Memorandum

Florida Department of Environmental Protection

To: Trina Vielhauer

Through: Al Linero aal

From: David Read DLR

Date: February 23, 2010

Subject: Draft Air Permit No. 0810226-001-AC
Florida Biomass Energy LLC
60.0 megawatt (MW) Woody Biomass Power Plant

Attached for your review is a draft air construction permit package for the Florida Biomass Energy, LLC (FBE) clean woody biomass power plant that will generate 60 MW (net) of electrical power. The FBE facility will be located in Manatee County at 11805 US Highway 41 North in Port Manatee, Palmetto, Manatee County, Florida. The plant will be located immediately west of U.S. Highway 41 and approximately 2 mile southwest of the Manatee County municipal airport.

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

This project is not subject to the rules for the Prevention of Significant Deterioration. We recommend your approval of the attached draft permit package.

Attachments

TLV/aal/dlr

P.E. CERTIFICATION STATEMENT

PERMITTEE

Florida Biomass Energy, LLC (FBE)
9040 Town Center Parkway
Bradenton, Florida 34202
Authorized Representative: Mr. Rick Jensen, President

Draft Permit No. 0810226-001-AC
FBE Biomass Power Plant
60.0 MW Grate-Type Suspension Boiler
Manatee County, Florida

PROJECT DESCRIPTION

The project is to construct a net 60.0 megawatt (MW, net) electric power plant utilizing a grate-type suspension boiler (GSB) and associated equipment, fueled by clean woody biomass. Biodiesel or backup ultralow sulfur distillate (ULSD) fuel oil (FO) will be used for GSB startup, shutdown and bed stabilization.

To insure that emissions are less than the respective major source thresholds for PSD and hazardous air pollutants (HAP) and that compliance is achieved with applicable new source performance standards, FBE will install or implement the following air pollution control equipment and practices: efficient combustion in the GSB and emergency equipment to minimize formation of particulate matter ($PM/PM_{10}/PM_{2.5}$), NO_X, CO and volatile organic compounds VOC; limitation of biomass to clean woody untreated biomass to minimize SO_2 and HAP formation; use of inherently clean fuels (biodiesel and backup ULSD FO) for startup, shutdown and bed stabilization of the GSB and the operation of emergency equipment; an oxidation catalyst (ox-cat) system to reduce CO, VOC and HAP; ammonia (NH_3) injection into a selective catalytic reduction (SCR) reactor to destroy NO_X and further reduce VOC and HAP; an in-duct sorbent injection system (IDSIS) of lime, trona, or sodium bicarbonate to control SO_2 and HAP such as hydrogen chloride (HCl) and hydrogen fluoride(HF); an electrostatic precipitator (ESP) to further control $PM/PM_{10}/PM_{2.5}$ and to remove reacted sorbents; and, reasonable precautions and best management practices to minimize fugitive dust emissions from biomass handling, storage and processing and ash (bottom and fly) handling, storage and shipment.

Continuous emissions monitoring systems (CEMS) will be required for SO_2, NO_X, CO, HCl and HF. A continuous opacity monitor system (COMS) will be required for visible emissions (VE).

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 details are provided in the public notice package available at:

www.dep.state.fl.us/Air/emission/construction/port_manatee.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 Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify any other aspects of the proposal (including, but not limited to, the electrical, civil, mechanical, structural, hydrological, geological, and meteorological features).*

2/24/2010

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

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

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor
Jeff Kottkamp
Lt. Governor
Michael W. Sole
Secretary

rjensen@fbenergy.com
Mr. Rick Jensen, President
Florida Biomass Energy, LLC
9040 Town Center Parkway
Bradenton, Florida 34202

Re: Draft Air Permit No. 0810226-001-AC
Florida Biomass Energy, LLC (FBE)
60.0 MW Woody Biomass Power Plant

Dear Mr. Jensen:

On October 13, 2009, you submitted an application for an air construction permit subject to the preconstruction review requirements of Rule 62-212.300, Florida Administrative Code (F.A.C.).

The purpose of the project is to construct a net 60.0 megawatt (MW) power plant that will be fueled by clean woody biomass. This work will be conducted at the new FBE woody biomass power plant that will be located in Manatee County at 11805 US Highway 41 North in Port Manatee, Palmetto, Manatee County, Florida. The plant will be located immediately west of U.S. Highway 41 and approximately 2 miles southwest of the Manatee County municipal airport.

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

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

Sincerely,

Trina L Vielhauer 2/26/10

Trina Vielhauer, Chief (Date)
Bureau of Air Regulation

Enclosures

TLV/aal/dlr

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

Florida Biomass Energy, LLC (FBE)	Draft Permit No. 0810226-001-AC
9040 Town Center Parkway	FBE Biomass Power Plant
Bradenton, Florida 34202	60.0 MW Grate-Type Suspension Boiler
Authorized Representative: Mr. Rick Jensen, President	Manatee County, Florida

Facility Location: FBE proposes to construct a new power plant fueled by clean woody biomass that will be located in Manatee County at 11805 US Highway 41 North in Port Manatee, Palmetto, Manatee County, Florida. The plant will be located immediately west of U.S. Highway 41 and approximately 2 miles southwest of the Manatee County municipal airport.

Project: The project involves the construction of a net 60.0 megawatt (MW) electric power plant utilizing a grate-type suspension boiler (GSB) and associated equipment, fueled by clean woody biomass. The project is subject to the preconstruction review requirements of Rule 62-212.300, Florida Administrative Code (F.A.C.). A review pursuant to the rules for Prevention of Significant Deterioration (PSD) and a determination of best available control technology (BACT) pursuant to Rule 62-212.400, F.A.C. were not required.

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

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at 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 for a period of 14 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 14-day period. If timely received comments result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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

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

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

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Written Notice of Intent to Issue Air Permit package (including the Written Notice of Intent to Issue Air Permit, the Public Notice of Intent to Issue Air Permit, the Technical Evaluation and Preliminary Determination and the Draft Permit with Appendices) was sent by electronic mail, or a link to these documents made available electronically on a publicly accessible server, with received receipt requested before the close of business on 2/26/10 to the persons listed below.

Mr. Rick Jensen, President, FBE: rjensen@fbenergy.com
Joe McClash, Chairman, MCPA: joe.mcclash@mymanatee.org
Deborah Getzoff, DEP SWD: deborah.getzoff@dep.state.fl.us
Mara Nasca, DEP SWD: mara.nasca@dep.state.fl.us
Scott Osbourn, P.E., Golder: sosbourn@golder.com
Kathy Forney, EPA Region 4: forney.kathleen@epa.gov
Heather Abrams, EPA Region 4: abrams.heather@epa.gov
Robert K. Lincoln, Esq.: arickwa@icardmerrill.com
Ron Stewart, Florida Pulp and Paper Association: rstewart@fppaea.org
Vickie Gibson, DEP BAR Reading File: victoria.gibson@dep.state.fl.us

Clerk Stamp

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

(Clerk) 2/26/10 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

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

Draft Air Permit No. 0810226-001-AC
Florida Biomass Energy, LLC Clean Woody Biomass Power Plant
Manatee County, Florida

Applicant: The applicant for this project is Florida Biomass Energy, LLC (FBE). The applicant's authorized representative and mailing address is: Mr. Rick Jensen, President, Florida Biomass Energy, LLC, 9040 Town Center Parkway, Bradenton, Florida 34202.

Facility Location: FBE proposes to construct a new net 60.0 megawatt (MW) power plant fueled by clean woody biomass that will be located in Manatee County at 11805 US Highway 41 North in Port Manatee, Palmetto, Manatee County, Florida. The plant will be located immediately west of U.S. Highway 41 and approximately 2 miles southwest of the Manatee County municipal airport.

Project: The fuel feedstock for the project will consist of clean woody biomass, which will be processed at a remote fuel preparation area. At this remote area, the feedstock will be sorted, screened and chipped to size. Although some leaves and small branches may inadvertently find their way into the feedstock, the focus is on producing wood chips from the clean woody biomass. In addition, a fuel crop is under consideration to supplement available feedstock supplies. The fuel will be combusted in a grate-type suspension boiler (GSB) to produce a net 60.0 MW of electric power. Biodiesel or as a backup ultralow sulfur distillate (ULSD) fuel oil (FO) will be used for GSB startup, shutdown and bed stabilization and also for use in emergency equipment.

Based on the air permit application, the project will result in emissions increases of: 99.0 tons per year (TPY) of carbon monoxide (CO); 67.6 TPY of nitrogen oxides (NO_X); 44.6 TPY of particulate matter (PM); 36.2 TPY of PM with a mean diameter of 10 micrometers (µm) or less (PM_{10}); 34.0 TPY of PM with a mean diameter of 2.5 µm or less ($PM_{2.5}$); 1.2 TPY of sulfuric acid mist (SAM); 53.1 TPY of sulfur dioxide (SO_2); 10.1 TPY of volatile organic compounds (VOC); 0.16 TPY of lead (Pb); and 24.95 TPY of hazardous air pollutants (HAP) and less than 10 TPY of any individual HAP.

A review for the Prevention of Significant Deterioration (PSD) and a best available control technology (BACT) determination were not required because the potential-to-emit (PTE) any single PSD-pollutant will be less than 250 TPY. A case-by-case maximum achievable control technology (MACT) determination was not required because the PTE of any single HAP will be less than 10 TPY and the PTE for all HAP is less than 25 TPY.

To insure that emissions are less than the respective major source thresholds for PSD and HAP and that compliance is achieved with applicable new source performance standards, FBE will install or implement the following air pollution control equipment and practices: efficient combustion in the GSB and emergency equipment to minimize formation of particulate matter ($PM/PM_{10}/PM_{2.5}$), NO_X, CO and volatile organic compounds (VOC); limitation of biomass to clean woody untreated biomass to minimize SO_2 and HAP formation; use of inherently clean fuels (biodiesel and backup ULSD FO) for startup, shutdown and bed stabilization of the GSB and the operation of emergency equipment; an oxidation catalyst (ox-cat) system to reduce CO, VOC and HAP; ammonia (NH_3) injection into a selective catalytic reduction (SCR) reactor to destroy NO_X and further reduce VOC and HAP; an in-duct sorbent injection system (IDSIS) of lime, trona, or sodium bicarbonate to control SO_2 and HAP such as hydrogen chloride (HCl) and hydrogen fluoride(HF); an electrostatic precipitator (ESP) to further control $PM/PM_{10}/PM_{2.5}$ and to remove reacted sorbents; and, reasonable precautions and best management practices to minimize fugitive dust emissions from biomass handling, storage and processing and ash (bottom and fly) handling, storage and shipment.

Continuous emissions monitoring systems (CEMS) will be required for SO_2, NO_X, CO, HCl and HF. A continuous opacity monitor system (COMS) will be required for visible emissions (VE).

The Department reviewed an air quality analysis prepared by the applicant. The analysis demonstrated that the sum of ground-level concentrations of nitrogen dioxide (NO_2), PM_{10}, CO and SO_2 caused by the project and background concentrations will be much less than the respective National or Florida ambient air quality standards (AAQS).

The Technical Evaluation and Preliminary Determination document and the air quality analysis are available at the following web link: www.dep.state.fl.us/Air/emission/construction/port_manatee.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, Florida Administrative Code (F.A.C.). The proposed project is not exempt from air permitting requirements and an air permit is required to perform the proposed work. The Florida Department of Environmental Protection's Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Bureau of Air Regulation's physical address is 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301 and the mailing address is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Bureau of Air Regulation's phone number is 850/488-0114.

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

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 for a period of 14 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 14-day period. If timely received comments result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's Agency Clerk in the Office of General Counsel of the Department of Environmental Protection, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000 (Telephone: 850/245-2241; Fax: 850/245-2303). Petitions filed by 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

Florida Biomass Energy, LLC
9040 Town Center Parkway
Bradenton, Florida 34202

FBenergy Manatee Facility
ARMS Facility ID No. 0810226

PROJECT

Project No. 0810226-001-AC

60.0 Megawatt (net) Woody Biomass Power Plant

COUNTY

Manatee County, Florida

PERMITTING AUTHORITY

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

February 26, 2010

1. APPLICATION INFORMATION

1.1. Applicant Name and Address

Florida Biomass Energy, LLC (FBE)
9040 Town Center Parkway
Bradenton, Florida 34202

Authorized Representative: Mr. Rick Jensen, President

1.2. Key Dates

- October 13, 2009 Received air construction permit application from FBE.
- October 31 FBE published Notice of Application in The Bradenton Herald.
- November 10 Department issued request for additional information (RAI).
- November 24 Received response from FBE to Department's RAI.
- December 18 Department issued second RAI.
- January 12, 2010 Received response from FBE to Department's second RAI.
- February 26 Department issued Revised Draft Permit package and posted documents.

1.3. Facility Location

The proposed plant will be located in Manatee County at 11805 US Highway 41 North in Port Manatee, Palmetto, Manatee County. The location of Manatee County (shown in red) and the proposed site are shown in Figures 1 and 2 respectively. The approximate UTM coordinates for this site are Zone 16; 347.8 kilometers (km) East and 3,056.2 km North. The nearest Prevention of Significant Deterioration (PSD) Class I area is the Chassahowitzka National Wilderness Refuge (CNWR). The CNWR is located approximately 110 km north of the site and straddles the coastline in Citrus and Hernando Counties.

Figure 1 – Manatee County, Florida

Figure 2 – Map of Manatee County, Location of FBE Site

The immediate environs are visible at the following link: Environs of Proposed FBE Facility

The site is a 44 acre parcel of citrus groves and woods located in northwest Manatee County near Port Manatee. The site is southwest of the defunct Piney Point Phosphates fertilizer complex. It is bordered by the CSX Railroad on the west and US Highway 41 N on the east (see Figure 3). There are woods and an electrical substation to the north. Trielectron Industries is located to the south. Excavation, sand and gravel operations are located to the east across US Highway 41. There are row crops and woods to the west of the CSX Railroad. A conservation area called the Port Manatee Ecological Park lies further west of the mentioned row crops and extends nearly to the Gulf of Mexico shoreline.

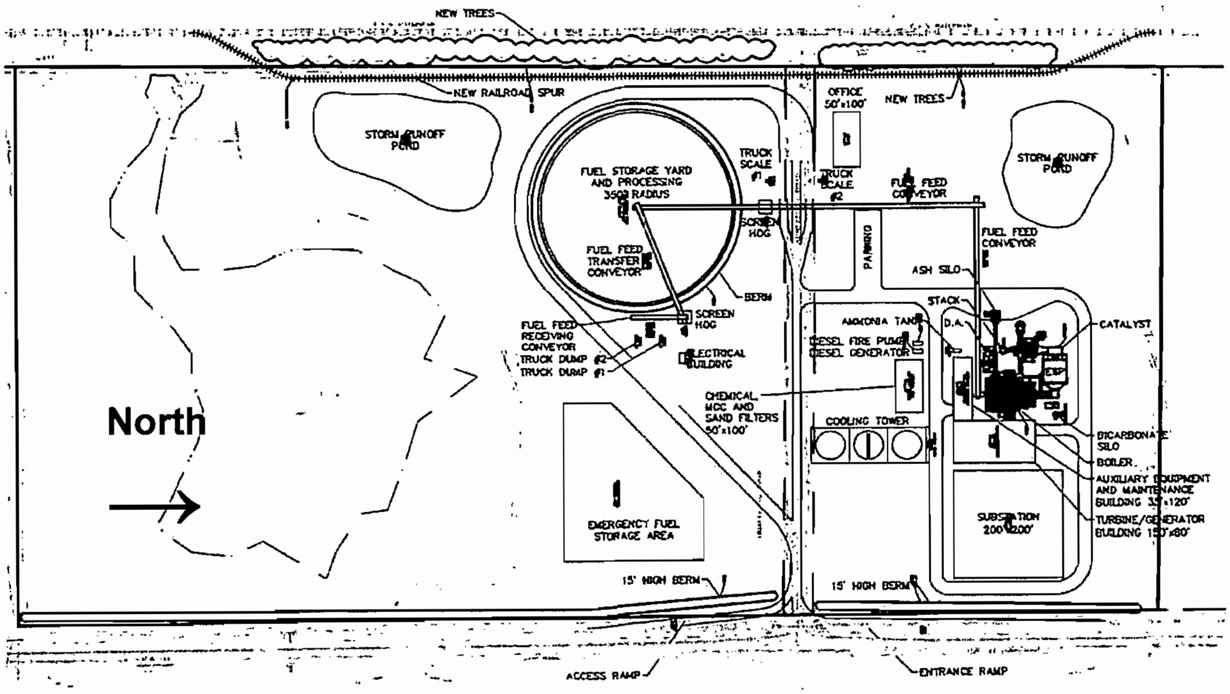


Figure 3 – Proposed Layout between US Highway 41 and the CSX Railroad

1.4. Applicable Federal and State Regulations

Standards of Performance for New Stationary Sources

- 40 CFR 60, Subpart A – General Provisions;
- 40 CFR 60, Subpart Db – Industrial, Commercial, Institutional Steam Generating Units; and
- 40 CFR 60, Subpart IIII – Stationary Compression Ignition Internal Combustion Engines (ICE).

National Emissions Standards for Hazardous Air Pollutants (NESHAP)

The facility is not a major source of hazardous air pollutants (HAP) because it will not have the potential to emit (PTE) 10 tons per year (TPY) of any single HAP or 25 TPY of all HAP. However, the following NESHAP applies to emergency equipment:

- 40 CFR 63, Subpart ZZZZ – Stationary Reciprocating Internal Combustion Engines (RICE).

Title IV, Acid Rain Provisions

The facility will be subject to the Title IV, Acid Rain Provisions of the Clean Air Act. The proposed plant will serve an electric generator capable of generating 25 megawatts (MW) or more of electricity and will sell the resultant electricity.

Title V, Permits

The facility is a Title V or "Major Source" of air pollution because the PTE of at least one regulated pollutant will exceed 100 TPY. Key regulated pollutants include carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfur dioxide (SO_2) and volatile organic compounds (VOC).

Prevention of Significant Deterioration (PSD)

The facility is not classified as a "Major Stationary Source" because it will not have the PTE 250 TPY or more of a PSD regulated air pollutant and is not one of the facility categories with the PSD applicability threshold of 100 TPY as described in Rule 62-210.200, Florida Administrative Code (F.A.C.).

Clean Air Interstate Rule (CAIR)

The FBE facility is subject to CAIR in accordance with the Final Department Rules issued pursuant to CAIR as implemented by the Department in Rule 62-296.470, F.A.C.

Power Plant Siting

The facility is not subject to certification pursuant to the power plant siting provisions of Rule 62-17, F.A.C. because it will produce less than 75 MW of steam power.

2. PROPOSED PROJECT

2.1. Project Description

The applicant proposes to construct a woody biomass electric power plant. The proposed plant will be capable of generating approximately 60.0 MW (net – i.e. after deducting the parasitic load to operate the plant) of electrical power by combusting woody biomass in a grate-type suspension boiler (GSB) and feeding the steam to a steam turbine-electrical generator (STG).

The power plant will be comprised of four process areas. These process areas include:

- Fuel receiving, handling, storage and processing;
- Power island (steam generating unit), including a GSB, cooling tower and STG;
- Ash handling, storage and shipment; and
- Emergency support equipment.

2.2. Additional Project Features

Fuel

FBE proposes to fuel the new GSB with biomass fuel wood chips. The boiler will be equipped with start-up ignition burners using biodiesel fuel and occasionally, ultralow sulfur distillate (ULSD) fuel oil (FO). The emergency generator and fire water pump will be also fueled with bio-diesel or with ULSD FO as back up fuel.

Air Pollution Controls

The proposed power plant will utilize the following control devices and techniques to control air pollutants, as described below:

Fuel Receiving, Handling, Storage and Processing

- Employment of a first-in/first-out stacking and reclaiming system with minimal drop lengths to minimize dust generation, biological degradation and odors.
- All conveyor systems in the fuel receiving, handling, storage and processing system will be designed to minimize emissions of $PM/PM_{10}/PM_{2.5}$ through the use of Best Management Practices (BMP).
- BMP will include enclosed conveyors, also to the extent possible enclosed chutes for dropping fuel to and from conveyors, and maintenance of paved roads to minimize fugitive dust generating materials on roadways.
- Other reasonable precautions as described in Rule 62-296.320(4)(c), F.A.C.

Power Island

- Emissions of $PM/PM_{10}/PM_{2.5}$ from the GSB will be controlled by a "hot-side" electrostatic precipitator (ESP) located upstream of the air heater.
- SO_2 and sulfuric acid mist (SAM) from the GSB will be controlled by use of inherently low sulfur wood, biodiesel and ULSD FO, and a dry in-duct sorbent injection system (IDSIS).

- NO_X from the GSB will be controlled by good combustion practices (GCP) and an ammonia (NH_3) based selective catalytic reduction (SCR) system located on the "clean-side" downstream of the ESP.
- Emissions of CO and VOC from the boiler will be controlled by GCP and an oxidation catalyst (ox-cat) system also located on the "clean side" downstream of the ESP.
- Emissions of HAP from the GSB will be controlled by GCP, use of untreated woody biomass (inherently low in chloride), the IDSIS, the ESP, the SCR system and the ox-cat system.

Ash Handling, Storage and Shipment

- Emissions of $PM/PM_{10}/PM_{2.5}$ from the fly ash silo will be controlled by a baghouse or similar filter.
- BMP will be utilized during truck loading operations to minimize PM/PM_{10} emissions.

Emergency Support Equipment

- An emergency diesel generator and a fire pump will be designed to meet the emission limits given in NSPS Subpart IIII and NESHAP Subpart ZZZZ.
- Biodiesel and backup ULSD FO will be used in the emergency equipment. Operation will be limited to 500 hours per year (hr/yr) for the emergency diesel generator and 250 hr/yr for the fire pump.

3. PROCESS DESCRIPTION

3.1. Principle

Wood chips will be combusted in a nominal 757 million Btu per hour (mmBtu/hr) GSB. The total maximum heat input capacity will be 833 mmBtu/hr on a 4-hour average basis. The maximum heat input capacity of the backup ULSD FO to the unit is limited to less than 250 mmBtu/hr. The steam produced will then be sent to a STG that will generate approximately 66 MW (gross) of electricity of which approximately 60.0 MW will be delivered to the grid.

3.2. Biomass Feedstock

FBE's contract fuel processor will collect wood waste at several off-site locations, where the fuel will be air-dried, chipped to size, and screened at a remote fuel preparation area. A fuel crop is under consideration to supplement available feedstock supplies. Biomass fuel will generally be delivered via truck to the site on 6-days a week, 12 hour per day schedule.

Delivery trucks will be unloaded via a truck receiving system equipped with two hydraulically operated truck dumpers. The fuel will be conveyed, via an enclosed collecting conveyor, to the fuel storage pile. The fuel storage pile will contain 10 to 14 days of fuel storage. From the fuel storage pile, the fuel will be conveyed to a magnetic separator/sizing screen and will then be transferred to the day-bins within the boiler structure.

3.3. Stackout System

The feedstock material handling process associated with fuel delivery (stackout) is depicted in Figure 4. All wood waste material will be delivered to the project site via truck. The fuel trucks will have an average net load of 25 tons of wood chips. The truck receiving system will be equipped with two hydraulically operated truck dumpers, which will slide each 25 ton load into a 50 ton capacity, fully-enclosed live-bottom receiving hopper. Each hopper will have a very slow moving chain drag to minimize dust. The hoppers will have a discharge rate capability of 150 tons per hour (TPH).

From the bottom of the two collection hoppers, the wood chips will be discharged at a controlled rate, via an enclosed chute, onto a collecting conveyor. The collecting conveyor transfers the incoming fuel to a magnetic separator, sizing screen, and hog mill for reduction of oversize material. These components are mounted in a tower, which is equipped with dust collection hoods at transfer points, which convey emissions to a fabric filter to minimize dust. Separated ferrous metal is discharged by chute to a skip at grade for recycling. The combined streams from the sizing screen and the hog mill are then discharged onto a covered collection conveyor which feeds the stack-out system.

The stack-out system will provide approximately 20,000 tons of biomass storage, using a stacking system that continuously adjusts the height of the discharge just above the pile height, to minimize dust.

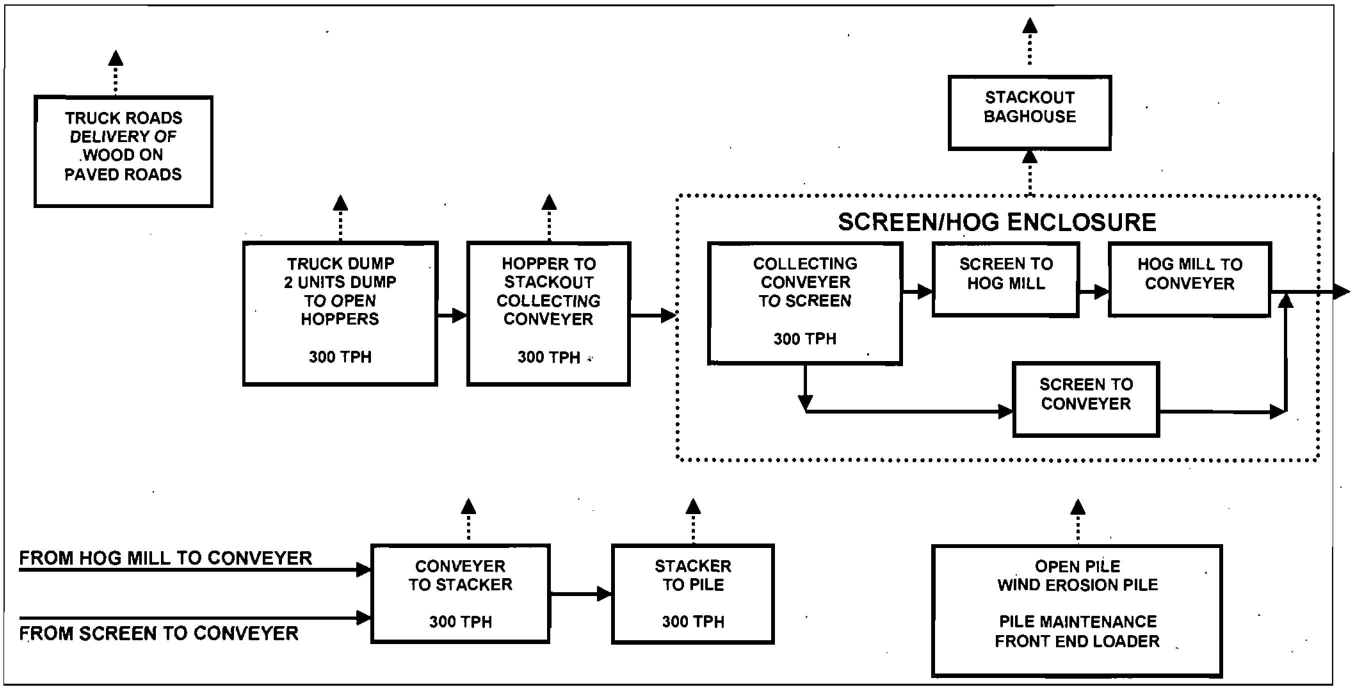


Figure 4 – Material Handling Emission Points – Stackout (Emission Point Material Flow)

3.4. Reclaim System

The feedstock material handling process associated with fuel reclaim is depicted in Figure 5. Wood chips will be reclaimed from the storage pile via a drag chain or auger type reclaimer to a covered conveyor identified as Reclaim Conveyor No. 1. Reclaim Conveyor No. 1 will transfer the material to a second enclosed magnetic separator and sizing screen system and then transfer the screened fuel to the covered Supply Conveyor No. 2. The magnetic separator and sizing screen system will be controlled by a fabric filter. The covered reclaim conveyors are rated at 150 TPH.

The anticipated average reclaim rate is estimated equal to 68 TPH hour based on a boiler heat input rate of 757 mmBtu/hr. Covered belt conveyors will then transport the feedstock to a storage silo (day bin) within the boiler structure. Particulate emissions from these transfer points are kept to a minimum through special designs. All conveyors will be covered to reduce particulate emissions. In addition, and as depicted in Figure 5, a fabric filter will control emissions from the day bin and from transfer of material from the day bin to the boiler.

3.5. Emergency Short-Term Fuel Feed System

The feedstock material handling process will also include an emergency short-term fuel feed system, as depicted in Figure 6. An at-grade back-up emergency fuel storage area, located adjacent to the fuel truck access road, sufficient for an additional 30,000 tons of fuel, will be used in the event of major repairs to the stack out or reclaim systems. The emergency pile will be transferred to the truck dump hoppers via front-end loaders and will utilize the enclosed by-pass conveyor to by-pass the stacker to transport the material directly to the boiler.

The enclosed by-pass conveyor between the primary screening tower and the reclaim conveyor screening tower will enable the stack-out and reclaim systems to undergo routine maintenance without shutting down the boiler. The transfer points to and from this conveyor are covered by the same hoods and extraction systems that control dust from the screening towers.

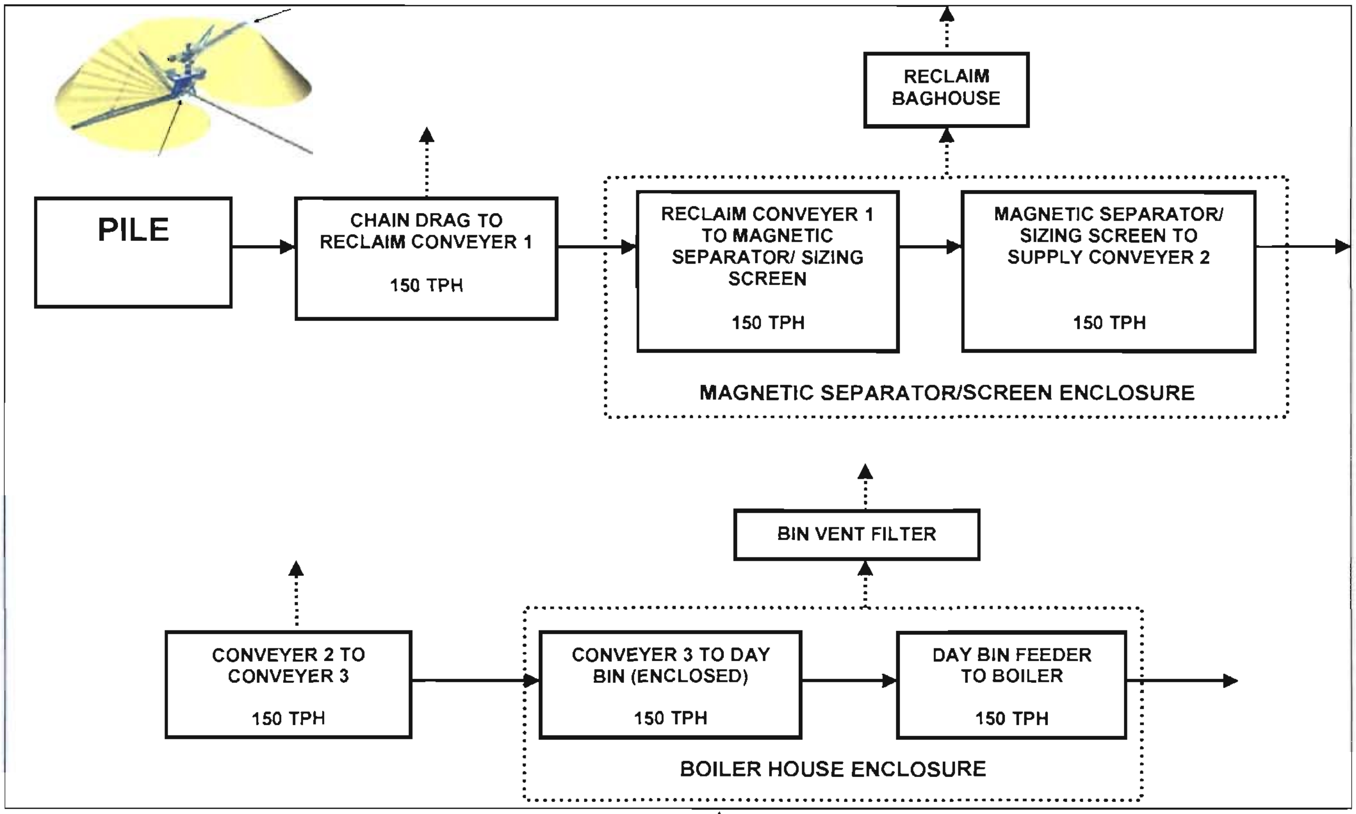


Figure 5 – Material Handling – Reclaim (Emission Point ⋮ Material Flow ——►)

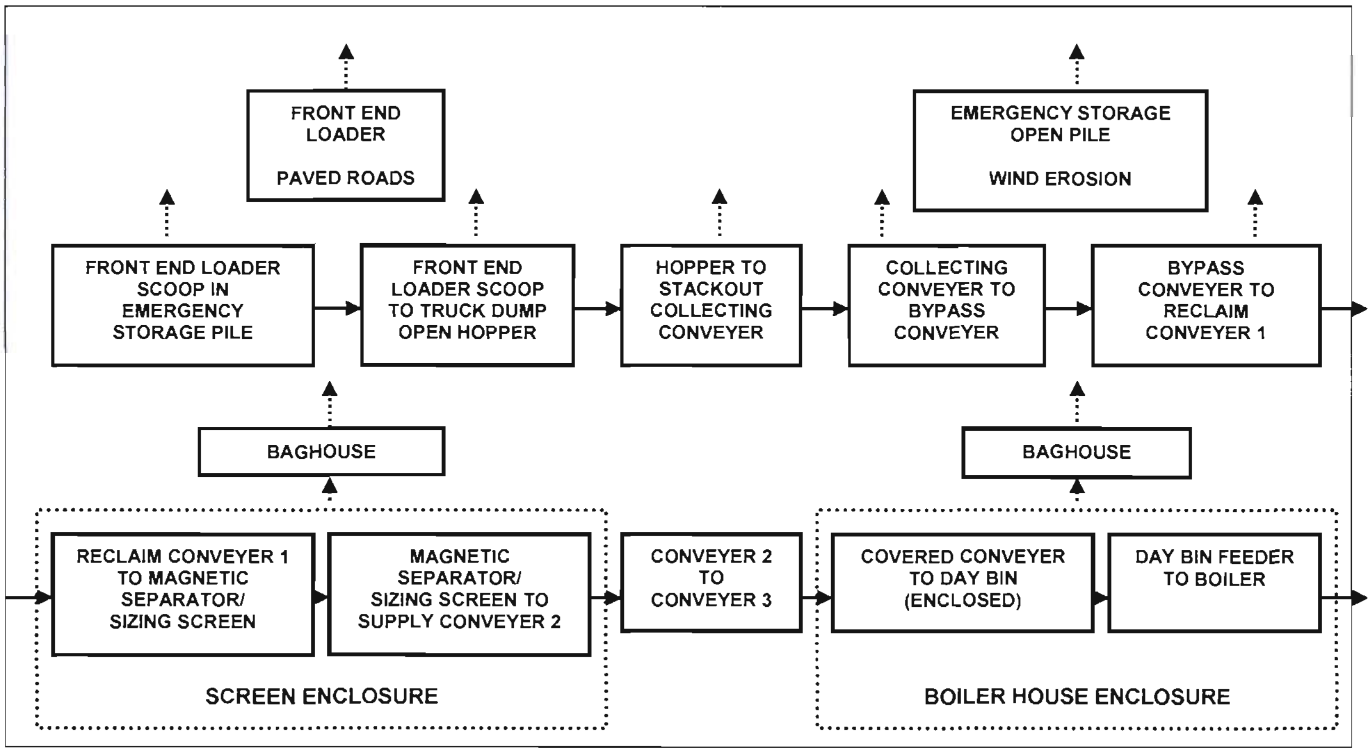


Figure 6 – Material Handling –Short-Term Feed System (Emission Point ⋮ Material Flow ——►)

3.6. Material Handling, Ash and Sorbent

The material handling systems for the ash and sorbent streams are depicted in Figure 7. Sodium Bicarbonate ($NaHCO_3$) will be delivered to the site via truck and will be unloaded to bicarbonate storage silos. The storage silos will be equipped with fabric filters to minimize PM emissions from the unloading process. The sorbent will then be injected by the dry sorbent injection control system.

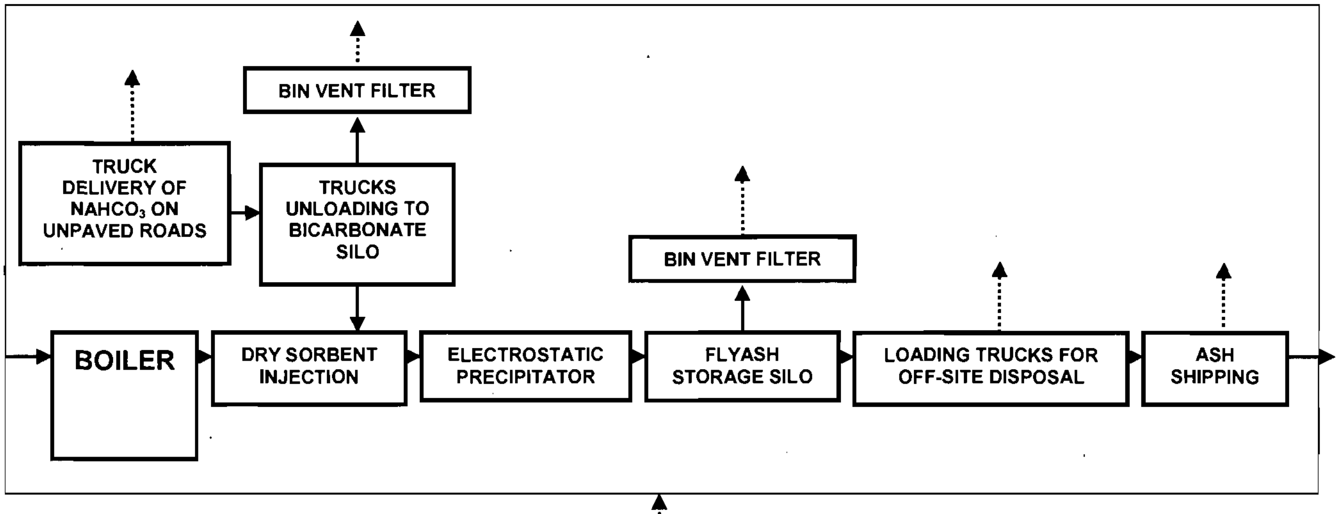


Figure 7 – Ash and Sorbent Handling (Emission Point Material Flow ⟶)

Bottom ash will be collected from the boiler by a submerged drag-chain conveyor, which will deliver a wet material to the ash silo. Fly ash captured by the ESP will be transported by an enclosed conveyor or similar configuration to the ash storage silo. The storage silo will be equipped with a fabric filter to minimize any PM emissions from the transfer operation. Ash from the storage silo will then be loaded, via an ash conditioning mixer which produces a non-dusting material, to a truck for removal off-site.

3.7. FBE's Best Management Practices Plan Proposal

In response to a request for additional information, FBE submitted the principles and specifics listed below for a preliminary BMP plan. The Department incorporated these principles and specifics along with additional requirements in a BMP plan given in Section 6 that will be incorporated into the permit.

FBE Best Management Plan to manage the fuel pile will have as its goals:

1. *Avoidance of conditions giving rise to spontaneous combustion, supported by the fire control systems to be provided after approval by State and insurance entities, which specifically will provide fuel pile fire control, and these systems will be reviewed and approved as part of the overall fire prevention plans by the County Fire Marshall;*
2. *Minimization of fugitive dust emissions, also using fuel pile fire protection facilities for dust suppression as required; and*
3. *Blending of the various fuels received to ensure reasonably consistent fuel properties as delivered to the boiler.*

The following preliminary BMP for fuel handling dust control is subject to the provision of further detail and adjustment during the project's detailed design phase to reflect final equipment selection:

Measures to Minimize Spontaneous Combustion

1. *Daily inspection for fire hazards, plus video surveillance;*
2. *The stack-out/reclaim plan will ensure reclaim of older material to avoid accumulation of fuel with a significant age. The first-in/first-out (FIFO) procedure will be slightly modified to ensure blending of*

older and newer fuel for consistent fuel properties. The equipment, by design, will manage and handle the approximate 10 to 14 day supply of fuel (approximately 20,000 to 25,000 tons depending on moisture content). This will ensure a quick turnover of feedstock in order to make more room for deliveries. Additional space has been reserved for the potential short term handling of material such as processed storm debris from sources such as FEMA, the County and State. Short term material stored on-site will be protected from fire hazard and will be moved to the primary fuel storage, generally within 14 to 21 days.

3. *Use of daily inspections and fire-water cannons, mounted on elevated structures, together with mobile equipment to uncover and rapidly extinguish any smoldering materials found; and*
4. *The size of the fuel storage pile will not exceed the design value – this is a primary control measure, based upon the limited on-site fuel storage of about 2 weeks' worth of fuel. Specifically, the stacker will build a pile in zones up to 40 feet high and the reclaimer will start with the first zone built and reclaim the pile down to within two inches of grade.*

Measures to Minimize Fugitive Dust

1. *The size of the fuel storage pile, about 2 weeks' worth of fuel, minimizes the area subject to wind erosion and reduces the travel time required for mobile equipment;*
2. *Conveyor transfer points are enclosed or partially enclosed;*
3. *Drop points to the fuel storage areas are designed to minimize the exposed drop height;*
4. *Transfer points and fuel bins are equipped with vent filters;*
5. *Underpile fuel reclaimers do not generate fugitive dust;*
6. *Fuel handling equipment is observed daily for proper operation and for maintenance requirements;*
7. *Plant fuel handling personnel will implement a procedure for observing and controlling unplanned fugitive dust emissions, including truck handling and unloading, and dirt or fuel on roads; and*
8. *All major roadways will be paved. Plant personnel will spray, scrape, or otherwise remove dirt or spilled fuel on plant roads.*

Storage Pile Management

1. *Operational plans will recognize conditions such as high winds likely to result in excessive fugitive dust and will curtail movement of fuel by mobile equipment under such conditions;*
2. *Mobile equipment will be used to maintain the pile's design shape and to ensure adherence to FIFO in reclaim operations; and*
3. *The area surrounding the fuel storage as well as bordering the property will have significant landscape screening that will provide further shielding of the fuel pile from winds.*

3.8. Power Generation

Biomass Fired-Boiler

FBE will utilize grate stoker technology within a conventional waterwall furnace. Modern stoker units for wood 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 overfire air (OFA) system. Depending on the fuel moisture content, the combustion air is pre-heated to 350 to 650 °F.

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 is carried out of the furnace. In order to recover the energy value 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 precipitator.

The grate for the project boiler will be provided by Detroit Hydro-Grate. Figure 8 includes a diagram of such a 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 overfire air (OFA). Coarser, heavier fuel particles are spread evenly on the grate forming a thin, fast-burning fuel bed.

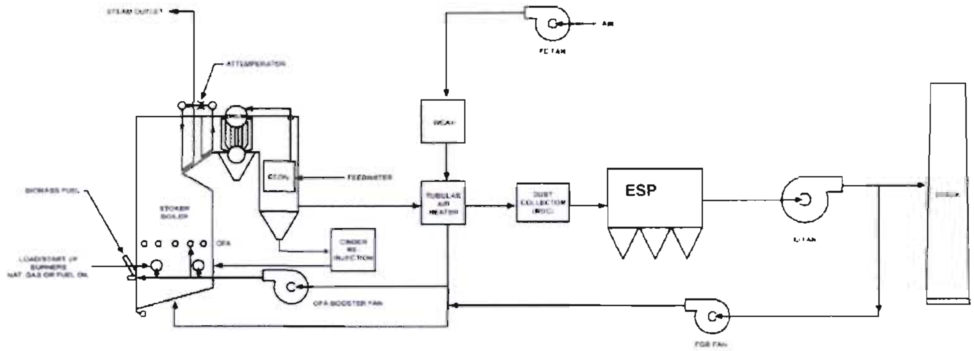


Figure 8 – Detroit Hydro-Grate and Typical Stoker-based Process Schematic

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.

The boiler will be rated at 757 mmBtu/hr (833 mmBtu/hr maximum). The average heat content of the fuel is estimated to be approximately 5,600 mmBtu/lb on a higher heating value (HHV) basis. The planned layout differs from that given in Figure 8 because the dust collector and ESP as well as SCR and ox-cat systems (not shown) will be placed upstream of the air heater.

The GSB will generate 560,000 pounds per hour of (lb/hr) of steam at 1,550 psi and 960 degrees °F in conventional waterwall boiler tubes. The boiler will be equipped with start-up ignition burners using biodiesel fuel and as a backup ULSD FO. The boiler will be a top-mounted unit in which the boiler pressure parts are suspended from a steel structure and support grid. The boiler is complete with all necessary fans, economizers, air heaters, duct-work and controls, as well as steam soot-blowers.

A 133 foot stack will be located downstream of the final heat recovery equipment. The stack will be adjacent to the boiler structure and will include a dedicated platform for stack testing.

<u>Steam Turbine</u>

The steam cycle consists of a single STG with a minimum of three extraction points at which steam at different pressures is extracted for regenerative heating of the boiler feed water, as well as stripping the feed water of dissolved oxygen in the de-aerator section to minimize corrosion. Feed water to the boiler economizer is supplied at 440 degrees °F.

Turbine exhaust steam enters the condenser, where its heat is rejected to atmosphere by heating and evaporating water. From the condenser, turbine condensate is pumped through heat exchangers first to the de-aerator, and then by high pressure boiler feed water pumps to the boiler economizer to complete the cycle.

<u>Cooling Tower</u>

The heat absorbed by the circulating cooling water in the condenser tubes must also be removed to maintain the ability of the water to cool as it circulates. This is done by pumping the warm water from the condenser through a cooling tower that reduces the temperature of the water by evaporation and expelling the heat to the atmosphere.

FBE is evaluating the alternatives of a conventional separate condenser fed by cooling water from a cooling tower and circulating pumps and a wet surface evaporative condenser.

3.9. Emergency Support Equipment

The proposed plant will also require:

- One 500 kilowatt (kW) emergency electrical generator fueled by biodiesel or backup ULSD FO;
- One 250 kW emergency fire water pump fueled by biodiesel or backup ULSD FO; and
- Two above ground storage tanks for biodiesel and backup ULSD FO.

3.10. State Regulations

The project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.) and to the following rules in 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 of Air Pollution
62-214	Requirements for Sources Subject To the Federal Acid Rain Program
62-296	Stationary Sources - Emission Standards
62-297	Stationary Sources - Emissions Monitoring

3.11. Potential Emissions and PSD Non-Applicability Determination

The Department regulates major stationary sources of air pollution in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. Per Rule 62-210.200, (Definitions), F.A.C., a major stationary source is

1. *Any of the following stationary sources of air pollutants which emits, or has the PTE, 100 TPY or more of any PSD pollutant:*

   - *Fossil fuel-fired steam electric plants of more than 250 mmBtu/hr heat input,*
   - *Coal cleaning plants (with thermal dryers),*
   - *Kraft pulp mills,*
   - *Portland cement plants,*
   - *Primary zinc smelters,*
   - *Iron and steel mills,*
   - *Primary aluminum ore reduction plants,*
   - *Primary copper smelters,*
   - *Municipal incinerators capable of charging more than 250 tons per day of refuse,*
   - *Hydrofluoric, sulfuric, or nitric acid plants,*
   - *Petroleum refineries,*
   - *Lime plants,*
   - *Phosphate rock processing plants,*
   - *Coke oven batteries,*
   - *Sulfur recovery plants,*
   - *Carbon black plants (furnace process),*
   - *Primary lead smelters,*

- *Fuel conversion plants,*
- *Sintering plants,*
- *Secondary metal production plants,*
- *Chemical process plants,*
- *Fossil-fuel boilers (or combination thereof) totaling more than 250 mmBtu/hr heat input,*
- *Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels,*
- *Taconite ore processing plants,*
- *Glass fiber processing plants,*
- *Charcoal production plants; or*

2. *Any stationary source which emits, or has the PTE, 250 TPY or more of a PSD pollutant; or*
3. *Any physical change that would occur at a stationary source not otherwise qualifying as a major stationary source, if the change would constitute a major stationary source by itself.*

The proposed plant category is not among the bulleted stationary sources listed in paragraph 1 above, that would be classified as a major stationary source based on the PTE 100 TPY of a regulated PSD air pollutant. To be considered a major stationary source, it would be necessary for the PTE from this project to equal or exceed 250 TPY of any regulated PSD air pollutant.

The project will result in emissions of NO_X, CO, particulate matter (PM, PM_{10} and $PM_{2.5}$), SO_2, small amounts of SAM (sometimes expressed as H_2SO_4), VOC and HAP.

Table 1 summarizes the applicant's estimates of key regulated air pollutants from the proposed woody biomass electric power plant.

Potential emissions of any regulated PSD air pollutant will not equal or exceed 250 TPY, based on operational design and associated emission limits. Therefore, the proposed woody biomass electric power plant will not be subject to the PSD rules including PSD ambient air modeling or a requirement for a best available control technology (BACT) determination under that program.

Table 1 - Estimated PTE Criteria Air Pollutants (in TPY)

Source Operation	PM	PM_{10}	$PM_{2.5}$	NO_X	SO_2	H_2SO_4	CO	VOC	HAP
Boiler	33.16			66.31	53.05	1.19	97.81	9.95	24.94
Emergency Generator	0.055			0.99	0.002	minimal	1.0	0.12	0.003
Emergency Fire Pump	0.014			0.25	0.0005	minimal	0.24	0.03	0.001
Material Handling	8.91	2.58	0.43	--	--	--	--	--	--
Cooling Tower	2.44	0.38	0.38						
Project Total	44.6	36.2	34.0	67.6	53.1	1.2	99.0	10.1	24.95

3.12. <u>New Source Performance Standards and National Emissions Standards for HAP</u>

The proposed project is subject to the following NSPS regulations:

- NSPS Subpart A – General Provisions;
- NSPS Subpart Db – Industrial, Commercial, Institutional Steam Generating Units; and
- NSPS Subpart IIII – Stationary Compression Ignition Internal Combustion Engines.

The relevant emission standards presented in Table 2 include the NSPS Subpart Db emission standards applicable to the GSB.

Table 2 - NSPS Subpart Db – Emission Standards Applicable to GSB

Source	SO_2 limit[1, 4] (lbs/mmBtu)	PM Limit[2] (lb/mmBtu)	Opacity[3] (%)	NO_X[4] (lb/mmBtu)
GSB	0.32	0.030	20%	0.20

1. Sources that achieve this limit are excluded from other SO_2 reductions under NSPS Db.
2. Filterable PM only.
3. 6-minute average, except for one 6-minute period per hour of not more than 27% opacity.
4. 30-day basis.

Tables 3 and 4 include the NSPS Subpart IIII emissions standards for the emergency generator and the emergency fire pump.

Table 3 - NSPS Subpart IIII – Emission Standards Applicable to Emergency Generator

Emergency Generator (> 450 kW and ≤ 560 kW)	**CO** (g/kW-hr)[1]	**PM** (g/kW-hr)	**SO_2**[2] (% S)	**NMHC[3]+NO_X** (g/kW-hr)
Subpart IIII (2007 and later)	3.5	0.20	0.0015	4.0

1. g/kW-hr means grams per kilowatt-hour
2. SO_2 emission standard will be met by using biodiesel or ULSD FO in the emergency generator with fuel sulfur (S) content of 0.0015% by weight.
3. NMHC means Non-Methane Hydrocarbons.

Table 4 - NSPS Subpart IIII – Emission Standards Applicable to Emergency Pumps

Emergency Pumps (≥ 175 hp and < 750 hp)	**CO** (g/hp-hr)[1]	**PM** (g/hp-hr)	**SO_2**[2] (% S)	**NMHC+NO_X** (g/hp-hr)
Subpart IIII (2009 and later)	2.6	0.15	0.0015	3.0

1. g/hp-hr means grams per horsepower-hour
2. SO_2 emission standard will be met by using biodiesel or ULSD FO in the emergency pump with a fuel sulfur content of 0.0015% by weight.

In addition to NSPS Subparts Db and IIII, other conditions and emission standards are required to insure that the facility-wide PTE of each PSD pollutant (excluding fugitive emissions) will be less than 250 TPY.

The emergency equipment associated with the proposed woody biomass power plant is also subject to the applicable area source requirements of NESHAP Subpart ZZZZ. This subpart requires all affected area source units to meet the applicable emission standards of Subpart IIII.

3.13. <u>Other Department Rules Potentially Applicable to the Project</u>

- Rule 62-296.401, F.A.C. - Incinerators;
- Rule 62-296.410, F.A.C. - Carbonaceous Fuel Burning Equipment;
- Rule 62-296.416, F.A.C. - Waste-to-Energy Facilities;
- Rule 62-296.406, F.A.C. – Fossil Fuel Steam Generators with Less than 250 mmBtu Heat Input, New and Existing Units; and
- Rule 62-296.320, F.A.C. - General Pollutant Emission Limitation Standards.

Incinerators and waste to energy facilities combust waste. The fuel slate authorized by this permit does not constitute a waste or municipal solid waste according to the Department's rules. Therefore, Rules 62-296.401 and 62-296.416, F.A.C. do not apply to this project.

Carbonaceous fuel is defined in Rule 62-210.200, F.A.C. as "solid materials composed primarily of vegetative matter such as tree bark, wood waste, or "bagasse". The fuel slate described by the applicant falls into this category. Therefore, Rule 62-296.410, F.A.C. applies to this project. This provision includes a visible emissions standard of 30% opacity, a PM standard of 0.1 lb/mmBtu for the fossil fuel component and 0.2 lb/mmBtu for the carbonaceous fuel part.

The GSB will use biodiesel or as a backup ULSD FO for startup, shutdown and bed stabilization. But the fossil fuel capability will be less than 250 mmBtu/hr of heat input. Therefore, Rule 62-296.406, F.A.C. applies to the extent that fossil fuel is burned in the GSB. This section requires a BACT determination for PM and SO_2 and imposes a visible emissions standard of 20%. The BACT requirement for the fossil fuels will be satisfied by use of ULSD FO, the requirements of 40 CFR Subpart Db and the permit requirements intended to insure that the facility-wide PTE of PM and SO_2 are less than 250 TPY.

The project is subject to Rule 62-296.320, F.A.C., including provisions on VOC storage and handling; objectionable odor; open burning; visible emissions; and reasonable precautions to control fugitive emissions.

4. EMISSIONS FORMATION AND CONTROL FOR THE GSB

4.1. <u>NO_X Emissions</u>

Discussion: The biomass-fueled GSB has a maximum heat input rate of 833 mmBtu/hr on a 4 hour average basis with a maximum heat input of less than 250 mmBtu/hr from fossil fuel (backup ULSD FO) for startup, shutdown and bed stabilization. Following are the general characteristics of the biomass-fueled GSB for the FBE project:

Table 5 - Characteristics of the Biomass-fueled GSB

Parameter	Description
Boiler Type	Grate stoker, conventional waterwall boiler tube design
Primary Fuel	Clean woody biomass at average of 68 TPH, basis 5,600 Btu/pound (HHV)
Supplemental Fuel	Biodiesel and ULSD FO as backup
Bottom Ash Removal	Transported wet by submerged drag-chain conveyor to ash silo
Fly Ash Removal	Transported by enclosed conveyer from ESP to ash storage silo
Heat Input Rate	Nominal 757 mmBtu/hr (maximum 833 mmBtu/hr on a 4-hour average basis) of which less than 250 mmBtu/hr is from fossil fuels
Thermal Efficiency	To be established
Steam Production	Approximately 560,000 lb/hour at 1,550 pounds per square inch (psi), 960 °F
Stack Parameters	Approximately 9.3 feet diameter; 145 feet tall
Flue Gas	Approximately 266,000 actual cubic feet per minute (acfm) at 300 °F
Particulate Control	Mechanical cyclone(s) and ESP greater than 99% efficiency
NO_X Control	Furnace design, OFA, SCR
SO_2 Control	IDSIS before ESP, low sulfur in wood, biodiesel and backup ULSD FO
VOC and CO Control	GCP, ox-cat

NO_X formation 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. The biomass GSB is expected to emit 66.3 TPY of NO_X the majority of which will be thermal NO_X.

There are several NO_X reduction processes available including pre and post combustion control equipment. Selective non-catalytic reduction (SNCR) is a technology whereby NO_X emissions are controlled by reaction with NH_3 or urea at high temperature in the furnace. The products of the reaction are N_2 and water vapor (H_2O). SCR involves the same reaction but in the presence of catalyst and at lower temperature. The catalyst is typically located in the dusty, medium temperature zone *upstream* of the air heater and other control equipment including particulate control devices.

FBE will locate both the ESP and SCR systems upstream of the air heater. The SCR system will be located between the ESP and the air heater.

Applicant's Proposal for NO_X: The NSPS Subpart Db establishes a limit of 0.20 lbs NO_X/mmBtu on a 30-day rolling average. The applicant proposes a limit of 15.1 lb/hr on a 12-month average (equal to 66.3 TPY), rolled monthly achieved by an SCR system located downstream of the ESP. The proposed limit equates to approximately 0.02 lb NO_X/mmBtu.

Department's Review: For reference, some biomass projects comparable to the FBE project are listed in Table 6. The characteristics of the FBE project (though not actually proposed as limits) are given in the first row.

Some of the projects listed in the table triggered PSD for NO_X while others took synthetic minor limits to avoid triggering PSD or Non-Attainment New Source Review. All include use of biomass, wood chips or woody debris. Most projects, especially those imbedded within the RACT/BACT/LAER Clearinghouse (RBLC) survey, rely on SNCR or SCR.

The NO_X emission characteristic of the FBE project (0.02 lb/mmBtu) is much lower than the limits from projects that trigger PSD and a BACT determination as well as projects that took limits to avoid PSD and a BACT determination. Because the value is so low compared with comparable projects, the Department required FBE to provide reasonable assurance that such a low limit is achievable.

The applicant provided a quotation from Haldor-Topsoe (HT), a reputable provider of SCR catalyst. HT would provide its high temperature titanium (Ti) and tungsten (W) formulation (DNX-949) for high temperature SCR applications (~ 800 °F) under "clean" (after ESP) conditions to reduce emissions from 0.30 to 0.02 lb/mmBtu for a reduction of greater than 93 percent (%).

Given the experience of HT in providing SCR catalysts for high temperature non-dusty applications (such as simple cycle gas turbines) and the willingness to quote the guarantee for the biomass application, the Department has reasonable assurance that the FBE project can meet the proposed limits.

The Department accepts the NO_X proposal of 15.1 lb/hr on a 12-month average basis, rolled monthly as requested by FBE. This equates to 0.02 lb/mmBtu and 66.3 TPY. The Department will also incorporate the 30-day limit of 0.20 lb/mmBtu required by 40 CFR 60, Subpart Db. Compliance with the mass emission rate limit and the Subpart Db concentration limit shall be by demonstrated by a NO_X continuous emission monitoring system (CEMS).

4.2. SO_2 Emissions

Discussion: SO_2 is formed from sulfur compounds contained in biomass. According to the application, the biomass GSB is expected to emit 53.0 TPY of SO_2. The clean woody biomass to be used by FBE will be typically low in sulfur content. A conservatively (high) figure of 0.07% sulfur was provided in the application for short-term emissions and 0.02% sulfur on a long-term basis. These values are included in Table 7 along with heating value, ash and sulfur content of various types of biomass and fossil fuels. The values are on a dry basis except as otherwise noted.

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

Project Location	CO	VOC	NO_X	PM/PM_{10}	SO_2
FBE, Manatee County, FL GSB – woody biomass ~757 mmBtu/hr (equivalents)	~0.0295 12-month Ox-cat	~0.003 stack test Ox-cat	~0.020 12-month SCR	~0.01 stack test ESP	~0.016 12-month sorbent in ducts
GREC, Alachua County, FL BFB – woody biomass ~758 mmBtu/hr (equivalents)	~0.12 24-hour GCP	~0.013 stack test GCP	~0.070 24-hour SCR	~0.029 stack test fabric filter	~0.041 24-hour sorbent in ducts
ADAGE, Gretna County, FL BFB – woody biomass ~758 mmBtu/hr (equivalents)	~0.074 12-month GCP	~0.017 stack test GCP	~0.070 12-month SCR	~0.029 stack test fabric filter	~0.045 12-month sorbent in ducts
ADAGE, Hamilton County, FL BFB – woody biomass ~758 mmBtu/hr (equivalents)	~0.074 12-month GCP	~0.017 stack test GCP	~0.070 12-month SCR	~0.029 stack test fabric filter	~0.045 12-month sorbent in ducts
HEF, Highlands County, FL stillage, wood, gas, ULSD FO ~198 mmBtu each (proposed)	0.10 30-day GCP	0.005 stack test GCP	0.075 30-day SNCR	0.01 stack test fabric filter	0.06 30-day BFB limestone
Wheelabrator, Auburndale, FL GSB – wood and tires ~630 mmBtu/hr (1990s)	0.32 30-day GCP	0.035 stack test GCP	0.14 30-day SNCR	0.02 stack test fabric filter	0.10 30-day lime spray
U.S. Sugar Clewiston, FL GSB - bagasse ~1,000 mmBtu/hr (2003)	0.38 12-month GCP	0.05 Stack test GCP	0.14 30-day SNCR	0.26 stack test fabric filter	0.06 30-day no control
RBLC Survey All designs – any biomass ≥ 100 mmBtu/hr	0.1 – 0.63 typical 30-day GCP	0.005 – 0.05 stack test GCP	0.075-0.45 30-day various	0.0125 – 0.8 stack test various	0.02-1.54 typical 30-day various
Whitefield Power & Light, NH whole tree chips (WTC) 15 MW	Not known	Not known	0.075 guarantee RSCR	Not known	Not known
Boralex Stratton, ME WTC 50 MW	Not known	Not known	0.075 guarantee RSCR	Not known	Not known
Bridgewater Power, NH WTC 16 MW	Not known	Not known	0.075 guarantee RSCR	Not known	Not known
Burlington Electric, VT WTC 54 MW	Not known	Not known	0.065 guarantee RSCR	Not known	Not known
Palmer Springfield, MA construction/demolition (C&D) debris and WTC. 38 MW	Not known	Not known	0.065 guarantee RSCR	Not known	Not known
NSPS Subpart Db NG, wood, ULSD FO ≥ 100 mmBtu/hr	No standard	No standard	0.10-0.20 based on heat release rate	0.03 20% opacity wood basis	0.32 if achieved by low S fuels
NESHAP Subpart DDDDD[a] large solid fuel category ≥ 100 mmBtu/hr	~0.35 400 ppm @ 3% O_2[b] GCP	No standard	No standard	0.025 stack test	No standard

a. Subpart DDDDD was promulgated and then vacated

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

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

Fuel Class	Fuel	Gross Heating Value Btu/lb	Ash (%)	S (%)
Bioenergy Feedstocks	**application basis**	**5,600**		**0.07, 0.02**
	hog fuel [1]	**5,301 (wet)**	**1.0**	**0.02**
	forest slash [1]	**4,879 (wet)**	**1.0**	**0.02**
	manufacturing waste [1]	**7,409**	**1.1**	**0.03**
	cellulosic ethanol stillage	4,200 (wet)	7	0.08
	sweet sorghum	6,570	5.5	0.15
	sugarcane bagasse	7,720	3.2-5.5	0.10-0.15
	hardwood	8,745	0.45	0.009
	softwood	8,360	0.3	0.01
	hybrid poplar	8,105	0.5-1.5	0.03
	bamboo	8,085	0.8-2.5	0.03-0.05
	switchgrass	7,810	4.5-5.8	0.12
	miscanthus	7,785	1.5-4.5	0.1
	arundo donax	7,295	5-6	0.07
Liquid Biofuels	bioethanol	11,940	~0	<0.01
	biodiesel	17,050	<0.02	0.0015 [2]
Fossil Fuels	coal (low rank)	6,400-8,100	5-20	1.0-3.0
	coal (high rank)	11,500-12,800	1-10	0.5-1.5
	ULSD FO	18,150	negligible	<0.0015
	Natural Gas	1,030 Btu/cubic foot	negligible	< 0.002
1. Database estimates given in FBE application				
2. Grade S15 biodiesel per ASTM D6751-09 required for FBE project				

Applicant's SO_2 Proposal. The applicant proposes a limit of 12.1 lb SO_2/hr on a 12-month average, rolled monthly achieved by the use of low sulfur fuel and an IDSIS system located upstream of the ESP. The value is equivalent to 53.0 TPY and 0.016 lb SO_2 /mmBtu. The IDSIS will use either sodium bicarbonate ($NaHCO_3$) or trona [$Na_3(CO_3)(HCO_3)\cdot 2(H_2O)$] to react with SO_2 in the gas stream with subsequent removal in particulate form in the ESP. According to the applicant the SO_2 removal efficiency of the IDSIS is 88%.

Department's Review. According to Table 7, the woody biomass, biodiesel and ULSD FO are all low in sulfur content. Per 40 CFR 60.42b(k)(2), units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 0.32 lb/mmBtu or less are exempt from SO_2 emissions limits in 40 CFR 60.42b(k)(1). The language is as follows:

(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 0.20 lb/mmBtu heat input or 8 percent (0.08) of the potential SO_2 emission rate (92 percent reduction)

and 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) *Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 0.32 lb/mmBtu heat input or less are exempt from the SO_2 emissions limit in paragraph (k)(1) of this section.*

Based on Table 7, the woody biomass to be burned by FBE will contain between 0.02 and 0.07% sulfur on a wet basis. The pre-control SO_2 emission potential is calculated as follows:

(0.02 - 0.07 lb S/100 lb fuel)(2 lb SO_2/lb S)(lb fuel/5,600 Btu)(10^6 Btu/mmBtu) = 0.07 - 0.25 lb SO_2/mmBtu.

The range is less than the 0.32 lb/mmBtu value given in 40 CFR 60.42b(k)(2). Any combination of biomass combustion with biodiesel or ULSD FO will result in even lower emissions. Therefore, it is reasonable to conclude that the potential (uncontrolled) SO_2 emission rate is less than 0.32 lb/mmBtu and that the project is exempt from any additional SO_2 emission limits in Subpart Db. The after-control limit proposed by FBE is equivalent to 5% of the 0.32 lb/mmBtu "low sulfur" fuel mixtures.

According to 40 CFR 60.49(r),

(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.*

The Department will include a limit of 12.1 lb SO_2/hr on a 12-month average, rolled monthly. The SO_2 emission characteristics of the FBE project are less than emission limits from projects that trigger PSD and a BACT determination as well as projects that took limits to avoid PSD and a BACT determination. Compliance with the mass emission rate limit shall be by demonstrated by a SO_2 CEMS.

The separate Department SO_2 BACT requirement under Rule 62-296.406, F.A.C. for the fossil fuels will be satisfied by use of biodiesel or as a backup ULSD FO.

4.3. SAM Emissions

Discussion: 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 (H_2SO_4). SAM condenses on the cool surfaces in the exhaust duct, air pollution control equipment or on fly ash particles.

Applicant's SAM Proposal: The applicant does not propose a limit for SAM. According to the application and as a worst case, the biomass GSB is expected to emit 0.3 lb SAM/hr from the boiler stack when burning woody biomass. Annual uncontrolled H_2SO_4 emissions are estimated at approximately 1.19 TPY from the boiler stack.

Department's Review: Excessive emissions of SAM are reflected as increased plume opacity. The Department will limit visible emissions to 10% opacity to insure compliance with PM/PM_{10} limits as discussed below. This requirement will discourage excessive emissions of SAM.

Sorbent injection coupled with PM/PM_{10}/$PM_{2.5}$ removal in the ESP will also tend to minimize SAM emissions. The Department will not establish an actual SAM limit because it is clear that emissions will be much less than 250 TPY. Control of SO_2, opacity limitations and the PM/PM_{10}/$PM_{2.5}$ controls will minimize SAM emissions. The Department will require an initial stack test to determine the SAM emission characteristics of the GSB.

4.4. CO Emissions

Discussion: CO is a product of incomplete combustion. Refer to Table 6 above for a listing of CO limits from biomass projects.

Applicant's CO Proposal: The applicant proposes a limit of 22.3 lb CO/hr on a 12-month average, rolled monthly achieved by GCP in the boiler and an ox-cat system after the ESP to further oxidize CO. The value is equivalent to 97.8 TPY and 0.0295 lb CO/mmBtu.

Department's Review: The Department will set a mass emission rate limit of 22.3 lb/hr on a 12 month average basis, rolled monthly as requested by the applicant. The limit will insure that the PTE of the entire project is much less than 250 TPY that would otherwise trigger a PSD review and a BACT determination. Additionally, the limit is consistent with the applicant's request for annual emission limits less than 100 TPY.

The CO emission characteristics of the FBE project are less than permitted emission limits for projects that trigger PSD and a BACT determination as well as projects that took limits to avoid PSD and a BACT determination. For reference, the recently vacated NESHAP Subpart DDDDD would have required compliance with a CO limit of 400 ppm @ 3% O_2 as a surrogate for organic HAP. This value is roughly equal to 0.35 lb CO/mmBtu. By comparison, the limit request by FBE is approximately 1/10th of the previous Subpart DDDDD limit.

4.5. VOC Emissions

Discussion: VOC is a product of incomplete combustion. Refer to Table 6 above for a listing of VOC limits from biomass projects.

Applicant's VOC Proposal: The applicant does not propose a limit for VOC. Low emissions will be achieved by GCP and the ox-cat system. The applicant has estimated VOC emissions from the boiler at 2.3 lb/hr and 9.9 TPY.

Department's Review: The Department will not establish an actual VOC limit because it is clear that emissions will be much less than 250 TPY. However, the Department will require an initial stack test to determine the VOC emission characteristics of the GSB when controlled by GCP and an ox-cat system. The Department also notes that incorporation of the ox-cat will also reduce emissions of organic HAP. The SCR system for NO_X control will also help reduce VOC emissions including organic HAP emissions such as dioxin and furan (D/F).

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

Discussion: PM/PM_{10}/$PM_{2.5}$ are formed from ash contained in the biomass, products of incomplete combustion and from chemical reactions between products of combustion that form alkali and ammoniated chlorides, sulfates, nitrates and other such species.

Applicant's Proposal: The applicant proposes a PM/PM_{10} limit of 0.01 lb/mmBtu (filterable fraction), based on a 3-hour EPA Method 5. This limit will insure compliance with the NSPS Subpart Db PM limit of 0.03 lb/mmBtu (filterable fraction only) and the carbonaceous fuel PM limit under Rule 62-296.410, F.A.C. of 0.2 lb/mmBtu (filterable fraction only).

The proposal of 0.01 lb/mmBtu will limit emissions of PM/PM_{10} to 33.2 TPY (filterable) and well below 250 TPY PSD-threshold.

The applicant proposes to comply with a visible emissions (VE) limit of 20% based on an annual compliance test using EPA Method 9.

Department's Review: The Department will set a PM limit of 0.01 lb/mmBtu (filterable) using EPA Method 5. This limit will readily insure compliance with the Subpart Db and with Rule 62-296.410, F.A.C.

The separate Department PM BACT requirement under Rule 62-296.406, F.A.C. for the fossil fuels will be satisfied by use of biodiesel or as a backup ULSD FO.

The Department will also set a VE standard of 10% opacity (6-minute average), except for one 6-minute period per hour of not more than 20% opacity as measured by a continuous opacity monitoring system (COMS).

The Department will establish a NH_3 limit of 10 parts per million, by volume at 7% O_2 (ppmvd) to be demonstrated by initial and annual tests using EPA Method 320. The NH_3 limit will be readily achieved by SCR.

4.7. HAZARDOUS AIR POLLUTANTS

The applicant believes that the facility is not a major source of HAP because it will not have the PTE 10 TPY of any single HAP or 25 TPY of all HAP. If the PTE of any single HAP is equal to or greater than 10 TPY or if the PTE of all aggregated HAP is equal to or greater than 25 TPY then the source would be a major source of HAP and a case-by-case determination of Maximum Achievable Control Technology (MACT) would be required. MACT would require limitations for several HAP or surrogates for those HAP such as PM-metals or organic HAP.

Estimates of individual key HAP emissions are provided in Table 8. Only the GSB HAP emissions are listed because the contribution from other sources is only 0.01 TPY. The sum of HCl, metals and organic HAP is so close to 25 TPY that reasonable assurance in the form of limits and monitoring is required.

Table 8 – Applicant's Estimated PTE of HAP from the GSB in TPY

Pollutant [1]	HCl	HF	Metals	C_3H_4O	C_6H_6	CH_2O	C_8H_8	Other Organics	Total
Emissions	9.83	0.00	0.28	3.3	3.5	3.6	1.6	2.83	24.94

1. HCl is hydrogen chloride; HF is hydrogen fluoride; C_3H_4O is acrolein; C_6H_6 is benzene; CH_2O is formaldehyde; C_8H_8 is styrene

HCl Emissions

Discussion: Untreated woody biomass will typically contain less than 0.02% Cl. The biodiesel and ULSD FO are even lower in chloride (Cl) content. The Cl can be released as HCl and or it can be bound to the ash. Cl can also condense in the form of alkali salts (NaCl and KCl) or as NH_4Cl in the presence of NH_3. Some Cl can react further with organic species forming organic HAP including D/F.

According to the application the uncontrolled HCl emissions from the GSB would emit approximately 19.7 lb/hr (equal to 86.3 TPY).

Applicant's HCl Proposal: According to the application, the biomass GSB has the PTE 9.83 TPY of HCl after control by the IDSIS and the ESP. The applicant does not propose an emission limit or a compliance method to insure the HCl emissions are less than 10 TPY.

Department's Review: The Department will set a limit of 9.86 TPY of HCl on a 12-month rolling average, rolled monthly. Compliance shall be demonstrated by a HCl-CEMS. The 12-month limit equates to 2.25 lb/hr HCl. The limit, the IDSIS, the ESP and the continuous measurement requirement will provide reasonable assurance that HCl will not be emitted at the rate of 10 TPY or greater.

HF Emissions

Discussion: Fluorine (F) is a naturally occurring constituent of vegetative matter. The F can be released as HF and or it can be bound to the ash. F can also condense in the form of alkali salts (NaF, KF, alkali fluorosilicates, etc.).

Applicant's HF Proposal: According to the application, the biomass GSB has the PTE 0.00071 TPY (2.36 lb/yr) of HF after control by the IDSIS and the ESP. The applicant does not propose an emission limit or a compliance method to demonstrate the projected minimal HF emissions.

Department's Review: The Department believes the PTE of HF is much greater than the projection submitted by the applicant due to an error in the submittal. Actual annual emissions of HF should be on the order of several tons. The Department will set a limit of 2.25 lb HF/hr (9.86 TPY) to insure HF emissions do not exceed the 10 TPY HAP threshold. In addition, the Department will require a HF-CEMS.

The Department will also set a limit for combined emissions of HCl and HF to 11.5 TPY as part of an overall facility-wide cap discussed further below to insure aggregate HAP emissions will be less than 25 TPY.

Organic HAP and Chlorine (Cl_2)

Discussion: According to the application and Table 8, no single organic HAP will be emitted at a level approaching 10 TPY. Total organic HAP plus Cl_2 emissions will equal approximately 14.83 TPY.

Table 9 is a further breakdown of the key organic HAP plus Cl_2 expected by the applicant to be emitted at levels greater than or equal to 0.1 TPY.

Table 9 – Applicant's Estimated PTE of Organic HAP plus Cl_2 from the GSB in TPY

Pollutant [1]	C_3H_4O	C_6H_6	CH_2O	C_8H_8	C_2H_4O	Cl_2	CH_2Cl_2	C_7H_8	**Other**	**Total**
Emissions	3.3	3.5	3.6	1.6	0.69	0.64	0.24	0.76	0.49	14.83
1. C_2H_4O is acetaldehyde; CH_2Cl_2 is dichloromethane; C_7H_8 is toluene										

Applicant's Organic HAP Proposal: The applicant will install an SCR system and an ox-cat system that will provide additional control of organic HAP beyond that provided by good combustion methods. The applicant does not propose an emission limit or testing requirements for organic HAP or Cl_2.

Department's Review: The Department notes that this is the first known biomass boiler to incorporate both SCR and ox-cat systems. Therefore, organic HAP will be destroyed to a very high degree. Because organic HAP comprise almost 60% of all projected HAP emissions, it is necessary to limit these to insure the PTE of all HAP is less than 25 TPY.

According to the application, the sum of projected emissions of the seven key listed organic HAP (C_3H_4O, C_6H_6, CH_2O, C_8H_8, C_2H_4O, CH_2Cl_2 and C_7H_8) plus Cl_2 is 14.34 TPY of the listed total of 14.83 TPY. Rather than setting individual limits for each of the eight species identified in Table 9, the Department will limit their total emissions 2.75 lb/hr and 12 TPY as part of an overall facility-wide cap discussed further below to insure aggregate HAP emissions will be less than 25 TPY. Compliance will be determined by an initial and annual compliance tests conducted in accordance with EPA Method 320 for organic and inorganic HAP by Fourier Transform Infrared (FTIR) spectroscopy.

Good combustion practices, catalytic systems and low fuel chloride content will also tend to minimize and destroy D/F.

Overall HAP Emissions

To provide reasonable assurance that the potential to emit HAP is less than 25 TPY, combined emissions of HCl and HF based on CEMS data will be limited to 11.5 TPY and the combined emissions of the 7 key organic HAP plus Cl_2 will be limited to 12.0 TPY. These limits account for 23.5 TPY as shown in Table 10 below.

Table 10 – Department's Proposed Limitation on HAP emissions in TPY

Pollutant	HCl	HF	Σ 7 Organic HAP, Cl_2	Total [1]
Limit	9.86	9.86	12.0	23.5
	Σ HCl, HF = 11.5			

1. By adding the estmates 0.28, 0.49 and 0.01 for metals, other organic and miscellaneous HAP, respectively, to this limit, the Department estimates annual emissions of 24.28 TPY of HAP from the facility.

The remainder consists of metal HAP, other organic HAP and miscellaneous emissions equal 0.78 TPY. The total estimate for the facility is 24.28 TPY. Compliance with the permitted PM/PM_{10} limits will provide reasonable assurance that emissions of metal HAP will be as low as projected.

The Department has reasonable assurance that the facility is not a major source of HAP because:

- The IDSIS and ESP will control acid gases and metal HAP;
- A HCl-CEMS and a HF-CEMS will be installed to monitor emissions of the two HAP expected to be emitted at the highest levels;
- There will be an annual cap of 11.5 TPY on HF and HCl combined;
- Good combustion practices will minimize formation of organic HAP;
- SCR and ox-cat systems will destroy organic HAP including D/F;
- There will be an annual cap of 12 TPY and required tests for the 7 key organic HAP identified by the applicant plus Cl_2;
- Measurement, whether by CEMS or by annual test, will be conducted to demonstrate total HAP emissions of 23.5 TPY excluding metal HAP, other organic HAP and miscellaneous HAP;
- PM/PM_{10} testing including visible emissions will serve as a surrogate for the metals HAP; and
- The total estimated HAP emissions from the facility will be 24.28.

Based on fuel properties, control equipment, and measurement requirements, the Department has reasonable assurance that the FBE facility will not equal or exceed 10 TPY of any single HAP or 25 TPY of all HAP and will not be a major source of HAP.

For reference, the vacated MACT standard (40 CFR 63, Subpart DDDDD) would have allowed HCl emissions of 66 TPY and would not have limited HF emissions. The vacated Subpart DDDDD had no limits on organic HAP and relied on CO control which would have been 1,160 TPY, compared with 99 TPY allowed for this project and limited by CO-CEMS.

In addition to having reasonable assurance that the plant will not be a major source of HAP, the Department concludes that it will be much better controlled than EPA believed necessary for a major source of HAP.

5. STARTUP, SHUTDOWN AND MALFUNCTIONS

The boiler will be designed to accommodate biodiesel and backup ULSD FO for boiler startup, shutdown and boiler bed stabilization only. The maximum burner heat input will be limited to less than 250 mmBtu/hr.

The applicable CEMS-based SO_2, NO_X, CO, HCl and HF emissions limits are largely 30-day or 12-month rolling limits that do not provide for data exclusion per the applicable NSPS Subpart or the nature of emission caps for the purposes of avoiding PSD. PM/PM_{10} and VOC emissions are measured by a once per year test. The Department will not allow exclusion of any measured emission data.

The only other limit for which the excess emission rule could apply is opacity. In the case of the NSPS Subpart Db requirements, the 20% opacity standard (6-minute average) applies at all times except for one 6-minute period per hour of not more than 27 percent opacity and during periods of startup, shutdown, or malfunction.

The Department proposes a separate 10% opacity standard except for a single 6-minute period per hour of during which VE may not exceed 20% opacity. The Department will allow excess visible emissions by applying a standard of 20% during startups, shutdown and malfunctions except for one 6-minute period per hour of not more than 27% opacity during periods of startup, shutdown and malfunction.

It is important to limit the occurrences of startups, shutdowns and malfunctions as well as the visible emissions (opacity) during those occurrences to insure that PSD is not triggered.

6. BEST MANAGEMENT PRACTICES PLAN TO CONTROL FUGITIVE EMISSIONS

Table 11 is a listing of the estimated fugitive emissions from the project.

Table 11 - Estimated PTE of Criteria Air Pollutants (TPY)

Source Operation	PM	PM_{10}	$PM_{2.5}$
Truck Traffic on Paved Roads	7.65	1.51	0.22
Stack Out Operations	0.07	0.03	0.00
Reclaim Operations	0.018	0.009	0.001
Screens and Hog Mill	0.232	0.089	0.061
Material Storage Silos	0.94	0.94	0.14
Project Total Fugitive Sources	8.91	2.58	0.42

Fugitive emissions are not counted in determining whether this particular project is subject to PSD. However, the Department requires adherence to Rule 62-296.320(4)(c), F.A.C., which specifies the types of reasonable precaution required to control unconfined emissions of PM.

Accordingly, the applicant submitted a preliminary BMP plan that described the principles and specifics of fugitive dust control measures and storage pile management to comply with the rule and additional measures for fire prevention and response procedures to excess fugitive dust emissions. The Department incorporated these principles and specifics along with additional requirements into a BMP plan that is provided in Tables 12, 13, 14 and 15 below.

Table 12 - BMP for Storage Pile Management

- A woody biomass storage pile fugitive dust management plan shall be developed and maintained onsite. The plan shall identify warning signs and identify corrective actions for conditions that could result in excessive wind erosion and fugitive dust formation. Plant personnel shall be trained to recognize such warning signs.
- Operational plans will recognize conditions such as high winds likely to result in wind erosion and excessive fugitive dust and will instruct plant personnel to curtail movement of fuel by mobile equipment under such conditions.
- Mechanical moving of woody biomass by front end loaders and other supporting equipment shall be minimized on high wind event days.
- First in first out biomass utilization shall be implemented to minimize objectionable odors.
- The woody biomass storage areas shall be monitored and if conditions are conducive to wind erosion and fugitive dust formation, procedures from the fugitive dust plan shall be implemented.
- Mobile equipment will be used to maintain the pile's design shape and to ensure adherence to FIFO in reclaim operations

Table 13 - BMP for Minimization of Fugitive Dust Emissions

- Conveyor systems and associated drop points shall be enclosed to the extent practicable to minimize exposure to air currents. 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.
- Drop points to woody biomass storage areas shall be designed to minimize the overall drop height exposed to air current.
- Periodic equipment inspection and maintenance shall be performed to maintain the integrity of conveyor systems and associated drop point enclosures. Appropriate plant records shall be maintained on equipment maintenance performed.
- Fuel silos shall be equipped with vent filters.
- Plant personnel shall conduct daily inspections of the conveyor systems and associated drop point integrity to identify any equipment abnormalities.
- Signs shall be posted identifying warning signs of potential equipment malfunction.
- Plant personnel shall be trained on identification of warning signs for potential equipment malfunction.
- Procedures shall be established for defining excessive fugitive dust from woody biomass truck unloading operations. Plant personnel shall monitor truck unloading operations and if excessive fugitive dust is detected plant personnel shall implement appropriate fugitive dust minimization techniques. Plant personnel shall be trained on procedures for defining and minimizing excessive

dust from the truck unloading operations. • All major roadways at the plant shall be paved. • Mud, dirt, spilled biomass or similar debris shall be removed promptly from the paved roads. • Plant personnel shall be trained on what constitutes excessive dust on paved roads. • Transfer points and fuel bins are equipped with vent filters. • Fuel handling equipment shall be inspected for proper operation and for maintenance requirements. • Plant fuel handling personnel shall implement procedures for monitoring and controlling unplanned fugitive dust emissions, including truck handling and unloading, and dirt or spilled biomass fuel on roads. • Plant personnel shall spray, wash, scrape, or otherwise remove dirt or spilled biomass fuel on plant roads as necessary to reduce fugitive emissions

Table 14 - BMP for Fire Prevention / Spontaneous Combustion Minimization Practice

• A fire management plan (FMP) shall be developed to identify and list the causes and conditions giving rise to spontaneous combustion. • Contact local fire marshal to develop fire management plan. The FMP shall be maintained on site. • The FMP shall 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. • Sufficient inspections of the woody 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. • Signs which identify potential fire hazards shall be posted at the plant. • Incoming unprocessed materials shall be stored in areas in accordance with clearance ranges between each storage area as described in the FMP. • The stacker reclaimer shall maximize the removal of older material in order to minimize the stacking of newer material on top of older material. • Compaction of woody biomass materials in the storage areas shall be minimized. • Fuel pile fire protection equipment may be used for minimization of fugitive dust emissions and dust suppression as required. • Plant personnel shall conduct daily inspection for fire hazards and monitor the hazards using video surveillance. • The FMP shall describe the use of fire-water cannons, mounted on elevated structures, together with mobile equipment to uncover and rapidly extinguish any smoldering materials. • The size of the fuel storage pile will not exceed the design value – this is a primary control measure, based upon the limited on-site fuel storage of about 2 weeks' worth of fuel. Specifically, the stacker will build a pile in zones up to a maximum of 60 feet high (an average of 40 feet high) and the reclaimer will start with the first zone built and reclaim the pile down to within two inches of grade.

Table 15 - BMP for Quality Assurance of Clean Woody Biomass

Clean woody biomass shall mean: the feedstock will consist of woody biomass that will be processed at a remote fuel preparation area (or areas) where it will be sorted, screened and chipped to size. Woody biomass is characterized by cellulose, hemicellulose, lignin and mineral content. The biomass for this project is limited to clean woody biomass meaning trees and woody plants, including limbs, tops, trunks, needles, leaves, stalks and other woody parts, grown in a forest, urban and suburban environments, utility rights-of-way, woodland, rangeland environment, tree farm or agricultural crop farm. The term also includes the residues and rejects from the physical (non-chemical) processing of such woody biomass. The woody biomass feedstock will be delivered via truck to the site at a rate of approximately 65 trucks per day.

Clean Woody Biomass can include: saw dust; hogged fuel; processed butt cuts, and fuel crop.

- *Saw Dust* is defined as a by-product of forest and forest product operations.
- *Hogged Fuel* is material that comprises land clearing debris that has either been pre-processed, run through a tub grinder, or a horizontal mill at a specific private forest clearing site.
- *Butt Cuts* are untreated round residues that are either of oversized or undersized non processible materials from post or pole manufacturers.
- *Fuel Crop* is a vegetative product specifically grown for energy use or a waste product of agricultural operations (e.g., corn stover, peanut hulls, etc.).

The following is required from the permittee:

1) Woody biomass feedstocks shall be obtained from vendors that certify that the woody biomass feed stocks they supply to FBE meet the definition of woody biomass specified above. In addition, the vendor must certify that the woody biomass does not contain any of the prohibited items listed in **Item 10,** below.
2) Any such vendor certification shall include, in legible fashion, the name of the vendor's representative making the certification as well as the representative's signature. The permittee shall retain records of the certifications for 5 years.
3) The woody biomass feedstock will be delivered to the FBE facility in vehicles designed to prevent release. Woody biomass feedstock shall be delivered to FBE primarily by trucks.
4) The permittee shall inspect each shipment of woody 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.
5) For each original source of woody biomass feedstock, the permittee shall retain documentation of the original source's procedures to prevent the contamination of the woody biomass with any materials not specifically authorized by this permit. Such documentation shall explicitly identify the procedures used to prevent the introduction of any treated wood or any other prohibited materials into the woody biomass.
6) The permittee shall retain documentation of the off-site material handling facility's procedures for receiving, segregating and loading the woody biomass from the original sources. In addition, the permittee shall retain documentation of the quality assurance procedures in place at the off-site handling facility to ensure the woody biomass is not contaminated with any materials not specifically authorized by this permit. Such documentation shall explicitly identify the procedures used to prevent the introduction of any treated wood or any other prohibited materials into the woody biomass.

7) For each shipment of woody biomass, the permittee shall record the date received, the original source and the material description of the woody biomass and the quantity received, and the name of the inspector, in a legible fashion, and the signature of the individual(s) responsible for performing the visible inspection in **Item 8**, below.

8) The permittee shall inspect each shipment of woody biomass upon receipt and during unloading for any material not specifically authorized by this permit. If the permittee identifies any such material, the material must be removed from the shipment and the material vendor notified. The rejected material must be disposed of following all applicable Department regulations. The permittee shall maintain a record of rejected materials, the amount of material rejected and the reason(s) for rejection.

9) The permittee shall maintain records of rejected shipments and disposition thereof. Such records shall be made available to the Department upon request and kept for a period of 5 years.

10) The following items <u>are not</u> 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) yard trash;
    e) municipal solid waste;
    f) paper;
    g) treated wood such as CCA or creosote;
    h) painted wood; and
    i) wood wastes from landfills.

7. AMBIENT AIR QUALITY

7.1. <u>Introduction</u>

The proposed project will not increase emissions at levels in excess of PSD significant amounts. Therefore, an ambient air quality modeling analysis was not required for this project. However, the applicant provided an ambient air quality analysis to show compliance with the Ambient Air Quality Standards (AAQS). The following sections include the AAQS analysis, a review of current air quality in the vicinity of the project, and information regarding this project and how it relates to other nearby sources of pollution.

7.2. <u>Major Stationary Sources Near the Proposed FB Energy Site</u>

The proposed project is in the northern part of Manatee County and within 3 km of the Hillsborough and Manatee county line. Tables 16 through 20 are lists of the largest stationary sources, by pollutant, in Manatee and Hillsborough counties. The information is from annual operating reports submitted by the operators to the Department for 2008. The future emissions from the FBE project are included for comparison purposes.

The largest sources in the area are the TECO Big Bend Station approximately 26 km north, northeast and the FPL Manatee Power Plant approximately 20 km east of the proposed FBE site. For reference, emissions have greatly decreased from the power plants in the area since 1998 when emissions from TECO Big Bend and FPL Manatee were 107,400 and 33,500 tons of SO_2, respectively. In 2008, the TECO Big Bend and FPL Manatee SO_2 emissions were 9,615 and 8,241 tons, respectively. The TECO Bayside Station (formerly TECO Gannon) emitted approximately 64,600 tons of SO_2 in 1998 and only 16 tons in 2008. Similar reductions occurred for NO_X. In 1998, TECO Big Bend and FPL Manatee emitted 37,500 and 10,400 tons of NO_X respectively while TECO Bayside emitted 30,800 tons. In 2008 the three plants emitted 17,200, 2,085 and 385 tons respectively.

Table 16 - Largest Sources of SO_2 (2008)

Owner	Site Name	TPY
Tampa Electric Company (TECO)	TECO Big Bend Station	9,615
Florida Power and Light (FPL)	FPL Manatee Power Plant	8,241
Mosaic Fertilizer	Mosaic Fertilizer Riverview Facility	3,037
Envirofocus Technologies	Envirofocus Technologies	1,108
FBE	**FBE Port Manatee (Proposed)**	**53**
City of Tampa	McKay Bay Refuse to Energy Facility	18
TECO	TECO Bayside Station	16

Table 17 - Largest Sources of NO_X (2008)

Owner	Site Name	TPY
TECO	TECO Big Bend Station	17,200
FPL	FPL Manatee Power Plant	2,082
Hillsborough County	Hillsborough Resource Recovery Facility	621
TECO	TECO Bayside Station	385
City of Tampa	McKay Bay Refuse to Energy Facility	377
Mosaic Fertilizer	Mosaic Fertilizer Riverview Facility	149
Tropicana Manufacturing	Tropicana Bradenton	87
CF Industries Phosphate	CF Industries Plant City Complex	82
FBE	**FBE Port Manatee (Proposed)**	**68**
Trademark Nitrogen	Trademark Nitrogen	55

Table 18 - Largest Sources of PM/PM_{10} (2008)

Owner	Site Name	TPY
TECO	TECO Big Bend Station	1,015
FPL	FPL Manatee Power Plant	713
TECO	Bayside Power Station	178
Kinder Morgan	Kinder Morgan Tampa Terminal	117
CF Industries Phosphate	CF Industries Plant City Complex	57
Kinder Morgan	Kinder Morgan Sutton Terminal	57
Conagra Foods	Conagra	56
FBE	**FBE Port Manatee (Proposed)**	**45**
Tropicana Manufacturing	Tropicana Bradenton	34
Manatee County Utility Operations	Manatee County Landfill	31

Table 19 - Largest Sources of CO (2008)

Owner	Site Name	TPY
TECO	FPL Big Bend Station	6,777
FPL	FPL Manatee Power Plant	959
Envirofocus Technologies	Envirofocus Technologies	743
Tampa Electric Company	Bayside Power Station	358
Tropicana Manufacturing	Tropicana Bradenton	101
FBE	**FBE Port Manatee (Proposed)**	**99**
Hillsborough County	Hillsborough Resource Recovery Facility	75

Table 20 - Largest Sources of VOC (2008).

Owner	Site Name	TPY
Tropicana Manufacturing	Tropicana Bradenton	527
TECO	TECO Bayside Power Station	190
Central Florida Pipeline	Central Florida Pipeline Tampa Terminal	164
Manatee County Utility Operations	Manatee County Landfill	149
Dart Container	Dart Container	133
FPL	FPL Manatee Power Plant	106
Marathon Petroleum	Marathon Petroleum Tampa	95
Ball Metal Container	Ball Metal Container	94
TECO	TECO Big Bend Station	94
Hess Corporation	Hess Corporation Tampa Terminal	84
Citgo Petroleum	Citgo Tampa Terminal	81
Flowers Baking Company	Flowers Baking Company Bradenton	56
FBE	**FBE Port Manatee (Proposed)**	**10**

The overall reduction in NO_X and SO_2 emissions from the three largest facilities has been roughly 70 and 90%, respectively. Substantial reductions occurred in nearby Pinellas County where the Progress Energy Bartow Plant was repowered to use natural gas instead of residual fuel oil in 2007. The FBE project will be a small emission source compared with the past and present emissions of the large sources in Manatee and Hillsborough counties.

For reference, further emission reductions are expected at TECO Big Bend due to an ongoing improvement program that added an SCR unit on Unit 2 in 2009 and will add one on Unit 1 in 2010, thus cutting future emissions of NO_X by more than 50% when compared with 2008.

The emission trends provide some insight regarding the likely direction of regional ambient air quality drivers (excluding meteorology) for pollutants like ozone and $PM_{2.5}$ that are formed from precursors such as NO_X and SO_2.

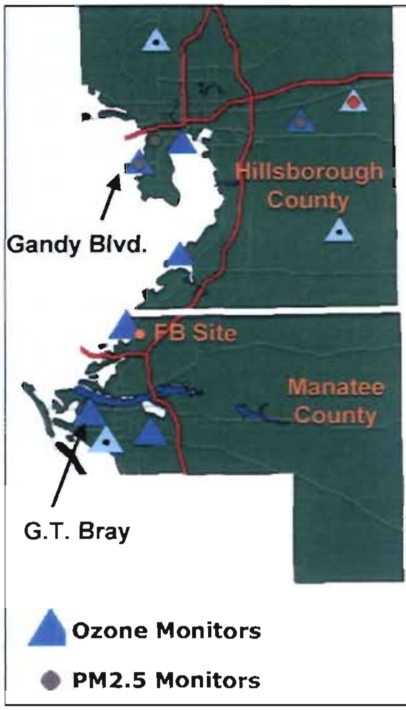
7.3. <u>Ambient Air Monitoring – Ozone</u>

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 fires and vegetation (e.g. isoprene). These two precursors participate in photochemical reactions that occur on an area-wide basis and are highly dependent on meteorological factors.

There are three ozone monitors in Manatee County and four in Hillsborough County as shown in Figure 9. Ozone limits and measurements are summarized on three year blocks, rolled annually. The reported value was calculated by taking the maximum 8-hour readings recorded each day during the three years. The fourth highest of the recorded maxima are identified for each year and then the average of those three values is identified as the compliance value.

The average of the annual fourth highest measurements (design value) over the period 2006-2008 at the monitor (designated as G.T. Bray) recording the highest readings was 78 parts per billion (ppb) in Manatee County. The result is shown in Figure 10 along with similarly calculated values throughout the state.

The values in Manatee and Hillsborough counties are greater than the compliance value limit of 75 ppb. However an official designation has not yet been made by EPA who recently announced that they will reconsider and lower the present standard to the range of 60-70 ppb in the summer of 2010.



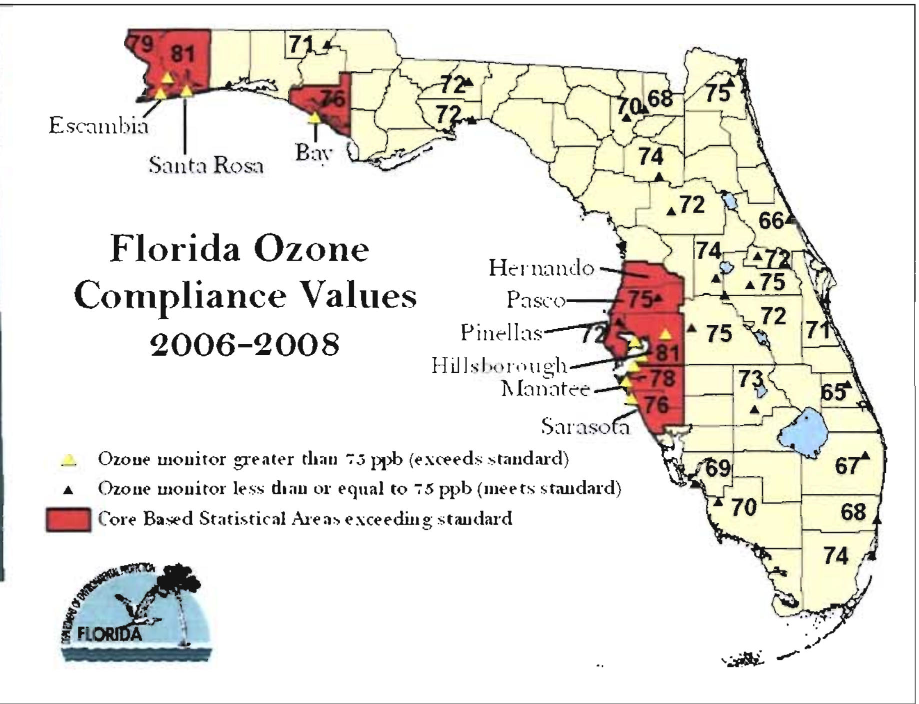


Figure 9 – Ozone and $PM_{2.5}$ Monitors **Figure 10. Florida Ozone Compliance Values**

FBE limited emissions from the project to less than 100 TPY of any of the PSD-pollutants (including ozone precursors NO_X and VOC) such that the project will not trigger PSD or more stringent Non-Attainment Area New Source Review (NAANSR) requirements (that could have applied had EPA not reconsidered the ozone regulation). Such limitations also minimize the extent to which the project contributes to regional ozone formation.

7.4. Ambient Air Monitoring – $PM_{2.5}$

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

There are no $PM_{2.5}$ monitors in Manatee County. However there are three in Hillsborough County that are suitable for this analysis given the similar setting of the two counties with respect to Tampa Bay and the Gulf of Mexico.

$PM_{2.5}$ limits and measurements are summarized on three year blocks, rolled annually. The reported value for $PM_{2.5}$ given in Table 21 was calculated by taking the average 24-hour readings recorded each day during the three years (2006-2008). The value for each year that exceeds 98% of all daily measurements within that year is identified for each year and then the average of those three numbers is identified as the value compared with the standard. The value calculated in the described manner for $PM_{2.5}$ measured at the U.S. Marine Corps Reserve Station on Gandy Boulevard is given in Table 21 as 22.5 micrograms per cubic meter ($\mu g/m^3$) compared with a standard of 35 $\mu g/m^3$.

The simple average of all measurements within each three years (2006-2008) was also calculated and then the mean of the three annual averages (11.5 $\mu g/m^3$) was reported and compared with the standard of 15 $\mu g/m^3$. Although the $PM_{2.5}$ stations are not used for official attainment determinations, they accurately reflect regional $PM_{2.5}$ concentrations.

Table 21 - Ambient Air Quality Measurements Nearest to the Project Site (2008)

Pollutant	Location	Averaging Period	Ambient Concentration			
			Compliance Period	Value	Standard	Units
Ozone	G.T. Bray, Manatee	8-hour	2006-08	78 [a]	75 [a]	ppb
$PM_{2.5}$	USMC, Gandy Blvd. Hillsborough	24-hour	2006-08	22.5 [b]	35 [b]	$\mu g/m^3$
		Annual	2006-08	11.5 [c]	15 [c]	$\mu g/m^3$
PM_{10}	Gardinier Park Hillsborough	24-hour	2008	58	150 [d]	$\mu g/m^3$
		Annual	2008	23 [e]	50 [e]	$\mu g/m^3$
SO_2	Simmons Park Hillsborough	3-hour	2008	45	1300 [f]	$\mu g/m^3$
		24-hour	2008	18	260 [f]	$\mu g/m^3$
		Annual	2008	5	60 [f]	$\mu g/m^3$
NO_2	Simmons Park Hillsborough	Annual	2008	6	100 [f]	$\mu g/m^3$
CO	Seminole Adult Day School (SADS) Hillsborough	1-hour	2008	2,750	40,000 [f]	$\mu g/m^3$
		8-hour	2008	1,980	10,000 [f]	$\mu g/m^3$

a. Three year average of the 4th highest daily maximum.
b. Three year average of the 98th percentile of 24-hour concentrations.
c. Three year average of the weighted annual mean.
d. Not to be exceeded on more than an average of one day per year over a three-year period.
e. Arithmetic mean.
f. Not to be exceeded more than once per year.

7.5. Ambient Air Monitoring – NO_2, SO_2, PM_{10} and CO

Nitrogen dioxide (NO_2), SO_2, CO and PM_{10} are directly emitted from combustion sources. PM_{10} is also transported from distant sources or generated from local material processing operations, traffic, construction, farming and other human activities.

There are no active NO_2, SO_2, CO or PM_{10} monitors in Manatee County. However, the extensive network in Hillsborough County is adequate. The highest values from the Hillsborough monitors likely provide conservative (high) estimates for Manatee County.

The southernmost Simmons Park monitor is located approximately 16 km north, northeast of the FBE site and approximately 10 km southwest of the TECO Big Bend Station. Measured SO_2 and NO_2 values are much less than the applicable standards given in Table 21 and reflect the substantial emission reductions from the nearby power plants as well as the use of ultralow sulfur fuel diesel for transportation.

CO concentrations at the SADS site were also very low compared with the applicable standards.

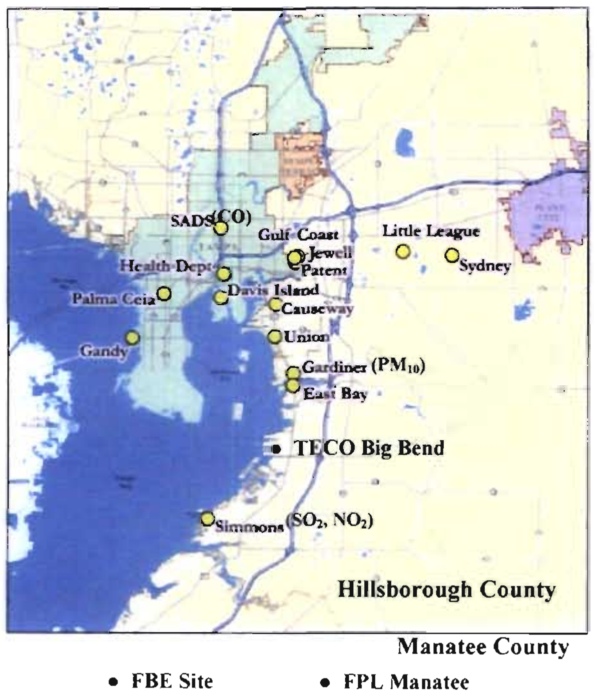


Figure 11 – Hillsborough County Monitors

The Gardinier PM_{10} monitor is well within the influence of industrial zones and exhibited values well below the applicable standard.

7.6. Air Quality Impact Analysis

FBE limited emissions from the project to less than 100 TPY of any of the PSD-pollutants. For that reason, little, if any, impact is expected from the project compared with the applicable standards. The applicant nevertheless submitted an assessment of the project on ground level concentrations of key air pollutants.

Significant Impact Analysis

Significant Impact Levels (SIL) are defined for SO_2, CO, PM/PM_{10}, and NO_2. A significant impact analysis (SIA) is performed on each of these pollutants to determine if a project is predicted to cause an increase in ground level concentration greater than the SIL for each pollutant.

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

For the Class II analysis, a combination of fence line, near field and far field receptors were chosen for predicting maximum concentrations in the vicinity of the project. The receptor grid consisted of receptors spaced at 50-meter (m) intervals around the facility fence line. The remaining receptors were spaced at 100 m from the property line out to 2 kilometers (km) and 250m spacing from 2 to 4 km.

If this modeling at worst-load conditions shows ground-level increases less than the SIL, the applicant is exempted from conducting any further modeling. If the modeled concentrations from the project exceed the SIL, then additional modeling including emissions from all major facilities or projects in the region (multi-source modeling) is required to determine the proposed project's impacts compared to the AAQS and PSD increments. Since the proposed project is not PSD, a PSD Increment Analysis is not required. However, the applicant has provided a multi-source AAQS analysis to ensure that the project will not cause or contribute to a violation of an ambient air quality standard.

The results of applicant's SO_2, CO, PM/PM_{10} and NO_X air quality SIA for this project are shown below in Table 22.

Table 22 - Maximum Predicted Air Quality Impacts from FB Energy for Comparison to the PSD Class II SILs

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	2008 Baseline Concentrations ($\mu g/m^3$)	Ambient Air Standard ($\mu g/m^3$)	Significant Impact?
PM_{10}	Annual	7	1	~58	50	Yes
	24-Hour	19	5	~23	150	Yes
SO_2	Annual	0.1	1	~5	80	No
	24-Hour	1	5	~18	365	No
	3-hour	3	25	~45	1300	No
NO_2	Annual	0.1	1	~6	100	No
CO	1-hour	6	2,000	~2,750	40,000	No
	8-hour	4	500	~1,980	10,000	No

Maximum predicted impacts from all pollutants are less than the applicable SIL for the Class II area except for PM_{10}. In addition, these impacts are compared with existing ambient air quality measurements from the local ambient monitoring network. It is clear that maximum predicted impacts from the project are much less than the respective AAQS.

For the Class I analysis, 360 receptors were located along a perimeter 50 km away from the property line. While the Chassahowitzka National Wilderness Refuge (CNWR) is 110 km away from the proposed project location, the applicant provided the SIA for 50 km out using Class II SIA (AERMOD) modeling methods to demonstrate that no further Class I analyses should be required based on distance and projected emission rates.

Maximum air quality impacts from the proposed project at a distance of 50 km are summarized in the Table 23. The results of the initial PM_{10}, NO_2 and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts are much less than the applicable SILs for the Class I area.

Table 23 - Maximum Air Quality Impacts from FB Energy for Comparison to the PSD Class I SILs

Pollutant	Averaging Time	Max. Predicted Impact at 50 km µg/m^3)	Class I SIL (µg/m^3)	Significant Impact?
PM_{10}	Annual	0.001	0.2	No
	24-hour	0.02	0.3	No
NO_2	Annual	0.001	0.1	No
SO_2	Annual	0.001	0.1	No
	24-hour	0.02	0.2	No
	3-hour	0.1	1	No

Models and Meteorological Data Used in the Foregoing Air Quality Analysis

PSD Class I and II Areas: The AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area, and also in the Class I area. AERMOD was approved by the EPA in November 2005. The AERMOD modeling system incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including the treatment of both surface and elevated sources, and both simple and complex terrain. AERMOD contains two input data processors, AERMET and AERMAP. AERMAP is the terrain processor and AERMET is the meteorological data processor.

A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfied the good engineering practice (GEP) stack height criteria.

The AERMET meteorological data used for this analysis consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from Sarasota-Bradenton Airport and the Tampa International Airport respectively. The 5-year period of meteorological data was from 2001 through 2005.

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.

AAQS Analysis

The applicant provided an AAQS review to ensure compliance. The AAQS is determined by adding a "background" concentration to the maximum modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled, and was based on the highest-second high concentration measured at the Hillsborough Gardinier Park PM_{10} monitor during the five year period 2004-2008. The maximum predicted annual and maximum predicted high, sixth high short term average for the AAQS analysis are summarized in Table 24 below. As shown in this table, emissions from the proposed facility are not expected to significantly cause or contribute to a violation of an AAQS.

Table 24 – PM_{10} Ambient Air Quality Impacts

Pollutant	Averaging Time	Major Sources Impact ($\mu g/m^3$)	Background Conc. 2003- 2007 ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Total Impact Greater Than AAQS?	Florida AAQS ($\mu g/m^3$)
PM_{10}	24-hour	25	86	111	No	150
	Annual	8	28	35	No	50

8. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, review of the air quality impact analysis, and the conditions specified in the draft permit. Deborah Nelson is the project meteorologist responsible for reviewing and validating the air quality impact analysis. She may be contacted at deborah.nelson@dep.state.fl.us and 850-294-3870. David Read is the project engineer responsible for preparing the draft permit. He may be contacted at david.read@dep.state.fl.us and 850-414-7268. Alvaro Linero, program administrator supervised their work. He may be contacted at alvaro.linero@dep.state.fl.us and 850-921-9523.

DRAFT PERMIT

PERMITTEE

Florida Biomass Energy (FBE), LLC
9040 Town Center Parkway
Bradenton, Florida 34202

Authorized Representative:
Mr. Rick Jensen, President

DEP File No. 0810226-001-AC
Expires: December 31, 2013
60.0 Megawatt (MW) Woody Biomass Power Plant
Facility ID No. 0810226
Manatee County

PROJECT

This is the final air construction permit, which authorizes construction of a net 60.0 megawatt (MW) power plant fueled by clean woody biomass. The facility is an electrical services plant categorized under Standard Industrial Classification (SIC) No. 4911. The proposed plant will be located in Manatee County at 11805 US Highway 41 North in Port Manatee, Palmetto, Manatee County, Florida. The plant will be located immediately west of U.S. Highway 41 and approximately 2 miles southwest of the Manatee County municipal airport. The UTM coordinates are Zone 16; 347.8 kilometers (km) East and 3056.2 km North.

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

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of: Chapter 403 of the Florida Statutes (F.S.) and Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.). The permittee is authorized to conduct the proposed work in accordance with the conditions of this permit. This project is subject to the general preconstruction review requirements in Rule 62-212.300, F.A.C.

Upon issuance of this final permit, any party to this order has the right to seek judicial review of it under Section 120.68 of the 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

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

CERTIFICATE OF SERVICE

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

Mr. Rick Jensen, President, FBE: rjensen@fbenergy.com
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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.

______________________________ ________
(Clerk) (Date)

PROPOSED PROJECT

The project is the construction of a net 60.0 MW electric power plant utilizing a grate-type suspension boiler (GSB), fueled by clean woody biomass. The GSB will provide steam to a steam turbine generator (STG). The proposed plant will be located in Manatee County at 11805 US Highway 41 North in Port Manatee, Palmetto, Manatee County. The plant will be located immediately west of U.S. Highway 41 and approximately 2 miles southwest of the Manatee County municipal airport. The GSB will use biodiesel or as a backup ultra low sulfur distillate (ULSD) fuel oil (FO) as startup, shutdown and bed stabilization fuels. Biodiesel or ULSD FO will also be used as the fuels for all emergency equipment.

The FBE project will incorporate the following pollution control equipment and measures:

- Efficient combustion in the GSB and emergency equipment to minimize formation of particulate matter ($PM/PM_{10}/PM_{2.5}$), nitrogen oxides (NO_X), carbon monoxide (CO) and volatile organic compounds (VOC);
- Limitation of biomass to clean woody untreated biomass to minimize sulfur dioxide (SO_2) and hazardous air pollutant (HAP) formation, including hydrogen chloride (HCl) and hydrogen fluoride (HF);
- Use of inherently clean fuels for startup, shutdown and bed stabilization of the GSB and the operation of emergency equipment;
- An oxidation catalyst (ox-cat) to reduce CO and VOC;
- Ammonia (NH_3) injection into a selective catalytic reduction (SCR) reactor to destroy NO_X and help in the reduction of VOC and dioxin/furan (D/F);
- An in-duct sorbent injection system (IDSIS) of lime, trona, or sodium bicarbonate to control SO_2, HCl, HF and other acid gas HAP;
- An electrostatic precipitator (ESP) to further control $PM/PM_{10}/PM_{2.5}$ and to remove injected sorbents; and,
- Reasonable precautions and best management practices to minimize emissions from biomass handling, storage and processing and ash (bottom and fly) handling, storage and shipment.

The project will incorporate the following emission measurement systems:

- Continuous emission monitoring systems (CEMS) for CO, SO_2, NO_X, HCl, and HF; and,
- A continuous opacity monitoring system (COMS) for visible emissions (VE).

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

Facility ID No. 0810226	
EU ID No.	**Emission Unit Description**
001	Feedstock delivery, handling and preparation
002	Woody biomass-fueled, grate-type suspension boiler (GSB) with a maximum heat input capacity of 833 mmBtu per hour (mmBtu/hr) on a 4 hour average basis
003	Ash handling, storage and shipment
004	500 kilowatt (kW) emergency generator
005	250 kW emergency fire pump
006	Cooling Tower

Facility Regulatory Classification

- The facility is not a major source of hazardous air pollutants (HAP).
- The facility operates units subject to the acid rain provisions of the Clean Air Act (CAA).
- The facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.
- The facility is not a major stationary source in accordance with Rule 62-212.400(PSD), F.A.C.
- The facility is subject to the provisions of the Clean Air Interstate Rule (CAIR), including applicable portions of Chapters 62-204, 62-210 and 62-296, F.A.C.
- The facility is subject to Chapter 62-204-800, F.A.C for New Source Performance Standards (NSPS) under Section 111 of the Clean Air Act (CAA) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) under Section 112 of the CAA.

1. Permitting Authority: The Permitting Authority for this project is the Bureau of Air Regulation in the Division of Air Resource Management of the Department. The mailing address for the Bureau of Air Regulation is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. All documents related to applications for permits shall be submitted to the Air Resource Section of the Department's Southwest District Office at: 13051 North Telecom Parkway, Temple Terrace, Florida 33637-0926 (Ph: 813-632-7600).

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resource Section of the Department's Southwest District Office at: 13051 North Telecom Parkway, Temple Terrace, Florida 33637-0926 (Ph: 813-632-7600).

3. Appendices: The following Appendices are attached as a part of this permit and the permittee must comply with the requirement of the appendices:

Appendix ASTM	ASTM Standard D6751-09 for Biodiesel;
Appendix BMP	Best Management Practices Plan;
Appendix CC	Common Conditions;
Appendix CEMS	Continuous Emissions Monitoring System (CEMS) Requirements;
Appendix CF	Citation Formats and Glossary of Common Terms;
Appendix CTR	Common Testing Requirements;
Appendix Db	NSPS, 40 CFR 60, Subpart Db – Standards of Performance Small Industrial-Commercial-Institutional Steam Generating Units;
Appendix F	40 CFR 75, Appendix F, Section 5 - Measurement of Boiler Heat Input Rate;
Appendix GC	General Conditions;
Appendix GP	Identification of General Provisions - NSPS 40 CFR 60, Subpart A from and NESHAP 40 CFR 63, Subpart A;
Appendix IIII	NSPS, Subpart IIII - Stationary Compression Ignition Internal Combustion Engines; and
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) At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

   (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 exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

   (c) At such time that the affected source becomes a major source of HAP by virtue of a relaxation in any enforceable limitation which was established by this permit or by actually equaling or exceeding 10 TPY of any HAP or 25.0 TPY of all HAP, then the requirements of 40 CFR 63, Subpart B - Requirements for Control Technology With Clean Air Act Sections, Sections 112(g) and 112(j), shall apply to the source as though construction had not yet commenced on the source.

   [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. Objectionable Odors Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor. [Rule 62-296.320(2), F.A.C.]
   {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.}

10. Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency (EPA) in Atlanta, Georgia. This permit does not specify the Acid Rain program requirements. These will be included in the Title V air operation permit. [40 CFR 72].

11. 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. Appendix BMP of this permit provides a Best Management Plan (BMP) of reasonable precautions specific to the FBE facility to control fugitive PM emissions. General reasonable precautions include the following: a. Paving and maintenance of roads, parking areas and yards; b. Application of water or chemicals to control emissions from such activities as demolition of buildings, grading roads, construction, and land clearing; c. Application of asphalt, water, oil, chemicals or other dust suppressants to unpaved roads, yards, open stock piles and similar activities; d. Removal of particulate matter from roads and other paved areas under the control of the owner or operator of the facility to prevent re-entrainment, and from buildings or work areas to prevent particulate from becoming airborne; e. Landscaping or planting of vegetation; f. Use of hoods, fans, filters, and similar equipment to contain, capture and/or vent particulate matter; g. Confining abrasive blasting where possible; and h. Enclosure or covering of conveyor systems. In determining what constitutes reasonable precautions for a particular facility, the Department shall consider the cost of the control technique or work practice, the environmental impacts of the technique or practice, and the degree of reduction of emissions expected from a particular technique or practice. [Rule 62-296.320(4)(c), F.A.C.]

A. Feedstock delivery, handling and preparation (EU-001)

This section of the permit addresses the following emissions unit.

EU ID No. 001	Emission Unit Description
Feedstock delivery, handling and preparation: This emission unit will consist of three primary components: (1) a stackout system; (2) a reclaim system; and, (3) an emergency short-term fuel feed system. • Stackout System: All clean woody biomass feedstock will be delivered to the project site via truck. The fuel trucks will have an average net load of 25 tons of wood chips. The truck receiving system will be equipped with two hydraulically operated truck dumpers, which will slide each 25 ton load into a 50 ton capacity, fully-enclosed live-bottom receiving hopper. The hoppers will have a discharge rate capability of 150 tons per hour (TPH). The stackout system will provide approximately 20,000 tons of biomass storage, using a stacking system that continuously adjusts the height of the discharge just above the pile height, to minimize dust. • Reclaim System: Wood chips will be reclaimed from the storage pile via a drag chain or auger type reclaimer to a covered conveyor which will transfer the material to a sizing screen system and then transfer the screened fuel to another covered conveyor. Fugitive emissions will be controlled by a fabric filter. The covered reclaim conveyors are rated at 150 TPH. The anticipated average reclaim rate is estimated equal to 68 TPH. Conveyors will transport the feedstock to a storage silo (day bin) within the boiler structure. All conveyors will be covered to reduce particulate emissions. • Emergency Short-Term Fuel Feed System: An at grade back-up emergency fuel storage area, located adjacent to the fuel truck access road, sufficient for an additional 30,000 tons of fuel, will be used in the event of major repairs to the stackout or reclaim systems. The emergency pile will be transferred to the truck dump hoppers via front-end loaders and will utilize the enclosed by-pass conveyor to by-pass the stacker to transport the material directly to the boiler.	

EQUIPMENT

1. Equipment: The permittee is authorized to construct Emission Unit EU-001, which consists of a stackout, a reclaim and emergency short-term fuel feed systems containing the following equipment classified as potential sources of PM/PM_{10}/$PM_{2.5}$ emissions hence forth called PM:
   a. Truck Dumper Areas: Truck Dumpers #1 and 2 and two (2) Self-Dumping Stations;
   b. Enclosed Conveyor Systems: Enclosed Conveyor Systems for woody biomass handling. Associated drop points within the conveyor system shall be enclosed and fugitive emissions controlled by fabric or bin vent filters where technically feasible;
   c. Woody Biomass Storage Areas: The stackout and emergency fuel storage areas and associated drop points from conveyor system to storage areas shall be designed to minimize fugitive PM emissions; and,
   d. Boiler Storage Silo (Day Bin): The day bin shall be constructed with a bin vent screen to control PM emissions.

   [Application No. 0810226-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

2. Control of Fugitive Emissions: To minimize fugitive PM, woody biomass conveyors shall be covered. Dust collectors shall be installed on the conveyor transfer drop points where practical. Vent screens associated with the fuel bins shall be installed on the fuel bins to minimize PM emissions.

*{Permitting Note: One small section of the conveyance belt of the conveyors near the receiving point shall provide for visible inspection from above so that woody biomass that does not meet **Condition 6** of this subsection can be removed.}*

[Application No. 0810226-001-AC and Rule 62-4.070, F.A.C. Reasonable Assurance]

3. Baghouses: Based on the preliminary design, the permittee shall install the following baghouses. Each baghouse shall be designed and maintained to achieve an outlet dust loading rate of 0.01 grains per dry standard cubic feet (gr/dscf) in its exhaust. Based on the final engineering design needs, additional baghouses may be installed as necessary to control fugitive dust from material handling and storage. The Compliance Authority shall be notified 180 days before FBE becomes operational of any final engineering design changes. Should the preliminary design change, the permittee shall provide final design details for all baghouses in the application for a Title V air operation permit along with a concurrent modification of this air construction permit.
   a. *Stackout Baghouse* shall control dust from the screen and hog enclosure.
   b. *Reclaim Baghouse* shall control dust from the magnetic separator and screening enclosure.
   c. *Emergency Fuel Feed System Baghouse #1* shall control dust from the screening enclosure.
   d. *Emergency Fuel Feed System Baghouse #2* shall control dust from the boiler house enclosure.

   [Application No. 0810226-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

4. BMP Plan: A BMP plan shall be utilized to minimize fugitive PM emissions from receiving, handling, storage and processing of woody biomass. Best management practices shall be utilized to reduce the potential for spontaneous combustion of stored woody biomass and odors. A preliminary BMP plan is contained in Appendix BMP of this permit. This plan also includes quality control and assurance (Q&A) procedures to ensure woody biomass delivered by vendors and suppliers to the FBE facility meet the requirements given in the BMP plan. No later than 180 days before the FBE facility becomes operational, a final BMP plan shall be filed with the Compliance Authority to reflect the final engineering designs of the biomass receiving, handling, storage and processing systems. The final BMP plan will also be incorporated into the Title V operating permit.

   *{Permitting Note: As part of that final BMP, technical information may be provided by FBE to the Compliance Authority based on the final engineering of the fuel conveyance system that describes methods or equipment designed to control fugitive PM emissions from the conveyor transfer drop points. These methodologies and equipment designs may obviate the requirement to install dust collectors on the conveyor transfer drop points stipulated in **Condition 2** of this subsection. Acceptance of the final BMP by the Compliance Authority with the reference to the specific design of the conveyor transfer drop points may satisfy the requirement to install dust collectors.}*

   {Permitting Note: PM emissions from this emission unit during operation of the FBE facility are estimated to be 10.2 tons in any consecutive twelve month period, of this amount 2.8 tons are PM_{10}.}

   [Application No. 0810226-001-AC; Rule 62-4.070, F.A.C. Reasonable Assurance, and Rule 62-296.320, F.A.C.]

PERFORMANCE RESTRICTIONS

5. Hours of Operation: The hours of operation of this emissions unit is not limited (i.e., unrestricted at 8,760 hours per year).

   [Application No. 0810226-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

6. Clean Woody Biomass: Municipal Solid Waste (MSW) is prohibited from use at this facility. The fuel to be received, handled, stored and processed shall consist of untreated woody biomass as defined in the Appendix BMP of this permit. Inspection and testing procedures describe in Appendix- BMP shall be followed to insure that appropriate woody biomass is used as fuel and that MSW is not used as fuel.
[Application No. 0810226-001-AC and Rules 62-4.070(3) F.A.C., and 40 CFR 60.51b.]

7. Clean Woody Biomass Storage Areas: Clean woody biomass storage areas shall consist of the stackout and emergency fuel feed storage piles. The stackout pile will contain approximately 20,000 tons of woody biomass while the emergency pile will contain approximately 30,000 tons of woody biomass. Biomass placed in the piles will be largely managed by mechanical means. The biomass will then be taken by covered conveyors to the boiler storage silo and from there to the GSB boiler. Each storage pile area will be on level, firm ground and wet suppression used as necessary to control fugitive dust emissions. [Application No. 0810226-001-AC]

8. Emergency Biomass Pile Storage Restriction: Due to concerns about odor and the fire hazard posed by spontaneous combustion, the longest duration that biomass shall be stored in the emergency pile before it is combusted in the GSB is 30 days. [Rules 62-296.320(2), F.A.C. and 62-4.070(3) F.A.C.]

9. Paved Roadways and Gravel Areas: Fugitive dust emissions from the plant's paved roadways and gravel areas shall be controlled in accordance with **Condition 11 of Section 2** of this permit and the BMP plan.
[Rule 62-4.070, F.A.C. Reasonable Assurance, and Rule 62-296.320, F.A.C.]

EMISSIONS STANDARDS

10. General Opacity: As determined by EPA Method 9, there shall be no visible emissions greater than 10% opacity, except for one 6 minute period no greater than 20% from the outlets of the drop points, transfer points, vent screens and dust collectors associated with this emission unit.
[Application No. 0810226-001-AC and Rule 62-212.400(5)(c), F.A.C.].

11. Opacity from Baghouses: Opacity from the baghouses of this emission unit shall not exceed 5% opacity based on EPA Method 9 during initial and annual tests.
[Rule 62-4.070(3) F.A.C., Reasonable Assurance]

TESTING AND MONITORING REQUIREMENTS

12. Initial VE Compliance Tests: The outlets of the drop points, transfer points, the silo vent screens associated with the fuel bins and the baghouses of this emissions unit shall be tested to demonstrate initial compliance with the emissions standards for opacity. The initial tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial operation of the emission unit. [Rules 62-4.070(3) and 62-297.310(7)(a)1, F.A.C.]

13. Annual VE Compliance Tests: During each federal fiscal year (October 1st to September 30th), the outlets of the drop points, transfer points, the silo vent screens associated with the fuel bins and the baghouses of this emissions unit shall be tested to demonstrate compliance with the emissions standards for opacity. [Rule 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 which is included as Appendix GP of this permit and as 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.]

B. Grate-Type Suspension Biomass Boiler (EU-002)

This section of the permit addresses the following emissions units.

<table>
<tr><th>EU ID No. 002</th><th>Emission Unit Description</th></tr>
<tr><td colspan="2">
<u>Description</u>: The boiler will be a woody biomass-fueled grate-type suspension boiler (GSB) wherein wood is combusted on water cooled movable grates. The heat from the exhaust will be recovered to generate superheated steam to generate 60.0 MW (net) of electricity in a STG.
<u>Fuels</u>: The primary fuel will be clean woody biomass as described in Appendix BMP of this permit. Biodiesel or as a backup ULSD FO will be used for startup, shutdown and bed stabilization of the GSB.
<u>Capacity</u>: The maximum heat input capacity is 833 mmBtu per hour (4-hour average basis). The steam production capability will be approximately 560,000 pounds per hour (lb/hour) at 1,550 psi and 960 degrees °F.
<u>Controls</u>: Efficient combustion of woody biomass in the GSB boiler to minimize formation of PM, NO_X, CO and VOC; limitation of biomass to woody untreated biomass to minimize SO_2 and HAP formation; use of an inherently clean fuels for startup, shutdown and bed stabilization; a oxidation catalyst (ox-cat) to further control CO, VOC, and HAP; NH_3 injection into SCR reactor to destroy NO_X and help in the reduction of VOC, HAP and D/F; an IDSIS to further control SO_2 and HAP, including HCl; and, an ESP with a design efficiency of 99.9% to further control PM and VE, (i.e. opacity) and remove injected sorbents.
<u>Stack Parameters</u>: The stack will be approximately 9.3 feet in diameter (maximum) and 145 feet tall (minimum). Exhaust flue gas will exit the stack at the following approximate conditions: an exit temperature of 300 °F and a volumetric flow rate of 265,972 actual cubic feet per minute (acfm).
<u>CEMS and COMS</u>: Emissions of CO, NO_X, SO_2, HCl and HF will be monitored and recorded by CEMS. VE will be monitored and recorded by a COMS.
<u>Applicability of NSPS 40 CFR Subpart Db</u>: This unit is subject to NSPS Subpart Db – for Industrial-Commercial-Institutional Steam Generating Units because it has a maximum heat input capacity greater than 100 mmBtu/hr from all combusted fuels and is not subject to NSPS Subpart Da because it has a maximum heat input capacity of less than 250 mmBtu/hr from the combustion of fossil fuels.
</td></tr>
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EQUIPMENT

1. Construction of GSB: The permittee is authorized to construct one GSB with startup burners, overfire air ports, steam drum, superheater, economizer, air heater, ash hoppers, ducts, STG, fuel feeding equipment, air-cooled condensing unit, air pollution control equipment and other associated equipment. [Application No. 0810226-001-AC]

2. Air Pollution Control Equipment: To comply with the emission standards of this permit, the permittee shall install the following add-on air pollution control equipment on the GSB.

   a. ESP: The permittee shall design, install, operate and maintain an ESP to control PM and VE. The control efficiency of the ESP shall be 99.9% as demonstrated by an emission limit of 0.01 gr/dscf at 7% oxygen (O_2) at its outlet.
   [Application No. 0810226-001-AC and Rule 62-4.070(3), F.A.C.]

   b. SCR System: The permittee shall design, install, operate, and maintain an NH_3-based SCR system including reagent storage tank, pumps, metering system, injection grid, reactor and catalyst to reduce NO_X emissions in the flue gas exhaust and achieve the NO_X emissions standards specified in this subsection. The SCR shall be brought on line and functioning properly whenever the boiler is in operation in accordance with the manufacturer's procedures and guidelines. [Application No. 0810226-001-AC and Rule 62-4.070(3), F.A.C.]

c. IDSIS: An IDSIS shall be installed that consists of the pumps, the metering and injection equipment required to inject the sorbent into the GSB duct work to control SO_2 and HAP acid gas emissions. A sorbent injection rate will be set to the amount necessary (lb/hr) to control SO_2 and HAP emissions to the standards specified in this subsection. [Application No. 0810226-001-AC and Rule 62-4.070(3), F.A.C.]

d. Ox-Cat: The permittee shall design, install, operate and maintain an ox-cat to control CO, VOC and HAP emissions to the emission standards specified in this section. [Application No. 0810226-001-AC and Rule 62-4.070(3), F.A.C.]

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

3. Biodiesel and ULSD FO Storage Tanks: The permittee is authorized to construct two 50,000 gallon tanks to store biodiesel and ULSD FO for use as GSB fuels for startup, shutdown and bed stabilization and for use in emergency equipment. The biodiesel used at the FBE facility must meet the ASTM D6751-09 Standard for biodiesel given in Appendix ASTM of this permit. [62-4.070(3), Reasonable Assurance]

{Permitting Note: The biodiesel and ULSD FO storage tanks at the FBE facility are not subject to NSPS Subpart Kb because they are larger or equal to 40,000 gallons (151 cubic meters) and store liquids (biodiesel and ULSD FO) with a maximum true vapor pressure less than 3.5 kPa (0.51 pounds per square inch (psi)). Accordingly they are unregulated emissions units.}

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

4. Sorbent Storage Silos: The permittee is authorized to construct sorbent storage silos with bin vent filters to control fugitive dust emissions during loading from trucks to store lime, trona, or sodium bicarbonate for use by the IDSIS. Bin vent filters shall be installed on the sorbent storage silos to control PM emissions. The bin vent filters shall be designed to achieve a PM emission rate of 0.01 gr/dscf. [Application No. 0810226-001-AC and Rule 62-4.070(3), F.A.C.]

PERFORMANCE REQUIREMENTS

5. Authorized Fuels: The GSB is authorized to combust as its primary fuel clean woody biomass as defined in **Appendix BMP** of this permit. In addition, the GSB is authorized to combust biodiesel and as a backup ULSD FO for startup, shutdown and bed stabilization. The biodiesel must meet the ASTM specification given in Appendix ASTM of this permit. As per **Condition 7** below, the burner equipment to fire fossil fuels in the GSB shall have the physical capabilities to burn less than 250 mmBtu/hr of fossil fuel heat input consisting of ULSD FO to satisfy the heat input limitation requirements of NSPS, Subpart Db.

{Restriction of fossil fuels to ULSD FO satisfies the requirement to determine BACT for PM and SO_2 to the extent that fossil fuel is fired in accordance with Rule 62-296.410, F.A.C. for this class of boiler.}

[Application No. 0810226-001-AC; Rules 62-4.070(3), 62-296.410, 62-210.200(PTE), F.A.C., and NSPS, Subpart Db]

6. Heat Input Rate from all Fuels: The maximum heat input capacity from all fuel combinations to the GSB is 833 mmBtu per hour on a 4-hour average basis. [Application No. 0810226-001-AC; NSPS Subpart Db; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

7. Heat Input from Fossil Fuels: The maximum heat input capacity to combust ULSD FO in the GSB, as determined by the physical design and characteristics of the boiler is limited to less than 250 mmBtu/hr.
[Application No. 0810226-001-AC; NSPS Subpart Db; Rules 62-4.070(3); and 62-210.200(PTE), F.A.C.]

8. Operational Hours: The hours of operation of this emission unit are not restricted (8760 hours/year).
[Application No. 0810226-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

EMISSIONS STANDARDS

9. Emission Limits: Emissions from GSB shall not exceed the following standards.

Pollutant	Initial (I) or Annual (A) Test	CEMS/COMS Based Averages	
NO_X [a]	15.1 lb/hr (I)	15.1 lb/hr 12-month, rolled monthly	0.20 lb/mmBtu 30-day basis
SO_2 [b]	12.1 lb/hr (I)	12.1 lb/hr, 12-month, rolled monthly	
CO [c]	22.3 lb/hr (I)	22.3 lb/hr, 12-month, rolled monthly	
HCl [d]	2.25 lb/hr (I)	9.86 TPY 12 month, rolled monthly	Σ (HCl, HF) = 11.5 TPY 12 month, rolled monthly [e]
HF [d]	2.25 lb/hr (I)	9.86 TPY 12 month, rolled monthly	
PM/PM_{10} [f, g]	7.6 lb/hr (I,A) 0.01 lb/mmBtu (I,A) 0.01 gr/dscf @ 7% O_2	10 percent (%) opacity (6-minute blocks) 20% opacity (one 6-minute block per hour)	
THC [h]	(I)	Not applicable	
SAM [i]	(I)	Not applicable	
Σ (CH_4O, C_6H_6, CH_2O, C_8H_8 C_2H_4O, Cl_2, CH_2Cl_2; C_7H_8) [j]	2.75 lb/hr (12.0 TPY) (I,A)	Not applicable	
NH_3 Slip [k]	10 ppmvd @ 7% O_2 (I,A)	Not applicable	

a. NO_X limit in pounds per million Btu heat input (lb/mmBtu) on a 30-day basis is pursuant to NSPS Subpart Db. Mass rate limit in pounds per hour insures annual emissions will be less than 250 tons per year (TPY).
b. Use of low sulfur fuels including wood, biodiesel and ULSD FO insure that uncontrolled SO_2 emissions are less than 0.32 lb/mmBtu. Therefore, no specific limit from NSPS Subpart Db applies. Mass rate limit in lb/hr insures annual emissions will be less than 250 TPY.
c. Mass rate CO emission limit insures annual emissions will be less than 250 TPY.
d. Individual HCl and HF mass emission limits to provide reasonable assurance that annual emissions of each HAP will be less than 10 TPY.
e. Combined HCl and HF mass rate helps provide reasonable assurance that the facility aggregate PTE of HAP is less than 25 TPY.

f. Compliance with the PM/PM_{10} concentration emission limit insures compliance with the 40 CFR 60, Subpart Db limit of 0.030 lb PM/mmBtu (filterable PM only). Mass rate limit insures annual emissions will be less than 250 TPY. The gr/dscf emission limit applies to bin vent filters of sorbent storage silos.

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

h. Total hydrocarbon (THC) as a surrogate for VOC. One initial test required to verify emission rate.

i. One initial test required to verify emission rate.

j. CH_4O, C_6H_6, CH_2O, C_8H_8, C_2H_4O, Cl_2, CH_2Cl_2, C_7H_8 means: acrolein; benzene; formaldehyde; styrene; acetaldehyde; chlorine; dichloromethane; and toluene, respectively. Initial and annual tests to verify mass emission rates for these organic HAP to provide reasonable assurance that the facility aggregate potential to emit HAP is less than 25 TPY.

k. Ammonia (NH_3) slip in parts per million by dry volume at 7% oxygen (ppmvd @ 7% O_2).

[Application No. 0810226-001-AC; Rules 62-210.200(PTE), 62-296.406, 62-296.410, and 62-4.070(3)(Reasonable Assurance), F.A.C. to avoid triggering PSD Requirements under Rule 62-212.400, F.A.C.; 40 CFR 60, Subpart Db]

10. <u>Sorbent Storage Silos VE</u>: As determined by EPA Method 9, there shall be no VE greater than 5% opacity from the bin vent filters of the sorbent storage silos during loading by truck.
[Application No. 0810226-001-AC; Rules 62-4.070(3), 62-210.200(PTE), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

11. <u>PM Emission Standard:</u> PM emissions from bin vent filters of the sorbent storage silos shall not exceed 0.01 gr/dscf @ 7% O_2. [Application No. 0810226-001-AC; Rules 62-4.070(3), 62-210.200(PTE), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

12. <u>Bin Vent Filter PM Standard by Opacity Measurement:</u> A VE reading of 5% opacity or less may be used to demonstrate compliance with the PM emission standard in **Condition 11** above. A VE reading greater than 5% opacity will require the permittee to perform a PM emissions test on the bin vent filter within 60 days to show compliance with the PM standard.
[Application No. 0810226-AC; Rules 62-296.603, 62-296.712, F.A.C.; and 40 CFR 60.122(a)(2) and Rule 62-4.070, F.A.C. Reasonable Assurance]

13. <u>Acid Gas HAP Testing:</u> In accordance with EPA Method 26 or 26A, the permittee shall conduct initial performance tests to determine the acid gas HCl and HF HAP emission rates. The emissions rates of HCl and HF shall not exceeded 2.25 lb/hr (9.86 TPY) individually and 11.5 TPY combined. The initial performance tests shall be conducted after completing shakedown of all equipment and beginning commercial operation with the CO CEMS fully functional. Shakedown shall not exceed 180 days after first fire. CO emissions from the CEMS shall be reported for each test run.
[Rule 62-4.070(3), F.A.C.]

14. <u>Inorganic and Organic HAP Testing</u>: In accordance with EPA Method 320, the permittee shall conduct initial and annual performance tests to determine CH_4O, C_6H_6, CH_2O, C_8H_8, C_2H_4O, Cl_2, CH_2Cl_2 andC_7H_8 emission rates. The combined emissions rate of the seven key organic HAP plus CL_2 shall not exceeded 2.75 lb/hr (12.0 TPY). The initial performance tests shall be conducted after completing shakedown of all equipment and beginning commercial operation with the CO CEMS fully functional. Shakedown shall not exceed 180 days after first fire. CO emissions from the CEMS shall be reported for each test run. Annual performance tests shall be conducted during each federal fiscal year (October 1 – September 30). [Rule 62-4.070(3), F.A.C.]

15. <u>Individual and Total Annual HAP Emission Cap</u>: HAP emissions are limited to less than 10 TPY of any individual HAP or 25.0 TPY of all HAP. [Rule 62-4.070(3), F.A.C.]

CONTINUOUS EMISSION MONITORS

16. Continuous Monitoring Requirements: The permittee shall install, calibrate, maintain and operate CEMS and a diluent monitor to measure and record the emissions of SO_2, NO_X, CO, HCl and HF from the boiler stack in a manner sufficient to demonstrate continuous compliance with the CEMS-based emission standards in **Condition 9** above (see Appendix CEMS for further information). The permittee shall install, calibrate, maintain and operate COMS to measure and record the opacity to demonstrate compliance with the COMS-based emission standard in **Condition 9** 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 the CEMS or COMS based VE, SO_2, NO_X, CO, HCl or HF standard, the permittee shall notify the Compliance Authority.

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

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

    c. CO CEMS: The CO CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60. The CO monitor span values shall be set, 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 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 23 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 26 or 26A as detailed in Appendix A of 40 CFR 60 or by Method 320 as detailed in Appendix A of 40 CFR 63. The HCl monitor span values shall be set, considering the allowable methods of operation and corresponding emission standards. Approval of specific initial performance specifications and quality assurance and control (Q&A) procedures must be provided to the Department prior to installation and operation of the CEM system.

    e. HF CEMS: The HF CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 15, EPA 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 23 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 HF monitor shall be performed using EPA Method 26 or 26A as detailed in Appendix A of 40 CFR 60 or by Method 320 as detailed in Appendix A of 40 CFR 63. The HF monitor span values shall be set, considering the allowable methods of operation and corresponding emission standards. Approval of specific initial performance specifications and quality assurance and control (Q&A) procedures must be provided to the Department prior to installation and operation of the CEM system.

f. 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.

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

[Application No. 0810226-001-AC; Rule 62-4.070(3), F.A.C.; 40 CFR 60, Subpart Db and Appendices]

STARTUP, SHUTDOWN, AND MALFUNCTION REQUIREMENTS

17. Malfunction Notifications: In case of excess emissions resulting from malfunctions, each owner or operator shall notify the Compliance Authority. 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.]

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

19. 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.

20. Emission Limit Compliance and Excess Emission: Because of the long-term nature of all of the NO_X, SO_2, CO, HF and HCl CEMS-based mass emission rate limits and to avoid triggering PSD and a case-by-case MACT 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. [Rules 62-210.700(4), 62-210.200(PTE) and 62-4.070(3), F.A.C.]

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

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

    [Rules 62-210.700(5), 62-210.200(PTE) and 62-4.070(3), F.A.C.]

TESTING REQUIREMENTS

22. Boiler Heat Input Rate Calculation: 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 GSB at the FBE facility is contained in Appendix F of this permit. This procedure shall be used to calculate the heat input rate in mmBtu/hr to the boiler when using clean woody biomass as its primary fuel and biodiesel as a startup and

shutdown. [Rule 62-4.070(3), F.A.C. Reasonable Assurance]

23. Initial and Annual Stack Tests: In accordance with test methods specified in this permit, the boiler stack shall be tested to demonstrate initial compliance with the emission standards for NH_3, CO, NO_X, PM, SO_2, SAM, THC, opacity (boiler and bin vent filters of sorbent storage silos), HCl and HF. In accordance with test methods specified in this permit, the boiler stack shall be tested to determine emissions rates of CH_4O, C_6H_6, CH_2O, C_8H_8, C_2H_4O, Cl_2, CH_2Cl_2, and C_7H_8. Tests of the bin vent filters shall be conducted while the silos are being loaded with sorbent from trucks. The tests shall be conducted within 60 days after achieving the maximum heat input rate to the boiler, but not later than 180 days after the initial startup of the boiler. Subsequent compliance stack tests for CH_4O, C_6H_6, CH_2O, C_8H_8, C_2H_4O, Cl_2, CH_2Cl_2, C_7H_8, NH_3 slip, PM and opacity (vent filter stacks of sorbent storage silos) shall also be conducted during each federal fiscal year (October 1st to September 30th). Tests shall be conducted between 90 and 100% of the maximum heat input rate when firing only the primary fuels. CEMS data for CO, NO_X, SO_2, HCl and HF along with COMS data for opacity shall be reported for each run of the required tests for CH_4O, C_6H_6, CH_2O, C_8H_8, C_2H_4O, Cl_2, CH_2Cl_2, C_7H_8, NH_3 and PM. The Department may require the permittee to repeat some or all of these initial stack tests after major replacement or major repair of any air pollution control or process equipment. [Rules 62-212.400(5)(c) and 62-297.310(7)(a) and (b), F.A.C.; 40 CFR 60.8]

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

24. Sorbent Storage Silos PM Compliance Test: The initial and annual VE tests in **Condition 22** of this subsection with regard to the bin vent filters of the sorbent storage silos serve as a surrogate for the PM emissions tests. If the VE emissions standard in **Condition 10** of this subsection is not met for the bin vent filters, a PM test utilizing EPA Method 5 must be conducted on bin vent filter stack to show compliance with the PM emissions standard in **Condition 11** of this subsection within 60 days. [Rule 62-297.620(4), F.A.C.]

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

EPA Method	Description of Method and Comments
CTM-027	Measurement of NH_3 Slip
320	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, 5B, 17	Measurement of PM
6C	Measurement of SO_2 Emissions (Instrumental)
7E	Measurement of NO_X Emissions (Instrumental)
9	Visual Determination of the Opacity
10	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) *{For concurrent use with EPA Method 25A to deduct emissions of methane and ethane from the THC emissions measured by Method 25A.}*
19	Calculation Method for NO_X, PM, and SO_2 Emission Rates

25	Determination of Total Gaseous Nonmethane Organic Emissions as Carbon
25A	Measurement of Gaseous Organic Concentrations (Flame Ionization)
26, 26A	Determination of HCl and HF 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.

[Rules 62-204.800, F.A.C. and 40 CFR 60, Appendix A]

OTHER MONITORING REQUIREMENTS

26. Steam Parameters: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, operate and maintain continuous monitoring and recording devices for the following parameters: steam temperature (°F), steam pressure (psig) and steam production rate (lb/hour). Records shall be maintained on site and made available upon request.
[Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

27. SCR Ammonia Injection: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a flow meter to measure and record the ammonia injection rate for the SCR system for the steam generating unit. The permittee shall document the general range of NH_3 flow rates required to meet the NO_X standard over the range of load conditions by comparing NO_X emissions with ammonia flow rates. During NO_X CEMS downtimes or malfunctions, the permittee shall operate at an NH_3 flow rate that is consistent with the documented flow rate for the given load condition. Records shall be maintained on site and made available upon request.
[Rule 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

28. 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 or gallons per hour as appropriate) and emission rates (NH_3 slip in ppmvd @ 7% oxygen; PM, THC, SAM, NO_X, SO_2, CO, CH_4O, C_6H_6, CH_2O, C_8H_8, C_2H_4O, Cl_2, CH_2Cl_2, C_7H_8, HCl and HF in lb/hr).
[Rule 62-4.070(3), F.A.C.]

29. Monthly Operations Summary: By the tenth calendar day of each month, the permittee shall record the following for each fuel used in the biomass boiler in a written or electronic log for the previous month of operation: hours of operation; tons of clean woody biomass and gallons of biodiesel; pounds of steam per month; total heat input rate; and the updated 12-month rolling totals for each of these operating parameters. In addition, the hourly heat input rate to the biomass boiler shall be recorded and reported. The Monthly Operations Summary shall be maintained on site and made available for inspection when requested by the Department.
[Rules 62-4.070(3) F.A.C. Reasonable Assurance]

30. Quarterly CO, NO_X, SO_2, HCl, HF and Opacity Emissions Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing CO, NO_X, SO_2, HCl, HF 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 malfunction, the permittee shall include a description of the malfunction, the actual emissions recorded, and the actions taken to correct the malfunction in the quarterly report. 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.]

C. Ash and Handling, Storage and Shipment (EU-003)

This section of the permit addresses the following emissions unit.

EU ID No. 003	Emission Unit Description
Ash handling, storage and shipment: The combustion of biomass in the proposed boiler will result in the formation of bottom and fly ash. Bottom ash will be collected from the boiler by a submerged drag-chain conveyor, which will deliver the wet ash to the ash silo. The fly ash is the entrained exhaust particulate matter captured by the ESP. An enclosed conveyor will be used to transport the fly ash from the ESP to the ash storage silo. The storage silo will be equipped with a baghouse to minimize any fugitive dust emissions from the transfer operations. The baghouse will be designed to achieve a PM emission rate of 0.01 gr/dscf. Ash from the storage silo will be loaded, via an ash conditioning mixer which produces a non-dusting material, to a truck for removal off-site.	

EQUIPMENT

1. Equipment: The permittee is authorized to construct Emission Unit EU-003, which consists of ash (fly and bottom) handling, storage and shipment systems containing the following equipment:
   a. Fly Ash Handling: The fly ash handling system consisting of enclosed hoppers, drop points and conveyors associated with the collection and transfer of fly ash to a storage silo from the ESP used to control PM emissions from the biomass boiler.
   b. Fly Ash Storage: A fly ash storage system consisting a storage silo and baghouse to control PM emissions.
   c. Fly Ash Shipment: The fly ash shipment system consisting of the drop points, conditioner and chutes associated with the transfer of the fly ash from the storage silo to trucks for shipment.
   d. Bottom Ash Handling and Shipment: The bottom ash handling and shipment system consisting of the hoppers, drop points, and submerged drag-chain conveyor associated with the collection, transfer and shipment of bottom ash from the biomass boiler to the storage silo.

   [Application No. 0810226-001-AC]

2. Air Pollution Control Equipment: To comply with the emission standards of this subsection, the permittee shall install and operate the following air pollution control equipment on the ash (fly and bottom) handling, storage and shipment emission unit.
   a. Enclosures and Dust Collectors: To minimize fugitive PM, bottom and fly ash conveyors shall be covered. Where practical, dust collectors shall be installed on the bottom ash and fly ash transfer points, drop points, hoppers and chutes.
   [Application No. 0810226-001-AC and Rule 62-4.070, F.A.C. Reasonable Assurance].
   b. Fly Ash Silo Baghouse: One baghouse shall be installed and maintained to remove PM from the fly ash storage silo exhaust. The baghouse shall be installed and operational before the silo is operated. The baghouse will be designed to achieve a PM emission rate of 0.01 gr/dscf.
   [Application No. 0810226-001-AC; Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTION

3. Hours of Operation: The hours of operation of this emissions unit is not limited (i.e., unrestricted at 8,760 hours per year).

EMISSIONS STANDARDS

4. VE Standard: As determined by EPA Method 9, there shall be no visible emissions greater than 10% opacity, except for one 6 minute period no greater than 20% from the bottom and fly ash conveyors, transfer points, drop points, hoppers, chutes and dust collectors. As determined by EPA Method 9,

there shall be no visible emissions greater than 5% opacity from the ash silo baghouse. [Rule 62-4.070, F.A.C. Reasonable Assurance and Rule 62-212.400(5)(c), F.A.C.]

5. PM Emission Standard: PM emissions from baghouse of the fly ash silo shall not exceed 0.01 gr/dscf @ 7% O_2. [Application No. 0810226-001-AC; Rules 62-4.070(3), 62-210.200(PTE), F.A.C. and Rule 62-4.070, F.A.C. Reasonable Assurance]

6. Baghouse PM Standard by Opacity Measurement: A VE reading of 5% opacity or less may be used to demonstrate compliance with the PM emission standard in **Condition 5** above. A VE reading greater than 5% opacity will require the permittee to perform a PM emissions stack test within 60 days to show compliance with the PM standard.
[Application No. 0810226-AC; Rules 62-296.603; 62-296.712, F.A.C.; and 40 CFR 60.122(a)(2) and Rule 62-4.070, F.A.C. Reasonable Assurance]

7. Best Management Practices to Control Unconfined Emissions of PM: To ensure the emission standards with regard to opacity and PM of this subsection are complied with, the procedures set forth in **Condition 11** of **Section II** of this permit, "Unconfined Emissions of Particulate Matter," shall be adhered to where practical and cost effective. In addition, the procedures set forth in Appendix BMP of this permit with regard to fugitive emissions shall be adhered to.
[Application No. 0810226-001-AC; Rule 62-4.070, F.A.C. Reasonable Assurance, and Rule 62-296.320 F.A.C.]

TESTING AND MONITORING REQUIREMENTS

8. Initial Compliance Tests: The bottom and fly ash conveyors, transfer points, drop points, hoppers, chutes, dust collectors and fly ash silo baghouse associated with this emission unit shall be tested to demonstrate initial compliance with the VE standards specified in **Condition 4** of this subsection. The initial tests shall be conducted within 180 days after initial operation.
[Rule 62-297.310(7)(a)1., F.A.C. and Rule 62-4.070(3), F.A.C.]

9. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the bottom and fly ash conveyors, transfer points, drop points, hoppers, chutes and dust collectors and ash silo baghouse associated with this emission unit shall be tested to demonstrate compliance with the VE emissions standards specified in **Condition 4** of this subsection.
[Rule 62-297.310(7)(a)4, F.A.C. and Rule 62-4.070(3), F.A.C.]

10. Fly Ash Silo PM Compliance Test: The initial and annual VE tests in **Conditions 8 and 9** of this subsection with regard to the ash silo baghouse shall serve as a surrogate for the PM emissions tests. If the VE emissions standard in **Condition 4** of this subsection is not met for the ash silo baghouse, a PM test utilizing EPA Method 5 must be conducted on baghouse stack to show compliance with the PM emissions standard in **Condition 5** of this subsection within 60 days.
[Rule 62-297.620(4), F.A.C.]

11. Bag Leak Detection: The permittee shall maintain continuous operation of bag leak detection systems, including records, on the ash storage silo baghouse. Baghouse leak detection records shall be kept on site and made available upon request. [Rule 62-4.070(3), F.A.C.].

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

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

RECORDS AND REPORTS

13. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the requirements specified in Appendix CTR (Common Testing Requirements) of this permit. 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.

EU ID No.	Emission Unit Description
004	One emergency diesel generator with a maximum design rating of 500 kW

NSPS AND NESHAP APPLICABILITY

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

EQUIPMENT

3. Emergency Generators: The permittee is authorized to install, operate, and maintain one emergency generator with a maximum design rating of 500 kW (671 horsepower (hp)) or smaller.
[Application No. 0810226-001-AC and Rule 62-210.200 (PTE), F.A.C.].

PERFORMANCE RESTRICTIONS

4. Hours of Operation: The emergency generator may operate up to 500 hours per year for maintenance and testing purposes. [Application No. 0810226-001-AC and Rule 62-210.200 (PTE), F.A.C.]
5. Authorized Fuel: The emergency generator shall fire biodiesel or as a backup ULSD FO fuels only. The biodiesel must meet the ASTM specification given in Appendix ASTM of this permit.
[Application No. 0810226-001-AC and Rule 62-210.200 (PTE), F.A.C.]

EMISSION STANDARDS

6. Emissions Limits: The emergency generator shall comply with the following emission limits and demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII. A link to the full text of Subpart IIII is given in Appendix IIII of this permit. Manufacturer certification, when using USLD FO and, if available, biodiesel, can be provided to the Department in lieu of actual stack testing.

Emergency Generator (≥ 450 kW and ≤ 560 kW)	**CO** (g/kW-hr)[1]	**PM** (g/kW-hr)	**SO_2**[2] **(% S)**	**NMHC[3]+NO_X** (g/kW-hr)
Subpart IIII (2007 and later)	3.5	0.2	0.0015	4.0

1. g/kW-hr means grams per kilowatt-hour
2. SO_2 emission standard will be met by using biodiesel or ULSD FO in the emergency generator with vendor certification of sulfur content of 0.0015% or less.
3. NMHC means Non-Methane Hydrocarbons.

[Application No. 0810226-001-AC and 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. [40 CFR 60.4211]

E. Emergency Firewater Pump (EU-005)

This section of the permit addresses the following emissions unit.

EU ID No.	Emission Unit Description
005	One emergency diesel fire pump engine with a maximum design rating of 250 kW

NSPS AND NESHAP APPLICABILITY

1. NSPS Subpart IIII Applicability: The fire pump engine is an Emergency Stationary Compression Ignition Internal Combustion Engine (Stationary ICE) and shall comply with applicable provisions of 40 CFR 60, Subpart IIII.
   [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines]
2. NESHAP Subpart ZZZZ Applicability: The emergency pump engine is a Liquid Fueled Reciprocating Internal Combustion Engines (RICE) and shall comply with applicable provisions of 40 CFR 63, Subpart ZZZZ. Pursuant to 40 CFR 63.6590(c) the fire pump 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)]

EQUIPMENT

3. Engine Driven Fire Pump: The permittee is authorized to install, operate, and maintain one emergency diesel fire pump engine. The pump engine will have a maximum rating of 250 kW (335 hp) or smaller. [Application No. 0810226-001-AC and Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE RESTRICTIONS

4. Hours of Operation: The fire pump engine may operate up to 250 hours per year for maintenance and testing purposes. [Application No. 0810226-001-AC and Rule 62-210.200 (PTE), F.A.C.]
5. Authorized Fuel: This unit shall fire biodiesel or as a backup ULSD FO fuels only. The biodiesel must meet the ASTM specification given in Appendix ASTM of this permit.
   [Application No. 0810226-001-AC and Rule 62-210.200 (PTE), F.A.C.]

EMISSION STANDARDS

6. Emissions Limits: The emergency fire pump engine shall comply with the following emission limits and demonstrate compliance in accordance with the procedures given in 40 CFR 60, Subpart IIII. A link to the full text of Subpart IIII is given in Appendix IIII of this permit. Manufacturer certification, when using USLD FO and, if available, biodiesel, may be provided to the Department in lieu of actual testing. [40 CFR 60.4211 and Rule 62-4.070(3), F.A.C.]

Emergency Pumps (≥ 300 hp and < 600 hp)	CO (g/hp-hr)[1]	PM (g/hp-hr)	SO_2[2] (% S)	$NMHC+NO_X$ (g/hp-hr)
Subpart IIII (2009 and later)	2.6	0.15	0.0015	3.0

1. g/hp-hr means grams per horsepower-hour.
2. SO_2 emission standard will be met by using biodiesel or ULSD FO in the fire pump engine with vendor certification of sulfur content of 0.0015% or less.

[Application No. 0810226-001-AC; 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]

F. Cooling Tower (EU-006)

This section of the permit addresses the following emissions unit.

EU ID No.	Emission Unit Description
006	Cooling tower with a design circulating water flow rate of 1,100 gallons per minute (gpm).

Equipment Design

1. Cooling Tower Design: The permittee is authorized to construct a cooling tower system for the GSB/ STG system with mist eliminators designed for a drift rate of 0.01% of the circulating water flow rate. [Application No. 0810226-001-AC; and Rules 62-4.070(3) and 62-210.200(PTE), F.A.C.]

Performance Requirements

2. Hours of Operation: Operation of the cooling tower system is not restricted (8,760 hours per year). [Application No. 0810226-001-AC and Rule 62-210.200 (PTE), F.A.C.]
3. Circulating Water Flow Rate: Upon request, the applicant shall provide a means for determining the circulating water flow rate through the cooling tower system. [Rule 62-4.070, F.A.C.]
4. Drift Rate: The permittee shall provide certification along with the application for Title V air operation permit that the cooling tower was constructed and installed to the design specifications in this permit. After this certification is provided, the cooling tower will be considered an unregulated emissions unit. [Rules 62-4.070 and 62-210.200 (PTE), F.A.C.]

SECTION IV. APPENDICES

CONTENTS

ASTM STANDARD D6751-09 FOR BIODIESEL

ASTM standard for biodiesel is defined as the mono alkyl esters of long chain fatty acids derived from vegetable oils or animal fats, for use in compression-ignition (diesel) engines. This specification is for pure (100%) biodiesel prior to use or blending with diesel fuel.

Standards for Biodiesel	ASTM D-6751	IS 15607 : 2005
Density	Not Mentioned	860 - 900 Kg / m^3
Ester Content	Not Mentioned	96.5 %
Flash point (closed cup)	130°C min. (150°C average)	120°C
Water and sediment	0.050% by vol., max.	500 mg / Kg, max.
Kinematic viscosity at 40°C	1.9-6.0 mm^2/s	2.5-6.0 mm^2/s
Oxidation Stability	Not Mentioned	6 hours min, at 110°C
Ramsbottom carbon residue, % mass	0.10	
Sulfated ash	0.020% by mass, max.	
Sulfur	0.0015% by mass, max*.	50 mg / Kg max
Copper strip corrosion 3 hrs. 50°C	No. 3 max	Class 1
Cetane	47 min.	51 min.
Carbon residue	0.050% by mass, max.	
Acid number, mg KOH/g	0.80 max.	0.50 max.
Methanol or Ethanol	Not Mentioned	0.2 % m/m, max
Free glycerin	0.020 % mass	0.020 % mass
Total glycerine (free glycerine and unconverted glycerides combined)	0.24% by mass, max.	0.25% by mass, max.
Group I Metal (Na+K)	5 mg/Kg, max	5 mg/Kg, max
Group II Metal (Ca+Mg)	Not Mentioned	5 mg/Kg, max
Phosphorus content	0.001 max. % mass	10 mg/Kg, max
Distillation	90% @ 360°C	Not Mentioned

* **S 15 Grade Biodiesel** is required for the FBE Project to meet the fuel sulfur requirements of 40 CFR 60, NSPS Subparts IIII and Db.

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

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 FBE as the engineering of the Biomass Feedstock delivery, handling and preparation emission unit (EU-001) is finalized. The final BMP plan must be submitted to the Compliance Authority no later than 180 days before the FBE facility becomes operational}

Practice	Description
Minimization of Fugitive Dust	1) Conveyor systems and associated drop points shall be enclosed to the extent practicable to minimize exposure to air currents. 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. 2) Drop points to woody biomass storage areas shall be designed to minimize the overall drop height exposed to air current. 3) Periodic equipment inspection and maintenance shall be performed to maintain the integrity of conveyor systems and associated drop point enclosures. Appropriate plant records shall be maintained on equipment maintenance performed. 4) Fuel silos shall be equipped with vent filters. 5) Plant personnel shall conduct daily inspections of the conveyor systems and associated drop point integrity to identify any equipment abnormalities. 6) Signs shall be posted identifying warning signs of potential equipment malfunction. 7) Plant personnel shall be trained on identification of warning signs for potential equipment malfunction. 8) Procedures shall be established for defining excessive fugitive dust from woody biomass truck unloading operations. Plant personnel shall monitor truck unloading operations and if excessive fugitive dust is detected plant personnel shall implement appropriate fugitive dust minimization techniques. Plant personnel shall be trained on procedures for defining and minimizing excessive dust from the truck unloading operations. 9) All major roadways at the plant shall be paved. 10) Plant personnel shall be trained on what constitutes excessive dust on paved roads. 11) Transfer points and fuel bins are equipped with vent filters. 12) Fuel handling equipment shall be inspected for proper operation and for maintenance requirements. 13) Plant fuel handling personnel shall implement procedures for monitoring and controlling unplanned fugitive dust emissions, including truck handling and unloading. 14) Plant personnel shall will spray, wash, scrape, or otherwise remove dirt or spilled biomass fuel on plant roads as necessary to reduce fugitive emissions.
Storage Pile Management	1) A woody biomass storage pile fugitive dust management plan shall be developed and maintained onsite. The plan shall identify warning signs and identify corrective actions for conditions that could result in excessive wind erosion and fugitive dust formation. Plant personnel shall be trained to recognize such warning signs. 2) Operational plans will recognize conditions such as high winds likely to result in wind erosion and excessive fugitive dust and will instruct plant personnel to

	curtail movement of fuel by mobile equipment under such conditions. 3) Mechanical moving of woody biomass by front end loaders and other supporting equipment shall be minimized on high wind event days. 4) First in first out biomass utilization shall be implemented to minimize objectionable odors. 5) The woody biomass storage areas shall be monitored and if conditions are conducive to wind erosion and fugitive dust formation, procedures from the fugitive dust plan shall be implemented. 6) Mobile equipment will be used to maintain the pile's design shape and to ensure adherence to FIFO in reclaim operations
Fire Prevention /Spontaneous Combustion Minimization	1) A fire management plan (FMP) shall be developed to identify and list the causes and conditions giving rise to spontaneous combustion. 2) Contact local fire marshal to develop fire management plan. The FMP shall be maintained on site. 3) The FMP shall 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. 4) Sufficient inspections of the woody 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. 5) Signs which identify potential fire hazards shall be posted at the plant. 6) Incoming unprocessed materials shall be stored in areas in accordance with clearance ranges between each storage area as described in the FMP. 7) The stacker reclaimer shall maximize the removal of older material in order to minimize the stacking of newer material on top of older material. 8) Compaction of woody biomass materials in the storage areas shall be minimized. 9) Fuel pile fire protection equipment may be used for minimization of fugitive dust emissions and dust suppression as required. 10) Plant personnel shall conduct daily inspection for fire hazards and monitor the hazards using video surveillance. 11) The FMP shall describe the use of fire-water cannons, mounted on elevated structures, together with mobile equipment to uncover and rapidly extinguish any smoldering materials. 12) The size of the fuel storage pile will not exceed the design value – this is a primary control measure, based upon the limited on-site fuel storage of about 2 weeks' worth of fuel. Specifically, the stacker will build a pile in zones up to a maximum of 60 feet high (an average of 40 feet high) and the reclaimer will start with the first zone built and reclaim the pile down to within two inches of grade.
Quality Assurance of Clean Woody Biomass	Clean woody biomass shall mean: the feedstock will consist of woody biomass that will be processed at a remote fuel preparation area (or areas) where it will be sorted, screened and chipped to size. Woody biomass is characterized by cellulose, hemicellulose, lignin and mineral content. The biomass for this project is limited to <u>clean woody</u> biomass meaning trees and woody plants, including limbs, tops, trunks, needles, leaves, stalks and other woody parts, grown in a forest, urban and suburban environments, utility rights-of-way, woodland, rangeland environment, tree farm or agricultural crop farm. The term also includes the residues and rejects from the physical (non-chemical) processing of such woody biomass. The woody biomass feedstock will be delivered via truck to

	the site at a rate of approximately 65 trucks per day. Clean Woody Biomass can include: saw dust; hogged fuel; processed butt cuts, and fuel crop. • *Saw Dust* is defined as a by-product of forest and forest product operations. • Hogged Fuel is material that comprises land clearing debris that has either been pre-processed, run through a tub grinder, or a horizontal mill at a specific private forest clearing site. • Butt Cuts are untreated round residues that are either of oversized or undersized non processible materials from post or pole manufacturers. • Fuel Crop is a vegetative product specifically grown for energy use or a waste product of agricultural operations (e.g., corn stover, peanut hulls, etc.). The following is required from the permittee: 1) Woody biomass feedstocks shall be obtained from vendors that certify that the woody biomass feed stocks they supply to FBE meet the definition of woody biomass specified above. In addition, the vendor must certify that the woody biomass does not contain any of the prohibited items listed in **Item 10,** below. 2) Any such vendor certification shall include, in legible fashion, the name of the vendor's representative making the certification as well as the representative's signature. The permittee shall retain records of the certifications for 5 years. 3) The woody biomass feedstock will be delivered to the FBE facility in vehicles designed to prevent release. Woody biomass feedstock shall be delivered to FBE primarily by trucks. 4) The permittee shall inspect each shipment of woody 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. 5) For each original source of woody biomass feedstock, the permittee shall retain documentation of the original source's procedures to prevent the contamination of the woody biomass with any materials not specifically authorized by this permit. Such documentation shall explicitly identify the procedures used to prevent the introduction of any treated wood or any other prohibited materials into the woody biomass. 6) The permittee shall retain documentation of the off-site material handling facility's procedures for receiving, segregating and loading the woody biomass from the original sources. In addition, the permittee shall retain documentation of the quality assurance procedures in place at the off-site handling facility to ensure the woody biomass is not contaminated with any materials not specifically authorized by this permit. Such documentation shall explicitly identify the procedures used to prevent the introduction of any treated wood or any other prohibited materials into the woody biomass. 7) For each shipment of woody biomass, the permittee shall record the date received, the original source and the material description of the woody biomass and the quantity received, and the name, in a legible fashion, and signature of the individual(s) responsible for performing the visible inspection in **Item 8**, below. 8) The permittee shall inspect each shipment of woody biomass upon receipt and during unloading for any material not specifically authorized by this permit. If the permittee identifies any such material, the material must be removed from the shipment and the material vendor notified. The rejected material must be disposed of following all applicable Department regulations. The permittee

	shall maintain a record of rejected materials, the amount of material rejected and the reason(s) for rejection. 9) The permittee shall maintain records of rejected shipments and disposition thereof. Such records shall be made available to the Department upon request. 10) 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) yard trash; e) municipal solid waste; f) paper; g) treated wood such as CCA or creosote; h) painted wood; and i) wood wastes from landfills.

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

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.]

CEMS OPERATION PLAN

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

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

INSTALLATION, PERFORMANCE SPECIFICATIONS AND QUALITY ASSURANCE

2. Timelines:

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

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

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

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

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

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

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

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

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

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

   c. *HCl CEMS*: The HCl CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 15, EPA Method OTM 22 or alternative specifications approved by the Department.

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. *HF CEMS*: The HF CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 15, EPA Method OTM 22 or alternative specifications approved by the Department. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority.

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

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 HCl CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 15, EPA 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 23 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 26 or 26A as detailed in Appendix A of 40 CFR 60 or by 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 assurance and control (Q&A) procedures must be provided by the Department prior to installation and operation of the CEM system.

e. *HF CEMS*: The HF CEMS shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 15, EPA 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 23 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 HF monitor shall be performed using EPA Method 26 or 26A as detailed in Appendix A of 40 CFR 60 or by Method 320 as detailed in Appendix A of 40 CFR 63. The HF 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 assurance and control (Q&A) procedures must be provided by the Department prior to installation and operation of the CEM system.

10. Substituting RATA Tests for Compliance Tests: Data collected during CEMS quality assurance RATA tests can substitute for annual stack tests, and vice versa, at the option of the owner or operator, provided

the owner or operator indicates this intent in the submitted test protocol and follows the procedures outlined in the CEMS Operation Plan.

CALCULATION APPROACH

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

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

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

14. Valid Hourly Averages: Each CEMS shall be designed and operated to sample, analyze and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.
    a. Hours that are not operating hours are not valid hours.
    b. For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data, the 1-hour block average is not valid, and the hour is considered as "monitor unavailable."

15. Calculation Approaches: The owner or operator shall implement the calculation approach specified by this permit for each CEMS, as follows:
    a. *Rolling 12-month average, rolled monthly:* Compliance shall be determined after each operating month by calculating the arithmetic average of all the valid hourly averages from that operating month and the prior x-1 operating months.
    b. *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 30-1 operating days.

MONITOR AVAILABILITY

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

EXCESS EMISSIONS

17. Definitions:

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

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

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

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

19. Data Exclusion Procedures for SIP Compliance: As per the procedures in this condition, limited amounts of CEMS 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. *Excess Emissions.* Data in excess of the applicable emission standard may be excluded from compliance calculations if the data are collected during periods of permitted excess emissions (for example, during startup, shutdown or malfunction). The maximum duration of excluded data is 2 hours in any 24-hour period, unless some other duration is specified by this permit. For the CEMS on the grate-type suspension boiler stack at the FBE facility, excess emissions of NO_X, SO_2 and CO during periods of startup, shutdown and malfunction cannot be excluded. This is to ensure that the 250 TPY emission limits for these pollutants are not exceeded which if they were would trigger PSD regulations.

    b. *Limited Data Exclusion.* If the compliance calculation using all valid CEMS emission data, as defined in Condition 12 of this appendix, indicates that the emission unit is in compliance, then no CEMS data shall be excluded from the compliance demonstration.

    c. *Event Driven Exclusion.* The underlying event (for example, the startup, shutdown or malfunction event) must precede the data exclusion. If there is no underlying event, then no data may be excluded. Only data collected during the event may be excluded.

    d. *Reporting Excluded Data.* The data exclusion procedures of this condition are not necessarily the same procedures used for excess emissions as defined by federal rules. Quarterly or semi-annual reports required by this permit shall indicate not only the duration of data excluded from SIP compliance calculations but also the number of excess emissions as defined by federal rules.

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 FBE facility.

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. <u>Test Reports</u>: 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 FBE project. Parts that are critical to the FBE 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) NA due to election by applicant to comply with (k)(2) below.

(2) Units firing only very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 0.32 lb/mmBtu heat input or less are exempt from the SO_2 emissions limit in paragraph (k)(1) of this section.

(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:

(1) 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

(2) 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.

(3) 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_2or CO_2 concentrations shall both be monitored at the inlet and outlet of the SO_2control device. If the owner or operator has installed and certified SO_2 and O_2or CO_2 CEMS according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

(1) When relative accuracy testing is conducted, SO_2 concentration data and CO_2 (or O_2) data are collected simultaneously; and

(2) In addition to meeting the applicable $SO_2$and CO_2(or O_2) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(3) The reporting requirements of §60.49b are met. $SO_2$and CO_2(or O_2) data used to meet the requirements of §60.49b shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO_2data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) NA.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average SO_2 emission rates measured by the CEMS required by paragraph (a) of this section and required under §60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under §60.42(b). Each 1-hour average SO_2 emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to §60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) Except as provided for in paragraph (e)(4) of this section, all CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Except as provided for in paragraph (e)(4) of this section, quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the SO_2CEMS at the inlet to the SO_2control device is 125 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO_2control device is 50 percent of the maximum estimated hourly potential SO_2 emissions of the fuel combusted. Alternatively, SO_2span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(4) As an alternative to meeting the requirements of requirements of paragraphs (e)(1) and (e)(2) of this section, the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(i) For all required $CO_2$and O_2monitors and for $SO_2$and NO_X monitors with span values greater than or equal to 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part.

(ii) For all required $CO_2$and O_2monitors and for $SO_2$and NO_X monitors with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for SO_2 and NO_X span values less than or equal to 30 ppm; and

(iii) For SO_2, CO_2, and O_2 monitoring 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 SO_2 control.

(b) The owner or operator of each affected facility subject to the SO_2, PM, and/or NO_X emission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) NA because the applicant will demonstrate NO_X compliance by use of a CEMS

(d) Except as provided in paragraph (d)(2) of this section, the owner or operator of an affected facility shall record and maintain records as specified in paragraph (d)(1) of this section.

(1) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(2) NA.

(e) NA.

(f) For an affected facility subject to the opacity standard in §60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in §60.48b(a) shall maintain records according to the requirements specified in paragraphs (f)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) NA because the applicant will use a COMS.

(2) NA because the applicant will use a COMS.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NO_X standards under §60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NO_X emission rates (expressed as NO_2) (lb/mmBtu heat input) measured or predicted;

(3) The 30-day average NO_X emission rates (lb/mmBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards in §60.43b(f) or to the operating parameter monitoring requirements in §60.13(i)(1).

(2) Any affected facility that is subject to the NO_X standard of §60.44b, and that:

(i) Combusts natural gas, distillate oil, gasified coal, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_X emissions on a continuous basis under §60.48b(g)(1) or steam generating unit operating conditions under §60.48b(g)(2).

(3) For the purpose of §60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under §60.43b(f).

(4) For purposes of §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under §60.46b(e), that exceeds the applicable emission limits in §60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_X under §60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the SO_2 standards under §60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of §60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;
(2) Each 30-day average SO_2 emission rate (lb/mmBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken; For an exceedance due to maintenance of the SO_2control system covered in paragraph 60.45b(a), the report shall identify the days on which the maintenance was performed and a description of the maintenance;
(3) Each 30-day average percent reduction in SO_2 emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;
(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;
(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;
(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;
(7) Identification of times when hourly averages have been obtained based on manual sampling methods;
(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;
(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3;
(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and
(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of §60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:
(1) Calendar dates when the facility was in operation during the reporting period;
(2) The 24-hour average SO_2 emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;
(3) Identification of the steam generating unit operating days that coal or oil was combusted for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;
(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action

taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(5) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(6) Identification of times when hourly averages have been obtained based on manual sampling methods;

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(8) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§60.47b(e)(4)(i) through (e)(4)(iii), each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by §§60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the SO_2 standards 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

{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 FBE will utilize to calculate the heat input rate to the grate-type suspension biomass boiler. To access the full version of 40 CFR 75, Appendix F, follow the link at the end of this appendix.}

5. 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:

$$HI = Q_w \frac{1}{F_c} \frac{\%CO_{2w}}{100} \quad (Eq.\ F\text{-}15)$$

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:

$$HI = Q_h \left[\frac{(100 - \%H_2O)}{100 F_c}\right]\left[\frac{\%CO_{2d}}{100}\right] \quad (Eq.\ F\text{-}16)$$

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:

$$HI = Q_w \frac{1}{F} \frac{[(20.9/100)(100 - \%H_2O) - \%O_{2w}]}{20.9} \quad (Eq.\ F\text{-}17)$$

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_2during unit operation, percent O_2wet 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_2concentration are on a dry basis, use the following equation:

$$HI = Q_w \left[\frac{(100-\%H_2O)}{100\ F}\right]\left[\frac{(20.9-\%O_{2d})}{20.9}\right] \qquad (Eq.\ F\text{-}18)$$

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_2during unit operation, percent O_2dry 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:

$$HI_q = \sum_{hour=1}^{n} HI_i t_i \qquad (Eq.\ F\text{-}18a)$$

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:

$$HI_c = \sum_{q=1}^{\text{the current quarter}} HI_q \qquad (Eq.\ F\text{-}18b)$$

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_2emissions 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:

$$HI_i = HI_{CS}\left(\frac{t_{CS}}{t_i}\right)\left[\frac{SF_i t_i}{\sum_{i=1}^{n} SF_i t_i}\right] \qquad (Eq.\ F\text{-}21b)$$

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:

$$HI_{Unit} = \frac{\sum_{s=1}^{u} HI_s t_s}{t_{Unit}} \qquad (Eq.\ F\text{-}21c)$$

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:

$$HI_i = HI_{CP}\left(\frac{t_{CP}}{t_i}\right)\left[\frac{FF_i t_i}{\sum_{i=1}^{n} FF_i t_i}\right] \qquad (Eq.\ F\text{-}21d)$$

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_2generated 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 grate-type suspension biomass boiler at the FBE facility.

Table 1—F- and F_C-Factors[1,2]

Fuel	F-factor (dscf/mmBtu)	F_C-factor (scf CO_2/mmBtu)
Coal (as defined by ASTM D388–99[3]):		
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.
2 FBE may develop F-Factors specific to the grate-type suspension boiler and woody biomass used at their facility
3 Incorporated by reference under §75.6 of this part.

Appendix F of 40 CFR 75 including the F-Factor Table

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.
4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.
6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

   a. Have access to and copy and records that must be kept under the conditions of the permit;

   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,

   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

   Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

   a. A description of and cause of non-compliance; and

   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

   The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.
10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
    a. Determination of Best Available Control Technology ( );
    b. Determination of Prevention of Significant Deterioration ( );
    c. Compliance with National Emission Standards for Hazardous Air Pollutants ( ); and
    d. Compliance with New Source Performance Standards (X).
14. The permittee shall comply with the following:
    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
    c. Records of monitoring information shall include:
        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

NSPS Subpart A and NESHAP Subpart A - Identification of General Provisions

NSPS - Subpart A, Identification of General Provisions

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

NESHAP - Subpart A, Identification of General Provisions

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a National Emission Standards for Hazardous Air Pollutants of 40 CFR 63 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 63.1 Applicability.

§ 63.2 Definitions.

§ 63.3 Units and abbreviations.

§ 63.4 Prohibited Activities and Circumvention.

§ 63.5 Preconstruction Review and Notification Requirements.

§ 63.6 Compliance with Standards and Maintenance Requirements.

§ 63.7 Performance Testing Requirements.

§ 63.8 Monitoring Requirements.

§ 63.9 Notification Requirements.

§ 63.10 Recordkeeping and Reporting Requirements.

§ 63.11 Control Device Requirements.

§ 63.12 State Authority and Delegations.

§ 63.13 Addresses of State Air Pollution Control Agencies and EPA Regional Offices.

§ 63.14 Incorporation by Reference.

§ 63.15 Availability of Information and Confidentiality.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

NSPS, SUBPART IIII - STATIONARY COMPRESSION IGNITION INTERNAL COMBUSTION ENGINES

A 500 kW or less emergency generator (EU ID 004) and a 335 hp or less fire pump (EU-005) are proposed for the FBE facility and 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 ZZZZ – STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES

A 500 kW or less emergency generator (EU ID 004) and a 335 hp or less fire pump (EU-005) are proposed for the FBE facility and they are subject to the requirements of 40 CFR 63, Subpart ZZZZ--National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. The complete provisions of Subpart ZZZZ may be provided in full upon request and are also available beginning at Section 63.6580 at:

Link to Subpart ZZZZ

Livingston, Sylvia

From:	Livingston, Sylvia
Sent:	Friday, February 26, 2010 2:56 PM
To:	'rjensen@fbenergy.com'
Cc:	'joe.mcclash@mymanatee.org'; Getzoff, Deborah; Nasca, Mara; 'sosbourn@golder.com'; 'forney.kathleen@epa.gov'; 'abrams.heather@epa.gov'; 'arickwa@icardmerrill.com'; 'rstewart@fppaea.org'; Gibson, Victoria; Read, David; Linero, Alvaro; Walker, Elizabeth (AIR)
Subject:	Florida Biomass Energy, LLC - FBENERGY MANATEE FACILITY, LLC; 0810226-001-AC
Attachments:	0810226-001-AC FBEnergyIntent.pdf

Dear Sir/ Madam:

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Note: We must receive verification that you are able to access the documents. Your immediate reply will preclude subsequent e-mail transmissions to verify accessibility of the document(s).

Click on the following link to access the permit project documents:

http://ARM-PERMIT2K.dep.state.fl.us/adh/prod/pdf_permit_zip_files/0810226.001.AC.D_pdf.zip

Owner/Company Name: FLORIDA BIOMASS ENERGY, LLC
Facility Name: FBENERGY MANATEE FACILITY, LLC
Project Number: 0810226-001-AC
Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: MANATEE
Processor: David Read

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Permit project documents are addressed in this email may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible, and verify that they are accessible. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record. If you have any problems opening the documents or would like further information, please contact the Florida Department of Environmental Protection, Bureau of Air Regulation

Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
850/921-9506
sylvia.livingston@dep.state.fl.us

Livingston, Sylvia

From: Rick Jensen [rjensen@fbenergy.com]
Sent: Friday, February 26, 2010 3:48 PM
To: Livingston, Sylvia
Subject: RE: Florida Biomass Energy, LLC - FBENERGY MANATEE FACILITY, LLC; 0810226-001-AC

Thank you, I received the link and it opened to provide the permit.

Rick Jensen

FBenergy

9040 Town Center Parkway
Bradenton, Fl. 34202
O - 941-567-1631
C - 404-229-8845

From: Livingston, Sylvia [mailto:Sylvia.Livingston@dep.state.fl.us]
Sent: Friday, February 26, 2010 2:56 PM
To: 'rjensen@fbenergy.com'
Cc: 'joe.mcclash@mymanatee.org'; Getzoff, Deborah; Nasca, Mara; 'sosbourn@golder.com'; 'forney.kathleen@epa.gov'; 'abrams.heather@epa.gov'; 'arickwa@icardmerrill.com'; 'rstewart@fppaea.org'; Gibson, Victoria; Read, David; Linero, Alvaro; Walker, Elizabeth (AIR)
Subject: Florida Biomass Energy, LLC - FBENERGY MANATEE FACILITY, LLC; 0810226-001-AC

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Project Number: 0810226-001-AC
Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: MANATEE
Processor: David Read

Livingston, Sylvia

From: Osbourn, Scott [Scott_Osbourn@golder.com]
To: Livingston, Sylvia
Sent: Friday, February 26, 2010 3:56 PM
Subject: Read: Florida Biomass Energy, LLC - FBENERGY MANATEE FACILITY, LLC; 0810226-001-AC

Your message was read on Friday, February 26, 2010 3:55:50 PM (GMT-05:00) Eastern Time (US & Canada).

Livingston, Sylvia

From: Amra Rickwa [arickwa@icardmerrill.com]
Sent: Wednesday, March 10, 2010 10:30 AM
To: Livingston, Sylvia
Subject: re: FW: Florida Biomass Energy, LLC - FBENERGY MANATEE FACILITY, LLC;0810226-001-AC

I apologize. Yes, the email has been received and we were able to access the attached documents.

Amra

Amra Dillard Rickwa
Florida Registered Paralegal to
Robert K. Lincoln, Esq. & Stacy Dillard-Spahn, Esq.

A Firm Commitment To You.
ICARD MERRILL
ATTORNEYS & COUNSELORS

Icard, Merrill, Cullis, Timm, Furen & Ginsburg, P.A.
2033 Main Street, Suite 600
Sarasota, FL 34237
Telephone: (941) 366-8100 x 340
Facsimile: (941) 366-6384
arickwa@icardmerrill.com

> On Wednesday, March 10, 2010 10:25 AM, Livingston, Sylvia wrote:
>
> Dear Mr. Lincoln:
> We have not received confirmation that you were able to access the documents attached to this February 26th e-mail. Please confirm receipt by opening the attachment and sending a reply to me.
> The Division of Air Resource Management is sending electronic versions of these documents rather than sending them Return Receipt Requested via the US Postal service. Your "receipt confirmation" reply serves the same purpose as tracking the receipt of the signed "Return Receipt" card from the US Postal Service. Please let me know if you have any questions.
> Sylvia Livingston
> Bureau of Air Regulation

Division of Air Resource Management (DARM)
Department of Environmental Protection
850/921-9506
sylvia.livingston@dep.state.fl.us

The Department of Environmental Protection values your feedback as a customer. DEP Secretary Michael W. Sole 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.

From: Livingston, Sylvia
Sent: Friday, February 26, 2010 2:56 PM
To: 'rjensen@fbenergy.com'
Cc: 'joe.mcclash@mymanatee.org'; Getzoff, Deborah; Nasca, Mara; 'sosbourn@golder.com'; 'forney.kathleen@epa.gov'; 'abrams.heather@epa.gov'; 'arickwa@icardmerrill.com'; 'rstewart@fppaea.org'; Gibson, Victoria; Read, David; Linero, Alvaro; Walker, Elizabeth (AIR)
Subject: Florida Biomass Energy, LLC - FBENERGY MANATEE FACILITY, LLC; 0810226-001-AC

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Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)

Livingston, Sylvia

From: yvonne.tryon@mymanatee.org
Sent: Friday, February 26, 2010 3:07 PM
To: Livingston, Sylvia
Subject: Florida Biomass Energy, LLC - FBENERGY MANATEE FACILITY, LLC; 0810226-001-AC

Return Receipt

Your document:
Florida Biomass Energy, LLC - FBENERGY MANATEE FACILITY, LLC; 0810226-001-AC

was received by:
yvonne.tryon@mymanatee.org

at:
02/26/2010 03:07:45 PM

Livingston, Sylvia

From: Osbourn, Scott [Scott_Osbourn@golder.com]
To: Livingston, Sylvia
Sent: Friday, February 26, 2010 3:56 PM
Subject: Read: Florida Biomass Energy, LLC - FBENERGY MANATEE FACILITY, LLC; 0810226-001-AC

Your message was read on Friday, February 26, 2010 3:55:50 PM (GMT-05:00) Eastern Time (US & Canada).

Livingston, Sylvia

From: Ron Stewart [rstewart@fppaea.org]
Sent: Wednesday, March 10, 2010 11:13 AM
To: Livingston, Sylvia
Subject: RE: Florida Biomass Energy, LLC - FBENERGY MANATEE FACILITY, LLC; 0810226-001-AC

Sylvia,

Yes, I received the document and could open it.

Thanks,

Ron Stewart, PE
Executive Director, FPPAEA
2015 Ayrsley Town Boulevard
Suite 202
Charlotte, NC 28273

Tel: (803) 448 0116| Fax: (704) 749-9402 | Email: rstewart@fppaea.org | Web: http://www.fppaea.org

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From: Livingston, Sylvia [mailto:Sylvia.Livingston@dep.state.fl.us]
Sent: Wednesday, March 10, 2010 10:28 AM
To: rstewart@fppaea.org
Subject: FW: Florida Biomass Energy, LLC - FBENERGY MANATEE FACILITY, LLC; 0810226-001-AC

Dear Mr. Stewart:

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Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
Department of Environmental Protection
850/921-9506
sylvia.livingston@dep.state.fl.us

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From: Livingston, Sylvia
Sent: Friday, February 26, 2010 2:56 PM
To: 'rjensen@fbenergy.com'
Cc: 'joe.mcclash@mymanatee.org'; Getzoff, Deborah; Nasca, Mara; 'sosbourn@golder.com'; 'forney.kathleen@epa.gov'; 'abrams.heather@epa.gov'; 'arickwa@icardmerrill.com'; 'rstewart@fppaea.org'; Gibson, Victoria; Read, David; Linero, Alvaro; Walker, Elizabeth (AIR)
Subject: Florida Biomass Energy, LLC - FBENERGY MANATEE FACILITY, LLC; 0810226-001-AC

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Facility Name: FBENERGY MANATEE FACILITY, LLC
Project Number: 0810226-001-AC
Permit Status: DRAFT
Permit Activity: CONSTRUCTION
Facility County: MANATEE
Processor: David Read

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Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
850/921-9506
sylvia.livingston@dep.state.fl.us

Livingston, Sylvia

From: shirley.talley@mymanatee.org on behalf of joe.mcclash@mymanatee.org
Sent: Wednesday, March 10, 2010 3:01 PM
To: Livingston, Sylvia
Subject: Fw: Florida Biomass Energy, LLC - FBENERGY MANATEE FACILITY, LLC; 0810226-001-AC
Attachments: 0810226-001-AC FBEnergyIntent.pdf

Hi Silvia again,

Please forgive me for all the e-mails. **If these e-mails pertain to Title 5 permits in Manatee County, please copy "Commissioner Joe McClash, At-Large Commissioner" on all of them** at **Joe.McClash@mymanatee.org** .

THANKS, for your patience!!!!

Shirley

----- Forwarded by Shirley Talley/MCG on 03/10/2010 02:52 PM -----
From: Joe McClash/MCG
To: "Livingston, Sylvia" <Sylvia.Livingston@dep.state.fl.us>
Cc: Larry Bustle/MCG@MCG, Yvonne Tryon/MCG@MCG
Date: 03/10/2010 02:45 PM
Subject: Fw: Florida Biomass Energy, LLC - FBENERGY MANATEE FACILITY, LLC; 0810226-001-AC
Sent by: Shirley Talley

Dear Ms. Livingston:

In looking at the attached letter, I note you copied Commissioner McClash as the "Chairman of the Port Authority".

The current Chairman of the Manatee Port Authority is Commissioner Larry Bustle. In the future, please direct any e-mail directed to the Chairman of the Manatee Port Authority to the following e-mail address:
Larry.Bustle@mymanatee.org .

Thank you in advance for your assistance in this matter,

Sincerely,

Shirley

Shirley Talley, Executive Assistant
to Commissioner McClash
Manatee County Government
Board of County Commissioners
Post Office Box 1000
Bradenton, Florida 34206-1000
Telephone: 941-745-3709
Facsimile: 941-745-3790
shirley.talley@mymanatee.org

----- Forwarded by Shirley Talley/MCG on 03/10/2010 02:29 PM -----
From: Joe McClash/MCG

To: Bobbi Roy/MCG@MCG, Debbie Bassett/MCG@MCG
Date: 03/10/2010 02:24 PM
Subject: Fw: Florida Biomass Energy, LLC - FBENERGY MANATEE FACILITY, LLC; 0810226-001-AC
Sent by: Shirley Talley

----- Forwarded by Shirley Talley/MCG on 03/10/2010 02:21 PM -----
From: Joe McClash/MCG
To: "Livingston, Sylvia" <Sylvia.Livingston@dep.state.fl.us>
Date: 03/10/2010 02:02 PM
Subject: Re: FW: Florida Biomass Energy, LLC - FBENERGY MANATEE FACILITY, LLC; 0810226-001-AC
Sent by: Shirley Talley

Good Afternoon Sylvia,

Yes, I was able to access the attached document. I will see that it is in Commissioner McClash's e-mail folder.

Shirley

Shirley Talley, Executive Assistant
to Commissioner McClash
Manatee County Government
Board of County Commissioners
Post Office Box 1000
Bradenton, Florida 34206-1000
Telephone: 941-745-3709
Facsimile: 941-745-3790
shirley.talley@mymanatee.org

From: "Livingston, Sylvia" <Sylvia.Livingston@dep.state.fl.us>
To: "joe.mcclash@mymanatee.org" <joe.mcclash@mymanatee.org>
Date: 03/10/2010 10:21 AM
Subject: FW: Florida Biomass Energy, LLC - FBENERGY MANATEE FACILITY, LLC; 0810226-001-AC

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US Postal Service. Please let me know if you have any questions.

Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
Department of Environmental Protection
850/921-9506
sylvia.livingston@dep.state.fl.us

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Cc: 'joe.mcclash@mymanatee.org'; Getzoff, Deborah; Nasca, Mara; 'sosbourn@golder.com'; 'forney.kathleen@epa.gov'; 'abrams.heather@epa.gov'; 'arickwa@icardmerrill.com'; 'rstewart@fppaea.org'; Gibson, Victoria; Read, David; Linero, Alvaro; Walker, Elizabeth (AIR)
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