM_{10} is 0.015 lb/mmBtu for <u>filterable</u> (f) PM/PM_{10} based on an ESP (following a wet sand cyclone). According to HEF:

"Fabric filters are considered technically infeasible for application to the proposed bagasse boiler. There are only few known applications of a fabric filter to a grate-type biomass-fired boiler and the fabric filter was used due to the use of a spray dryer for SO_2 control.

"No hybrid suspension/grate bagasse-fired boiler is known to utilize a fabric filter. Further, serious concerns exist over the ability of a baghouse to operate long-term in a harsh environment with a flue gas containing significant moisture and light, stringy bagasse particles. There are also serious concerns with potential fire hazards due to burning particles being carried out of the boiler. This is the nature of bagasse-fired boilers, where the bagasse fuel is light and stringy. As a result, fabric filter technology was not further considered for the HEF."

HEF proposes an alternative monitoring procedure (AMP) for a surrogate to VE that relies on the measurement of total power input to the ESP as monitored by secondary voltage and secondary current to each field rather than on a continuous opacity monitoring system (COMS).

Department's Review. The proposed PM/PM_{10} limit of 0.015 lb(f)/mmBtu is less than the NSPS, Subpart Db limit of 0.03 lb(f)/mmBtu applicable to units that (like HEF) burn less than 250 mmBtu/hr of fossil fuel. The applicable PM limit in the area source NESHAP Subpart JJJJJJ is also 0.03 lb(f)/mmBtu.

The capacity of the HEF boiler is 504 mmBtu/hr (4-hr) for all fuels combined. For reference, the proposed PM/PM_{10} limit is equal to the limit of 0.015 lb(f)/mmBtu applicable to boilers (those subject the NSPS, Subpart Da) burning a variety of fuels including at least 250 mmBtu/hr of fossil fuels.

As discussed above, major source NESHAP, Subpart DDDDD is not applicable to this project and its applicability to major sources has been delayed while it is reconsidered. For reference, the PM limit given in Subpart DDDDD is 0.0011 lb(f)/mmBtu.

The Department reviewed the initial and annual compliance tests conducted at the USS Bagasse Boiler No. 8 (controlled by an ESP) from 2005 to 2009 inclusive and found that the range of emissions was 0.004 to 0.015 lb(f) /mmBtu with an average of 0.0089 lb/mmBtu.

In the case of the Aspen Power (Lufkin, TX) biomass grate stoker power project listed in Table 6, the State of Texas Council of Environmental Quality (TCEQ) initially issued a permit with a PM limit of 0.025 lb/mmBtu. The permit was appealed while the project was already under construction. After an ensuing settlement and remand to TCEQ, the permit was reissued with a limit 0.012 lb PM/mmBtu (f).[24]

The Department reviewed the request for an AMP in lieu of a VE limit. According to the definition given above, BACT is *"an emission limitation, including a **visible emissions** standard."* (emphasis added). It is practicable to set a VE limit and to install a COMS to measure opacity. Although EPA Region 4 allowed, by letter, the use of the AMP in the case of USS Bagasse Boiler No. 8, the action was limited to compliance with the relevant NSPS 20% VE standard and would not provide reasonable assurance of continuous compliance with the lower BACT 10% VE limit for the present project.[25]

In determining the feasibility of a VE limit and COMS, the Department reviewed compliance tests conducted at USS Bagasse Boiler No. 8 following construction and information from the HEF application and found the following:

- USS Bagasse Boiler No. 8 includes a wet sand cyclone in front of the ESP;
- The stack temperature at USS Boiler No. 8 is in the range of 300-325 °F suggesting that no water vapor should form in the stack;[26]
- The moisture content of the exhaust gas at the stack is in the range of 25-30%;
- The projected stack temperature at the HEF stack is 340 °F at 25% moisture;

[24] Attachment. Joint Motion by Applicant, TCEQ and Protestants to Remand Aspen Power Permit to TCEQ. Texas State Office of Administrative Hearings. October 20, 2009. Aspen Power Remand

[25] Such NSPS related requests are now typically handled through a more involved process including a published EPA order in the Federal Register. At this time, the Department would not simply follow the previous NSPS action by EPA Region 4 as a binding precedent for a BACT determination.

[26] Report. C.E.M. Solutions. NO_X and CO Relative Accuracy Test Audit. USS Boiler No.8, December 4-5, 2009.

- During compliance testing, the VE observed by a contracted certified smoke reader was 0% opacity for all readings during the 1-hour test;[27]
- The observer noted the water droplets were not present in the USS Bagasse Boiler 8 stack exhaust;
- The observer noted the presence of a steam plume from the USS Bagasse Boilers Nos. 1, 2 and 4 that are controlled by scrubbers and not ESP;
- Discussion with plant personnel indicated that there is usually no visible plume from USS Boiler No. 8 except when burning oil;[28]
- Any plume from USS Boiler No. 8 typically has a slight tinge, less than 10% opacity and not associated with water vapor; and
- Discussion with Department compliance personnel confirms the observations of the plant personnel and the contractor.[29]

The Department concludes that any steam plume would form outside the stack if it forms at all. The Department also concludes that moisture should not interfere with the function of a COMS.

Department's BACT Determinations PM/PM_{10} and VE. The Department will specify a filterable PM/PM_{10} limit of 0.015 lbmmBtu on the basis of an ESP. The Department's determination is equal to the BACT determination for the recently approved SRF sorghum to ethanol and steam project.

The Department has not yet finalized adoption of the SER threshold for $PM_{2.5}$ an SER.

A BACT VE standard of 10% opacity (6-minute average), except for one 6-minute period per hour of not more than 20% opacity, will also be established and demonstrated by a COMS.

4.3. HAP Emission Limits for the BFB Boiler

Refer to Table 5 in Section 3.5 above. The applicant estimated annual emissions of all HAP (aggregate) at 23.17 TPY from the project (18.26 TPY from the boiler) including 6.85 TPY of HCl (assuming 95% control). With the use of an ESP rather than a fabric filter baghouse, the HCl emissions can approach 10 TPY, which is the single HAP major source threshold. On the other hand, installation of Ox-cat will provide a margin of safety and it is likely that emissions of organic HAP will be less than the estimated value of 7.11 TPY from the boiler.

Because the PTE of HCl will be close to 10 TPY and the aggregate PTE of all HAP will be close to 25 TPY, it is necessary to establish enforceable HAP emission limits.

HCl Emissions

Although the applicant estimated 6.85 TPY, the Department will set a limit of 9.0 TPY of HCl on a 12-month rolling average, rolled monthly. The control method will be the same as previously discussed for SO_2 (i.e. removal by fly ash, the DSIS and the ESP). Compliance shall be demonstrated by an HCl-CEMS.

The 12-month limit equates to approximately 2.24 lb HCl/hr. The limit, the DSIS, the ESP and the HCl-CEMS requirement will provide reasonable assurance that HCl emissions will be less than 10 TPY.

Other HAP Emissions from the Boiler

The applicant estimates emissions of 1.05 TPY of metal HAP from the boiler (i.e. excluding the ethanol process) consisting primarily of Cr, Mn, Pb, Ni and, to a lesser degree, Hg. Total organic HAP and Cl_2 emissions from the boiler will equal approximately 7.29 and 3.03 TPY, respectively.

According to Table 5 in Section 3.5 above the applicant initially estimated Hg emissions of 0.025 TPY (50 lb/yr). According to the applicant, they made a very conservative (high) assumption and it is likely

[27] VE Test. Horton, Chuck. Record of Visual Determination of Opacity. USS Boiler No. 8. December 2, 2009.
[28] Telecom. Linero, A. and Tingleburg, K. Stack Plume Behavior for USS Boiler No. 8. August 31, 2010.
[29] Telecom. Linero, A., Heron, T. and Lewis, W. Stack Plume behavior for USS Boiler No. 8. September 7, 2010.

that annual emissions will be less than 20 lb/yr. There is no requirement to limit Hg from the project as long as it remains an area source of HAP and does not trigger the BACT SER of 200 lb/yr.

Rather than setting individual limits for each of the categories of Cl_2, organic and metal HAP (including Hg) from the boiler, the Department will limit the total annual HAP emissions from the boiler to 19.61 TPY. This limit is expressed as $\sum$ (HCl, HF, Cl_2, metal HAP, organic HAP) = 19.61 TPY. This limit will complement the individual enforceable limit of 9.0 TPY for HCl emissions.

The demonstration of compliance with 19.61 TPY limitation will be determined on a fiscal year basis, based on the initial and annual stack tests (organic HAP tested quarterly during first 24 months of HEF facility operation) conducted for the identified Cl_2, metal, HF and organic HAP stack tests coupled with the totalized HCl-CEMS data for the given fiscal year. The quarterly organic HAP test (if Ox-cat system removed, annual otherwise) will be averaged for each fiscal year. The HAP limit of 19.61 TPY from the boiler takes into consideration the applicant's separate estimate of 4.24 TPY of organic HAP from the ethanol process and 0.85 TPY of HAP as fugitive emissions and other HAP emissions from the boiler. Further details regarding the ethanol process are given further below.

The total HAP estimate for the facility is 24.7 TPY. The Department has reasonable assurance that the facility (after controls) is not a major source of HAP because:

- The DSIS, H_2S scrubber and ESP will control acid gases and metal HAP;
- HCl emissions are limited to 9.0 TPY respectively by enforceable conditions and required CEMS;
- Good combustion practices will minimize formation of organic HAP;
- An Ox-cat system is required by the permit for the purpose of controlling CO and VOC and will reduce organic HAP including D/F;
- There will be an annual HAP cap of 19.61 TPY from the boiler based on the HCl-CEMS, and the required initial, quarterly and annual HF, Cl_2, metal and organic HAP tests;
- Further assurance is provided by the CO-CEMS as a surrogate for continuous low organic HAP emissions measurement from the boiler;
- Further assurance is provided by the low VE limit and COMS requirement:
- Chemical reagents will be incorporated into the fermentation scrubber to control HAP such as acetaldehyde.
- The VOC leak detection and repair (LDAR) described further below for the ethanol process pursuant to 40 CFR 60, Subpart VVa and ethanol process VOC BACT and required monitoring and testing requirements will minimize the contribution of HAP from the ethanol process to total project HAP emissions.

4.4. Ammonia (NH_3) Slip

The applicant will comply with the NO_X limit given in the draft permit of 0.10 lb/mmBtu based on the installation of a hybrid suspension grate stoker boiler. There are no regulations that directly limit NH_3 emissions; however NH_3 can contribute to PM/PM_{10} and $PM_{2.5}$ emissions.

Low NH_3 emissions are easy to achieve when relying on SCR technology, but more difficult when relying on SNCR to achieve BACT-level NO_X emissions. The applicant for the previously permitted SRF project advised that FuelTech, a well-known supplier of SNCR systems, will guarantee NH_3 slip of 35 ppmvd for a grate stoker boiler. For the present project, HEF proposes a NH_3 limit of 30 ppmvd.

The Department will include the NH_3 slip requested by HEF and notes the following:

- Some of the NH_3 slip will tend to reduce HCl emissions because it will react with HCl to form ammonium chloride (NH_4Cl);

- Some of the NH_3 slip will tend to react with small amounts of SO_2, sulfur trioxide (SO_3) and SAM present in the exhaust to form ammoniated sulfates and sulfites; and
- Ammoniated chlorides and sulfates/sulfites will contribute to particulate matter (PM/PM_{10}) and visible emissions (opacity).

Installation of Ox-cat to control CO, VOC and organic HAP will allow HEF to tilt the GCP towards NO_X control. This will help make it possible for HEF to minimize NO_X without excessive use of NH_3 and thus also reduce the effects of NH_3 slip on PM/PM_{10} and opacity.

4.5. BACT Review for Cooling Towers (EU 003)

Discussion. Up to three cooling towers will be used for machine cooling, cooling the condensing set in the power block, and process cooling. The design parameters for the cooling towers are: one cell with a stack height of 35 feet, a combined circulating water flow rate of 34,000 gallons per minute (gpm), a temperature of 77 °F and a design drift rate of 0.001%.

Cooling towers emit $PM/PM_{10}/PM_{2.5}$ based on the total dissolved solids (TDS) loading in the recirculating water. According to the applicant, the plant will use fresh water with a concentration TDS of only 500 ppmw. The applicant estimated $PM/PM_{10}/PM_{2.5}$ emissions at 0.37/0.19/0.19 TPY.

If not properly maintained and operated, heat exchangers in the ethanol process and machines may leak thereby contaminating the water of the associated cooling tower with VOC. The VOC will subsequently be stripped from the water stream by the air flow thus emitting the VOC to the atmosphere. HEF did not estimate VOC or organic HAP from the cooling tower presumably due to expected good operation and maintenance.

Applicant's proposal. The applicant proposes to install drift eliminators on the cooling towers to limit the cooling tower drift 0.001% of the water recirculation rate.

Department's Determination. Recent determinations by the Department limited the drift rate to 0.0005% of the water recirculation rate. Those determinations were for facilities using water characterized by much greater TDS concentrations. For example, OUC used a value of 3,757 ppmw for the cooling tower on their Combined Cycle Unit B and Florida Power and Light (FP&L) used a value of 30,000 ppmw (maximum) for their Turkey Point Combined Cycle (Unit 5) project.

In view of the very low TDS value, the requested drift rate is acceptable at 0.001% together with a permit requirement recordkeeping requirement that can demonstrate that TDS of the incoming cooling makeup water is maintained less than or equal to 500 ppmw on an annual basis, the Department accepts the applicant's BACT proposal for the cooling towers.

As required by NSPS Subpart VVa, the applicant submitted a preliminary Leak Detection and Repair (LDAR) Program plan. The Department will require expansion of the LDAR Program plan required for the facility pursuant to NSPA Subpart VVa to include the machine cooling and process cooling towers. The applicant will be required to collect a sample of cooling water from each tower on a weekly basis and analyze it for VOC. This will enable the early detection of leaking heat exchangers, thereby minimizing VOC emissions (including organic HAP) and odors. The applicant is required to submit a final LDAR Program plan that includes the cooling tower to the Compliance Authority 90 days before the HEF facility becomes operational.

4.6. BACT Review for Ethanol Production Process (EU 004)

Discussion. The ethanol production process will result in the emissions of ethanol (C_2H_5OH) and other VOC such as acetic acid, lactic acid, and methanol (a HAP). These emissions will occur from the fermentation, distillation, and dehydration steps, as the ethanol is separated from the fermentation products. Properly designed scrubbers and thermal oxidizers (TO) can effectively control VOC and HAP emissions from ethanol production processes.

Wet scrubbers (water as solvent) can achieve good VOC reduction objectives when used on ethanol plants. Ethanol (C_2H_5OH), which comprises the bulk of the VOC emissions, is completely miscible in water. A properly designed scrubber could achieve a level of removal 99% or greater. Organic acids and strongly polarized molecules such as acetic acid (CH_3COOH) and methanol (CH_3OH – a HAP) can also be removed in a properly designed scrubber due to their strong interaction with water. A wet scrubber using water as a solvent can therefore be designed to accomplish excellent removal of VOC, especially from the distillation/dehydration steps.

Non-polar VOC such as ethyl acetate ($C_4H_8O_2$) and HAP such as acetaldehyde (C_2H_4O) and acrolein (C_3H_4O) are not as efficiently removed as C_2H_5OH when using a wet scrubber that uses only water as a solvent. Refer to Figure 21 from an equipment supplier presentation that suggests very good overall VOC removal efficiency (exceeding 99%) from a fermentation step scrubber (large carbon dioxide emitter), but poor performance for some of the miscellaneous VOC and HAP mentioned above.

Compound	Formula	Conc. Ppm	Inlet Lb/Hr	Removal Efficiency	Outlet Lb/hr
Water	H_2O	1,100	400	-	-
Carbon Dioxide	CO_2	970,000	8,300	-	-
Ethanol	C_2H_6O	2,200	2,000	99.8%	4.0
Methanol	CH_4O	16.0	1.0	99.7%	0.0
Formic acid	CH_2O_2	1.1	0.1	99.0%	0.0
Lactic acid	$C_3H_6O_3$	6.9	1.0	99.0%	0.0
Acetic acid	$C_2H_4O_2$	21.0	2.5	99.9%	0.0
Amyl alcohol	$C_5H_{12}O$	29.0	5.0	90.0%	0.5
Formaldehyde	CH_2O	3.4	0.2	99.9%	0.0
Acetone	C_3H_6O	0.4	0.1	35.9%	0.0
Acrolein	C_3H_4O	0.2	0.0	0.0%	0.0
Acetaldehyde	C_2H_4O	35.0	3.0	1.0%	3.0
Ethyl acetate	$C_4H_8O_2$	23.0	4.0	1.0%	4.0
Total TOC's			2,017	99.4%	11.5

Difficult to Remove with Water Solvent

Figure 21 – Typical Plant Performance Using Water as Solvent (source: Envitech. 2009)

According to Table 2-10 of the application, the HEF pre-control emission levels of the VOC ethyl acetate ($C_4H_8O_2$) and C_2H_4O (a HAP) are 568.2 and 144.3 TPY, respectively. Emissions of these two species would be very substantial if controlled by conventional wet scrubbers using water as the only solvent. Without additives in the water scrubber, the HEF project would emit more than 10 TPY of C_2H_4O even with 98% VOC control.

Reagents such as sodium bisulfite ($NaHSO_3$ - a food preservative) can be added to the scrubber water that will react with aldehydes to form an "adduct" that precipitates, thus allowing removal of at least the key HAP.

It is also possible to use other solvents, e.g. ethanol, as the scrubbing medium as well as inclusion of several stages to insure the required removal efficiency to meet the VOC reduction objective and to insure the source (when considering boiler and ethanol process emissions) does not emit 10 TPY of any HAP or 25 TPY of aggregate HAP.

While a TO can be used to treat emissions from the fermentation and distillation/dehydration scrubbers, these are typically used to control emissions from the drying of solid residue such as Dried Distillers Grains with Solubles (DDGS), which is a byproduct of the more traditional grain-to-ethanol production process.

Applicant's proposal. HEF proposes to use two wet scrubbers to control VOC and HAP emissions from the ethanol production process. One scrubber will be used to control VOC emissions from the fermentation system while the other scrubber will be used to control VOC emissions from the distillation/dehydration systems.

The exhaust gases from the fermentation scrubber will exit to the atmosphere through a stack which will have a design height of 25 feet (ft), a design diameter of 4.9 ft with a flow rate of 4,223 actual cubic feet per minute (acfm) and a temperature of 70 °F. The scrubbing liquor (water) will be fortified with $NaHSO_3$ to reduce C_2H_4O. The distillation/dehydration scrubber will use water for scrubbing and exit to the atmosphere through a vent with a flow rate of 120 acfm.

Each scrubber will be designed to achieve a minimum control efficiency of 98% control efficiency for VOC and HAP emissions. After control, VOC emissions are estimated at 76.41 TPY from the fermentation scrubber and 11.19 TPY from distillation/dehydration scrubber. Total HAP emissions from the two scrubbers combined are estimated to be 4.24 TPY.

According to the application, a TO would destroy ethanol product and is disadvantageous compared with the wet scrubbing option. Also, according to the applicant, a TO would require the combustion of additional fossil fuel leading to the emissions of criteria pollutants and GHG.

Department's Review. The Department believes that a TO can provide greater control than a wet scrubber. However, if a wet scrubber with additives is used to effectively control $C_4H_8O_2$ and C_2H_4O emissions, reducing VOC emissions by another 5-15 TPY and HAP emissions by several TPY, then utilizing a TO would not likely be cost-effective for this emission unit. Furthermore, the Department agrees with the applicant that the combustion of additional fossil fuels as required by a TO would result in additional emissions of criteria pollutants and GHG.

The Department accepts the wet scrubbers described by the applicant as BACT for this emissions unit with the following emission limits: VOC emissions through the fermentation scrubber stack shall not exceed 19.01 lb/hr (76.41 TPY); VOC emissions through the distillation/dehydration scrubber vent shall not exceed 2.78 lb/hr (11.19 TPY); and total combined organic HAP emissions through the wet scrubber stack and distillation/dehydration scrubber vent shall not exceed 1.05 lb/hr (4.24 TPY).

The Department notes that some of the traditional grain to ethanol projects have had difficulties in controlling VOC and HAP emissions.[30] The applicant will need to insure that the selected scrubber vendor has a full understanding and appreciation of the need to insure minimization of HAP emissions given the area HAP source determination made for this project. Also, the vendor will need to insure that the appropriate scrubber liquids or additives are used to remove $C_4H_8O_2$ (the key VOC other than ethanol) in order to comply with the VOC emission limit.

Initial and annual VOC stack tests on the ethanol process scrubbers will be required. Quarterly HAP tests will also be required except for those quarters when the Ox-cat system is available to control boiler CO/VOC emissions. In addition, the Department establishes the following requirements:

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

4.7. BACT Review Storage Tanks (EU-005)

Discussion. The facility includes five volatile organic liquids (VOL) storage tanks subject to NSPS Subpart Kb: a fuel ethanol tank; a 200 proof ethanol tank; an off-specification ethanol tank; a denatured/gasoline product storage tank denaturant/gasoline tank; and ethanol process tanks. Tank capacities are typically 100,000 gallons. Ethanol and gasoline vapors will be the primary VOC emitted from these tanks.

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

The facility will also include the following storage tanks that do not store VOL:

- A tank to store anhydrous ammonia or urea for the SNCR system. In accordance with 40 CFR 60.130, the storage of anhydrous ammonia or urea shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.
- A nominal 5,000 gallon tank to store ULSD fuel oil for emergency equipment.
- A tank to store sulfuric acid for use in the ethanol production process to adjust pH. In accordance with 40 CFR 60.130, the storage of sulfuric acid shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.
- A 2,300 gallon tank to store methanol, xylene and ethylbenzene that will be used as a corrosion inhibitor at the HEF facility.

Applicant's proposal. The applicant proposes to design the tanks subject to NSPS Subpart Kb 40 CFR per 60.110b(a)(2) with internal floating roofs or the equivalent to minimize VOC emissions. For the tanks not subject to Subpart Kb, the applicant proposes to use pressure relief valves/vapor condensers. The applicant asserts that it is no cost effective to fit these tanks with internal or external floating roofs, or to vent these tanks to a flare or vapor recovery unit. In lieu of internal floating roofs in the Blending and Storage tanks, HEF may use pressure relief valves provided that these meet the equivalency requirements of NSPS, Subpart Kb.

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 relief /vacuum conservation valves, which allow the tanks to operate at a slight internal pressure which 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 internal floating roofs on the tanks subject to Subpart Kb as BACT. Tanks containing volatile organic liquids but not subject to Subpart Kb shall use pressure relief valves/vapor condensers. The urea/ammonia and sulfuric acid storage tanks do not require BACT determinations. If HEF decides to use pressure relief valves in lieu of internal floating roofs, it must provide to the Compliance Authority before construction of the Blending and Storage VOL tanks commences, proof of the valves equivalency as defined in the NSPS.

4.8. BACT Review for Truck Rack Product Loadout and Flare (EU-006)

Discussion. The denaturant ethanol product (ethanol blended with gasoline) will be loaded onto tanker trucks at a maximum rate of 600 gallons per minute using submerged fill. The maximum throughput product rate is 36,000,000 gal/yr of ethanol blended with 1.620,000 gal/yr of gasoline. Vapors displaced from the trucks will be exhausted to a flare. The flare will be of the open type, which can be started immediately when the product loadout process starts. Ethanol and gasoline vapors will be the primary VOC emitted from the loading operation. These vapors will be controlled by combustion in the flare. The applicant estimates that emissions from the flare are: 0.0091 TPY SO_2; 1.04 TPY NO_X; 5.64 TPY CO; 0.052 $PM/PM_{10}/PM_{2.5}$ and 7.0 TPY of VOC. Total HAP emissions from the flare and the loadout process were estimated by the applicant to be 0.22 TPY.

Applicant's proposal. The applicant proposes to divert the VOC vapors displaced from the tanker trucks during product loadout to a flare. The product loadout flare will have a rated capacity of 9.8 mmBtu/hr and will provide 98% control efficiency for VOC vapors during the loading of the tanker 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.

4.9. BACT Review for Miscellaneous Dry Material Storage Silos (EU 007)

Discussion. The materials stored in these silos include one limestone, hydrated lime or trona storage silo for the DSIS; one lime storage silo for the water treatment system; if used in SNCR system, one urea storage silo; and one fly ash storage silo. The silos will emit small amounts of $PM/PM_{10}/PM_{2.5}$ with the applicant estimating the total to be 0.85 TPY.

Applicant's proposal. The applicant proposes to control $PM/PM_{10}/PM_{2.5}$ emissions from the miscellaneous dry material storage silos by standard type bin vent filters. These are passive control devices that do not have a fan. When the silos are pneumatically loaded from trucks, the conveying air must exit the silo through the bin vent filter. These filters will control dust emissions in the exhaust gas to a concentration of 0.01 grains per dry standard cubic foot (gr PM/dscf). These storage silos will each have a standard type bin vent filter to control dust emissions.

Department's review. The Department concurs with the applicant's proposal for BACT. The Department also establishes that VE from the each bin vent filter during material loading shall not exceed 5% opacity as demonstrated by initial and annual compliance tests. A VE emission reading of 5% opacity or less may be used to establish compliance with the 0.01 gr/dscf PM/PM_{10} standard. A visible emission reading greater than 5% opacity will require the permittee to perform a PM/PM_{10} emissions stack test on the bin vent filter within 60 days to show compliance with the PM limit.

4.10. BACT Review for Emergency Equipment (EU 008)

Discussion. One emergency generator rated at 2,000 kW will be installed to provide backup electrical power in the event of a power outage at the HEF facility. The engine will fire ULSD fuel oil or natural gas and will be limited to 500 hours per year of operation during emergencies. The 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 2006 or later.

Applicant's Proposal. The applicant proposes to use ULSD fuel oil or natural gas (1.5 gr $SO_2/100\ ft^3$) 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.)
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.

Discussion.

A 600 hp diesel fire pump engine will be installed to provide firewater during power outages. This unit will fire ULSD fuel oil or natural gas 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.

Applicant's Proposal.

The applicant proposes to use ULSD fuel oil or natural gas 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.)
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. 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.

4.11. BACT Review for VOC Fugitive Equipment Leaks (EU 009)

Discussion. Uncontrolled leaks from equipment 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. Because the HEF project is a SOCMI facility, it 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. The VOC emissions from the following other emission units at the proposed HEF facility also fall under EU-012:

- EU-003: Cooling Towers;
- EU-004: Ethanol Production Process;
- EU-005: Storage Tanks; and
- EU-006: Truck Rack Product Loadout and Flare.

Applicant's Proposal. The applicant proposes a LDAR program and compliance with the requirements of Subpart VVa as BACT for this emission unit. The applicant has submitted a preliminary LDAR program plan and will submit a final plan prior to the HEF facility becoming operational. The applicant estimates that VOC emissions from fugitive equipment leaks will 6.52 TPY. Total organic HAP emissions from the equipment leaks were estimated by the applicant to be 0.33 TPY.

Department's Review. Subpart VVa is a comprehensive requirement. Together with the LDAR program, Subpart VVa will complement the BACT determinations for each process emission unit that is a source of VOC and possibly odor. The Department accepts the applicant's proposal as BACT and will include a requirement to submit the details of a site-specific LDAR program pursuant to Subpart VVa no later than 90 days before the HEF becomes operational. In addition, 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 list submitted to the Compliance Authority no later than 90 days before the HEF facility becomes operational. Finally, per Subpart VVa, HEF must demonstrate compliance with NSPS, Subpart VVA no later than 180 days after the initial startup of the HEF facility.

4.12. Odor Considerations

Discussion. In previous sections, reference was made to Rule 62-296.320(2), F.A.C., which states: "no person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor". However, even with control measures, conventional grain ethanol plants are often associated with odors. The most important odor source in a conventional grain ethanol plant is from the residual grain material after fermentation and separation of the ethanol. The potential for odor from an ethanol plant utilizing sweet sorghum as its feedstock is probably less than a corn feedstock based facility. Still odor is a concern and must be addressed.

Applicant's Proposal. The applicant proposes the following measures to control VOC and odors at the HEF facility:

- 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;
- A Flare to control emissions from product load out;
- Maintaining only small storage piles of supplemental (wood chips, yard waste and harvest residue) to minimize odors;
- Prompt repair of any leaking components (such as heat exchangers) within the cooling towers to minimize contamination of the water by and subsequent stripping of VOC to the atmosphere; and
- 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 Department will require that 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 90 days prior to HEF commencing operation.

5. BIOMASS BOILER HEAT INPUT MONITORING

Monitoring of heat input is difficult when using biomass as fuel. Sugarcane and sweet sorghum bagasse can have high moisture contents (50%) and boiler energy will be expended to evaporate that moisture thus reducing the boiler efficiency.

To accurately calculate heat input, the Department will include in the permit a requirement to conduct a boiler thermal efficiency test in accordance with American Society of Mechanical Engineers (ASME) methods (refer to Appendix ASME of the draft permit). The boiler heat input rate calculations must then be performed using ASME methods or those provided in 40 CFR 75, Appendix F (refer to Appendix F of the draft permit.

6. AIR QUALITY IMPACT ANALYSIS

6.1. Introduction

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

At this time, $PM_{2.5}$ increments, SIL, and de minimus monitoring levels have not been adopted into Florida rules. NO_2 and SO_2 SIL and de minimis monitoring levels for the 1-hour standard have not been formally proposed, but the U.S. EPA has provided interim guidance on 1-hour NO_2 and SO_2 SIL until a formal proposal is made. There are no applicable PSD increments, AAQS, significant impact or de minimis monitoring levels for VOC.

6.2. Major Stationary Sources Near the Proposed HEF Advanced Biofuel Ethanol Biorefinery

The following tables list the largest existing stationary sources, by pollutant, in Highlands and nearby Counties. The maximum expected future emissions in TPY from the proposed project are also shown for comparison.

Table 11 - Largest Sources of SO_2 (2010) Nearest to the Proposed HEF Site (TPY)

Owner/Company Name	Site Name	County	Emissions
HEF (future)	**HEF (future)**	**Highlands**	**200**
Mosaic Fertilizer	Mosaic Fertilizer – South Pierce	Polk	7,899
Florida Power and Light (FP&L)	Manatee Power Plant	Manatee	7,491
FP&L	Martin Power Plant	Martin	5,295
Lakeland Electric	C.D. McIntosh, Jr. Power Plant	Polk	4,240
Mosaic Fertilizer	Mosaic Fertilizer – South Pierce	Polk	4,088
Indiantown Cogen	Indiantown Cogen Plant	Martin	2,040
Tampa Electric Company (TECO)	Polk Power Station	Polk	1,386
Mosaic Fertilizer	Mosaic Fertilizer – South Pierce	Polk	547
FP&L	Cape Canaveral Plant	Brevard	459
Waste Management	Okeechobee Landfill	Okeechobee	396
Waste Management	Gulf Coast Sanitary Landfill	Lee	369
Genon Florida	Indian River Power Plant	Brevard	351
TECO	Phillips Station	Highlands	530
Solid Waste Authority of Palm Beach County (SWAPBC)	SWAPBC	Palm Beach	140
Sugar Cane Growers Co-Op (SCGC)	SCGC	Palm Beach	213
New Hope Power	Okeelanta Cogeneration Plant	Palm Beach	202

Table 12 - Largest Sources of NO_X (2010) Nearest to the Proposed HEF Site (TPY)

Owner/Company Name	Site Name	County	Emissions
HEF	**HEF**	**Highlands**	**194**
FP&L	Martin Power Plant	Martin	4,034
FP&L	Manatee Power Plant	Manatee	2,161
Lakeland Electric	C.D. McIntosh, Jr. Power Plant	Polk	1,544
Indiantown Cogen	Indiantown Cogen Plant	Martin	1,533
SWAPBC	SWAPBC	Palm Beach	1,330
FP&L	Fort Myers Power Plant	Lee	1,263
U.S. Sugar Corp.	Clewiston Mill and Refinery	Hendry	887
New Hope Power	Okeelanta Cogeneration Plant	Palm Beach	800
Progress Energy	Hines Energy Complex	Polk	711
Lee County	Lee County Waste to Energy	Lee	702
FP&L	Cape Canaveral Plant	Brevard	612
SCGC	SCGC	Palm Beach	573
TECO	Polk Power Station	Polk	472
Osceola Farms	Osceola Farms	Palm Beach	460
TECO	Phillips Station	Highlands	442

Table 13 - Largest Sources of CO (2010) Nearest to the Proposed HEF Site (TPY)

Owner/Company Name	Site Name	County	Emission
HEF	**HEF**	**Highlands**	**560**
U.S. Sugar Corp	Clewiston Mill and Refinery	Hendry	14,919
Osceola Farms	Osceola Farms	Palm Beach	11,647
SCGC	SCGC	Palm Beach	11,563
New Hope Power	Okeelanta Cogeneration Plant	Palm Beach	1,947
FP&L	Martin Power Plant	Martin	1,446
Cutrale Citrus Juices USA	Cutrale Citrus	Polk	984
FP&L	Manatee Power Plant	Manatee	890
SWAPBC	SWAPBC	Palm Beach	655
Lakeland Electric	C.D. McIntosh, Jr. Power Plant	Polk	642
Progress Energy	Hines Energy Complex	Polk	446
Calpine	Osprey Energy Center	Polk	442
Southern Gardens Citrus	Southern Gardens Citrus	Hendry	401

Table 14 - Largest Sources of PM_{10} (2009) Nearest to the Proposed HEF Site (TPY)

Owner/Company Name	Site Name	County	Emission
HEF	**HEF**	**Highlands**	**31**
FP&L	Martin Power Plant	Martin	641
FP&L	Manatee Power Plant	Manatee	629
FP&L	West County Energy Center	Palm Beach	336
U.S. Sugar Corp	Clewiston Mill and Refinery	Hendry	309
SCGC	SCGC	Palm Beach	293
Osceola Farms	Osceola Farms	Palm Beach	285
FP&L	Fort Myers Power Plant	Lee	216
Lakeland Electric	CD McIntosh, Jr. Power Plant	Polk	195
Mosaic Fertilizer	Mosaic Fertilizer – South Pierce	Polk	113
FP&L	Cape Canaveral Plant	Brevard	43

Table 15 - Largest Sources of VOC (2010) Nearest to the Proposed HEF Site (TPY)

Owner/Company Name	Site Name	County	Emissions
Highlands EnviroFuels	**Highlands EnviroFuels (future)**	**Highlands**	**137**
US Sugar Corp	Clewiston Mill and Refinery	Hendry	2,001
Osceola Farms	Osceola Farms	Palm Beach	737
Cutrale Citrus Juices USA	Cutrale Citrus	Polk	561
Citrus World, Inc	Citrus World, Inc	Polk	516
SCGC	SCGC	Palm Beach	496
Tropicana Manufacturing Co.	Tropicana, Fort Pierce	St. Lucie	441
Citrosuco North America	Citrosuco North America	Polk	430
Southern Gardens Citrus	Southern Gardens Citrus	Hendry	279
Louis Dreyfus Citrus	Louis Dreyfus Citrus, Indiantown	Martin	258
Tropicana Manufacturing Co.	Tropicana, Bradenton	Manatee	250
Peace River Citrus Products	Peace River Citrus	De Soto	234
FP&L	Manatee Power Plant	Manatee	202
Genpak	Genpak	Highlands	197 (2009)

To further illustrate the major emission sources nearest to this proposed project, refer to Figure 22. All facilities within a 100 km radius of HEF that produce emissions of at least 100 TPY or greater in PM_{10}, SO_2, VOC, CO, or NO_X have been depicted. It should be noted that very few facilities with emissions greater than 100 TPY of a primary pollutant are located within a 50 km radius of the proposed HEF site.

There are regional efforts underway through the Federal Acid Rain Program and the CAIR to reduce emissions of NO_X and SO_2. Regional SO_2 emissions from existing power plants in the Southeast U.S. in 1995, 2007 and 2010 are listed in Table 16.

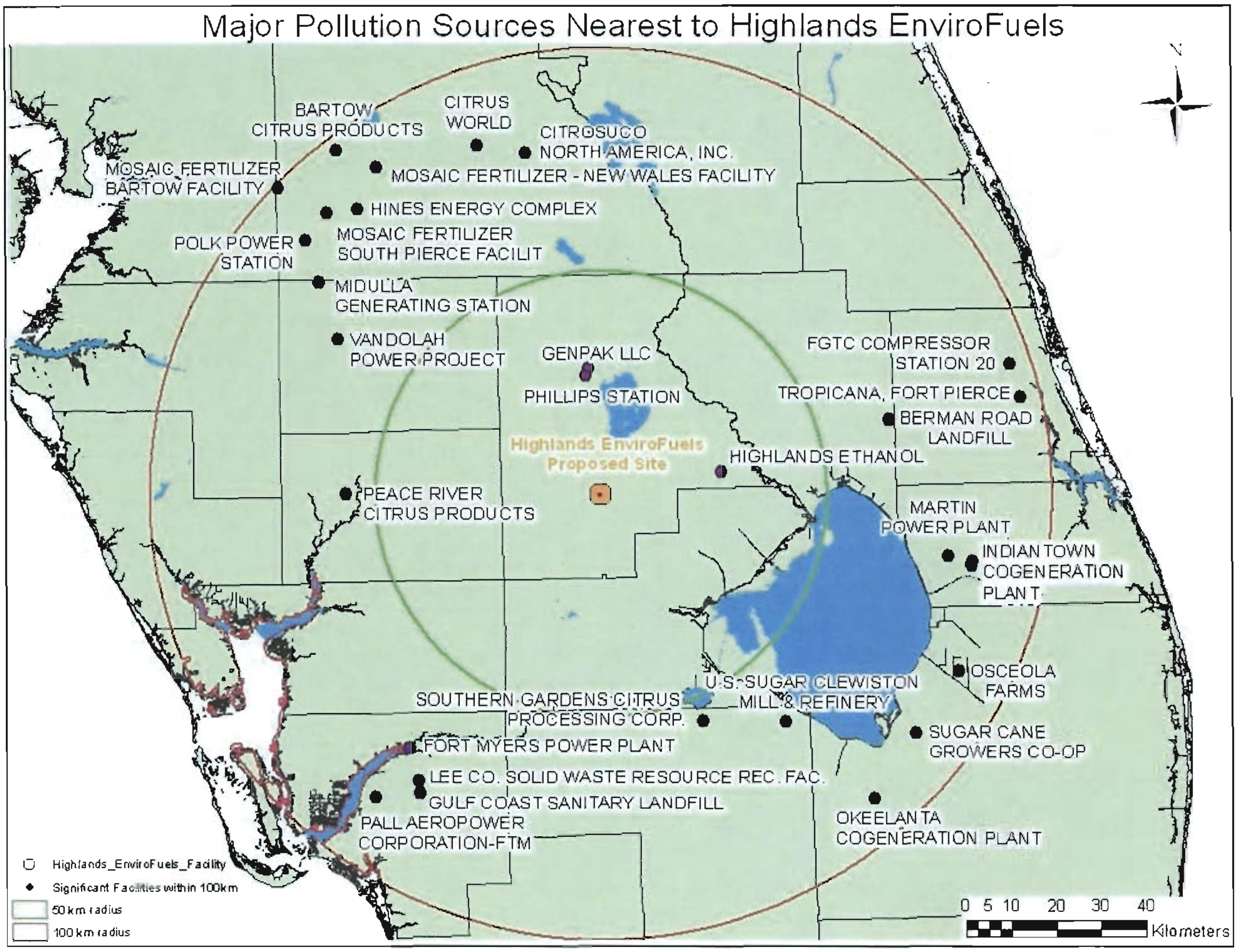


Figure 22 - Major Pollution Sources Nearest to Highlands EnviroFuels

Table 16. SO_2 Emission from Power Plants in the Southeast in 1995, 2007 and 2010 (TPY).

State	1995	2007	2010	Δ Since 1995 (%)	Δ Since 2007 (%)
Alabama	532,485	447,189	204,197	328,288 (62%)	242,992 (54%)
Florida	**598,262**	**317,582**	**144,552**	**453,710 (76%)**	**173,030 (54%)**
Georgia	478,904	635,484	218,911	259,993 (54%)	416,573 (66%)
Kentucky	676,263	379,837	271,514	404,749 (60%)	108,323 (29%)
Mississippi	83,869	69,796	54,696	29,173 (35%)	15,100 (22%)
North Carolina	385,737	370,826	120,387	265,350 (69%)	250,439 (68%)
South Carolina	177,855	172,726	94,656	83,199 (47%)	78,070 (45%)
Tennessee	493,472	237,231	118,723	374,749 (76%)	118,508 (50%)
Total	**3,426,847**	**2,630,671**	**1,227,636**	**2,199,211 (64%)**	**1,403,035 (53%)**

SO_2 emissions from power plants in the Southeast U.S. were reduced by nearly 2,200,000 TPY and 64% referenced to emissions in 1995. Over 1,200,000 TPY of those reductions occurred during the past three years alone. The state and regional SO_2 reduction trends will continue as coal fueled power plants continue to install scrubbers to control SO_2 emissions and in anticipation of additional regulations to control HAP and cross state pollution transport.

SO_2 emissions from power plants in Florida have declined by 453,710 TPY and 76% referenced to 1995. These reductions are the largest in the entire Southeast U.S. This is more than 2,200 times the future contribution of 200 TPY from the HEF project.

Regional NO_X emissions from existing power plants in the Southeast U.S. in 1995, 2007 and 2010 are listed in Table 17. NO_X emissions from power plants in the Southeast U.S. were reduced by nearly 1,300,000 TPY and 74% referenced to emissions in 1995. Almost 400,000 TPY of those reductions occurred during the past three years alone.

Table 17. NO_X Emission from Power Plants in the Southeast in 1995, 2007 and 2010 (TPY).

State	1995	2007	2010	Δ Since 1995 (%)	Δ Since 2007 (%)
Alabama	202,776	122,374	66,049	136,727 (67%)	56,325 (46%)
Florida	**297,056**	**184,171**	**79,493**	**217,263 (73%)**	**104,678 (57%)**
Georgia	169,999	107,471	60,588	109,411 (64%)	46,883 (44%)
Kentucky	365,532	174,840	91,979	273,553 (75%)	82,861 (47%)
Mississippi	47,243	48,546	29,774	17,469 (37%)	18,772 (39%)
North Carolina	258,469	59,417	57,305	201,164 (78%)	2,112 (4%)
South Carolina	93,480	46,062	28,833	64,647 (69%)	17,229 (37%)
Tennessee	309,237	102,886	35,056	274,181 (89%)	67,830 (66%)
Total	**1,743,792**	**845,767**	**449,077**	**1,294,415 (74%)**	**396,690 (47%)**

The state and regional NO_X reduction trends will continue as coal-fueled power plants operators throughout the southeastern states continue to install SCR systems to control NO_X and in anticipation of additional regulations to control HAP and cross state pollution transport.

NO_X emissions from power plants in Florida were reduced by more than 217,000 TPY (73%) with half of the reduction occurring in the past three years alone. This is about 1,100 times the future contribution of 184 TPY from the HEF project.

6.3. SO_2 and NO_X Emission Trends from FPL Peninsular facilities

Per Tables 11 and 12 above, FP&L facilities are the largest sources of SO_2 and NO_X (precursors of $PM_{2.5}$ and/or ozone) nearest to the proposed HEF site. To put emissions from the existing FP&L facilities and the future HEF into another perspective, the Department graphed the SO_2 and NO_X emission trends during the period 1998-2010 from FPL fossil-fueled plants located in the Florida peninsula. Most of the plants are in South Florida. The data source is the EPA Clean Markets Acid Rain database. The results are summarized in Figure 23.

During the period 1998-2009 there was a *decrease* from 221,400 to 24,700 TPY (89%) in SO_2 emissions from the FP&L fossil fleet in peninsular Florida. Similarly there was a *decrease* from 98,500 to 20,500 TPY (79%) in NO_X emissions. For comparison purposes, the future HEF will emit 200 TPY of SO_2 and 184 TPY of NO_X.

The contribution of 200 TPY of SO_2 and 184 TPY of NO_X from the HEF will not affect the general, overwhelming and continuing downward trend in $PM_{2.5}$ precursors. Similarly, it will not have an appreciable effect on local or regional $PM_{2.5}$ concentrations.

6.4. Ambient Air Monitoring Surrounding Proposed Facility

The State ambient air monitoring network operated by the Department and its partners (local air pollution control programs) includes monitors in counties containing over 90% of the population. As Figure 24 and 25 indicate, the ambient air monitoring sites are concentrated in areas of high population density, along the coasts and near major highways in the interior portion of the state.

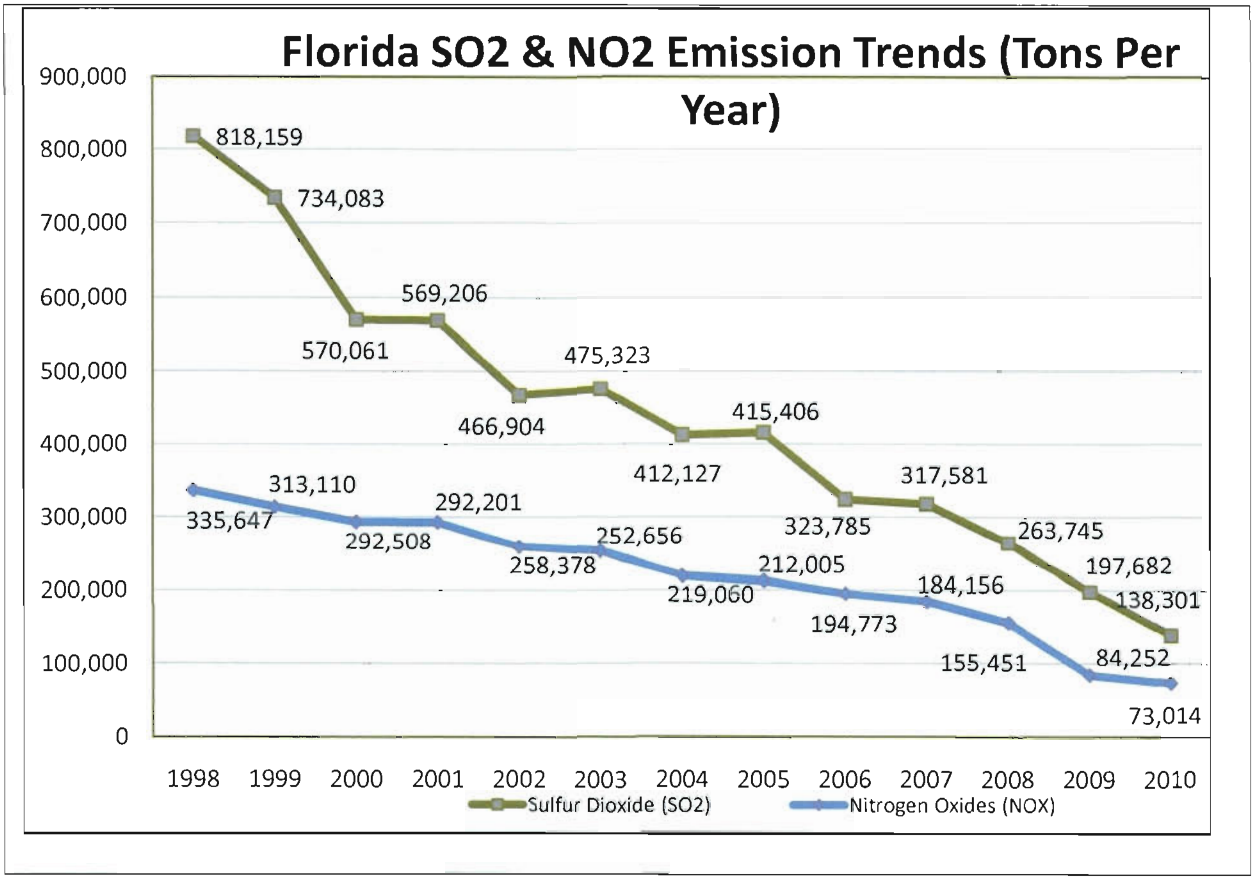
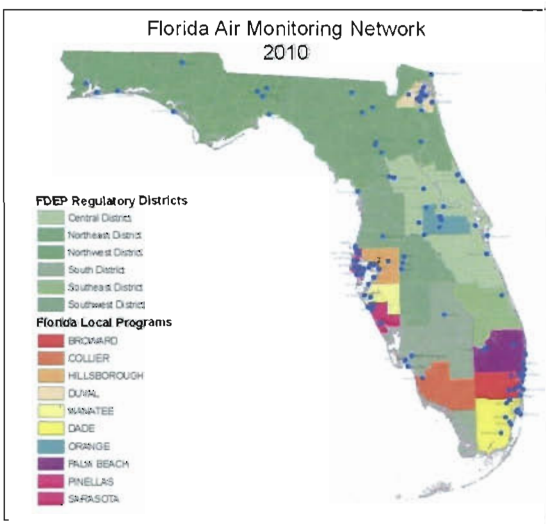


Figure 23 – SO_2 and NO_X reductions in TPY at FPL Peninsular Facilities (1998-2010)



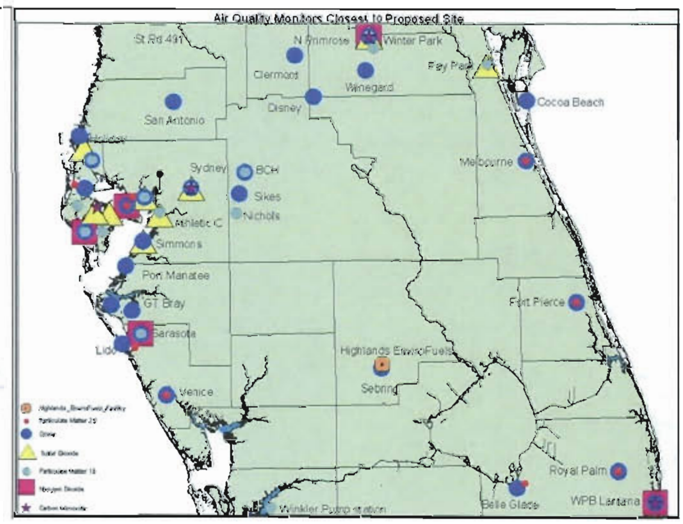


Figure 24 – Air Monitoring Network **Figure 25. Monitors Closest to proposed HEF site**

These monitors are used to estimate the existing air quality in the area of the proposed facility. The monitors in Belle Glade are most representative of the proposed site for PM_{10} and $PM_{2.5}$ due to their close proximity and rural setting. The Winter Park monitor is most representative of background SO_2 due to its similar rural setting, and was chosen over the Plant City station because the Plant City monitor is heavily influenced by CF Industries, a large SO_2 source. The NO_2 monitor located in Sarasota was also chosen due to its close proximity and similar rural setting, though it is still not quite as rural as the HEF site. Furthermore, the Sebring (Archbold) monitor was chosen to represent the background ozone concentration because it is located only 2 km from the proposed HEF site. Air quality measurements from these monitors are summarized in Table 18.

Table 18 - Ambient Air Quality Measurements Nearest to the Project Site (2007-2009)

Pollutant	Location (Site Number)	Averaging Period	Ambient Concentration			
			Compliance Period	Value	Standard	Units [a]
PM_{10}	Sarasota (1151006)	24-hour [b]	2008	59	150	μg/m³
		Annual [c]	2008	18.7	50	μg/m³
$PM_{2.5}$	Belle Glade (0990008)	24-hour [d]	2008-2010	14	35	μg/m³
		Annual [e]	2006-2008	6.2	15	μg/m³
SO_2	Winter Park (0952002)	1-hour [i]	2010	9	75	ppb
		3-hour [f]	2008	13.1	1300	μg/m³
		24-hour [f]	2010	5.2	260	μg/m³
		Annual [c]	2007-2009	2.6	60	μg/m³
NO_2	Sarasota (1511006)	Annual [c]	2010	4	53	ppb
		1-hour [h]	2008-2010	23	100	ppb
CO	WPB Lantana (0991004)	1-hour [f]	2007	1	35	ppm
		8-hour [g]	2009	0.9	9	ppm
Ozone	Sebring (0550003)	8-hour [g]	2009	0.066	0.075	ppm

a. Units are in: micrograms per cubic meter (μg/m³); parts per billion (ppb); or parts per million (ppm).
b. Not to be exceeded on more than an average of one day per year over a three-year period.
c. Arithmetic mean.
d. Three year average of the 98th percentile of maximum daily 24-hour concentrations.
e. Three year average of the arithmetic annual means.
f. Not to be exceeded more than once per year.
g. Three year average of the annual 4th highest daily 8-hour maximum.
h. Three-year average of the annual 98th percentile maximum daily 1-hour value
i. Three-year average of the annual 99th percentile maximum daily 1-hour value

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

The applicant had the option of excluding exceptional events from the dataset, but opted not to do so with the intention of erring on the conservative side. Therefore, for these reasons in combination with the fact that the above monitoring stations are generally located in slightly more urbanized areas than the proposed HEF project site, the background concentrations used in this modeling analysis are actually slightly higher than what is actually experienced at HEF site.

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

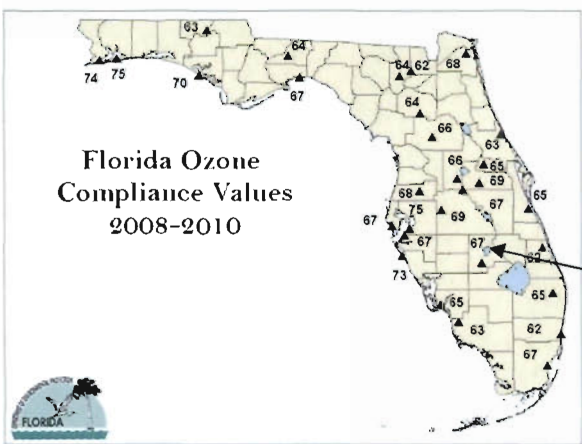
Ozone is a key indicator of the overall state of regional air quality. It is not emitted directly from combustion processes. Rather it is formed from VOC and NO_X emitted primarily from regional industrial and transportation sources. VOC is also emitted from authorized agricultural fires, natural drought-related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

Ozone limits and measurements in Table 18 are summarized on three year blocks, rolled annually. The reported ozone value was calculated by taking the maximum 8-hour readings recorded each day during the three years. The fourth highest of the recorded maxima were identified for each year and then the average of those three values was reported as the compliance value given in Table 18 and Figure 26.

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

$PM_{2.5}$ limits and measurements are summarized on three-year blocks, rolled annually. The reported 24-hour compliance value for $PM_{2.5}$ is 15 $\mu g/m^3$ as indicated in Table 18 for the Belle Glade site, and was calculated by taking the average 24-hour readings recorded each day during the three years (2008-2010). The value for each year that exceeds 98% of all daily measurements within each given year was identified and then the average of those three numbers was reported as the 24-hour compliance value and compared with the standard of 35 $\mu g/m^3$.

The simple average of all $PM_{2.5}$ measurements within each three years (2008-2010) was also calculated and then the mean of the three averages (6.3 $\mu g/m^3$) was reported as the annual compliance value and compared with the standard of 15 $\mu g/m^3$. Comparisons of the 24-hour and annual $PM_{2.5}$ compliance values for the Belle Glade station are shown in Figure 27 along with compliance values for the rest of the state.



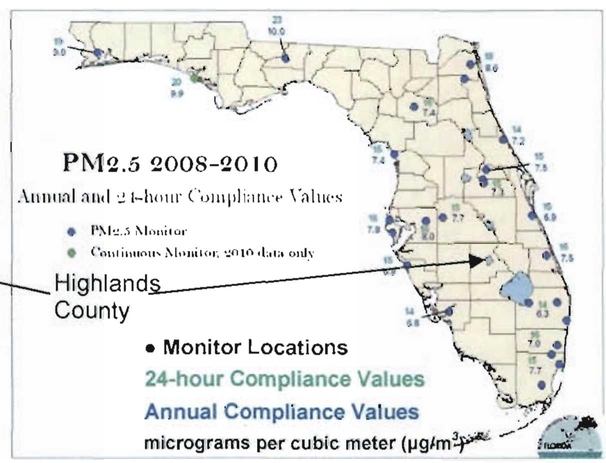


Figure 26 – Florida Ozone Compliance Values

Figure 27 – Florida $PM_{2.5}$ Compliance Values

The results indicate that Highlands County is in attainment with the applicable ozone and $PM_{2.5}$ AAQS. The results compiled from Highlands County (ozone) and Palm Beach County ($PM_{2.5}$) shown in Figures 26 and 27 support the conclusion that Highlands County is in attainment for both pollutants.

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

The overall reduction in $PM_{2.5}$ precursor emissions from stationary sources and the transportation sources (due to use of cleaner fuels) has contributed to the clear decline in ambient $PM_{2.5}$ levels in South Florida during the same period as shown in Figure 28. Basically the pronounced reductions in Miami are consistent with the mentioned reductions in emissions from stationary and transportation sources. By and large, the values in Belle Glade (within the rural sugar cane growing area) have been the lowest.

However, they have been more resistant to further declines most likely due to the nature of the sugar industry which is based on periodic burning followed by harvesting of sugar cane.

Figure 28 - South Florida Annual Average $PM_{2.5}$ Trends (1999 – 2010)

6.7. <u>Air Quality Impact Analysis</u>

<u>Significant Impact Analysis</u>

Significant Impact Levels (SIL) are defined for PM/PM_{10}, CO, NO_X and SO_2. A significant impact analysis 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.

The EPA-approved AERMOD modeling system was used by the applicant to address the significant impact on the PSD Class I area (Everglades National Park) with respect to the more restrictive Class I significance levels. The applicant used SIL recently established by the EPA for $PM_{2.5}$. In the case of NO_2 (1-hour) and SO_2 (1-hour), the EPA has not yet proposed SIL, but has provided an interim SIL equal to 4% of the NAAQS. The applicant agrees with this interim SIL and applied it for analysis of the latter two pollutants based on:

- The 4% SIL is more conservative (less than) the 5% SIL applicable to the only other pollutant (CO) that has a 1-hour averaging time [Rule 62-204.200(29), F.A.C.];
- The 4% SIL will capture all sources (regardless of size) within 2 km of HEF;
- The applicant also included all sources greater than 1,000 TPY beyond 10 km of HEF.

The applicant believes this approach encompasses all meaningful SO_2 and NO_X sources capable of interacting with HEF for the purposes of determining impacts with respect to the 1-hour SO_2 and NO_2 NAAQS.

In order to conduct a significant impact analysis, the applicant has used the proposed project's maximum short-term emissions as inputs to the models. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SIL for the PSD Class I and Class II Areas.

If this modeling for a particular pollutant shows ground-level increases less than its 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 for those pollutants.

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 fence line receptors consisted of discrete Cartesian receptors spaced at 50-meter intervals around the facility fence line. The remaining receptor grid consisted of densely spaced Cartesian receptors at 100 meters apart extending to 2 kilometers. From 2 to 7 kilometers, Cartesian receptors with a spacing of 250 meters were used from the facility. For addressing the 1-hour NO_2 NAAQS, the modeling grid was extended out to 15 km with additional receptors located every 500 meters, from 7 to 10 km, and every 1000 meters from 10 km to 15 km. The heights for all receptors were extracted using seamless National Elevation Data (NED) from USGS.

For the Class I analysis, project impacts were predicted at 68 receptors located at 50 and 100 km in the direction of Everglades National Park (ENP).

The results of the applicant's significant impact analysis are shown below in Tables 19 and 20. Maximum predicted impacts are greater than the applicable SIL for the Class II area for PM_{10}, $PM_{2.5}$, SO_2, and NO_2, with the exception of the NO_2 and SO_2 annual averaging times. Consequently, a full AAQS analysis (in which the PSD Increment analysis considering all sources of these pollutants in the area) is required.

Table 19 - Maximum Predicted Air Quality Impacts from the HEF Project for Comparison to the PSD Class II SIL

Pollutant	Averaging Time	Max Predicted Impact [a] ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Ambient Air Standards ($\mu g/m^3$)	Significant Impact?	Max Distance of Sig. Impact (km)
PM_{10}	Annual	1.5	1	50	Yes	0.4
	24-Hour	11.2	5	150	Yes	1.4
$PM_{2.5}$	Annual	0.43	0.3 [d]	15	Yes	0.4
	24-Hour	5.2	1.2 [d]	35	Yes	2.9
SO_2	Annual	0.58	1	60	No	-
	24-Hour	8.1	5	260	Yes	0.9
	3-hour	23.7	25	1300	No	-
	1-hour	29.7	7.9 [b]	196	Yes	4.8
NO_2 [c]	Annual	0.47	1	100	No	-
	1-Hour	53	7.6 [b]	189	Yes	12
CO	1-hour	562.1	2,000	40,000	No	-
	8-hour	296.8	500	10,000	No	-

a. Results based on the maximum impacts of either the boiler and truck flare operation or the biogas flare and truck flare operation.
b. Applicant's project SIL.
c. Assumes 80% conversion of NO_X to NO_2, i.e., the tier 2 modeling approach.
d. Final SIL for $PM_{2.5}$ was established by EPA on September 29, 2010.

Table 20 - Maximum Air Quality Impacts from the HEF Project for Comparison to the PSD Class I SIL for 2001 - 2005

Pollutant	Averaging Time	Max. Predicted Impact ($\mu g/m^3$)	Class I SIL ($\mu g/m^3$)	Significant Impact?
PM_{10}	Annual 24-hour	0.0019 0.10	0.2 0.3	No No
$PM_{2.5}$	Annual 24-hour	0.001 0.061	0.04 [a] 0.07 [a]	No No
NO_2 [b]	Annual	0.0064	0.1	No
SO_2	Annual 24-hour 3-hour	0.0091 0.25 (at 50 km), 0.13(at 100 km) 0.92	0.1 0.2 1	No No (at 100 km) No

a. Based on the lowest proposed concentration level from options in the proposed EPA rules for $PM_{2.5}$ SIL.
b. Assumes 80% conversion of NO_X to NO_2, i.e., the tier 2 modeling approach.

For the Class I analysis in the Everglades National Park, located 147 km from the project site, the maximum predicted impacts of due to the HEF project are all predicted to be less than the proposed PSD Class I significant impact levels for most pollutants and averaging periods at a 50km distance, except for the 24-hour SO_2 However, at a 100 km distance, the maximum impacts due to the HEF project are predicted to be less than the significant impact levels for all pollutants and averaging periods. Thus, no cumulative impact analyses were performed at Everglades National Park (ENP) since the project's impacts are expected to be well below the Class I SIL.

Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is performed for those pollutants with listed significant monitoring concentrations (de minimis levels). These are levels, which, if exceeded, would potentially require pre-construction ambient monitoring. As shown in Table 21 below, the maximum predicted impacts due to the proposed project are predicted to be below the PSD de minimis concentration levels for NO_2, SO_2 and CO, but above the de minimis concentration levels for ozone, PM_{10}, and $PM_{2.5}$.

Table 21 – Maximum Air Quality Impacts for Comparison to the De Minimis Concentration Levels

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	De Minimis Level ($\mu g/m^3$)	Impact Greater Than De Minimis?
PM_{10}	24-hour	33.7	10	Yes
$PM_{2.5}$	24-hour	23.4	4	Yes
NO_2	Annual	0.6 [a]	14	No
SO_2	24-hour	8.1	13	No
CO	8-hour	297	575	No
Ozone	8-hour	124 [b]	100	Yes

a. Assumes 75% conversion of NO_X to NO_2, i.e., the tier 2 modeling approach (annual).
b. Values shown are VOC. There is no explicit de minimus concentration for ozone, but an increase in 100 TPY or more requires a monitoring analysis for ozone.

Because the predicted maximum 24-hour $PM_{2.5}$ and PM_{10} concentrations are greater than the de minimis levels, a pre-construction ambient monitoring analysis is required for both $PM_{2.5}$ and PM_{10} as part of the application.

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

The EPA-approved AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project in the surrounding Class I & II Areas. 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.

Emissions data used in the modeling analysis were obtained from the DEP ARMS database, DEP permit files, and recent PSD permit reviews. Emissions data for the new proposed facility derive from the proposed maximum permit limits imposed on the facility for each pollutant. Emissions of all NO_X sources in the modeling inventory for the purpose of modeling NO_2 against the AAQS were adjusted in accordance with the federal regulations adopted by the department for this pollutant, per rule 62-204.800. This adjustment was made for both the annual (reduced by 15%) and 1-hour (reduced by 20%) NO_2 averaging periods. While this adjustment was developed for the annual average, the DEP believes that this adjustment is also appropriate for the short-term 1-hour emissions in this rural area.

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 Fort Myers Southwest Florida Regional (RSW) Airport and the Tampa International Airport (TIA) in Tampa, respectively. The 5-year period of meteorological data is from 2001 through 2005. The location of the proposed facility is 85 km north-northeast of the Fort Myers airport. To assess the representativeness of these data for the proposed site, a comparison was made of the land-use at the Fort Myers Airport with that at the proposed site. The three land-use parameters compared are the albedo (reflectivity of the land surface), Bowen ratio (measure of the surface moisture), and the surface roughness (a measure of the height of structures and vegetation surrounding the area). Both the albedo and the Bowen ratio are nearly the same values at both locations. The surface roughness at the airport is slightly higher than at the proposed site location. Because the area of the approximate 75-acre HEF site will be cleared and the trees will be removed, the surface roughness, shown based on existing land use, will be lower when the project is constructed and operated. As a result, the difference in land use values between the two sites, particularly for surface roughness, will be less and not expected to be a significant factor in evaluating impacts. Further, the general terrain in this part of Florida is flat, and large scale weather events are fairly uniform over a large area. While there would be localized differences between the two sites, especially with respect to sea or lake breezes when they occur, the fundamental set of meteorological conditions used to assess the proposed source would be similar. The Fort Myers/Tampa meteorological data set is judged representative for the proposed site's air quality analysis.

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. A PSD increment analysis was required for PM_{10} and SO_2. 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 22 below.

Table 22 - PSD Class II Increment Analysis

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Impact Greater Than Allowable Increment?	Percentage of Increment Consumed
PM_{10}	24-hour	9.6	30	No	32%
	Annual	2.4	17	No	14%
SO_2	24-hour	27.9	91	No	31%
$PM_{2.5}$	24-hour	7.6	9	No	84%
	Annual	1.1	4	No	28%

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 is based on existing monitoring data for each pollutant and representative of the area of the proposed source. This background is intended to account for sources of a particular pollutant that are not explicitly modeled. Since no attempt is typically made to subtract out the impacts due to the explicitly modeled sources on these monitored values, there is some amount of double-counting reflected in the total concentration (modeled + background) used to compare with the appropriate AAQS.

An evaluation of the NO_2 and SO_2 emission inventories for background sources considered in the PSD application for the HEF facility was performed to determine whether the method used to eliminate background sources from the 1-hour NO_2 and SO_2 NAAQS compliance modeling demonstration was reasonable. Background sources were included in the modeling demonstration if they were located within the significant impact area (SIA) of the project, or if they were located beyond the SIA but less than 50 kilometers (km) from the SIA and had potential 1-hour emissions of 1000 TPY or more.

In general, for the 1-hour averaging time, background sources are most likely to interact with a project if they are located near the project site, have source characteristics that are favorable to produce impacts under similar meteorological conditions as those for the project, and whose emissions (plume) can be realistically transported within 1 hour over distances to interact with other sources. As stated in EPA's memorandum of March 1, 2011, regarding modeling for the 1-hour NO_2 NAAQS, "the emphasis on determining which nearby sources to include in the modeling analysis should focus on the area within about 10 km of the project location in most cases. The routine inclusion of all sources within 50 km of the project location, the nominal distance for which AERMOD is applicable, is likely to produce an overly conservative result in most cases."

The locations of the NO_2 and SO_2 sources considered for the modeling analysis were presented in the application. For the 1-hour SO_2 and NO_2 concentrations, the project's SIA extended out to 4.75 and 12 km from the project location. The information also compares the emissions included in the modeling analysis within each distance range to the total emissions from all facilities located within that range.

Only one background source was located within 25 km from the project. Since it was located within the project's SIA, it was modeled. Beyond 25 km, there were only two sources with maximum 1-hour emissions greater than 1000 TPY. One source was located about 26 km and the other source located about 44 km from the project. Most of the other background sources had maximum 1-hour emissions of less than 25 lb/hr. Both of these sources were modeled. Based on this information, 100 percent of the SO_2 and 99 percent of the NO_2 emissions from all background sources located within 25 km and 45 km from the project were modeled.

To understand the meteorological conditions that produced the maximum 1-hour concentrations, modeling was performed for each year that produced the highest 5-year average of the 8th highest maximum daily 1-hour NO_2 concentration of 40.6 $\mu g/m^3$. Source contributions to that maximum value were also identified.

The proposed HEF project and a nearby facility, Lake Placid Asphalt Plant, were the only sources that contributed to the maximum 1-hour concentrations for each year. Background sources located more than 25 km from the project did not contribute. The maximum hourly concentrations were predicted to occur with wind speeds that ranged from 4.1 to 10.3 meters per second (m/s) during daytime hours, indicative of neutral and unstable stability conditions. With these wind speeds, the plumes from both sources can be transported to the receptor during the 1-hour period.

Maximum 1-hour NO_2 impacts were also predicted for a large emission source, Tampa Electric Phillips Station, located about 26 km from the project. Impacts were predicted at the same receptor that the maximum 1-hour concentrations were predicted from all sources. The maximum hourly concentrations were predicted to occur with wind speeds that ranged from 1.5 to 4.1 m/s during early morning hours, indicative of stable stability conditions. With these wind speeds, the plume from this source is not likely to be transported to the receptor during a 1-hour time period.

The sources that are explicitly modeled include the subject facility and nearby sources that are judged to potentially have a significant interaction with the proposed facility. The appropriate calculations for the modeled and background values are different for each pollutant, but generally follow the form for compliance with the AAQS. Table 23 shows the results of this analysis.

Table 23 - Ambient Air Quality Impacts

Pollutant	Averaging Time	Major Sources Impact ($\mu g/m^3$)	Background Conc. ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Total Impact Greater Than AAQS?	AAQS ($\mu g/m^3$)
PM_{10}	24-hour	12.9	59	71.9	No	150
	Annual	2.4	18.7	21.1	No	50
$PM_{2.5}$	24-hour	4.5	14	18.5	No	35
	Annual	1.0	6.2	7.2	No	15
SO_2	1-hour	76.4	23.6	100	No	196
	24-hour	27.9	5.2	33.1	No	260
NO_2	1-hour	32.4	43.3	75.7	No	189

The metrics used for the modeled impacts and the background concentrations provided in the footnotes. As shown in this table, emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS.

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

Ozone Modeling

Projects with VOC and NO_X emissions greater than 100 TPY are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The applicant estimated annual potential VOC and NO_X emissions from the project to be 137 and 194 TPY respectively.

The ozone monitoring data at Sebring is only 2 km south of HEF and is sufficient for the purposes of background values at the HEF site.

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

To conclusively prove that 194 TPY of NO_X will not cause or contribute to a violation, a very sophisticated and expensive model would need to be run for the entire region. The key inputs to the model would be traffic, power plants throughout the region, other industrial sources, and meteorology. As previously discussed, the NO_X emission reductions in South Florida from FP&L projects alone have declined by nearly 80,000 TPY. The effects of the HEF on ozone would not be measurable considering the overwhelming effects of the FP&L reductions and the climatological variability. The uncertainty in any regional ozone model would be greater than the contribution from this project.

6.8. Additional Impacts Analysis

General Description with Regard to Growth and Air Quality Impacts

Highlands County experienced a 123-percent increase in population for the years 1978 through 2009. During this period, there was an increase in population of 55,013. Similarly, the number of households in the county increased since 1977 by 24,128, or 127 percent.

Growth-Related Impacts Due to the Proposed Project

According to the application, construction of the HEF facility will occur over approximately 12 to 18 months and will require an average of approximately 500 to 1,000 workers during that time. It is anticipated that many of these construction personnel will commute to the site. A total of about 60 additional permanent workers will be employed for the operation of the facility. Both the construction and permanent jobs are all new jobs created within Highlands County. However, the workforce needed to construct and operate the facility represents a small fraction of the population already present in the immediate area. Therefore, while there would be a small increase in vehicular traffic in the area, the effect on air quality levels would be minimal. There are also expected to be no air quality impacts due to associated commercial and industrial growth, given the location of the HEF site. The existing commercial and industrial infrastructure is adequate to provide any support services that facility might require and would not increase with the operation of the facility. The addition of the HEF project will have a small positive effect on the increase of growth in the area. However, the surrounding area will certainly remain agricultural in the future. The air quality data measured in the region of the HEF site indicates that the maximum air quality concentrations are well below the AAQS. Based on the trends presented of these maximum concentrations, the air quality has generally improved in the region since the PSD baseline date of August 7, 1977. As demonstrated above, the maximum air quality impacts resulting from the HEF facility are predicted to be low and for some pollutants and averaging times, below the significant impact levels. The cumulative 24-hour and annual average PM_{10}, 24-hour and annual $PM_{2.5}$, and 1-hour and 24-hour average SO_2, and 1-hour NO_2 impacts predicted demonstrate that the HEF facility and background sources will comply with the PSD increments and AAQS. As a result, the air quality concentrations in the region are expected to remain below the AAQS when the HEF facility becomes operational.

Impact on Soils, Vegetation, and Wildlife

The primary vegetation, as well as agricultural crop, in the vicinity of the HEF is orange trees in citrus groves. The site is surrounded by orange groves for a large distance in all directions. Exotic species will colonize portions of the area, most notably melaleuca (Melaleuca quinquenervia) and Brazilian pepper (Schinus terebinthifolius), particularly within drainage features associated with the agricultural operations. Soils in the area are primarily sandy soils. According to the modeling results presented in Section 6.0, the maximum air quality impacts due to the proposed HEF project are predicted to be below the AAQS and PSD increments. The AAQS were established to protect both public health and welfare.

Public welfare is protected by the secondary AAQS, which Florida has adopted. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation, and buildings. Since the project's impacts on the local air quality are predicted to be less than the AAQS and less than the effect levels on soils and vegetation, the project's impacts on soils, vegetation, and wildlife in the vicinity of the site are expected to be negligible.

The major air quality risk to wildlife in the U.S. is from continuous exposure to pollutants above the NAAQS. This occurs in non-attainment areas. Risks to wildlife also may occur for wildlife living in the vicinity of an emission source that experiences frequent upsets or episodic conditions resulting from malfunctioning equipment, unique meteorological conditions, or startup operations. Under these conditions, chronic effects (e.g., particulate contamination) and acute effects (e.g., injury to health) have been observed. Although air pollution impacts to wildlife have been reported in the literature, many of the incidents involved acute exposures to pollutants, usually caused by unusual or highly concentrated releases or unique weather conditions. Compared to the AAQS, it is highly unlikely that emissions from HEF facility will cause adverse effects to wildlife due to the project's low impacts, which are predicted to be below the AAQS based on worst-case operation. Coupled with the mobility of wildlife, the potential for exposure of wildlife to the project's impacts is extremely unlikely.

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

An AQRV analysis was conducted to assess the potential risk to AQRV at the Everglades National Park (ENP), due to the proposed emissions from the HEF facility. Everglades National Park is the closest Class I area to the proposed project and is located 147 km to the south.

In October 2010, the Federal Land Managers (FLMs), consisting of the National Park Service, U.S. Forest Service, and U.S. Fish and Wildlife Service, issued the Federal Land Managers' Air Quality Related Values Work Group (FLAG), Phase I Report- Revised (2010). Based on the report, the FLMs recommended initial screening criteria that would exempt a source from AQRV impact review based on a source's annual emissions and distance from a Class I areas. The FLMs will consider a source located greater than 50 km from a Class I area to have negligible impacts with respect to Class I AQRVs if its total SO_2, NO_X, PM_{10}, and H_2SO_2 annual emissions (in TPY based on 24-hour maximum allowable emissions), divided by the distance (km) from the Class I area (Q/D) is 10 or less. The FLMs would not request any further Class I AQRV impact analyses from such sources.

From HEF emissions presented in Table 24, the maximum potential emissions are estimated to be as follows using the highest emission rate for the short-term period and assuming 8,760 hours/year operation:

With Q as 917.4 TPY and D as 147 km, Q/D (917.4 / 147) Q/D is equal to 6.2. This result is well below the FLM criteria of 10. As a result, an AQRV impact analyses is not required.

Table 24 – Maximum Potential Emissions for Short-Term Period

Pollutant	Averaging Period	Maximum Emission Rate (lb/hr)	
		Units	Value
SO_2	1-hour	lb/hr	70.6
PM_{10}	24-hour	lb/hr	8.94
NO_X	1-hour	lb/hr	126.76
H_2SO_4	24-hour	lb/hr	3.15
Total		lb/hr	209.4
		TPY	917.4

7. CONCLUSION

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

DRAFT PERMIT

PERMITTEE

Highlands EnviroFuels (HEF), LLC
10027 Water Works Lane
Riverview, Florida 33578

Authorized Representative:
Mr. Bradley Krohn
President and Managing Member

Air Permit No. 0550063-001-AC
PSD-FL-416
Expires: June 30, 2016
Facility ID No. 0550063
Sugarcane/Sweet Sorghum-to-Ethanol Advanced
Biorefinery and Cogeneration Plant
Highlands County

PROJECT

This is the final air construction permit authorizing the construction of a 36 million gallon per year (MGPY) ethanol production facility using sugarcane and sweet sorghum as the feedstock and a cogeneration power plant that will generate up to 30 megawatts (MW, gross) of electricity utilizing the leftover sugarcane and sweet sorghum stalk fiber (bagasse) from the ethanol production process as its primary fuel source. The new HEF facility will use natural fermentation processes to produce ethanol from biomass. The plant is categorized under Standard Industrial Classification (SIC) No. 2869, and will be located approximately 0.5 miles south-southwest of the intersection of U.S. Highway 27 and State Road 70, south of Lake Placid, in Highlands County, Florida. The UTM coordinates of the facility are Zone 17, 466.407 kilometers (km) East and 3,009.015 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 F.S., 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 (Department) 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
For the Division of Air Resource Management

(DRAFT)

______________________________ __________
(Signature) (Date)

____
(Printed Name of Above Designee)

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 was made available electronically on a publicly accessible server, with received receipt requested before the close of business on ______________________________ to the persons listed below.

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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.

(Draft)

______________________________ (Clerk) __________ (Date)

PROPOSED PROJECT

The project involves the construction of the HEF ethanol production facility that will utilize sugarcane and sweet sorghum as its feedstock to produce up to 36 MGPY of ethanol. In addition, the project involves the construction of a cogeneration plant utilizing the leftover cane and sorghum stalk fiber (bagasse) from the ethanol production process as its primary fuel source. The cogeneration plant will generate up to 30 MW (gross) of electricity of which up to 20 MW will be available for sale to the grid. The sugarcane and sweet sorghum feedstock for the HEF facility will be grown on adjacent and surrounding farmland. Juice will be extracted from the sugarcane and sweet sorghum and processed to increase its sucrose (sugar) concentration. The concentrated juice will then be fermented to convert the sugars to ethanol. The distilled ethanol will be blended with gasoline to yield a denatured ethanol product.

The sugarcane and sweet sorghum bagasse will be burned in a biomass boiler with a maximum heat input rate of 504.3 million British thermal units per hour (mmBtu/hr) on a 4-hour average basis and 458.5 mmBtu/hr on a 24-hour average basis. In addition to cane and sorghum bagasse, the HEF biomass boiler will also burn biomass consisting of energy crops, wood chips and vegetative debris and natural gas. The biomass boiler will generate steam that will be utilized in the ethanol production process and in a steam turbine electrical generator (STG) to produce electrical power. The energy crops, wood chips and vegetative debris will be used as a supplemental fuel in the boiler. The natural gas will be used as the boiler startup, shutdown and flame stabilization fuel, and also in the event of a disruption in the biomass supply. Ultra low sulfur distillate (ULSD) fuel oil or natural gas will be used in emergency equipment (one generator and one fire water pump engine).

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

Facility ID No. 0550063	
EU ID No.	**Emissions Unit Description**
001	Feedstock and Biomass Material Handling and Preparation
002	Cogeneration Biomass Boiler
003	Cooling Towers
004	Ethanol Production Process
005	Storage Tanks
006	Truck Rack Product Loadout and Flare
007	Miscellaneous Dry Material Storage Silos
008	Emergency Equipment
009	Facility-Wide Fugitive VOC Equipment Leaks

FACILITY REGULATORY CLASSIFICATION

- The facility is not a major source of hazardous air pollutants (HAP).
- Because HEF is a cogeneration facility, it does not operate units subject to the Title IV Acid Rain Program of the Clean Air Act (CAA).
- The facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400 (PSD), F.A.C.
- The facility is subject to Rule 62-296.100(3), F.A.C. for New Source Performance Standards (NSPS) under Section 111 of the CAA and the National Emissions Standards for Hazardous Air Pollutants (NESHAP) under Section 112 of the CAA.

- The HEF facility is not subject to Clean Air Interstate rule (CAIR) nor its replacement, the Cross-State Air Pollution Rule (CSAPR), because its biomass boiler is a cogeneration unit that will sell less than 219,000 megawatt hours (MWh) per year of electricity to the grid.

1. Permitting Authority: The Permitting Authority for this project is the Office of Permitting and Compliance in the Division of Air Resource Management of the Department. The mailing address for the Office of Permitting and Compliance is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. All documents related to applications for permits shall be submitted to the Office of Permitting and Compliance in the Division of Air Resource Management of the Department.

2. Compliance Authority: All documents related to compliance activities such as reports, tests and notifications shall be submitted to the Compliance Authority, which is 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 for Small Industrial-Commercial-Institutional Steam Generating Units;
   h. Appendix F: 40 Code of Federal Regulations (CFR) Part 75, Appendix F, Section 5 – Measurement of Boiler Heat Input Rate;
   i. Appendix GC: General Conditions;
   j. Appendix GP: Identification of General Provisions, Subpart A from NSPS 40 CFR 60 and Subpart A from NESHAP 40 CFR 63;
   k. Appendix IIII: NSPS, Subpart IIII – Stationary Compression Ignition Internal Combustion Engines;
   l. Appendix JJJJJJ: NESHAP, Subpart JJJJJJ – Industrial/Commercial/Institutional Steam Generating Units for Area Sources of HAP;
   m. Appendix Kb: NSPS, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels;
   n. Appendix LDAR: Preliminary Leak Detection and Repair (LDAR) Program;
   o. Appendix VVa: NSPS, Subpart VVa – Standards of Performance for Equipment Leaks of Volatile Organic Compounds (VOC) in the Synthetic Organic Chemical Manufacturing Industry (SOCMI); and
   p. 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 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 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.

[See also Appendix BMP; 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 VOC are subject to NSPS Subpart VVa – Standards of Performance for Equipment Leaks of VOC in the SOCMI. 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. The permittee must submit a list indentifying the devices or systems to the Compliance Authority no later than 90 days before the HEF facility becomes operational. A requirement of Subpart VVa is the development of a LDAR program. A preliminary LDAR program plan is included as Appendix LDAR in Section 4 of this permit. The permittee is required to submit a final LDAR program plan to the Compliance Authority for approval no later than 90 days before the HEF facility becomes operational. The HEF facility must demonstrate 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(3), F.A.C. Reasonable Assurance]

12. 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 no later than 90 days before the HEF facility becomes operational that addresses the procedures and practices that will be used to control facility wide 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.}

13. 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.]

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

A. Feedstock and Biomass Material Handling and Preparation (EU-001)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
001	Feedstock and biomass material handling and preparation consists of the following major functions: • Feedstock Harvesting: Both sugarcane and sweet sorghum stalks will be harvested as 6-inch to 12-inch billets from adjacent and nearby agricultural lands and transported to the HEF facility by truck or rail. The harvesting methods employed will ensure that "trash", i.e., cane and sorghum leaves and tops, will be minimized in the delivered feedstock. It is expected that "trash" will constitute less than 8 percent (%) by weight of the delivered feedstock to the facility. • Processing the Feedstock: The loaded trucks/railcars will be weighed on a weighing bridge as they enter the unloading area. The cane or sorghum in the trucks will then be transferred to the feed table via a tipping trailer. Railcars will be bottom dumped into a feed hopper, which feeds the feed table. The feed table is equipped with chains that convey the sugar cane and sweet sorghum billets toward the main conveyor that feeds the juice extraction system. • Juice Extraction: The feedstock will be passed through high efficiency knives and a heavy-duty shredder to increase the surface area of the material. Then the feedstock passes to a belt conveyor and then to the diffuser. The diffuser is designed to carry a uniform layer of feedstock through the diffuser and across the entire width of the diffuser to obtain maximum sucrose removal. Imbibition water is fed into the juice trough and falls onto the processed feedstock mat, percolates through the fibers, passes across the screen and is collected in the last juice receiver. From the juice receiver, this solution with low sucrose concentration is recirculated upstream back to the juice trough and falls again onto the feedstock mat. This recirculation continues to create a countercurrent pattern and a constant sucrose concentration gradient between the feedstock mat moving downstream and the recirculating juice moving upstream. The feedstock exiting the diffuser is termed "bagasse." The moisture content of the bagasse when it leaves the diffuser is approximately 80%. To reduce the moisture content further, the bagasse is sent through a dewatering mill system. The mill presses the bagasse until the moisture content is reduced to approximately 50%. • Boiler Fuel Feedstock (Biomass): Sugarcane and sweet sorghum bagasse from the juice extraction process will be used as the primary fuel in the HEF biomass boiler. The bagasse will be sent directly to the boiler or stored in a storage pile in the biomass yard. Biomass consisting of energy crops, wood chips and vegetative debris will be used as a supplemental boiler fuel. Natural gas will be used for boiler startup, shut down and flame stabilization and also in the event of a disruption in the biomass supply. • Biomass Fuel Feed System: A single biomass fuel feed system for the boiler will be used. The system will consist of a dewatering system for the cane and sorghum bagasse, covered conveyors, boiler metering bins and biomass storage piles (bagasse and supplemental biomass). The biomass fuel will be fed from the storage piles to the conveyor system using front-end loaders. Only one feed system is required, since bagasse and supplemental biomass may be fired in combination in the boiler. • Biomass Design Throughput: Under normal operation (no supplemental biomass burning), the amount of bagasse burned in the boiler is estimated to be 236,300 tons per year (TPY) each of cane and sorghum bagasse. A maximum 43,368 TPY of supplemental biomass may be burned in combination with 212,670 TPY each of cane and sorghum bagasse.

A. Feedstock and Biomass Material Handling and Preparation (EU-001)

EQUIPMENT

1. Biomass Delivery, Handling and Preparation: The permittee is authorized to install the following major pieces of equipment for the delivery, handling and processing of the sugarcane and sweet sorghum used in the ethanol production process and the bagasse and supplemental biomass used as boiler fuel:
   - Weighing bridge truck scale(s);
   - Tipping trailer/railcar unloader(s);
   - Sugar cane and sweet sorghum bagasse press drying system;
   - Feed table with transfer chains;
   - Enclosed transfer conveyors consisting of reclaim, return, transfer, distribution and surplus conveyors; and
   - Biomass yard containing biomass fuel storage piles (bagasse and biomass).

   [Application No. 0550063-001-AC and Rule 62-4.070(3), F.A.C.]

2. Air Pollution Control Equipment: To minimize fugitive particulate matter (PM), PM with a mean diameter of 10 micrometers (μm) or less (PM_{10}) and PM with a mean diameter of 2.5 μm or less ($PM_{2.5}$); henceforth called PM, biomass conveyors shall be enclosed. If required to meet the opacity requirement given in **Specific Condition 10** of this subsection, the permittee shall install dust collectors 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 (gr/dscf).

   {Permitting Note: Enclosed conveyors means that the conveyance belt for the biomass is totally enclosed from above thus preventing wind from causing fugitive dust emissions. However, the bottom of the conveyance belt shall be accessible for maintenance and repairs.}

   [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

3. Fugitive Dust Control: HEF shall utilize reasonable precautions for controlling fugitive PM emissions from this emission unit. These include but are not limited to:
   - Enclosing material drop points, transfer points, shredders and screens wherever practical;
   - Contouring storage piles to minimize wind erosion;
   - Utilizing water sprays on storage piles as needed to prevent fugitive dust caused by biomass from leaving the property;
   - Paving all main plant roads;
   - Watering of gravel surfaces as needed to control dust; and
   - Sweeping and watering of paved surfaces as needed to remove dust.

   The permittee shall also comply with additional precautions listed in Appendix BMP- Best Management Practices and **Specific Condition 9** of Section 2 of this permit.
   [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

PERFORMANCE RESTRICTIONS

4. Roadways: The plant roadways shall be paved and during dry conditions wetted sufficiently to maintain surface moisture to minimize fugitive dust emissions. Roadways shall be swept as necessary 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.
   [Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

5. Gravel Areas: The gravel surfaces at the HEF facility shall be wetted sufficiently during dry conditions to maintain surface moisture to minimize fugitive dust emissions. A record of the wetting shall be kept and made available to the Compliance Authority upon request.

[Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

6. Bagasse and Supplemental Biomass Storage Piles: The boiler fuel (bagasse and biomass) storage piles will be located in the fuel yard in the southwestern quadrant of the HEF site. To control odors and minimize the chance of spontaneous combustion, bagasse and biomass in the storage piles shall be used in a first-in first-out (FIFO) basis. To prevent fugitive dust caused by biomass from leaving the property, the plant shall apply water if necessary; otherwise, the material shall be kept dry to facilitate burning. Contouring storage piles shall be done to minimize wind erosion. Overall, fuel storage pile management shall follow the procedures described in Appendix BMP of this permit.
[Application No. 0550063-001-AC; Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]

7. Authorized Ethanol Production Feedstock: Feedstock used in the ethanol production process at the HEF facility shall be sugarcane and sweet sorghum. In addition, sweet sorghum syrup/molasses and/or sugarcane molasses may be used as the feedstock when sugarcane and sweet sorghum feedstocks are in low supply or not available. [Application No. 0550063-001-AC and Rule 62-4.070(3), F.A.C.]

8. Authorized Boiler Fuel Biomass: Biomass fuel authorized to be used in the biomass boiler at the HEF facility consists of sugarcane and sweet sorghum bagasse and supplemental biomass consisting of energy crops, wood chips and vegetative debris. Appendix BMP further defines the types of biomass that shall and shall not be used at the HEF facility in the ethanol production process and as boiler fuel and includes quality assurance (QA) procedures to ensure the biomass used meets the requirements specified in this permit.
[Application No. 0550063-001-AC and Rule 62-4.070(3), F.A.C.]

9. Hours of Operation: The hours of operation of this emission unit are not limited (8,760 hours per year).
[Application No. 0550063-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

10. Opacity Standard: As determined by EPA Method 9, there shall be no visible emissions (VE) greater than 5% opacity at drop points, transfer points and dust collector outlets that are required to meet this VE standard. [Rule 62-212.400(5)(c), F.A.C.]

11. Best Management Practices (BMP): A plan to control PM emissions from biomass (sweet sorghum bagasse, sweet sorghum bagasse and supplemental 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 biomass storage piles and QA measures for biomass delivered to the HEF facility. As the engineering details of the Feedstock Delivery, Handling and Preparation emissions unit become finalized, the permittee shall submit an updated BMP plan to the Compliance Authority no later than 90 days before the HEF facility becomes operational.
[Rules 62-212.400 (BACT) and 62-4.070(3), F.A.C.]
{Permitting Note: PM emissions from biomass deliveries, bagasse handling and supplemental biomass handling during operation of the HEF facility are estimated to be 7.9 tons in any consecutive twelve month period.} [Application No. 0550063-001-AC]

TESTING AND MONITORING REQUIREMENTS

12. Initial Compliance Tests: The drop points, transfer points and dust collector outlets (if installed) of this emissions unit shall be tested to demonstrate initial compliance with the emissions standards for opacity given in **Specific Condition 10** of this subsection. 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.]

13. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the drop points, transfer points and dust collector outlets (if installed) of the emissions unit shall be tested to demonstrate compliance with the emissions standards for opacity given in **Specific Condition 10** of this subsection.
[Rules 62-4.070(3) and 62-297.310(7)(a)4, F.A.C.]

14. 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.]

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

Method	Description of Method and Comments
9	Visual Determination of the Opacity of Emissions from Stationary Sources.

The above method is described in Appendix A of 40 CFR 60 and is 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

16. 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.]

17. Notification, Recordkeeping and Reporting Requirements: The permittee shall maintain records of the amount of biomass consisting of sugarcane, sweet sorghum, sweet sorghum syrup/molasses, sugarcane syrup/molasses, energy crops, wood chips and vegetative debris delivered, handled and processed on a daily, monthly, quarterly and 12 month rolling average basis. These records shall be submitted to the Compliance Authority on a semi-annual basis or upon request. [Rule 62-4.070(3), F.A.C.]

B. Cogeneration Biomass Boiler (EU-002)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
002	Description: The boiler will be a hybrid suspension/stoker (grate) type boiler wherein biomass (sugarcane bagasse, sweet sorghum bagasse and supplemental biomass) and natural gas are combusted to generate high temperature and high pressure steam. The steam will then be used in the ethanol production process and also sent to a STG to generate up to 30 MW (gross) of electrical power. Fuels: Sugarcane and sweet sorghum bagasse, a residual from the ethanol production process, will be used as the primary fuel in the biomass boiler with biomass consisting of energy crops, wood chips and vegetative debris used as a supplemental fuel. In addition, the boiler will be capable of combusting natural gas for startup, shutdown and flame stabilization and also in the event of a disruption in the biomass supply. Capacity: The maximum design heat input capacity to the boiler is 504.3 mmBtu/hr on a 4-hour basis and 458.5 mmBtu/hr on a 24-hour basis. Steam production capability will be approximately 275,800 pounds per hour (lb/hr) on a 4-hour basis and 250,000 lb/hr on a 24-hour basis. The maximum heat input capacity using natural gas in the biomass boiler shall be physically constrained by burner design to be less than 250 mmBtu/hr so the boiler is not subject to 40 CFR 60 NSPS, Subpart Da. Controls: Good combustion practices (GCP) leading to the efficient combustion of biomass in the boiler, including an over-fired air (OFA) system, to minimize formation of PM, nitrogen oxides (NO_X), carbon monoxide (CO), VOC and HAP; Selective Non-Catalytic Reduction (SNCR) with urea or anhydrous ammonia (NH_3) injection to destroy NO_X; an oxidation catalyst (Ox-cat) system to control VOC, CO and organic HAP; use of natural gas fired in low-NO_X burners (LNB) for boiler startup, shutdown and flame (bed) stabilization to minimize formation of PM, NO_X, sulfur dioxide (SO_2) and HAP; a dry sorbent injection system (DSIS) utilizing sodium bicarbonate, hydrated lime or trona to control SO_2, sulfuric acid mist (SAM) and acid gas HAP; a wet sand separator (cyclone) and a electrostatic precipitator (ESP) to further control PM and opacity; and, if necessary, a hydrogen chloride (HCl) and hydrogen fluoride (HF) control strategy to ensure the HEF facility is minor source for HAP emissions. Stack Parameters: Flue gas from the biomass boiler will discharge to the atmosphere via a stack with a design height of 150 feet and a design diameter of 14 feet. The flue gas exit temperature will be approximately 340 degrees Fahrenheit (°F) with a design volumetric flow rate of 204,080 actual cubic feet per minute (acfm). Continuous Emissions and Opacity Monitoring Systems (CEMS, COMS): Emissions of CO, NO_X, SO_2 and HCl will be monitored and recorded by CEMS. Opacity will be monitored and recorded by COMS. Applicability of 40 CFR 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 combusted fuels, and it 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. 0550063-001-AC]

{Permitting Note: In accordance with Rule 62-212.400, F.A.C., the Department established permit standards for the biomass-fueled boiler that represent the BACT for emissions of NO_X, PM/PM_{10}, VOC, SO_2 and CO. A SAM emission limit was set to avoid BACT for this pollutant. The biomass-fueled boiler is subject to the federal 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. Construction of Biomass-Fueled Boiler: The permittee is authorized to construct one biomass-fueled hybrid suspension/stoker (grate) type boiler at the HEF facility with maximum steam generation rates of 270,000 pounds per hour (lb/hr) on a 4-hour average basis and 250,000 lb/hr on a 24-hour average basis for steam and power generation. The boiler shall have a multi-stage superheater, air heater and economizer. LNBs shall be utilized for natural gas firing. The boiler shall include:
   - Biomass fuel feeders;
   - High-performance OFA system consisting of air headers, air nozzles, dampers and an OFA fan;
   - Soot blowers;
   - Forced draft (FD) fan;
   - Induced draft (ID) fan;
   - Pneumatic distribution air fans; and
   - Vibrating grate for ash removal.
   - One steam turbine electrical generator (STG).

   [Application No. 0550063-001-AC]

2. Air Pollution Control Equipment: To comply with the emission standards of this subsection, the permittee shall install the following air pollution control equipment on the biomass boiler.
   a. *Wet Sand Separator (Cyclone)*: The permittee shall design, install, operate and maintain a wet sand separator to remove fine sand particles from the flue gas exhaust prior to the ESP. The wet sand separator shall be on line and functioning properly whenever the boiler is in operation. If necessary, the wet sand separator shall be modified to aid in the removal of acid gases to meet the emission limits specified in this subsection.
   b. *ESP*: The permittee shall design, install, operate and maintain an ESP to remove PM from the flue gas exhaust and achieve the PM standards specified in this subsection. During startup conditions, the ESP shall be on line and functioning properly prior to combusting any biomass. During normal operation, the ESP shall be on line and functioning properly at all times.
   c. *SNCR*: The permittee shall design, install, operate and maintain a urea or NH_3 based SNCR system to reduce NO_X emissions in the flue gas exhaust and achieve the NO_X emissions standard specified in this subsection. The SNCR system shall be on line and functioning properly whenever the boiler is in operation, other than during startup conditions. During startup conditions, the SNCR manufacturer's instructions shall be followed regarding operation of the system.
   d. *DSIS*: The permittee shall design, install, operate and maintain a DSIS to inject lime, trona or sodium bicarbonate into the flue gas to control SO_2 emissions to the limit specified in this subsection. The DSIS will also help control acid gas HAP emissions. The SO_2 CEMS output data expressed in lbs/hr averaged over a 24-hour period shall be reviewed by plant personnel on a daily and monthly basis to determine required operation of, or adjustment to the sorbent injection augmentation to ensure the HCl, HF and SO_2 emission standards will be maintained. CEMS based SO_2 emissions data shall be reported to the Department on a quarterly basis.
   e. *Ox-cat*: The permittee shall install an Ox-cat system to control, in conjunction with GCP, emissions of CO and organic HAP to the standards specified in this subsection. The installation of the Ox-cat system is initially experimental in nature to determine if the Ox-cat catalyst lifetime is adversely effected by the alkali nature of the flue gas stream. After 24 months of initial Ox-cat operation, a test report per **Specific Condition 12** of this subsection will be submitted to the Department describing Ox-cat performance versus time with regard to CO and organic HAP emissions.

f. *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.]

[Applicant's Request; Application No. 0550063-001-AC; Rules 62-212.400(10) (PSD), Control Technology Review; 62-4.070(3) and 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

3. Authorized Fuels: The biomass boiler is authorized to combust as its primary fuels sugarcane and sweet sorghum bagasse that is a byproduct from the ethanol production process. Biomass consisting of energy crops, wood chips and vegetative debris will be used as a supplemental boiler fuel. In addition, the boiler is authorized to combust natural gas for startup, shutdown and flame stabilization and also in the event of a disruption in the biomass supply. [Application No. 0550063-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]
4. Boiler Heat Input Rate: The maximum heat input rate from all fuel combinations in the biomass boiler is 504.3 mmBtu/hr on a 4-hour average basis and 458.5 mmBtu/hr on a 24-hour average basis. Emission rates are based on the heat input of 458.5 mmBtu/hr. The permittee shall use the thermal efficiency method to calculate the boiler heat input rate, using the steam rate, steam pressure, and steam temperature measurements required per **Specific Condition 21** of this subsection, and feedwater temperature and pressure, to determine net enthalpy. The design boiler efficiency shall be used provided the boiler efficiency test required in **Specific Condition 20** of this subsection is at least 90% of the design boiler efficiency. The procedure given in Appendix ASME of this permit shall be used to measure the boiler efficiency. As an alternative, the procedures given in Appendix F of this permit may be used to calculate boiler heat input. [Application No. 0550063-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]
5. Heat Input from Fossil Fuels: The maximum heat input capacity from combusting natural gas in the biomass boiler, as determined by the physical design of the boiler and design characteristics of the boiler burners shall be less than 250 mmBtu/hr. The maximum amount of natural gas that shall be fired in the boiler in any 12-month consecutive period is 1,021 million standard cubic feet (mmscf). [Application No. 0550063-001-AC; NSPS Subpart Db; Rules 62-4.070(3); and 62-210.200(PTE), F.A.C.]
6. Hours of Operation: The hours of operation for the biomass boiler are restricted to 8,040 hours in any consecutive 12-month period.
[Application No. 0550063-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]
7. 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 GCP as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(5), F.A.C.]

NSPS APPLICABILITY

8. Subpart Db – Steam Generating Units: The HEF biomass boiler must meet all applicable requirements of NSPS 40 CFR 60, Subpart Db – Industrial-Commercial-Institutional Steam Generating Units. Subpart Db is contained in Appendix Db of this permit. For the HEF biomass boiler, NSPS Subpart Db contains limits for SO_2, NO_X, PM and opacity. [Application No. 0550063-001-AC and 40 CFR 60, Subpart Db]

NESHAP APPLICABILITY

9. Subpart JJJJJJ – Industrial/Commercial/Institutional Boilers: The HEF biomass boiler must meet all applicable requirements of NESHAP 40 CFR 63, Subpart JJJJJJ – Industrial/Commercial/Institutional Steam Generating Units for area sources of HAP. Subpart JJJJJJ is contained in Appendix JJJJJJ of this permit. In addition to a PM emission limit, Subpart JJJJJJ requires a biennial tune-up of the biomass boiler. [Application No. 0550063-001-AC and 40 CFR 63, Subpart JJJJJJ]

CROSS-STATE AIR POLLUTION RULE (CSAPR)

10. CSAPR Applicability: The HEF facility's biomass boiler meets the definition of a cogeneration unit in CSAPR. To be exempt from the rule, the cogeneration unit must supply 219, 000 MWh per year or less of electrical power for sale to the grid. The HEF facility shall not sell more than 219,000 MWh of electrical power to the grid in any consecutive 12 month period and thus is exempt from the CSAPR. [40 CFR Parts 51, 52, 72, 78, and 97, CSAPR and Rule 62-4.070(3), F.A.C.]

OX-CAT CATALYST LIFETIME TESTING

11. Ox-Cat Catalyst Testing: An Ox-cat system shall be installed on the biomass boiler prior to the HEF facility becoming operational. The Ox-cat system will help control CO and organic HAP emissions from the boiler. An initial 24-month test period will be conducted to determine if the alkali nature of the boiler flue gas stream will poison the Ox-cat catalyst. During this test period, the CO emission limit as given in **Specific Condition 13** of this subsection is 0.30 lb CO/mmBtu of boiler heat input on a 30-day rolling average basis. Also during this test period, the VOC emission limit as given in **Specific Condition 13** of this subsection is 0.017 lb VOC/mmBtu based on initial and annual stack tests. After 24 months of initial Ox-cat operation, a test report per **Specific Condition 12** of this subsection will be submitted to the Department describing Ox-cat performance versus time with regard to CO, VOC and organic HAP emissions. Based on this report, after public notice and comment, the Department shall modify the AC permit to either: 1) adjust the CO and VOC BACT emissions limits downward to reflect the actual long-term CO and VOC removal effectiveness of the Ox-cat system; or 2) authorize removal of the Ox-cat system. If removal of the Ox-cat system is authorized, the CO and VOC emission limits will remain 0.30 lb/mmBtu on a 30-day rolling average basis and 0.017 lb/mmBtu based on stack tests, respectively. [Rules 62-212.400(10); 62-210.200(PTE); and 62-4.070(3), F.A.C.]

12. Ox-Cat Catalyst Testing Report: Ninety days after completion of the Ox-cat system catalyst lifetime testing period, a test report shall be submitted to the Compliance Authority and the Department. At a minimum, for the duration of the testing, the report shall include: 24-hour (midnight to midnight) averages of boiler operating parameters to include heat input, steam generation, fuel mixtures (cane bagasse, sorghum bagasse, supplemental biomass fuel and natural gas) and corresponding weights of each biomass fuel used including each supplemental fuel (energy crops, wood chips and vegetative debris) and mmscf of natural gas burned; 24-hour NO_X and CO CEMS data in lb/mmBtu and lb/hr; 24-hour HCl CEMS data in lb/hr and lb/mmBtu; all VOC stack tests results in lb/mmBtu and lb/hr from the boiler stack; all HAP stack test results from both the boiler stack and ethanol process scrubber stacks in lb/mmBtu and lb/hr; all maintenance actions performed on the Ox-cat system and; if necessary, a recommendation for the Ox-cat system removal with supporting justification or any requested permit modification to allow the continued use of the Ox-cat system. Based on all the data (boiler parameters, pollutant and HAP emissions and maintenance actions) in the test report, the Department will either adjust the CO and VOC emission limits downward to reflect the CO and VOC BACT standards with the Ox-cat or allow removal of the Ox-cat system. If the Ox-cat system is removed, the CO and VOC emission limits will remain 0.30 lb/mmBtu on a 30-day rolling average basis and 0.017 lb/mmBtu based on stack tests, respectively. In addition, if the Ox-cat system is removed and HAP testing results (acid gas, organic and metal) from the boiler and ethanol process scrubbers are higher than anticipated, an enhanced HAP control strategy may be necessary to ensure the HEF facility remains a minor source for HAP emissions. This control strategy may consist of augmentation of any or all of the following: the wet sand cyclone and DSIS to improve their acid gas removal efficiency; fuel mix modifications to reduce overall HAP emissions; and ethanol process scrubber additives and/or modifications to improve organic HAP removal. [Rules 62-212.400(10); 62-210.200(PTE); and 62-4.070(3), F.A.C]

EMISSIONS STANDARDS

13. Emission Limits: Emissions from the biomass boiler at HEF facility shall not exceed the following standards.

Parameter	Limit	Basis	Compliance
NO_X [a]	0.10 lb/mmBtu	BACT	30-day rolling average by CEMS
SO_2 [b]	0.060 lb/mmBtu	BACT	30-day rolling average by CEMS
CO [c]	0.30 lb/mmBtu	BACT	30-day rolling average by CEMS [d]
SAM [e]	0.0037 lb/mmBtu	Rule 62-212.400(12), F.A.C.	Initial and Annual Stack Test
HCl [f]	9.00 TPY	Rule 62-4.070(3),F.A.C.	12-month rolled monthly by CEMS
HF [f]	0.30 lb/hr	Rule 62-4.070(3), F.A.C.	Initial and Annual Stack Tests
Σ HCl, HF, Cl_2, Organic HAP, Metal HAP [g]	19.61 TPY	Rule 62-4.070(3), F.A.C.	CEMS Data, Initial, Quarterly and Annual Stack Tests [h]
PM/PM_{10} (filterable) [i]	0.015 lb/mmBtu	BACT	Initial and Annual Stack Tests
VE [j]	10% Opacity (20% once/hr)	BACT	6-minute blocks by COMS Initial Stack Test
VOC [k]	0.017 lb/mmBtu	BACT	Initial and Annual Stack Tests
NH_3 Slip [l]	30 ppmvd @ 7% O_2	Rule 62-4.070(3), F.A.C.	Initial and Annual Stack Tests
Heat Input Rate [m]	458.5 mmBtu/hr	Rule 62-210.200(PTE), F.A.C.	24-hour, by Appendix ASME [n]
	504.3 mmBtu/hr	Rule 62-4.070(3), F.A.C.	4-hour, by Appendix ASME [n]

a. NO_X BACT limit in lb/mmBtu will ensure compliance with NSPS Subpart Db NO_X limit of 0.20 lb NO_X/mmBtu.
b. SO_2 BACT limit in lb/mmBtu will ensure compliance with NSPS Subpart Db SO_2 limit of 0.20 lb SO_2/mmBtu.
c. Initial emission rate during 24 month Ox-cat catalyst lifetime testing. After 24-month period, the CO limit may be lowered depending on catalyst lifetime testing results and CEMS emission data.
d. The limit is subject to CEMS data exclusion for startup, shutdown and malfunction.
e. SAM emission limit equals 6.82 TPY and thereby avoids the 7 TPY emission threshold that would require a BACT determination.
f. Individual HCl and HF mass emission limits to provide reasonable assurance that the annual emissions of all HAP from the HEF facility will be less than 25 TPY.
g. Sum (Σ) of the following HAP: HCl, HF, organic HAP [C_2H_4O (acetaldehyde), C_3H_4O (acrolein), C_6H_6 (benzene), $C_{24}H_{38}O_4$ (Bis(2-ethylhexyl)phthalate), Cl_2 (chlorine), CH_2O (formaldehyde), C_8H_8 (styrene), C_7H_8 (toluene), PAH/POM (polycyclic aromatic hydrocarbon/polycyclic organic matter)] and metal HAP [Cr (chromium), Pb (lead), Mn (manganese), Ni (nickel)].
h. During each Federal fiscal year (October 1 to September 30), the emission limit is the HCl, HF, organic and metal HAP emission rates in TPY from a stack tests during the same fiscal year. While the Ox-cat catalyst system is installed, organic HAP stack testing shall be conducted annually. If the Ox-cat system is removed as a result of catalyst poisoning, quarterly organic HAP testing is required. If required, quarterly organic HAP tests shall be averaged for each fiscal year.
i. Filterable fraction as measured by EPA Method 5. By meeting this BACT emission limit, the 0.2 lb/mmBtu limit of Rule 62-296.410, F.A.C., Carbonaceous Fuel Burning Equipment, the limit of 0.03 lb/mmBtu of 40 CFR 63, Subpart JJJJJJ and the limit of 0.03 lb/mmBtu of NSPS Subpart Db will also be met.
j. During startups, shutdowns and malfunction the following limits apply: 20% opacity (6-minute blocks) except for one 6-minute block per hour of 27%. By meeting the VE BACT standard the 30% opacity except that 40% opacity for no more than 2 minutes in any hour of Rule 62-296.410, F.A.C., Carbonaceous Fuel Burning Equipment and the VE standard the 20% opacity except that 27% opacity for no more than 6 minutes in any hour of NSPS Subpart Db will also be met.
k. Initial emission rate during 24 month Ox-cat catalyst lifetime testing. After 24-month period, the VOC limit may be lowered depending on catalyst lifetime testing results and stack test emission results.
l. NH_3 slip in parts per million by dry volume at 7% oxygen (ppmvd @ 7% O_2).
m. Except for initial and annual HCl and HF stack test emission rates, 24-hour average heat input rate of 488 mmBtu/hr in conjunction with lb/mmBtu limits obviates the need for lb/hr emission limits. The 4-hour average of 504.3 mmBtu/hr input is included as a limit to ensure the validity of air modeling results.
n. With the approval of the Compliance Authority, the Permittee may use the method given in 40 CFR 75, Appendix. F to calculate the boiler heat input rate.

[Application No. 0550063-001-AC; Rule 62-212.400(10) (PSD), Control Technology Review; and 40 CFR 60, Subpart Db]

14. 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 and opacity from the biomass boiler stack in a manner sufficient to demonstrate continuous compliance with the CEMS-based and COMS-based emission standards in **Condition 13** 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 opacity emission limit (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 B and F in 40 CFR 60.

   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 B and F in 40 CFR 60.

   {Permitting Note: While the NO_X and SO_2 CEMS shall be operated and maintained in accordance with the requirements of 40 CFR Part 75, this emission unit is not subject to the requirements of the Acid Rain Program.}

   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. 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, EPA Method Other Test Method (OTM) 22 or alternative specifications approved by the Department. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, EPA Method OTM 22 or alternative procedures approved by the Department. A Data Assessment Report 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 320 as detailed in Appendix A of 40 CFR 63. The HCl monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards. Approval of specific initial performance specifications and quality QA procedures must be provided to the Department prior to installation and operation of the CEMS.

   e. *COMS*: In accordance with 40 CFR 60.48b(a) the permittee shall install, calibrate, operate and maintain a COMS 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 Appendix B and F of 40 CFR 60.

   [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

15. 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.]

16. 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. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.].

17. Emission Limit Compliance and Excess Emissions: Because of the long-term nature of the NO_X and SO_2 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.]

18. Excess Emissions Allowed for CO: As specified in this condition, excess emissions resulting from startup, shutdown and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. CO emission data exclusions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the specific cases listed below. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal or electronic mail.

    a. *Cold Startup*: For a cold startup of the boiler-steam turbine system, CO emission data exclusions shall not exceed six hours in any 24-hour period. A cold "startup of the steam turbine system" is defined as startup of the boiler following a shutdown lasting at least 24 hours.

    b. *Warm Startup*: For a warm startup of the boiler-steam turbine system, CO emission data exclusions shall not exceed three hours in any 24-hour period. A warm "startup of the steam turbine system" is defined as startup of the boiler following a shutdown lasting less than least 24 hours.

    c. *Shutdown*: For shutdown of the boiler, CO emission data exclusions shall not exceed two hours in any 24-hour period. Shutdown is defined as the cessation of the operation of the boiler for any purpose after steam generation drops below 100,000 lb/hr.

19. Excess Emissions Allowed – Opacity Requirements: As provided by the authority in Rule 62-210.700(5), F.A.C., the following condition supersedes the provisions in Rule 62-210.700(1), F.A.C. 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

20. Boiler Performance Test: Within 180 days of first fire on the primary fuel (sugarcane or sweet sorghum bagasse) with natural gas used for flame stabilization, the HEF facility shall conduct a test to determine the boiler thermal efficiency. Within 180 days of first fire with sugarcane or sweet sorghum bagasse as the primary fuels and biomass (energy crops, wood chips and vegetative debris) as a supplemental fuel with natural gas for flame stabilization, the HEF facility shall conduct a test to determine the boiler thermal efficiency. Each test shall be conducted in general 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 specified fuels with as close of fuel mix and heating values to the boiler design fuel mix and heating values 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 fuel firing rate (in tons per hour and cubic feet per minute as appropriate) shall be calculated and recorded based on the steam parameters. Samples of the as-fired sugarcane or sweet sorghum bagasse and energy crops, wood chips and vegetative debris shall be analyzed for the heating value (Btu/lb) and moisture content (%). The actual heat input rate (mmBtu/hour) shall be determined using the method given in **Specific Condition 21** below. 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. [Rule 62-4.070(3), F.A.C.]

21. Boiler Heat Input Rate Calculation: The permittee shall use the thermal efficiency method in **Specific Condition 4** of this subsection to calculate the boiler heat input rate. The procedure given in Appendix ASME of this permit shall be used to measure the boiler efficiency. As an alternative, the procedures given in Appendix F of this permit may be used to calculate boiler heat input. If used, Section 5 of Appendix F of 40 CFR 75 provides a methodology for calculation of the heat input rate to a boiler using F-Factors. The applicable portions of 40 CFR 75 for the calculation of the heat input rate to the biomass boiler at the HEF facility is contained in Appendix F of this permit. This procedure may be used to calculate the heat input rate in mmBtu/hr to the biomass boiler. [Rule 62-4.070(3), F.A.C.; Reasonable Assurance]

22. Initial, Quarterly and Annual Stack Tests:
    a. *Acid Gas (HCl and HF) and Cl_2 HAP*: In accordance with test methods specified in this permit, the biomass boiler shall be tested to demonstrate initial compliance with the emission standards for HCl, HF and Cl_2 given in **Specific Condition 13** of this subsection. The tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after the initial startup of the boiler. Relative Accuracy Test Audit (RATA) test for the HCl CEMS can constitute the initial stack tests for this pollutant. Compliance stack tests for HF and Cl_2 shall also be conducted once 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 either sugarcane or sweet sorghum bagasse as the primary fuel. CEMS data for CO, NO_X, SO_2 and HCl along with COMS data for opacity shall be reported for each run of the required HF stack test.
    b. *Organic HAP*: In accordance with test methods specified in this permit, the biomass boiler shall be tested to demonstrate initial compliance with the organic HAP emission standards given in **Specific Condition 13** of this subsection. The tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after the initial startup of the boiler. If the Ox-cat system is installed, compliance stack tests for organic HAP shall also be conducted once during each federal fiscal year (October 1st to September 30th). If the Ox-cat system is removed due to catalyst poisoning, organic HAP compliance stack tests shall be conducted quarterly during each federal fiscal year. Tests shall be conducted between 90% and 100% of the maximum heat input rate when firing sugarcane or sweet sorghum bagasse as the primary fuel and biomass (energy crops, wood chips and vegetative debris) as a supplemental fuel. Tests shall be conducted between 90% and 100% of the maximum heat input rate when firing either sugarcane or sweet sorghum bagasse as the primary fuel. CEMS data for CO, NO_X and SO_2 along with COMS data for opacity shall be reported for each run of the required organic HAP stack tests
    c. *Other Pollutants and Metal HAP*: In accordance with test methods specified in this permit, the biomass boiler shall be tested to demonstrate initial compliance with the emission standards for PM, VOC, SAM, anhydrous ammonia slip (NH_3) and metal HAP given in **Specific Condition 13** of this subsection. RATA test for CEMS can constitute initial stack tests for these pollutants. The tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after the initial startup of the boiler. Subsequent compliance stack tests for ammonia slip, SAM, PM, VOC and metal HAP 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 and SO_2 along with COMS data for opacity shall be reported for each run of the required stack tests for ammonia slip, SAM, PM, VOC and metal HAP.

[Rules 62-212.400(5)(c) and 62-297.310(7)(a) and (b), F.A.C.; and 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.}

23. 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	Determination of Particulate Matter Emissions from Stationary Sources
6C	Measurement of SO_2 Emissions (Instrumental)
7E	Measurement of NO_X Emissions (Instrumental)
8	Determination of Sulfuric Acid and Sulfur Dioxide Emissions from Stationary Sources
9	Visual Determination of 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 total hydrocarbons (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 Halide and Halogen Emissions from Stationary Sources (Non-Isokinetic Method)
26A	Determination of Hydrogen Halide and Halogen Emissions from Stationary Sources (Isokinetic Method)
29	Metals 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 and the Office of Permitting and Compliance. [Rules 62-204.800, F.A.C. and 40 CFR 60, Appendix A]

OTHER MONITORING REQUIREMENTS

24. Steam Parameters: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain continuous monitoring and recording devices on the biomass boiler for the following parameters: feedwater temperature and pressure, steam temperature (°F), steam pressure (psig) and steam production rate (lb/hour). In addition, the hourly heat input rate to the biomass boiler shall be recorded and reported. 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.]

25. Fuel Flow Meter: A fuel flow meter shall be installed on the biomass boiler to record the amount of natural gas used in the boiler on a monthly and 12-month rolling average basis.
[Rule 62-4.070(3), Reasonable Assurance]

26. SNCR Urea or NH_3 Injection Rate: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a flow meter to measure and record the urea or NH_3 injection rate for the SNCR system for the biomass boiler. The permittee shall document the general range of urea or NH_3 flow rates required to meet the NO_X standard over the range of load conditions by comparing NO_X emissions with urea or NH_3 flow rates. During NO_X CEMS downtimes or malfunctions, the permittee shall operate at a urea or NH_3 flow rate that is consistent with the documented flow rate for the given load condition. Urea or NH_3 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

27. 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). Results from any HAP emission rate stack tests conducted during the period addressed by the stack test report shall be included.
[Rule 62-4.070(3), F.A.C.]

28. Monthly Operations Summary: By the tenth calendar day of each month, the permittee shall record the following parameters for the biomass boiler in a written or electronic log for the previous month of operation: hours of operation, tons of sugarcane and sweet sorghum bagasse, tons of supplemental biomass and cubic feet of natural gas, pounds of steam, total heat input rate and the updated 12-month rolling totals for each of these operating parameters. Cubic feet of natural gas used shall be recorded in a written or electronic log for the previous month of operation along with the updated 12-month rolling total. 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.]

29. Annual CO, NO_X, SO_2, HCl, HF, Organic HAP and Opacity Emissions Report: Within 30 days following the end of each federal fiscal year (October 1st to September 30th), the permittee shall submit a report to the Compliance Authority summarizing CO, NO_X, SO_2, HCl, and organic HAP (if Ox-cat system is removed) 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.]

This section of the permit addresses the following emissions units.

ID No.	Emission Unit Description
003	*Cooling Towers*: The HEF facility will have up to three mechanical draft cooling towers. The cooling towers will be used for the cooling of miscellaneous machinery, the condensing set and the process equipment used in ethanol production at the HEF facility. [Application No. 0550063-001-AC]

EQUIPMENT

1. Cooling Towers: The permittee is authorized to construct up to three cooling towers to provide cooling to miscellaneous machinery, the condensing set and process equipment used in ethanol production at the HEF facility. Typical design parameters for the cooling towers are: one cell with a stack height of 35 feet, a circulating water flow rate of 34,000 gallons per minute (gpm), a temperature of 77 °F and a design drift rate of 0.001%. [Application No. 0550063-001-AC and 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). [Application No. 0550063-001-AC and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

3. Total Dissolved Solids (TDS): The makeup water used in the cooling towers shall contain no more than 500 parts per million by weight (ppmw) of TDS on an annual basis. The makeup water in the cooling towers must be tested weekly for TDS using any of the five approved methods in 40 CFR, Part 136. These methods are: US EPA 160.2; US Geological Survey Method I-3765-85; Standard Method 2540 D 18th Edition; Standard Method 2540 D 19th Edition; and Standard Method 2540 D 20th Edition. Records of each test must be kept on site and made available to the Compliance Authority upon request. [62-4.070(3), F.A.C. Reasonable Assurance]

EMISSIONS STANDARDS

4. Drift Rate: Within 60 days of commencing operation, the permittee shall certify that the cooling towers were constructed to achieve the specified drift rate of no more than 0.001% of the circulating water flow rate. [Rule 62-212.400(BACT), F.A.C.]

   {Permitting Note: The applicant estimates PM and PM_{10} emission from the cooling towers to be 0.37 and 0.19 TPY, respectively.}

5. VOC Emissions: 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 from miscellaneous machinery and process equipment cooling towers and analyze it for VOCs to enable the early detection of leaking heat exchangers and thereby minimizing VOC emissions from the cooling towers.
   [Application No. 0550063-001-AC; Rules 62-210.200 (PTE), 62-212.400(BACT) and 62-4.070, F.A.C. Reasonable Assurance; 40 CFR 60 NSPS, Subpart VVa]

   {Permitting Note: These work practice standards are established as BACT for PM/PM_{10} and VOC emissions from the cooling towers.}

TESTING AND MONITORING REQUIREMENTS

6. VOC Cooling Water Monitoring Plan: A monitoring plan in compliance with NSPS Subpart VVa detailing how the cooling tower water shall be monitored for VOC contamination from leaking heat exchangers as required by **Specific Condition 5** above shall be submitted to the Compliance Authority for approval no later than 180 days before the HEF facility becomes operational.
   [Application No. 0550063-001-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. VOC Water Testing Frequency: Testing of the cooling water shall be conducted weekly unless VOC contamination is found during one of the weekly tests as compared to the baseline VOC concentration of the makeup water. Then daily testing will be required until the mechanical leak is corrected and no VOC contamination is detected in the cooling tower water as compared to the makeup water baseline. [Application No. 0550063-001-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. Notification: The permittee shall notify the Compliance Authority in writing within one working day after VOC contamination of the cooling tower water is discovered. Additionally, the permittee shall submit a plan to correct the problem within 7 calendar days for the approval of the Compliance Authority. [Application No. 0550063-001-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

9. Monitoring Test Reports: The permittee shall prepare and submit reports for all required monitoring tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit, including descriptions of any VOC contamination discovered and the corrective action taken. [Rule 62-297.310(8), F.A.C.]

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
004	<u>Ethanol Production Process</u>: The maximum design ethanol production rate is 120,000 gallons per day (gpd) and 36 MGPY. This emission unit consists of the following major processes: *Juice Filtration and Juice Evaporation*: After the juice extraction step described in subsection 3A is completed, the juice is pumped to a juice screen which separates fine particles prior to evaporation. Fine particles are recycled into the diffuser where they ultimately become part of the bagasse. The screened juice is then sent to the juice storage tank. The juice pH is adjusted as necessary to control corrosion. The evaporation process concentrates the sucrose juices extracted in the diffuser. The extracted juice is pumped from the juice storage tank to a multiple effect evaporator, where the juice is concentrated from 14% to 22% total solids. *Pre-Fermentation and Fermentation*: During fermentation, sugars contained in the concentrated juice are transformed to ethyl alcohol, CO_2 and various secondary products utilizing yeast. The fermentation process is a four-step continuous fermentation preceded by an agitated pre-fermenter, which serves as a yeast propagator and to initially acclimate the yeast to the fermentation conditions. Sulfuric acid is used to adjust the pH. The cooled, concentrated juice along with the yeast and urea (added as a nutrient) are fed to the pre-fermenter. The pre-fermenter continuously recirculates the ferment through a heat exchanger to keep the temperature in the optimum range for fermentation. The ferment is continuously transferred from the pre-fermenter to the first fermenter based on level. There are a total of four agitated fermenters in the series, each having controlled temperature and controlled additions of urea and yeast to maintain optimum fermentation conditions. Flow is maintained from one fermenter to another based on level. The product of fermentation, called "beer," has a weak ethanol solution along with the residue of fermentation components. *Distillation*: In distillation, the filtered beer from fermentation, with an alcohol concentration of approximately 8% by weight, is distilled to approximately 96% hydrated alcohol. The alcohol stream is increased to 91% by weight of ethanol concentration in the rectifier column. Rectifier overhead vapor is sent to the molecular sieve units to further remove water to less than 0.7% by weight in the ethanol product. Propanol and fusel oils are removed from the lower section of the rectifier column and combined with the 91% ethanol vapor which goes to the molecular sieves. *Vinasse Evaporation*: The beer column bottom stillage, called vinasse, is cooled using the incoming beer as the heat sink and sent to storage. From the storage, the vinasse is evaporated to 40% solids using a combination of several waste heat sources and live steam in three sets of multiple effect evaporators. The concentrated vinasse is stored and then loaded onto trucks for shipment to be utilized for animal feed. *Dehydration*: The final stage in the ethanol production process is dehydration. Hydrated alcohol from the distillation process, at about 96% by volume alcohol, undergoes dehydration with a molecular sieve to produce ethanol at 99.3% by weight purity. The process is performed in a continuous operation where the hydrated alcohol is superheated by steam in a shell and tube heat exchanger to ensure that the ethanol stream is always in the vapor phase as it passes through molecular sieve zeolite beds. The final ethanol product is condensed, cooled and sent to the 200-proof storage tank

EQUIPMENT

The permittee is authorized to construct the following equipment used during the production of ethanol and to control VOC emissions from the process:

D. Ethanol Production Process (EU-004)

1. Juice Extraction: The permittee is authorized to construct the following major components of a juice extraction system: revolving cane and sorghum high efficiency knives; heavy-duty shredder; high speed belt conveyor; chainless horizontal diffuser; various juice receivers; juice heaters; lime mixing tank; dewatering drum; and raw juice tank.
2. Juice Treatment and Evaporation: The permittee is authorized to construct the following major components of a juice treatment and evaporation system: rotary screens; juice evaporator; and clean and foul condensate tanks.
3. Pre-Fermentation and Fermentation: The permittee is authorized to construct the following major components of a pre-fermentation and fermentation system: a sulfuric acid tank; a urea tank; yeast mixing tank; pre-fermenter; pre-fermenter cooler; fermenters; fermenter coolers; beer well tank; beer/sucrose heat exchanger; and CO_2 scrubbing column.
4. Distillation: The permittee is authorized to construct the following major components of a distillation system: beer distillation column; degassing column; degassing condenser; stripping column; rectification column; heat exchangers; fusel oil decanter; hydrated alcohol tank; CO2 washing column; and scrubber water degasser.
5. Dehydration: The permittee is authorized to construct the following major components of a dehydration system: hydrated alcohol heater; zeolite absorber (molecular sieve); condensers and coolers; filter; dehydrated alcohol holding tank; and tie-in to CO_2 scrubbing column.
6. Vinasse Evaporation: The permittee is authorized to construct the following major components of a vinasse evaporation system: multiple effect evaporators; raw and concentrated vinasse storage vessels; and a load out system.
7. Air Pollution Control Equipment: The permittee shall install one liquid scrubber to control VOC emissions from the pre-fermentation and fermentation system, and one liquid scrubber to control VOC emissions from the distillation/dehydration systems. The liquid scrubbers shall have a design control efficiency of 98% and use a liquid with additives, as necessary, that ensures this degree of control is achievable. Emissions from the pre-fermentation/fermentation liquid scrubber shall discharge through a stack with a design height of 25 ft (minimum), a design diameter of 4.9 ft (maximum) at a design exit temperature of 70 °F and a design flow rate of 4,223 acfm. Emissions from the distillation/dehydration liquid scrubber shall discharge through a vent with a flow rate of 120 acfm.

   [Application No. 0550063-001-AC; Rules 62-212.400 (BACT); 62-4.070, Reasonable Assurance and 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

8. Hours of Operation: The hours of operation of the ethanol production process are limited to 8,040 hours in any consecutive twelve month period. [Applicants Request; Rules 62-212.400 (BACT); 62-4.070, Reasonable Assurance and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

9. VOC Standard: The ethanol process emission unit shall not discharge VOC through the fermentation liquid scrubber stack in excess of 19.01 lb/hr (76.41 TPY) and through the distillation/dehydration liquid scrubber vent in excess of 2.78 lb/hr (11.19 TPY). [Application No. 0550063-001-AC; Rules 62-212.400 (BACT); 62-4.070, Reasonable Assurance and 62-210.200(PTE), F.A.C.]
10. Organic HAP Standard: The ethanol process emission unit shall not discharge organic HAP through the fermentation liquid scrubber stack and through the distillation/dehydration liquid scrubber vent in a combined amount in excess of 1.05 lb/hr (4.24 TPY). Testing of organic HAP shall include at a minimum tests for methanol, acrolein, acetone, acetaldehyde and ethyl acetate. [Application No. 0550063-001-AC; Rules 62-212.400 (BACT); 62-4.070, Reasonable Assurance and 62-210.200(PTE), F.A.C.]

TESTING REQUIREMENTS

11. Initial Compliance Tests: The fermentation liquid scrubber stack and the distillation/dehydration liquid scrubber vent shall be tested to demonstrate initial compliance with the emissions standards for VOC and HAP given in **Specific Conditions 9 and 10**, of this subsection respectively. 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. Testing shall be done using a combination of EPA Methods 18, 25, 25A and 320 or alternative methods proposed by the applicant. The permittee shall submit to the office of Permitting and Compliance no later than 180 days before the HEF facility becomes operational an organic HAP testing protocol for approval. The organic HAP testing protocol shall at a minimum identifying how the permittee intends to use the identified EPA test methods to shown compliance with the organic HAP emissions limits given in **Specific Condition 10** of this subsection. During scrubber VOC and organic HAP testing, the water temperatures of each scrubber shall be measured and recorded. [Rules 62-212.400 (BACT); 62-4.070, Reasonable Assurance; 62-210.200(PTE); and 62-297.310(7)(a)1, F.A.C.]

12. Quarterly and Annual Compliance Tests: During the first 24 months of the HEF facility operation, VOC and organic HAP testing shall be conducted annually during each federal fiscal year (October 1st to September 30th) to demonstrate compliance with the emissions standard for VOC and organic HAP given in **Specific Conditions 9 and 10**, of this subsection respectively. During scrubber VOC and organic HAP testing, the water temperatures of each scrubber shall be measured and recorded. The annual organic HAP testing shall follow the approved testing protocol described in **Specific Condition 11** of this subsection. If after 24 months, the Ox-cat system is removed due to catalyst poisoning, quarterly VOC and organic HAP testing shall be required during each subsequent federal fiscal year to demonstrate compliance with the emissions standard for VOC and organic HAP. The quarterly organic HAP testing shall follow the approved testing protocol described in **Specific Condition 11** of this subsection. If the Ox-cat system is not removed, VOC and organic HAP testing shall continue on an annual basis during each federal fiscal year. [Rules 62-212.400 (BACT); 62-4.070, Reasonable Assurance; 62-210.200(PTE); and 62-297.310(7)(a)4, F.A.C.]

13. 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.]

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

Method	Description of Method and Comments
CTM-027 320	Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy
1-4	Traverse Points, Velocity and Flow Rate, Gas Analysis and Moisture Content
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography
25	Determination of Total Gaseous Nonmethane organic Emissions as Carbon
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

15. Liquid Scrubbers Monitoring Requirements:

a. Scrubbers Operating Parameters: The permittee shall install, calibrate, operate and maintain monitoring devices that continuously measure and record the total pressure drop across each 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. The temperature of each scrubber's water shall be measured daily and recorded. All records pertaining to the scrubbers shall be provided to the compliance authority upon request.

b. Scrubbers Guarantee: Prior to installation of the scrubber, the permittee shall submit to the Compliance Authority the proposed design information, including water additives, along with a manufacturer's guarantee that the scrubbers are 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

16. 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. In addition, the test reports shall include each scrubber's water temperature during VOC and organic HAP testing and the preceding 12 monthly averages of each scrubber's water temperature. [Rule 62-297.310(8), F.A.C.]
17. Notification, Recordkeeping and Reporting Requirements: The permittee shall maintain records of the amount of ethanol produced on a daily, monthly and 12-month rolling total basis along with the feed rate (sugarcane, sweet sorghum, sweet sorghum syrup and molasses, and sugarcane syrup and molasses) into the ethanol production process emission unit on a monthly basis and 12-month rolling total 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.]

E. Storage Tanks (EU-005)

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
005	Storage Tanks: This emissions unit consists of volatile organic liquid (VOL) storage tanks for ethanol, denaturant/gasoline, and corrosion inhibitor. Up to 1 million gallons of fuel ethanol will be stored. The tanks will be internal floating roof design, except for the small corrosion inhibitor storage tank, ethanol process tanks and miscellaneous tanks.

Tanks will be used during the ethanol production process to store ethanol, byproducts and intermediate products. In addition, the purified ethanol and gasoline (denaturant) will be stored in tanks and then blended, resulting in a denatured product. The denatured ethanol product will have dedicated storage tanks. Anhydrous ammonia or urea will be stored in a tank for use in the SNCR system for boiler NO_X control. ULSD fuel oil will be stored in a tank for use in emergency equipment.

EQUIPMENT

1. The permittee is authorized to construct the following tanks to store VOL at the HEF facility:
   a. *VOL Blending and Storage Tanks*:
      - Fuel Ethanol Tank: The permittee is authorized to construct one nominal 1,000,000 gallon ethanol product storage tank with a fixed roof and internal floating roof to minimize VOC emissions per 40 CFR 60.110b(a)(2).
      - 200 Proof Ethanol Tank: The permittee is authorized to construct one nominal 100,000 gallon, 200 proof ethanol storage tank with a fixed roof and internal floating roof to minimize VOC emissions per 40 CFR 60.110b(a)(2).
      - Off-Specification Tank: The permittee is authorized to construct one nominal 100,000 gallon tank to store off-specification ethanol product with a fixed roof and internal floating roof to minimize VOC emissions per 40 CFR 60.110b(a)(2).
      - Denaturant /Gasoline Product Storage Tank: The permittee is authorized to construct one nominal 100,000 gallon denatured/gasoline storage tank with a fixed roof and an internal floating roof to minimize VOC emissions as per 40 CFR 60.110b(a)(2).
        [Application No. 0550063-001-AC and NSPS 40 CFR 60, Subpart Kb]
      - *Ethanol Production Process Tanks*: As required, the permittee is authorized to install the following storage tanks required by the ethanol production process: Fusel Oil Storage Tank; Hydrated Alcohol Storage Tank; Final Product Metering Tank; Second Grade Alcohol Storage Tank; and Fusel Oil Alcohol Storage Tank. [Application No. 0550063-001-AC]

   b. *Other Tanks*:
      - Anhydrous Ammonia or Urea Storage Tank: The permittee is authorized to construct one nominal 5,000 gallon tank to store anhydrous ammonia or urea for the SNCR system. In accordance with 40 CFR 60.130, the storage of anhydrous ammonia or urea shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.
      - ULSD Fuel Oil Storage Tank: The permittee is authorized to construct one nominal 5,000 gallon tank to store ULSD fuel oil for use in emergency equipment.
      - Sulfuric Acid Storage Tank: The permittee is authorized to construct one tank to store sulfuric acid for use in the ethanol production process to adjust pH. In accordance with 40 CFR 60.130, the storage of sulfuric acid shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.
      - Corrosion Inhibitor Tank: The permittee is authorized to construct one nominal 2,300 gallon tank to store methanol, xylene and ethylbenzene that will be used as a corrosion inhibitor at the HEF facility.

[Application No. 0550063-001-AC]

PERFORMANCE RESTRICTIONS

2. Permitted Capacity: The maximum throughput (process) rate in gallons per year for this emissions unit is 36 million gallons of pure ethanol and 37.62 million gallons of denatured ethanol product in any consecutive twelve month period. [Application No. 0550063-001-AC and Rule 62-4.070, F.A.C. Reasonable Assurance]

3. Hours of Operation: The hours of operation of this emissions unit are not restricted (8,760 hours per year). [Application No. 0550063-001-AC and Rule 62-210.200(PTE), F.A.C.]

NSPS SUBPART Kb APPLICABILITY

4. VOL Blending and Storage Tanks: The four Blending and Storage tanks at the HEF facility are subject to NSPS Subpart Kb which applies to any storage tank for which construction, reconstruction, or modification is commenced after July 23, 1984 with a capacity greater than or equal to 151 cubic meters (m^3) or 39,990 gallons that is used to store a VOL with a maximum true vapor pressure greater than or equal to 3.5 kilopascals (kPa) or 0.51 pounds per square inch (psi). The four Blending and Storage tanks each have a capacity greater than 40,000 gallons and store liquids with maximum true vapor pressures greater than 3.5 kPa and consequently are subject to and must comply with the provisions of NSPS 40 CFR 60, Subpart Kb. [Application No. 0550063-001-AC and NSPS 40 CFR 60, Subpart Kb]

5. Ethanol Production Process, Ammonia/Urea and Sulfuric Acid Storage and Corrosion Inhibitor Tanks: The five Ethanol Production Process storage tanks, the ammonia or urea storage tank, the sulfuric acid storage tank and corrosion inhibitor tank at the HEF facility are not subject to NSPS Subpart Kb. These tanks are exempt because either they have a capacity less than 75 m^3 or 19,813 gallons or they have a capacity greater than or equal to 19,813 gallons but less than 39,990 gallons (151 m^3) and store a liquid with a maximum true vapor pressure less than 15 kPa (2.18 psi). [Application No. 0550063-001-AC]

6. ULSD Fuel Oil Storage Tank: The ULSD fuel oil storage tank at the HEF facility is not subject to NSPS Subpart Kb because it has a capacity of less than 19,813 gallons (75 m^3) and stores a liquid with a maximum true vapor pressure less than 3.5 kPa (0.51 psi). [Application No. 0550063-001-AC]

EMISSIONS STANDARDS

7. VOC Standard for Blending and Storage Tanks: Emissions of VOC from the Blending and Storage tanks will be controlled by the proper construction of the tanks per 40 CFR 60.110b(a)(2) which requires internal floating roofs in the tanks or the equivalent. In lieu of internal floating roofs in the Blending and Storage tanks, HEF may use pressure relief valves provided that these meet the equivalency requirements of NSPS, Subpart Kb. If HEF decides to use pressure relief valves in lieu of internal floating roofs, it must provide to the Compliance Authority, 90 days before construction of the Blending and Storage VOL tanks commences, proof of the valves equivalency as defined in the NSPS.
[Application No. 0550063-001-AC; Rule 62-212.400 (BACT), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

8. VOC Standard for Ethanol Production Process Storage Tanks: Emissions of VOC from the Ethanol Production Process storage tanks will be controlled by the use of pressure relief valves or vapor condensers. [Application No. 0550063-001-AC; Rule 62-212.400 (BACT), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

RECORDS AND REPORTS

9. 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]

10. NSPS Subpart Kb Reporting and Recordkeeping for Blending and Storage Tanks: 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.
[Rule 62-4.070(3) F.A.C and NSPS 40 CFR 60, Subpart Kb]

This section of the permit addresses the following emissions unit.

ID No.	Emission Unit Description
006	Truck Rack Product Loadout and Flare: The denatured blended ethanol product from the VOL Blending and Storage tanks will be loaded out to tanker trucks or railcars with displaced vapors sent to a product loadout flare for destruction.

The denatured ethanol product will be loaded onto tank trucks or railcars at a maximum rate of 600 gpm. Also E-85 product (85% ethanol and 15% gasoline fuel blend) may be loaded out via in-line blending. The maximum throughput rate of denatured ethanol product is 37,620,000 gallons per year (gpy). Vapors displaced from the trucks/railcars will be combusted by a product loadout flare. The product loadout flare will have a nominal rated heat input capacity of 9.8 mmBtu/hr to control vapors displaced from the tanker trucks or railcars during the loading of the denatured ethanol product. The flare will have a design control efficiency of 98%.

EQUIPMENT

1. Loading Rack: The permittee is authorized to construct a loading rack that is designed to transfer 600 gpm (37,620,000 gpy) of denatured ethanol product or E-85 product to tanker trucks or railcars.
[Application No. 0550063-001-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/railcar loadout. The flare shall be operated with a pilot 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. 0550063-001-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/railcars during the loading of the denatured ethanol product or E-85 product. The trucks and railcars are assumed to not be in dedicated denatured ethanol product service (i.e., some trucks/railcars will have returned from delivering gasoline and gasoline vapors will be displaced). The product loadout flare will have a rated capacity of 9.8 mmBtu/hr. Natural gas or propane will be used as the fuel for the pilot flame. The pilot fame will have a rated capacity of 0.184 mmBtu/hr and will utilize natural gas.
[Application No. 0550063-0010-AC and Rule 62-210.200(PTE), F.A.C.]

4. Hours of Operation: The flare shall be operated at all times when truck or railcar loading operations are taking place. Only denatured ethanol product or E-85 product shall be loaded into the trucks or railcars. Although the hours of operation of the pilot for the flare system are not limited (8,760 hours per year) the flare itself and product loadout is limited to 3,120 hours per year. [Application No. 0550063-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

5. VE Standard: The flare shall be designed for and operated with no VE except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.
[Rule 62-4.070(3), F.A.C. and NSPS 40 CFR 60, Subpart A]

NSPS SUBPART A APPLICABILITY

6. General Control Device Requirements: The product loadout flare associated with this emission unit must meet all applicable requirements of §60.18, General Control Device Requirements.
[NSPS Subpart A and Rule 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 5** of this subsection 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. [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. [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.]

This section of the permit addresses the following emissions units.

ID No.	Emission Unit Description
007	Miscellaneous Storage Silos: Silos at HEF will be used to store lime for the water treatment system, limestone, hydrated lime or trona for the DSIS systems; urea for the SNCR (if used); and fly ash from the boiler.

The HEF will include equipment and silos for the handling and storage of dry materials.

CONSTRUCTION

1. Equipment: The permittee is authorized to construct the following silos each with a baghouse (bin vent filters) to control PM emissions:
   - One limestone, hydrated lime or trona storage silo for the DSIS;
   - One lime storage silo for the water treatment system;
   - If used in SNCR system, one urea storage silo; and
   - Fly ash storage silo.

   [Application No. 0550063-001-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. 0550063-001-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: The bin vent filter baghouses (or equivalent) for each storage silo shall be designed, installed and maintained to remove PM from the storage silos exhaust during loading operations. The baghouses shall be installed and operational before the silos become operational. The baghouses shall be designed to achieve a dust outlet loading of 0.01 gr/dscf. Depending on the final equipment selection, the permittee may demonstrate to the Permitting Authority that the final baghouse design specification is equivalent to a dust outlet loading of 0.01 gr/dscf. [Application No. 0550063-001-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. [Application No. 0550063-001-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** of this subsection. The initial test shall be conducted within 180 days after initial operation.
   [Application No. 0550063-001-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** of this subsection. [Application No. 0550063-001-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. 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.]

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

Method	Description of Method and Comments
EPA 9	Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources (60 Minute Test)

RECORDS AND REPORTS

9. 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.]

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
008	One emergency generator rated at 2,000 kilowatts (kW) or 2,682 horsepower (hp) and one emergency diesel fire pump engine rated at 600 hp (448 kW)

One emergency generator rated at 2,000 kW will be installed to provide backup electrical power in the event of a power outage at the HEF facility. The generator will fire ULSD fuel oil or natural gas and will be limited to 500 hours per year of operation during emergencies. The 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 US EPA's emission standards listed in 40 CFR Part 60 Subpart IIII for model year 2006 or later.

One 600 hp diesel fire pump engine will be installed to provide firewater during power outages. This unit will fire ULSD fuel oil or natural gas 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 US EPA's emission standards listed in 40 CFR Part 60 Subpart IIII for model year 2009 or later.

EQUIPMENT

1. Emergency Generator: The permittee is authorized to install, operate and maintain one 2,000 kW or less emergency generator. [Application No. 0550063-001-AC and Rule 62-210.200 (PTE), F.A.C.]
2. Diesel Engine Driven Fire Pump Engine: The permittee is authorized to install, operate and maintain one diesel engine driven fire pump engine of 600 hp or less.
   [Application No. 0550063-001-AC and Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

3. Hours of Operation: The emergency generator and fire pump engine may operate in response to emergency conditions for up to 500 hours per year and 100 non-emergency hours per year for generator maintenance and testing purposes.
   [Application No. 0550063-001-AC; Rule 62-210.200 (PTE), F.A.C. and NSPS 40 CFR 60, Subpart IIII]
4. Authorized Fuel: These units shall fire ULSD fuel oil or natural gas. The ULSD fuel oil shall contain no more than 0.0015% sulfur by weight.
   [Application No. 0550063-001-AC; Rule 62-210.200 (PTE), F.A.C. and NSPS 40 CFR 60, Subpart IIII]

EMISSION STANDARDS

5. Emergency Generator Emissions Limits: The emergency generator shall comply with the following emission limits and demonstrate compliance in accordance with the procedures given in NSPS 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. [40 CFR 60.4211 and Rule 62-4.070(3), F.A.C.]

Source (model year)	CO (g/KW-hr)	PM (g/KW-hr)	SO_2[a] (% S)	Hydrocarbons (g/KW-hr)	NO_X (g/KW-hr)
Subpart IIII (2006 and later)	3.5	0.20	0.0015	6.4 (NMHC[b]+NO_X)	

a. SO_2 emission standard will be met by using biodiesel or ULSD fuel oil in the emergency generator with vendor certification of sulfur content of 0.0015% or less.
b. NMHC means Non-Methane Hydrocarbons.

[Application No. 0550063-001-AC; NSPS 40 CFR 60, Subpart IIII and Rule 62-4.070(3), F.A.C.]

6. Emergency Fire Pump Engine Emissions Limits: The emergency fire pump engine shall comply with the following emission limits and demonstrate compliance in accordance with the procedures given in NSPS 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)	SO_2[a] (% S)	NMHC[b] + NO_X (g/hp-hr)	PM (g/hp-hr)
Subpart IIII (2009 or later)	2.6	0.0015	3.0	0.15

a. SO_2 emission standard will be met by using biodiesel or ULSD fuel oil in the emergency generator with vendor certification of sulfur content of 0.0015% or less.
b. NMHC means Non-Methane Hydrocarbons.

[Application No. 0550063-001-AC; NSPS 40 CFR 60, Subpart IIII and Rule 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

7. 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

8. NSPS Subpart IIII Applicability: The emergency generator and the fire diesel fire pump engine 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

9. NESHAPS Subpart ZZZZ Applicability: The emergency generator and the diesel fire pump engine are Liquid Fueled RICE and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the generator and engine 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)]

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
009	Facility-Wide Fugitive VOC Emission Leaks: This emission unit consists of the fugitive VOC emissions from equipment leaks involved in the ethanol production process and associated processes at the HEF facility. Total fugitive VOC emissions from equipment leaks at the HEF facility were estimated to be 6.52 TPY. Total HAP emissions from equipment leaks at the HEF facility were estimated to be 0.33 TPY. To minimize VOC fugitive emissions, HEF shall implement a monthly LDAR program. The plan to implement the LDAR program shall be approved by the Compliance Authority in accordance with NSPS 40 CFR Part 60, Subpart VVa. The following emission units are either subject to the requirements of NSPS 40 CFR Part 60, Subpart VVa and must be addressed in the LDAR program plan or addressed by the plan as part of the BACT to minimize emissions of VOC from the HEF facility: • *EU-003: Cooling Towers;* • *EU-004: Ethanol Production Process;* • *EU-005: Storage Tanks; and* • *EU-006: Truck Rack Product Loadout and Flare.*

NSPS SUBPART VVa

1. LDAR Program: HEF is subject to NSPS 40 CFR 60, Subpart VVa - VOC Equipment Leaks in the SOCMI, for projects that commence construction or modifications after November 7, 2006. NSPS Subpart VVa requires a LDAR program. HEF must demonstrate 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 2 of this permit, a list of all the pumps, compressors, pressure relief devices in gas/vapor service, sampling connection systems, open-ended valves or lines and valves at HEF that are subject to NSPS Subpart VVa must be submitted to the Compliance Authority no later than 90 days prior to commencing operation.
[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 2 of this permit, the permittee must submit for approval a final LDAR program plan no later than 90 days prior to commencing operation. Once the program plan is approved by the Compliance Authority, the permittee shall implement the program within 180 days of initial startup of the HEF. A preliminary LDAR program plan is contained in Appendix LDAR of this permit. [40 CFR 60, Subpart VVa ; Application No. 0550063-001-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. 0550063-001-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 demonstrate that the HEF facility is in compliance with the requirements of NSPS Subpart VVa following the test methods and procedures specified in §60.485a. [Application No. 0550063-001-AC; Rule 62-210.200(PTE), F.A.C.; Rule 62-4.070(3), F.A.C. Reasonable Assurance and NSPS, Subpart VVa]

RECORDS AND REPORTS

6. NSPS VVa Recordkeeping Requirements: The permittee shall follow the recordkeeping requirements specified in §§60.486a to show compliance with NSPS Subpart VVa and submit the records to the Compliance Authority 180 days after the initial startup of the HEF and annually thereafter. [Application No. 0550063-001-AC; Rule 62-210.200(PTE), F.A.C.; Rule 62-4.070(3), F.A.C. Reasonable Assurance and NSPS, Subpart VVa]

CONTENTS

SECTION 4. APPENDIX ASME

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

Below is the form from the American Society of mechanical Engineers (ASME) that may be used by HEF, with concurrence of the Compliance Authority, to calculate the heat input rate (mmBtu/hr) into the biomass boiler as required by **Specific Condition 4 of Subsection 3-B** of this permit.

PTC 4.1-b (1964)

ASME TEST FORM
CALCULATION SHEET — FOR ABBREVIATED EFFICIENCY TEST — *Revised September, 1965*

	OWNER OF PLANT	TEST NO.	BOILER NO.	DATE
30	HEAT OUTPUT IN BOILER BLOW-DOWN WATER = LB OF WATER BLOW-DOWN PER HR × $\left[\frac{\text{ITEM 15} - \text{ITEM 17}}{1000}\right]$ = ... 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 = $\frac{11CO_2 + 8O_2 + 7(N_2 + CO)}{3(CO_2 + CO)} \times$ (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 × 100 =	LOSS %
65	HEAT LOSS DUE TO DRY GAS = LB DRY GAS PER LB AS FIRED FUEL × C_p × ($t_{lvg} - t_{air}$) = $\frac{\text{ITEM 25}}{\text{Unit}} \times 0.24$ (ITEM 13) − (ITEM 11) = ...	......	$\frac{65}{41} \times 100 =$	......
66	HEAT LOSS DUE TO MOISTURE IN FUEL = $\frac{\text{LB } H_2O \text{ PER LB}}{\text{AS FIRED FUEL}}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = $\frac{\text{ITEM 37}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) − (ENTHALPY OF LIQUID AT T ITEM 11)] = ...	......	$\frac{66}{41} \times 100 =$	......
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2 = $9H_2$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = 9 × $\frac{\text{ITEM 44}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) − (ENTHALPY OF LIQUID AT T ITEM 11)] = ...	......	$\frac{67}{41} \times 100 =$	......
68	HEAT LOSS DUE TO COMBUSTIBLE IN REFUSE = ITEM 22 × ITEM 23 = ...	......	$\frac{68}{41} \times 100 =$	......
69	HEAT LOSS DUE TO RADIATION* = $\frac{\text{TOTAL BTU RADIATION LOSS PER HR}}{\text{LB AS FIRED FUEL} - \text{ITEM 28}}$	......	$\frac{69}{41} \times 100 =$	......
70	UNMEASURED LOSSES **	......	$\frac{70}{41} \times 100 =$	......
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 90 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) Daily observations of the conveyor systems and associated drop point integrity to identify any equipment abnormalities. 5) Plant personnel shall be trained on identification of warning signs for potential equipment malfunction. 6) Signs shall be posted identifying potential warning signs of equipment malfunction. 7) Procedures shall be established for defining excessive fugitive dust from 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. 8) All major roadways at the plant shall be paved. 9) Plant gravel areas shall be wetted during dry conditions, as required, to minimize fugitive dust emissions. 10) Mud, dirt or similar debris shall be removed promptly from the paved roads by vacuum sweeping or watering. 11) Plant personnel shall be trained on recognizing conditions of excessive dust on paved roads. 12) All silos shall be equipped with vent filters. 13) When required to meet the opacity standard for the Biomass Material Handling and Preparation emission unit, dust collector shall be installed at all biomass drop and transfer points.
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 warning signs of excessive fugitive dust. 3) Mechanical moving of supplemental biomass by front end loaders and other supporting equipment shall be minimized on high wind event days. 4) Odors are minimized with first in, first out supplemental biomass utilization implemented. 5) Daily visual observations of the supplemental biomass storage areas shall be performed, and if conditions are favorable for fugitive dust formation, procedures from the fugitive dust plan shall be implemented.

BEST MANAGEMENT PRACTICES (BMP) PLAN

Best Management Practice – Fire Prevention /Spontaneous Combustion Minimization	1) Contact local fire marshal to develop fire management plan. Plan shall be 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) Reclaiming supplemental biomass shall be performed 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 biomass boiler will consist of sugarcane bagasse, sweet sorghum bagasse and supplemental biomass (energy crops, wood chips, and vegetative debris) that will be stored in designated areas. The primary biomass (bagasse) will normally be sent directly to the biomass boiler when the ethanol production process is operating. The excess bagasse and supplemental biomass will be placed in segregated storage areas, and when required will be sent directly to the biomass boiler. 2) The permittee will contract for biomass that specifically meets the definition of clean wood chips and vegetable debris and bagasse as identified below: • Wood chips and vegetative debris 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 and yard waste. 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 sugarcane and sweet sorghum and cannot contain any other vegetative. 3) The permittee shall include within their contracts with suppliers a provision that limits the content of field residue (non-stalk parts such as plant leaves and tops) within deliveries of sorghum stalks to 8 percent by weight. 4) The permittee shall not obtain sugarcane and sorghum field residue for the purpose of use as a fuel for the biomass boiler at the HEF facility. 5) The supplemental biomass feedstock will be delivered to the HEF in vehicles designed to prevent release of fugitive dust. 6) For each shipment of biomass, the permittee shall record the date, quantity and a description of the material received. 7) 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. 8) The permittee shall maintain records of rejected shipments and disposition thereof. Such records shall be made available to the Department upon request.

Best Management Practice – Quality Assurance of Biomass	9) Prohibited Materials: The following items are not considered woody biomass and are expressly prohibited: a. those materials that are prohibited by state or federal law; b. plastics; c. woody biomass that has been chemically treated or processed; d. municipal solid waste; e. paper; f. treated wood such as CCA or creosote; g. painted wood; and h. wood wastes from landfills.

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.}

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 19** 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.

b. *Rolling 12-month Average*: Compliance shall be determined after each operating month by calculating the arithmetic average of all the valid hourly averages in that month and then calculating the arithmetic average of that operating month with the preceding 11 operating month averages in units of tons per year.

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 18 of Subsection 3 B** of this permit, limited amounts of CEMS and 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

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 HEF project. Parts that are critical to the HEF 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_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO_2 emission 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 performance 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_2 sample 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_2 concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the SO_2 and either O_2 or CO_2 concentrations shall both be monitored at the inlet and outlet of the SO_2 control device. If the owner or operator has installed and certified SO_2 and O_2 or 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_2 data 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_2 control 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

40 CFR 75, APPENDIX F, SECTION 5 – MEASUREMENT OF BOILER HEAT INPUT RATE

{Permitting Note: This is the section (Section 5) of Appendix F of 40 CFR 75 including the F-Factor Table for fuels that deals with the calculation of the heat input rate to a steam generating boiler. This procedure is utilized by boilers that fall under the Acid Rain program. This is the procedure that HEF may utilize instead of the ASME procedure given in Appendix ASME to calculate the heat input rate to the biomass boiler. To access the full version of 40 CFR 75, Appendix F, follow the link at the end of this appendix.}

6. Procedures for Heat Input

Use the following procedures to compute heat input rate to an affected unit (in mmBtu/hr or mmBtu/day):

5.1 Calculate and record heat input rate to an affected unit on an hourly basis, except as provided in sections 5.5 through 5.5.7. The owner or operator may choose to use the provisions specified in §75.16(e) or in section 2.1.2 of appendix D to this part in conjunction with the procedures provided in sections 5.6 through 5.6.2 to apportion heat input among each unit using the common stack or common pipe header.

5.2 For an affected unit that has a flow monitor (or approved alternate monitoring system under subpart E of this part for measuring volumetric flow rate) and a diluent gas (O_2 or CO_2) monitor, use the recorded data from these monitors and one of the following equations to calculate hourly heat input rate (in mmBtu/hr).

5.2.1 When measurements of CO_2 concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F_c} \frac{\%CO_{2w}}{100} \qquad (Eq.\ F\text{-}15)$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F_c = Carbon-based F-factor, listed in section 3.3.5 of this appendix for each fuel, scf/mmBtu.

$\%CO_{2w}$ = Hourly concentration of CO_2 during unit operation, percent CO_2 wet basis.

5.2.2 When measurements of CO_2 concentration are on a dry basis, use the following equation:

$$HI = Q_h \left[\frac{(100 - \%H_2O)}{100 F_c}\right]\left(\frac{\%CO_{2d}}{100}\right) \qquad (Eq.\ F\text{-}16)$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F_c = Carbon-based F-Factor, listed in section 3.3.5 of this appendix for each fuel, scf/mmBtu.

$\%CO_{2d}$ = Hourly concentration of CO_2 during unit operation, percent CO_2 dry basis.

$\%H_2O$ = Moisture content of gas in the stack, percent.

5.2.3 When measurements of O_2 concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F} \frac{\left[(20.9/100)(100 - \%H_2O) - \%O_{2w}\right]}{20.9} \qquad (Eq.\ F\text{-}17)$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F = Dry basis F-factor, listed in section 3.3.5 of this appendix for each fuel, dscf/mmBtu.

$\%O_{2w}$= Hourly concentration of O_2 during unit operation, percent O_2 wet basis. For any operating hour where Equation F–17 results in an hourly heat input rate that is ≤ 0.0 mmBtu/hr, 1.0 mmBtu/hr shall be recorded and reported as the heat input rate for that hour.

$\%H_2O$ = Hourly average stack moisture content, percent by volume.

5.2.4 When measurements of O_2 concentration are on a dry basis, use the following equation:

$$HI = Q_w \left[\frac{(100 - \%H_2O)}{100\,F}\right]\left[\frac{(20.9 - \%O_{2d})}{20.9}\right] \quad (Eq.\ F\text{-}18)$$

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w= Hourly average volumetric flow during unit operation, wet basis, scfh.

F = Dry basis F-factor, listed in Table 1 at the end of this of this appendix for each fuel, dscf/mmBtu.

$\%H_2O$ = Moisture content of the stack gas, percent.

$\%O_{2d}$= Hourly concentration of O_2 during unit operation, percent O_2 dry basis.

5.3 Heat Input Summation (for Heat Input Determined Using a Flow Monitor and Diluent Monitor)

5.3.1 Calculate total quarterly heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_q = \sum_{hour=1}^{n} HI_i t_i \quad (Eq.\ F\text{-}18a)$$

Where:

HI_q= Total heat input for the quarter, mmBtu.

HI_i= Hourly heat input rate during unit operation, using Equation F–15, F–16, F–17, or F–18, mmBtu/hr.

t_i= Hourly operating time for the unit or common stack, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

5.3.2 Calculate total cumulative heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_c = \sum_{q=1}^{\text{the current quarter}} HI_q \quad (Eq.\ F\text{-}18b)$$

Where:

HI_c= Total heat input for the year to date, mmBtu.

HI_q= Total heat input for the quarter, mmBtu.

5.4 [Reserved]

5.5 For a gas-fired or oil-fired unit that does not have a flow monitor and is using the procedures specified in appendix D to this part to monitor SO_2 emissions or for any unit using a common stack for which the owner or operator chooses to determine heat input by fuel sampling and analysis, use the following procedures to calculate hourly heat input rate in mmBtu/hr. The procedures of section 5.5.3 of this appendix shall not be used to determine heat input from a coal unit that is required to comply with the provisions of this part for monitoring, recording, and reporting NO_X mass emissions under a State or federal NO_X mass emission reduction program.

5.5.1 (a) When the unit is combusting oil, use the following equation to calculate hourly heat input rate:

$$HI_o = M_o \frac{GCV_o}{10^6} \qquad (Eq.\ F\text{-}19)$$

Where:

HI_o= Hourly heat input rate from oil, mmBtu/hr.

M_o= Mass rate of oil consumed per hour, as determined using procedures in appendix D to this part, in lb/hr, tons/hr, or kg/hr.

GCV_o= Gross calorific value of oil, as measured by ASTM D240–00, ASTM D5865–01a, or ASTM D4809–00 for each oil sample under section 2.2 of appendix D to this part, Btu/unit mass (all incorporated by reference under (§75.6 of this part).

10^6 = Conversion of Btu to mmBtu.

(b) When performing oil sampling and analysis solely for the purpose of the missing data procedures in §75.36, oil samples for measuring GCV may be taken weekly, and the procedures specified in appendix D to this part for determining the mass rate of oil consumed per hour are optional.

5.5.2 When the unit is combusting gaseous fuels, use the following equation to calculate heat input rate from gaseous fuels for each hour:

$$HI_g = \frac{(Q_g \times GCV_g)}{10^6} \qquad (Eq.\ F\text{-}20)$$

Where:

HI_g= Hourly heat input rate from gaseous fuel, mmBtu/hour.

Q_g= Metered flow rate of gaseous fuel combusted during unit operation, hundred standard cubic feet per hour.

GCV_g= Gross calorific value of gaseous fuel, as determined by sampling (for each delivery for gaseous fuel in lots, for each daily gas sample for gaseous fuel delivered by pipeline, for each hourly average for gas measured hourly with a gas chromatograph, or for each monthly sample of pipeline natural gas, or as verified by the contractual supplier at least once every month pipeline natural gas is combusted, as specified in section 2.3 of appendix D to this part) using ASTM D1826–94 (Reapproved 1998), ASTM D3588–98, ASTM D4891–89 (Reapproved 2006), GPA Standard 2172–96 Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis, or GPA Standard 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, Btu/100 scf (all incorporated by reference under §75.6 of this part).

10^6 = Conversion of Btu to mmBtu.

5.5.3 When the unit is combusting coal, use the procedures, methods, and equations in sections 5.5.3.1–5.5.3.3 of this appendix to determine the heat input from coal for each 24-hour period. (All ASTM methods are incorporated by reference under §75.6 of this part.)

5.5.3.1 Perform coal sampling daily according to section 5.3.2.2 in Method 19 in appendix A to part 60 of this chapter and use ASTM D2234–00, Standard Practice for Collection of a Gross Sample of Coal, (incorporated by reference under §75.6 of this part) Type I, Conditions A, B, or C and systematic spacing for sampling. (When performing coal sampling solely for the purposes of the missing data procedures in §75.36, use of ASTM D2234–00 is optional, and coal samples may be taken weekly.)

5.5.3.2 All ASTM methods are incorporated by reference under §75.6 of this part. Use ASTM D2013–01, Standard Practice for Preparing Coal Samples for Analysis, for preparation of a daily coal sample and analyze each daily coal sample for gross calorific value using ASTM D5865–01a, Standard Test Method for Gross Calorific Value of Coal and Coke. On-line coal analysis may also be used if the on-line analytical instrument has been demonstrated to be equivalent to the applicable ASTM methods under §§75.23 and 75.66.

5.5.3.3 Calculate the heat input from coal using the following equation:

$$HI_c = M_c \frac{GCV_c}{500} \qquad (Eq.\ F\text{-}21)$$

(Eq. F–21)

where:

HIc = Daily heat input from coal, mmBtu/day.

Mc = Mass of coal consumed per day, as measured and recorded in company records, tons.

GCV_c= Gross calorific value of coal sample, as measured by ASTM D3176–89 (Reapproved 2002), or ASTM D5865–01a, Btu/lb. (incorporated by reference under §75.6 of this part).

500 = Conversion of Btu/lb to mmBtu/ton.

5.5.4 For units obtaining heat input values daily instead of hourly, apportion the daily heat input using the fraction of the daily steam load or daily unit operating load used each hour in order to obtain HI_i for use in the above equations. Alternatively, use the hourly mass of coal consumed in equation F–21.

5.5.5 If a daily fuel sampling value for gross calorific value is not available, substitute the maximum gross calorific value measured from the previous 30 daily samples. If a monthly fuel sampling value for gross calorific value is not available, substitute the maximum gross calorific value measured from the previous 3 monthly samples.

5.5.6 If a fuel flow value is not available, use the fuel flowmeter missing data procedures in section 2.4 of appendix D of this part. If a daily coal consumption value is not available, substitute the maximum fuel feed rate during the previous thirty days when the unit burned coal.

5.5.7 Results for samples must be available no later than thirty calendar days after the sample is composited or taken. However, during an audit, the Administrator may require that the results be available in five business days, or sooner if practicable.

5.6 Heat Input Rate Apportionment for Units Sharing a Common Stack or Pipe

5.6.1 Where applicable, the owner or operator of an affected unit that determines heat input rate at the unit level by apportioning the heat input monitored at a common stack or common pipe using megawatts shall apportion the heat input rate using the following equation:

$$HI_i = HI_{cs}\left(\frac{t_{cs}}{t_i}\right)\left[\frac{MW_i t_i}{\sum_{i=1}^{n} MW_i t_i}\right] \qquad (Eq.\ F\text{-}21a)$$

Where:

HI_i= Heat input rate for a unit, mmBtu/hr.

HI_{cs}= Heat input rate at the common stack or pipe, mmBtu/hr.

MW_i= Gross electrical output, MWe.

t_i= Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{cs}= Common stack or common pipe operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Total number of units using the common stack or pipe.

i = Designation of a particular unit.

5.6.2 Where applicable, the owner or operator of an affected unit that determines the heat input rate at the unit level by apportioning the heat input rate monitored at a common stack or common pipe using steam load shall apportion the heat input rate using the following equation:

$$HI_i = HI_{CS}\left(\frac{t_{CS}}{t_i}\right)\left[\frac{SF_i t_i}{\sum_{i=1}^{n} SF_i t_i}\right] \quad (Eq.\ F\text{-}21b)$$

Where:

HI_i= Heat input rate for a unit, mmBtu/hr.

HI_{CS}= Heat input rate at the common stack or pipe, mmBtu/hr.

SF = Gross steam load, lb/hr, or mmBtu/hr.

t_i= Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CS}= Common stack or common pipe operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Total number of units using the common stack or pipe.

i = Designation of a particular unit.

5.7 Heat Input Rate Summation for Units with Multiple Stacks or Pipes

The owner or operator of an affected unit that determines the heat input rate at the unit level by summing the heat input rates monitored at multiple stacks or multiple pipes shall sum the heat input rates using the following equation:

$$HI_{Unit} = \frac{\sum_{s=1}^{n} HI_s t_s}{t_{Unit}} \quad (Eq.\ F\text{-}21c)$$

Where:

HI_{Unit}= Heat input rate for a unit, mmBtu/hr.

HI_s= Heat input rate for the individual stack, duct, or pipe, mmBtu/hr.

t_{Unit}= Unit operating time, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_s= Operating time for the individual stack or pipe, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

s = Designation for a particular stack, duct, or pipe.

5.8 Alternate Heat Input Apportionment for Common Pipes

As an alternative to using Equation F–21a or F–21b in section 5.6 of this appendix, the owner or operator may apportion the heat input rate at a common pipe to the individual units served by the common pipe based on the fuel flow rate to the individual units, as measured by uncertified fuel flowmeters. This option may only be used if a fuel flowmeter system that meets the requirements of appendix D to this part is installed on the common pipe. If this option is used, determine the unit heat input rates using the following equation:

40 CFR 75, APPENDIX F, SECTION 5 – MEASUREMENT OF BOILER HEAT INPUT RATE

$$HI_i = HI_{CP}\left(\frac{t_{CP}}{t_i}\right)\left[\frac{FF_i t_i}{\sum_{i=1}^{n} FF_i t_i}\right] \qquad (Eq.\ F\text{-}21d)$$

Where:

HI_i= Heat input rate for a unit, mmBtu/hr.

HI_{CP}= Heat input rate at the common pipe, mmBtu/hr.

FF_i= Fuel flow rate to a unit, gal/min, 100 scfh, or other appropriate units.

t_i= Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CP}= Common pipe operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Total number of units using the common pipe.

i = Designation of a particular unit.

3.3.5 F, F_c=a factor representing a ratio of the volume of dry flue gases generated to the caloric value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Table 1 lists the values of F and F_c for different fuels. The permittee at their discretion may use the procedure of 40 CFR Part 75, Appendix F, Section 3.3.6 to calculate a site specific F factor for the BFB biomass boiler at the GREC facility.

Table 1—F- and F_c-Factors[1]

Fuel	F-factor (dscf/mmBtu)	F_C-factor (scf CO_2/mmBtu)
Coal (as defined by ASTM D388–99[2])		
Anthracite	10,100	1,970
Bituminous	9,780	1,800
Subbituminous	9,820	1,840
Lignite	9,860	1,910
Petroleum Coke	9,830	1,850
Tire Derived Fuel	10,260	1,800
Oil	9,190	1,420
Gas:		
Natural gas	8,710	1,040
Propane	8,710	1,190
Butane	8,710	1,250
Wood:		
Bark	9,600	1,920

Wood residue	9,240	1,830

[1]Determined at standard conditions: 20 °C (68 °F) and 29.92 inches of mercury. HEF may develop their own F factors for there fuels.

[2]Incorporated by reference under §75.6 of this part.

Link to 40 CFR 75, Appendix F

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 (X);
    b. Determination of Prevention of Significant Deterioration (X);
    c. Compliance with National Emission Standards for Hazardous Air Pollutants (X); 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 or at the following web link.

NSPS Subpart A

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 or at the following web link.

NESHAP Subpart A

NSPS, SUBPART IIII - STATIONARY COMPRESSION IGNITION INTERNAL COMBUSTION ENGINES

One 2000 kW or less emergency generator and one 600 hp or less water pump are proposed for the HEF 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

NESHAP, SUBPART JJJJJJ - INDUSTRIAL/COMMERCIAL/INSTITUTIONAL STEAM GENERATING UNITS FOR AREA SOURCES OF HAP

The biomass boiler at the HEF facility (EU 002) is subject to the requirements of 40 CFR 63, Subpart JJJJJJ: National Emission Standards for Hazardous Air Pollutants – For Area Source Industrial, Commercial, and Institutional Boilers. The applicable portion of Subpart JJJJJJ is given below. For the complete provisions of the subpart go to the link below.

The full provisions may be provided in full upon request and are also available beginning at the web link below:

Link to Subpart JJJJJJ

Table 1 is a listing of the emissions limits from Subpart JJJJJJ that apply to the HEF project.

Table 1. Emission Limits from NESHAP 40 CFR 63, Subpart JJJJJJ.

Boiler Type	Heat Input (mmBtu/hr)	PM Limit	CO Limit
New Biomass Boiler	≥ 30	0.03 lb/mmBtu	work and management practice standards

NSPS, SUBPART KB – STANDARDS OF PERFORMANCE FOR VOLATILE ORGANIC LIQUID STORAGE VESSELS

The blending and storage tanks, EU 005, at 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. These tanks have a capacity greater than or equal to 100,000 gallons. All the tanks store a liquid with a maximum true vapor pressure greater than 3.5 kilopascals (kPa). Consequently, all the 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

PRELIMINARY LEAK DETECTION AND REPAIR (LDAR) PROGRAM

The applicant provided the following LDAR program developed pursuant to Subpart VVa. The applicant shall provide a more comprehensive version for the HEF facility to the Compliance Authority no later than 90 days before the HEF becomes operational. The LDAR program applies to EU 009, Facility-Wide Fugitive VOC Equipment Leaks, at HEF.

Preliminary Leak Detection and Repair (LDAR) Program

Highlands EnviroFuels, LLC (HEF) will be subject to the new source performance standards (NSPS) contained in Title 40, Part 60 of the Code of Federal Regulations (40 CFR 60), Subpart VVa – Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006. This subpart applies to all process units within the Synthetic Organic Chemicals Manufacturing Industry (SOCMI). The SOCMI industry is defined as the industry that produces, as intermediates or final products, one or more of the chemicals listed in §60.489. Ethanol is one of those listed chemicals.

The following **preliminary** LDAR program was developed for the Highlands EnviroFuels facility pursuant to Subpart VVa.

1.0 INTRODUCTION

In order to comply with the leak detection and repair requirements of Subpart VVa, a LDAR program must be developed and implemented. HEF must be in compliance with Subpart VVa, including the LDAR program, no later than 180 days after the HEF facility becomes operational. The following presents the framework for establishing a LDAR program at the HEF facility. The use of this procedure will assure compliance with federal and state regulations. This procedure applies to all regulated equipment used in volatile organic compound (VOC) service within the ethanol production process at the HEF Biorefinery.

2.0 SCOPE

The provisions of this Subpart VVa apply to affected facilities in the synthetic organic chemicals manufacturing industry. In the case of the HEF facility, the affected facility is the process equipment that produces ethanol. The group of all equipment (defined in §60.481a) within a process unit is an affected facility. This LDAR procedure applies to all regulated components within a process unit which are in VOC service at the HEF facility. A "Process unit" for purposes of Subpart VVa means the following:

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.

"Storage vessel" under Subpart VVa is defined as follows:

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.

"In VOC service" means:

The piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight.

The preliminary applicability of Subpart VVa to each emissions unit at the HEF facility is presented below:

EU-001: Biomass Material Handling and Preparation

- Not Applicable- contains no fluids or no fluids in VOC service

PRELIMINARY LEAK DETECTION AND REPAIR (LDAR) PROGRAM

EU-002: Cogeneration Biomass Boiler

- Not Applicable- contains no fluids or no fluids in VOC service

EU-003: Cooling Tower

- Applicable- may contain contamination from equipment leaks. NSPS VVa does not directly apply to the cooling tower. However the tower's cooling water must be checked for VOC contamination to help identify heat exchanger leaks in the ethanol process equipment.

EU-004: Ethanol Production Process

- Applicable

EU-005: Storage Tanks

- Applicable to tanks in ethanol process and storage tanks that are in VOC service

EU-006: Truck Rack Product Loadout and Flare.

- Applicable

EU-007: Miscellaneous Storage Silos

- Not Applicable- contains no fluids or no fluids in VOC service

EU-008: Two Emergency Generators

- Not Applicable- not part of ethanol production process

EU-009: Facility-Wide Fugitive VOC Emission Leaks

- Only applicable as identified above for each emissions unit.

3.0 LDAR PROGRAM

3.1 Identification of Components

- Identify each regulated piece of equipment component, the type of equipment, and type of service. Document in a log.
- Assign a unique identification (ID) number to each piece of equipment. Update as necessary.
- Tag and physically locate each piece of equipment in the facility. Verify its location on the piping and instrumentation diagrams (P&IDs) or process flow diagrams. Update as necessary.
- Maintain log of dates when new equipment is added and replacement equipment is taken out of service.

3.2 Leak Definition

- Identify the definition of "leaking" for each piece of equipment. Leak definitions vary by equipment type, VOC service (e.g., light liquid, heavy liquid, gas/vapor), and monitoring frequency. The regulations may define a leak based on a measured VOC level, visual inspections and observations (such as fluids dripping, spraying, misting, or clouding around equipment), sound (such as hissing), or smell.

3.3 Monitoring Components

- Identify the monitoring frequency for each piece of equipment. Monitoring frequency may be weekly, monthly, quarterly, or annually. Document equipment and frequency in a log.
- Monitor all regulated equipment in accordance with U.S. Environmental Protection Agency (EPA) Method 21, contained in 40 CFR 60 Appendix A, which measures VOC emissions. Attach ID tags to all leaking equipment.

- Obtain background VOC readings from equipment designated as "no detectable emissions" initially, annually, and when requested by the Florida Department of Environmental Protection (FDEP). Record date of monitoring and instrument reading

3.4 Repairing Components

- Repair all leaking components as soon as practicable, but no later than the time period specified in the rule for each type of equipment (generally between 5 and 15 days for first attempt at repair).
- Test the repaired equipment per Method 21 to ensure the equipment 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.

3.5 Recordkeeping

- Maintain a list of ID numbers for all equipment subject to Subpart VVa.
- Maintain a list of ID numbers for all equipment designated as "no detectable leaks."
- Maintain a list of ID numbers for all valves designated as "unsafe to monitor," and an explanation/review of conditions for the designation.
- Maintain the results of performance testing and leak detection monitoring, including leak monitoring results per the leak frequency, monitoring no-leak equipment, and nonperiodic event monitoring.
- For all detected leaks, maintain records of the equipment ID number, the instrument and operator ID numbers, and the date the leak was detected.
- Maintain a log of the dates of each repair attempt and an explanation of the attempted repair method.
- Maintain a log of the dates of successful repairs. Document results of monitoring test to demonstrate the leak was repaired successfully.

NSPS SUBPART VVa – STANDARDS OF PERFORMANCE FOR EQUIPMENT LEAKS OF VOC IN THE SOCMI

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

(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 the Federal Register and 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 the Federal 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 during each 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

SECTION 4. APPENDIX ZZZZ

NESHAP, SUBPART ZZZZ – STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES

One 2000 kW or less emergency generator and one 600 hp or less fire water pump engine are proposed for the HEF 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

Friday, Barbara

To:	BKrohn@usenvirofuels.com
Cc:	Satyal, Ajaya; abrams.heather@epamail.epa.gov; 'dee_morse@nps.gov'; 'dbuff@golder.com'; john_holbrook@mylakeplacid.org; rhelms@hcbcc.org; amotlow@demtribe.com; ctepper@semtribe.com; Scearce, Lynn; Read, David; Linero, Alvaro
Subject:	DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant
Attachments:	0550063-001-ACSignedWrittenNoticeofIntent.pdf

Dear Mr. Krohn:

Attached is the official **Notice of Draft Permit** 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).

Attention: David Read

Owner/Company Name: HIGHLANDS ENVIROFUELS, LLC
Facility Name: HIGHLANDS ETHANOL and COGEN PLANT
Project Number: 0550063-001-AC
Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: HIGHLANDS

Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0550063.001.AC.D_pdf.zip

The Office of Permitting and Compliance 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/emission/apds/default.asp.

Permit project documents 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, Office of Permitting and Compliance.

Note: The attached document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: <http://www.adobe.com/products/acrobat/readstep.html> .

Regards,
Barbara Friday
Office of Permitting and Compliance (OPC)
Division of Air Resources Management

850-717-9095

The Department of Environmental Protection values your feedback as a customer. DEP Secretary Herschel T. Vinyard Jr. is committed to continuously assessing and improving the level and quality of services provided to you. Please take a few minutes to comment on the quality of service you received. Simply click on this link to the DEP Customer Survey. Thank you in advance for completing the survey.

Friday, Barbara

From: Bradley Krohn [bradleykrohn@usenvirofuels.com]
Sent: Thursday, August 11, 2011 2:43 PM
Subject: Read: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

Your message was read on Thursday, August 11, 2011 2:42:53 PM (GMT-05:00) Eastern Time (US & Canada).

Friday, Barbara

From:	Bradley Krohn [bradleykrohn@usenvirofuels.com]
Sent:	Thursday, August 11, 2011 3:13 PM
To:	Friday, Barbara
Cc:	Satyal, Ajaya; dbuff@golder.com; Scearce, Lynn; Read, David; Linero, Alvaro
Subject:	RE: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

Dear Barbara,

Thank you for sending the official Notice of Draft Permit plus weblink to the permit project documents for the Highlands EnviroFuels project. This is to confirm / verify that, Yes, I am able to access and open all six permit project documents provided in the link displayed below.

Best Regards,

Bradley Krohn
Manager
Highlands EnviroFuels, LLC
Office: 813-425-5478

From: Friday, Barbara [mailto:Barbara.Friday@dep.state.fl.us]
Sent: Thursday, August 11, 2011 2:42 PM
To: Bradley Krohn
Cc: Satyal, Ajaya; 'abrams.heather@epamail.epa.gov'; 'dee_morse@nps.gov'; 'dbuff@golder.com'; 'john_holbrook@mylakeplacid.org'; 'rhelms@hcbcc.org'; 'amotlow@semtribe.com'; 'ctepper@semtribe.com'; Scearce, Lynn; Read, David; Linero, Alvaro
Subject: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

Dear Mr. Krohn:

Attached is the official **Notice of Draft Permit** 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).

Attention: David Read

Owner/Company Name: HIGHLANDS ENVIROFUELS, LLC
Facility Name: HIGHLANDS ETHANOL and COGEN PLANT
Project Number: 0550063-001-AC
Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: HIGHLANDS

Click on the following link to access the permit project documents:
http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0550063.001.AC.D_pdf.zip

The Office of Permitting and Compliance 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/emission/apds/default.asp.

Permit project documents 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, Office of Permitting and Compliance.

Note: The attached document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: <http://www.adobe.com/products/acrobat/readstep.html> .

Regards,
Barbara Friday
Office of Permitting and Compliance (OPC)
Division of Air Resources Management
850-717-9095

The Department of Environmental Protection values your feedback as a customer. DEP Secretary Herschel T. Vinyard Jr. is committed to continuously assessing and improving the level and quality of services provided to you. Please take a few minutes to comment on the quality of service you received. Simply click on this link to the DEP Customer Survey. Thank you in advance for completing the survey.

Friday, Barbara

From:	Abrams.Heather@epamail.epa.gov
Sent:	Thursday, August 11, 2011 3:03 PM
To:	Friday, Barbara
Subject:	Re: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

we got it

Heather Ceron
Air Permits Section
U.S. EPA - Region 4
61 Forsyth St. SW
Atlanta, Georgia 30303

Phone: 404-562-9185
Fax: 404-562-9019

-----"Friday, Barbara" <Barbara.Friday@dep.state.fl.us> wrote: -----

To: "'BKrohn@usenvirofuels.com'" <BKrohn@usenvirofuels.com>
From: "Friday, Barbara" <Barbara.Friday@dep.state.fl.us>
Date: 08/11/2011 02:42PM
Cc: "Satyal, Ajaya" <Ajaya.Satyal@dep.state.fl.us>, Heather Abrams/R4/USEPA/US@EPA, "'dee_morse@nps.gov'" <dee_morse@nps.gov>, "'dbuff@golder.com'" <dbuff@golder.com>, "'john_holbrook@mylakeplacid.org'" <john_holbrook@mylakeplacid.org>, "'rhelms@hcbcc.org'" <rhelms@hcbcc.org>, "'amotlow@semtribe.com'" <amotlow@semtribe.com>, "'ctepper@semtribe.com'" <ctepper@semtribe.com>, "Scearce, Lynn" <Lynn.Scearce@dep.state.fl.us>, "Read, David" <David.Read@dep.state.fl.us>, "Linero, Alvaro" <Alvaro.Linero@dep.state.fl.us>
Subject: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

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Attention: David Read

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Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: HIGHLANDS

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Regards,
Barbara Friday
Office of Permitting and Compliance (OPC)
Division of Air Resources Management
850-717-9095

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[attachment "0550063-001-ACSignedWrittenNoticeofIntent.pdf" removed by Heather Abrams/R4/USEPA/US]

Friday, Barbara

From: Microsoft Exchange
To: Satyal, Ajaya
Sent: Thursday, August 11, 2011 2:42 PM
Subject: Delivered: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

Your message has been delivered to the following recipients:

Satyal, Ajaya

Subject: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

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Sent by Microsoft Exchange Server 2007

Friday, Barbara

From: Satyal, Ajaya
To: Friday, Barbara
Sent: Thursday, August 11, 2011 2:42 PM
Subject: Read: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

Your message was read on Thursday, August 11, 2011 2:42:07 PM (GMT-05:00) Eastern Time (US & Canada).

Friday, Barbara

From: Microsoft Exchange
To: 'dee_morse@nps.gov'
Sent: Thursday, August 11, 2011 2:42 PM
Subject: Relayed: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

Delivery to these recipients or distribution lists is complete, but delivery notification was not sent by the destination:

'dee_morse@nps.gov'

Subject: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

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Sent by Microsoft Exchange Server 2007

Friday, Barbara

From: Dee_Morse@nps.gov
Sent: Thursday, August 11, 2011 3:51 PM
To: Friday, Barbara
Subject: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

Return Receipt

Your document:	DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant
was received by:	Dee Morse/DENVER/NPS
at:	08/11/2011 01:50:09 PM MDT

Friday, Barbara

From: Buff, Dave [DBuff@GOLDER.com]
To: Friday, Barbara
Sent: Thursday, August 11, 2011 7:21 PM
Subject: Read: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

Your message was read on Thursday, August 11, 2011 7:21:20 PM (GMT-05:00) Eastern Time (US & Canada).

Friday, Barbara

From: Microsoft Exchange
To: 'john_holbrook@mylakeplacid.org'
Sent: Thursday, August 11, 2011 2:42 PM
Subject: Relayed: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

Delivery to these recipients or distribution lists is complete, but delivery notification was not sent by the destination:

'john_holbrook@mylakeplacid.org'

Subject: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

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Sent by Microsoft Exchange Server 2007

Friday, Barbara

From: Microsoft Exchange
To: 'rhelms@hcbcc.org'
Sent: Thursday, August 11, 2011 2:42 PM
Subject: Relayed: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

Delivery to these recipients or distribution lists is complete, but delivery notification was not sent by the destination:

'rhelms@hcbcc.org'

Subject: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

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Sent by Microsoft Exchange Server 2007

Friday, Barbara

From: Microsoft Exchange
To: 'amotlow@semtribe.com'; 'ctepper@semtribe.com'
Sent: Thursday, August 11, 2011 2:42 PM
Subject: Relayed: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

Delivery to these recipients or distribution lists is complete, but delivery notification was not sent by the destination:

'amotlow@semtribe.com'

'ctepper@semtribe.com'

Subject: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

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Sent by Microsoft Exchange Server 2007

Friday, Barbara

From: Nicki Manson [NickiManson@semtribe.com]
To: Friday, Barbara
Sent: Thursday, August 11, 2011 4:00 PM
Subject: Read: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

Your message was read on Thursday, August 11, 2011 4:00:17 PM (GMT-05:00) Eastern Time (US & Canada).

Friday, Barbara

From: Microsoft Exchange
To: Read, David; Linero, Alvaro; Scearce, Lynn
Sent: Thursday, August 11, 2011 2:43 PM
Subject: Delivered: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

Your message has been delivered to the following recipients:

Read, David

Linero, Alvaro

Scearce, Lynn

Subject: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

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Sent by Microsoft Exchange Server 2007

Friday, Barbara

From: Read, David
To: Friday, Barbara
Sent: Thursday, August 11, 2011 2:46 PM
Subject: Read: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

Your message was read on Thursday, August 11, 2011 2:45:52 PM (GMT-05:00) Eastern Time (US & Canada).

Friday, Barbara

From: Linero, Alvaro
To: Friday, Barbara
Sent: Thursday, August 11, 2011 3:41 PM
Subject: Read: DEP File No. 0550063-001-AC(PSD-FL-416) - Sugarcane/Sweet Sorghum-to-Ethanol Advanced Biorefinery and Cogeneration Plant

Your message was read on Thursday, August 11, 2011 3:41:14 PM (GMT-05:00) Eastern Time (US & Canada).