TECHNICAL EVALUATION

&

PRELIMINARY DETERMINATION

APPLICANT

Gainesville Renewable Energy Center, LLC
75 Arlington Street, 5th Floor
Boston, Massachusetts 02116

PROJECT

DEP File No. 0010131-001-AC (PSD-FL-411)
100 Megawatts (net) Woody Biomass Power Plant

COUNTY

Alachua 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

July 14, 2010

1. APPLICATION INFORMATION

1.1. Applicant Name and Address

Gainesville Renewable Energy Center (GREC), LLC
75 Arlington Street, 5th Floor
Boston, Massachusetts 02116

Authorized Representative: Mr. James S. Gordon, Chief Executive Officer

1.2. Key Dates

- November 30, 2009 — Received a Prevention of Significant Deterioration (PSD) air construction permit application from GREC.
- December 30 — Department issued first request for additional information (RAI).
- February 10, 2010 — Department received response to first RAI from GREC.
- March 15 — Department issued second RAI.
- May 10 — Department received response to second RAI from GREC.
- June 18 — Department received application from Gainesville Regional Utilities (GRU) requesting sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emission caps on contiguous Deerhaven Generating Station (DGS) Unit 2.
- July 14 — Department issued Draft Permit package for GREC and posted documents.

1.3. Facility Location

The GREC will be located on the 131 acres which are delineated by the red outline in Figure 1. GREC LLC has a long-term lease from the City of Gainesville for this parcel. The property is within the site (delineated in blue) of the GRU DGS. The GRU DGS is located where shown in Figure 2 at 10001 Northwest 13th Street (U.S. Highway 441) in Gainesville, Alachua County, Florida. The UTM coordinates are Zone 17; 365.0 kilometers (km) East and 3,293.8 km North.

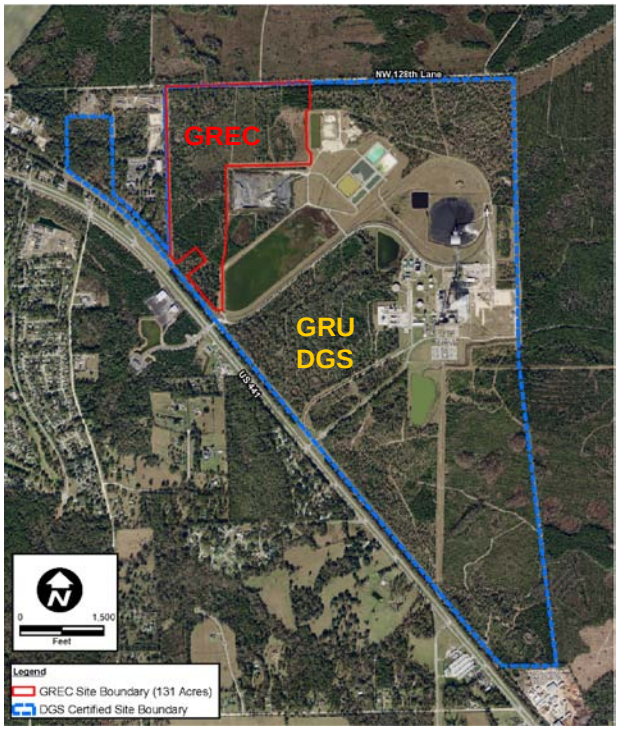


Figure 1 - GREC Site Location, Alachua County

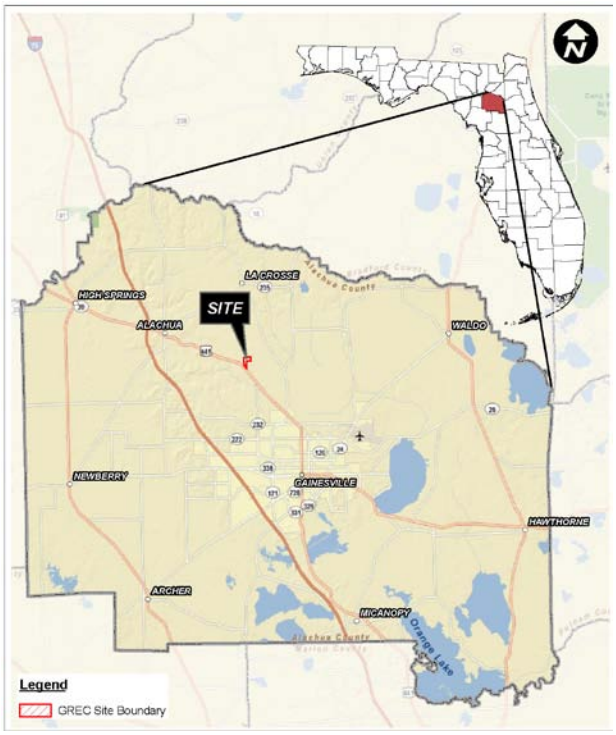


Figure 2 – GREC boundary within GRU DGS Site

The nearest Prevention of Significant Deterioration (PSD) Class I areas are the Okefenokee National Wildlife Area (NWA) located approximately 93 km north of the proposed GREC and the Chassahowitzka NWA located approximately 110 km southwest of the proposed GREC.

GRU DGS Units 1 and 2 are shown in Figure 3 below. The stack on the right hand side belongs to gas and oil-fueled Unit 1, which has a generating capacity of approximately 75 megawatts (MW). The taller, wider stack on the left hand side belongs to Unit 2, which is primarily a coal-fueled unit with an approximate generating capacity of 251 MW. Figure 4 is a photograph of the coal storage and handling operation for Unit 2.

Figure 3 – GRU DHS Units 1 (right) and 2

Figure 4 – Coal Storage and Handling Operation

Figure 5 is a photograph taken within the GRU DGS site and in the direction of the proposed GREC property. Figure 6 was taken from within the west boundary of the GREC property and in the direction of some Alachua County Department Public Works operations.

Figure 5 – View towards Proposed GREC Site

Figure 6 – Alachua County Public Works

1.4. Project Description

The applicant proposes to construct a woody biomass-fueled electric power plant. The proposed plant will be capable of generating approximately 116 MW (gross) of electrical power by combusting woody biomass in a bubbling fluidized bed (BFB) boiler and associated steam turbine-electrical generator (STG). The plant will export to the grid approximately 100 MW (net) after deducting the parasitic load required to operate the plant. Figure 7 is a preliminary artist rendering of the GREC as seen from the top of the GRU DGS Unit 2 boiler building.

Figure 7 – Future GREC Woody Biomass Power Plant as seen from GRU DGS Unit 2 Boiler Building

The power plant will be comprised of five major process areas. These process areas are:

- Biomass fuel delivery, unloading and processing;
- Biomass fuel handling and storage;
- Power island (steam generating unit), including a BFB boiler, STG and cooling tower;
- Ash (bottom and fly) handling, storage and shipment; and
- Emergency support equipment.

Table 1 indicates the new emissions units (EUs) that will be added by this project.

Table 1. - New EUs at GREC Facility

Facility ID No. 0010131	
EU ID No.	**Emission Unit Description**
001	Biomass fuel delivery, preparation, storage and handling
002	Woody biomass-fueled BFB boiler with a maximum heat input capacity of 1,358 million British thermal units (Btu) per hour (mmBtu/hr)
003	Ash handling, storage and shipment
004	Mechanical draft cooling tower
005	564 kilowatt (kW) emergency generator
006	275 horsepower (hp) emergency fire pump

1.5. Additional Project Features

Fuels

GREC proposes to fuel the new BFB boiler with only clean woody biomass under normal operation. Natural gas will be used as a startup fuel. Natural gas is provided to the site via a pipeline.

Air Pollution Controls

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

Biomass Fuel Delivery, Unloading, Processing, Handling and Storage

- Employment of a first-in/first-out stacking and reclaiming system with a telescoping chute and 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 particulate matter (PM) through the use of Best Management Practices (BMP).
- The BMP where practical will include enclosed conveyors, dust collectors at drop points and to the extent possible enclosed, telescoping chutes for dropping fuel to and from conveyors.
- Wetting will be used, as needed, to minimize fugitive dust emissions from biomass storage piles and from paved roads and gravel areas within the facility.
- Other reasonable precautions as described in Rule 62-296.320(4)(c), F.A.C.

Power Island

- Formation of particulate matter (PM) of all sizes, carbon monoxide (CO) and volatile organic compounds (VOC) from the boiler will be controlled by the BFB design including good combustion practices (GCP).
- Emissions of PM and PM with aerodynamic diameters less than 10 and 2.5 micrometers (PM_{10} and $PM_{2.5}$) from the BFB boiler will be controlled by a fabric filter baghouse. $PM_{2.5}$ will be further controlled by the SO_2, NO_X and ammonia (NH_3) controls and limits described below.
- SO_2 and sulfuric acid mist (SAM) from the BFB boiler will be controlled by use of untreated biomass fuel (inherently low in sulfur) and natural gas, reaction with alkaline fly ash and a dry in-duct sorbent injection system (IDSIS).
- NO_X and VOC from the BFB boiler will be further controlled by an NH_3 based selective catalytic reduction (SCR) system.
- Emissions of HAP from the BFB boiler will be controlled by use of GCP, use of untreated woody biomass fuel (inherently low in chloride), reaction with alkaline fly ash, the IDSIS, the fabric filter baghouse and the SCR system.
- PM emissions from the cooling tower will be minimized by utilizing high efficiency drift eliminators.

Ash (bottom and fly) Handling, Storage and Shipment

- Emissions of PM 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 emissions.

Emergency Support Equipment

- Emergency equipment will be designed to meet the emission limits given in New Source Performance Standards (NSPS) Subpart IIII and National Emission Standards for Hazardous Air Pollutants (NESHAP) Subpart ZZZZ.
- Ultra low sulfur distillate (ULSD) fuel oil will be utilized and operation of support equipment will be limited to 500 hours per year or less per unit.

2. APPLICABLE REGULATIONS

2.1. State Regulations

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

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

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

2.2. Federal Regulations

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

3. MAJOR SOURCE APPLICABILITY

3.1. PSD Major Stationary Source Applicability Determination

The Department regulates major stationary sources in accordance with Florida's PSD program pursuant to Rule 62-212.400, F.A.C. PSD preconstruction review is required in areas that are currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or areas designated as "unclassifiable" for these regulated pollutants.

As defined in Rule 62-210.200, (Definitions), F.A.C., a facility is considered a "major stationary source" if it emits or has the potential to emit 5 tons per year of lead, 250 tons per year or more of any PSD pollutant, or 100 tons per year or more of any PSD pollutant and the facility belongs to one of the 28 listed PSD major facility categories. The existing GRU DGS is a major stationary source because it is:

> *"A fossil fuel-fired steam electric plant of more than 250 mmBtu/hr heat input and which emits, or has the potential to emit (PTE), 100 tons per year (TPY) or more of any PSD pollutant."*

PSD pollutants include: CO; NO_X; SO_2; PM; PM_{10}; VOC; lead (Pb); Fluorides (F); SAM; hydrogen sulfide (H_2S); total reduced sulfur (TRS), including H_2S; reduced sulfur compounds, including H_2S; municipal waste combustor (MWC) organics measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans (D/F); MWC metals measured as PM; MWC acid gases measured as SO_2 and hydrogen chloride (HCl); municipal solid waste (MSW) landfill emissions measured as non-methane organic compounds (NMOC); and mercury (Hg).

For existing major stationary sources, PSD applicability for further projects (i.e. major modifications) is based on emissions thresholds known as the significant emission rate (SER) as defined in Rule 62-210.200, (Definitions) F.A.C. Net emissions increases of PSD pollutants from the project exceeding these SER are considered "significant" and BACT must be employed to minimize emissions of each PSD pollutant. Although a facility may be "major" for only one PSD pollutant, a project must include BACT controls for any PSD pollutant that exceeds the corresponding SER given in Table 2.

Table 2 – List of SER by PSD-Pollutant [1]

Pollutant	SER (TPY)	Pollutant	SER (TPY)
CO	100	NO_X	40
PM/PM_{10} [2]	25/15	Ozone (VOC) [3]	40
Ozone (NO_X) [3]	40	SAM	7
SO_2	40	F	3
Pb	0.6	TRS	10
H_2S	10	Hg [4]	0.1

1. Excluding those defined exclusively for MWC and MSW landfills.
2. $PM_{2.5}$ is also a PSD pollutant, but SER have not yet been defined. It is regulated by its precursors and surrogates (e.g. SO_2, NO_X and PM/PM_{10}).
3. Ozone is regulated by its precursors (VOC and NO_X).
4. Hg is not a PSD pollutant but has a defined SER.

Table 3 summarizes the applicant's estimates of key regulated air pollutants from the proposed woody biomass electric power plant. The project will result in emissions of NO_X, CO, PM, SO_2, small amounts of SAM (sometimes expressed as H_2SO_4), VOC and HAP. NH_3 slip emissions from the SCR system are also included in the table.

Table 3 – Applicant's Estimated PTE of Key PSD Pollutants (in TPY) for the GREC Facility

Source Operation	PM [1]	PM_{10} [1]	NO_X	SO_2	H_2SO_4	CO	VOC	Pb
BFB Boiler	89.2	249.8	416.4	170.7	5.9	713.8	77.3	0.12
Biomass Handling Point Sources	28.0	28.0	--	--	--	--	--	--
Biomass Handling Fugitive Sources	11.6	2.3	--	--	--	--	--	--
Cooling Tower	1.5	1.0	--	--	--	--	--	--
Emergency Generator	0.063	0.063	1.4	0.0008	--	1.46	0.60	--
Emergency Fire Pump Engine	0.023	0.023	0.32	0.002	--	0.39	0.14	--
Project Total PTE All Sources	130.4	281.2	418.1	170.7	5.9	715.7	78.0	0.12

1. PM is estimated as filterable (front-half sampling train) material. PM_{10} estimates includes condensible (back-half) material.

In 2007 the Department issued a permit to GRU for an air pollution control system (APCS) project (DEP File 0010006-005-AC) to reduce emissions from the GRU DGS Unit 2. In its technical evaluation, the Department estimated future reductions of 7,139 TPY of SO_2 and 3,262 of NO_X. These values are for informational purposes only (expectations) and are not permit conditions. It will take several more years to confirm these expectations.

On July 12, 2010 the Department issued a permit (DEP File No. 0010006-012-AC) to GRU providing for emission caps on Unit 2 such that there will be enforceable and permanent reductions in SO_2 and NO_X (418 and 171 TPY respectively) equal to the increases based on the PTE from the GREC.

The required reductions imposed by the requested caps will ensure when considering the APCS project and the GREC project that there will not be a net emissions increase of SO_2 or NO_X. Table 4 provides PSD applicability calculations based on the net emission increases from the GREC considering the GRU DGS Unit 2 APCS.

Table 4 – Net PSD Pollutant Emission Increases (in TPY) due to the GREC Project

Source Operation	PM	PM_{10}	NO_X	SO_2	H_2SO_4	CO	VOC	Pb
GREC Project Emissions Increases	130.4	281.2	418.1	170.7	5.9	715.7	78.0	0.12
Enforceable Reductions GRU DGS Unit 2			-418	-171				
Net Emissions Increases	130.4	281.2	~0	~0	5.9	715.7	78.0	0.12
SER	25	15	40	40	7	100	40	0.6
PSD Applies? (Yes/No)	**Yes**	**Yes**	No	No	No	**Yes**	**Yes**	No

The required reductions of SO_2 and NO_X from the GRU DGS are much less than the expected future reductions that will be achieved by the DGS Unit 2 APCS. The proposed increases are also less than reductions already demonstrated by early operation of the APCS on DGS Unit 2.

The SCR and flue gas desulfurization (FGD) systems began operation on GRU DGS Unit 2 in the late spring and late summer of 2009 respectively. The monthly SO_2 and NO_X (tons per month) emissions since the middle of 2005 are shown in the graph below. Graphs of the rolling 24-month averages (rolled monthly) and expressed in TPY are also shown for each pollutant. Some of the extreme dips are related to outages and not the effect of the APCS.

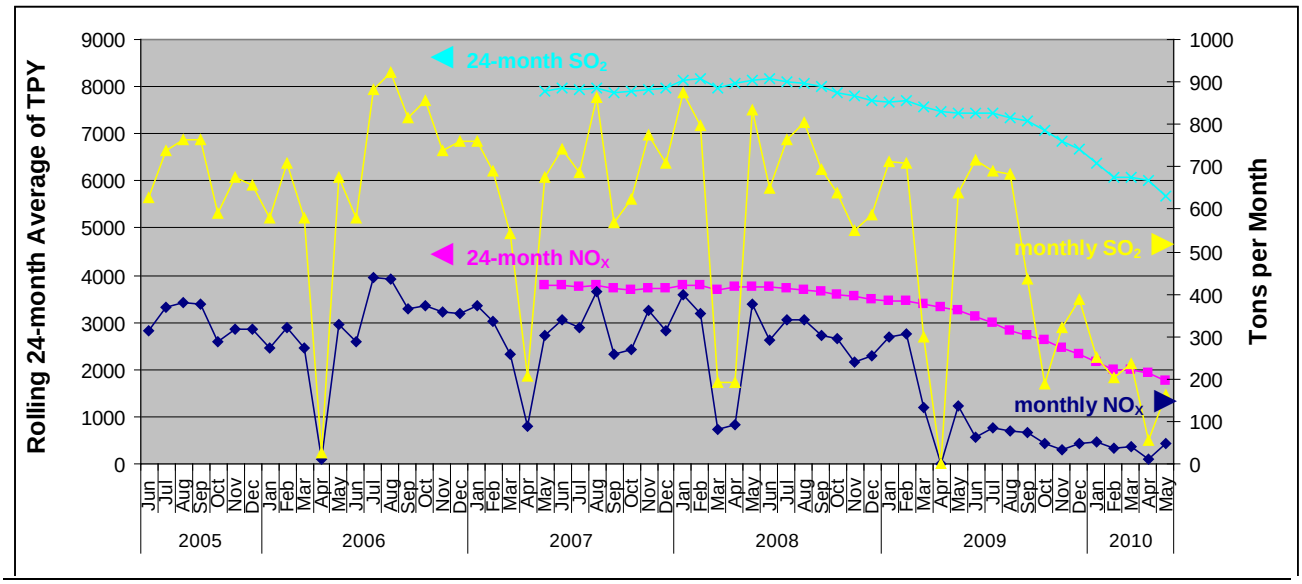


Figure 8 – Progressively Declining SO_2 and NO_X Emissions from GRU DGS Unit 2

In addition to SO_2 and NO_X, the APCS installed at GRU DGS will, in the long term, reduce emissions of SAM and Hg by more than the increases caused by the GREC project. However, the reductions are not enforceable or continuously measured and were not considered in the PSD applicability.

In summary, net emissions increases of regulated PSD air pollutants PM/PM_{10}, CO and VOC exceed their respective SER. Therefore, the GREC will be subject to the PSD rules including PSD ambient air modeling and a requirement for a best available control technology (BACT) for the cited pollutants.

3.2. HAP Major Source Determination

The Department regulates major sources of HAP in accordance with applicable portions of 40 CFR 63 adopted in Rule 62-204.800(11), F.A.C. The GRU DGS is already classified as a major source of HAP because it has a PTE of 10 TPY of any single HAP or 25 TPY of all HAP. The applicant believes that the proposed GREC project alone (the BFB in particular) will not have a PTE of any single HAP that is equal to or greater than 10 TPY or of all aggregated HAP equal to or greater than 25 TPY.

Estimates of individual key HAP emissions are provided in Table 5.

Table 5 – Applicant's Estimated PTE of HAP from the GREC BFB in TPY

Pollutant[1]	HCl	HF	Phosphorus	Other Metal HAP	CH_3Cl	C_6H_6	CH_2O	Other Organic HAP	Total
Emissions	9.72	9.72	2.2	1.39	0.15	0.37	0.8	0.32	24.7
1. CH_3Cl is methyl chloride; C_6H_6 is benzene; CH_2O is formaldehyde.									

For reference, HCl and hydrogen fluoride (HF) reductions due to the APCS projects at GRU DGS Unit 2 will also exceed the increases from the GREC project. However the HAP decreases from the GRU DGS Unit 2 cannot be considered in calculating the HAP increases from the GREC project.

Because the GREC project by itself is not a major source of HAP, a case-by-case MACT determination pursuant to 40 CFR 63, Subpart B is not required. Additional details are provided in Section 4.2 below.

4. DEPARTMENT'S PROJECT REVIEW

4.1. Applicable State Regulations

As provided in Table 6 below, this project is subject to the applicable environmental laws specified in Chapter 403 of the Florida Statutes (F.S.) and to the following rules in the F.A.C.

Table 6 - Applicable Rules from the F.A.C.

F.A.C. Rule	Description
62-4	Permits
62-204	Air Pollution Control – General Provisions
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Stationary Sources – Preconstruction Review
62-213	Operation Permits for Major Sources 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

4.2. Regulatory Classification

Following is a summary of the applicability of key regulations to the GREC project.

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

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

This rule applies to all permitting decisions:

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

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

- The GREC project requires a modification of the previously issued conditions of certification for the GRU DGS pursuant to the power plant siting provisions of this rule.

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

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

This rule applies to all air permitting decisions.

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

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

This rule applies to all air permitting decisions.

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

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

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

- 40 CFR 60, Subpart A – General Provisions;
- 40 CFR 60, Subpart Da – Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978 (and After February 28, 2005); and
- 40 CFR 60, Subpart IIII – Stationary Compression Ignition Internal Combustion Engines (ICE).

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

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

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

The following (otherwise applicable) provision was vacated and remanded in 2007 by the U.S. Court of Appeals, D.C. District:

- 40 CFR 63, Subpart DDDDD – NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.

On June 4, 2010 EPA published notice in the Federal Register and is presently accepting comments on a proposed rule to be issued by EPA as Subpart DDDDD. When finalized, Subpart DDDDD potentially applies to the GREC BFB boiler. Otherwise, it will ultimately be subject to a rule under development for utility boilers.

The following provision does not apply to the project because chromium-based water treatment chemicals will not be used in the cooling tower:

- 40 CFR 63, Subpart Q - NESHAP for Industrial Process Cooling Towers.

The following provision incorporated into Rule 62-204.800(11), F.A.C. adopted from 40 CFR 63 and incorporated into this rule does not apply to this project:

- 40 CFR 63, Subpart B – Requirements for Control Technology Determinations for Major Sources in Accordance With Clean Air Act Sections, Sections 112(g) and 112(j).

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

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

- The facility (including the GRU DGS) is a Title V or "Major Source" of air pollution because the PTE of at least one regulated pollutant will exceed 100 TPY.
- The facility (including the GRU DGS) is a major source of HAP because it emits or has a PTE of 10 TPY or more of any one HAP or 25 TPY or more of any combination of HAP.
- The facility (including the GRU DGS) is classified as a "Major Stationary Source" (PSD-source) because it emits 100 TPY or more of a PSD pollutant and is one of the 28 facility categories listed in the definition with the PSD applicability threshold of 100 TPY.

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

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

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

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

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

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

- Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
- Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.
- Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest.

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

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

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

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

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

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

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

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

- The proposed plant will be a Title V source, will serve an electric generator capable of generating 25 MW or more of electricity and will sell the resultant electricity. It will be required to apply for and obtain a Title IV Acid Rain Part within its Title V operation permit.

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

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

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

Rules 62-296.401, F.A.C., Incinerators and Rule 62-296.416, F.A.C., Waste-to-Energy Facilities.

- 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, these two rules do not apply to this project.

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

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

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

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

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

- The GREC facility is subject to CAIR.

4.3. Process Description

Principle

The steam generating unit will utilize a BFB boiler with a maximum heat input capacity of 1,358 mmBtu/hr on a 4-hour basis. The maximum heat input capacity of the fossil fuel (natural gas) to the unit is 341 mmBtu/hr. The steam produced will then be sent to a STG that will generate approximately 116 MW (gross) of electricity of which approximately 100 MW will be delivered to the grid.

The biomass fuel delivery, unloading, processing, handling and storage operations will be capable of delivering the clean woody biomass to the BFB boiler. Residual fly ash collected by the boiler system baghouse will be conveyed and stored for future shipment offsite by truck. The bottom ash from the BFB biomass boiler will be collected, transferred and shipped offsite. An emergency generator and fire pump engine will be used in the event that emergency situations arise at the plant.

Fuel Slate and Sources

The feedstock to the BFB boiler will consist of clean, untreated woody biomass. The woody biomass will be processed at a remote fuel preparation area(s) where it will be sorted, screened and chipped to size.

GREC will only use clean woody biomass in the proposed BFB boiler. The clean, untreated woody biomass will include: in-forest residues such as tree limbs, slash, bark; sawdust; sander dust; wood chips and pellets; scraps; slabs; millings; and shavings.

Table 7 further identifies types of woody biomass to be combusted in the BFB boiler.

Table 7 - Summary of Woody Biomass Fuel Descriptions

Fuel Type	Description
In-forest residue and slash	Tops, limbs, whole tree material and other residues from soft and hardwoods that result from traditional silvicultural harvests.
Mill residue	Saw dust, bark, shavings and kerf waste from cutting/milling whole green trees; fines from planning kiln-dried lumber; wood waste material generated by primary wood products industries such as round-offs, end cuts, sticks, pole ends; and reject lumber as well as residue material from the construction of wood trusses and pallets.
Pre-commercial tree trimmings and understory clearings	Tops, limbs, whole tree material and other residues that result from the cutting or removal of certain, smaller trees from a stand to regulate the number, quality, and distribution of the remaining commercial trees; and forest understory which includes smaller trees, bushes, and saplings.
Storm, fire and disease debris	Tops, limbs, whole tree material and other residues that are damaged due to storms, fires or infectious diseases.
Urban wood waste	Tree parts and/or branches generated by landscaping contractors and power line/roadway clearance contractors that have been cut down for land development or right-of-way clearing purposes.
Recycled industrial wood	Wood derived from used pallets packing crates; and dunnage disposed by commercial or industrial users.
Supplementary fuel material	Herbaceous plant matter; clean agricultural residues (i.e., rice hulls, straw, etc.; no animal wastes or manure); and whole tree chips and pulpwood chips.

Biomass Fuel Delivery, Unloading and Processing

The GREC biomass fuels will be initially chipped/ground and processed at offsite locations and then transported to the site by truck. Between 130 and 150 fuel truck deliveries per day are expected based on the maximum BFB boiler biomass fuel consumption rate at average moisture content and a 6-day-per-week delivery schedule.

During peak delivery periods, the delivery facilities will be capable of unloading 24 truckloads of biomass fuel per hour. The GREC biomass fuel handling system will include scales to weigh each truck entering and departing the facility to determine the delivered fuel weight. The maximum designed hourly biomass processing rate is 600 tons per hour (TPH) with a maximum designed yearly rate of 1,395,030 TPY.

A preliminary schematic of the biomass fuel delivery, unloading and processing system is shown in Figure 9. Principal equipment consists of three truck dumpers, various conveyors and a screen/hog building containing two sets of screens and hogs (i.e., machines used to size wood chips). PM from the screen/hog building will be control by a fabric filter baghouse.

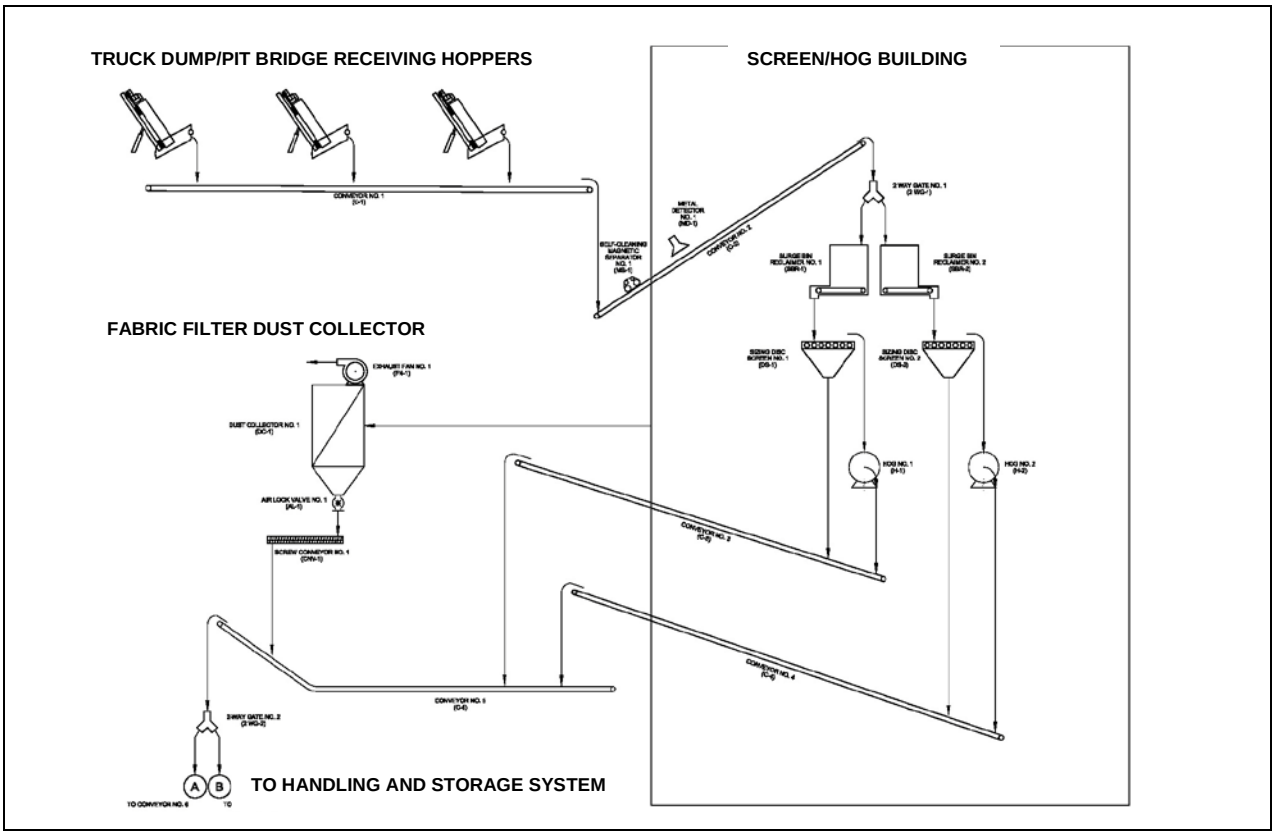


Figure 9 – Biomass Fuel Delivery, Unloading, and Processing System

Biomass Fuel Handling and Storage System

A preliminary schematic of the biomass fuel handling and storage system is shown in Figure 10. Principal equipment consists of conveyors, stacker/reclaimers, a telescoping chute, and metering bins for the BFB boiler. In addition, four biomass storage piles will be utilized. The biomass storage piles will be built and managed on the principle of first-in/first-out (FIFO). The purpose is to allow good chip blending, high stacking and reclaiming, low chip damage, and low operation costs. Such piles are fairly resistant to high winds. FIFO operation will minimize dust generation, biological degradation and odors.

There will be four biomass storage piles as described below:

- Storage Pile 1: Storage Pile No. 1 will be a kidney shaped pile that is formed with an automatic stacker/reclaimer. The pile will be up to 85 feet (ft) high and will have a storage capacity of approximately 125,000 cubic yards (yd^3) of fuel.
- Stock Pile 1: Stock Pile No. 1 will consist of a conical shaped pile that is fed with a fixed stacker, which includes a telescoping chute to minimize the distance the fuel will drop when the pile is empty. The pile will be up to 60 ft high and will have a storage capacity of approximately 8,500 yd^3 of fuel.
- Storage Pile 2: Storage Pile No. 2 will be approximately 35 ft high with a storage capacity of approximately 79,000 yd^3. A bulldozer or front-end loader will be used to remove fuel from Stock Pile 1 and deliver it to Storage Pile No. 2.
- Saw Dust Pile: In addition to the chipped/ground biomass fuel, moist sawdust will be received at the site. Sawdust will be delivered with self-unloading trucks and deposited in an open area adjacent to Storage Pile 2 in a fourth, small pile. Front-end loaders will be used to reclaim sawdust.

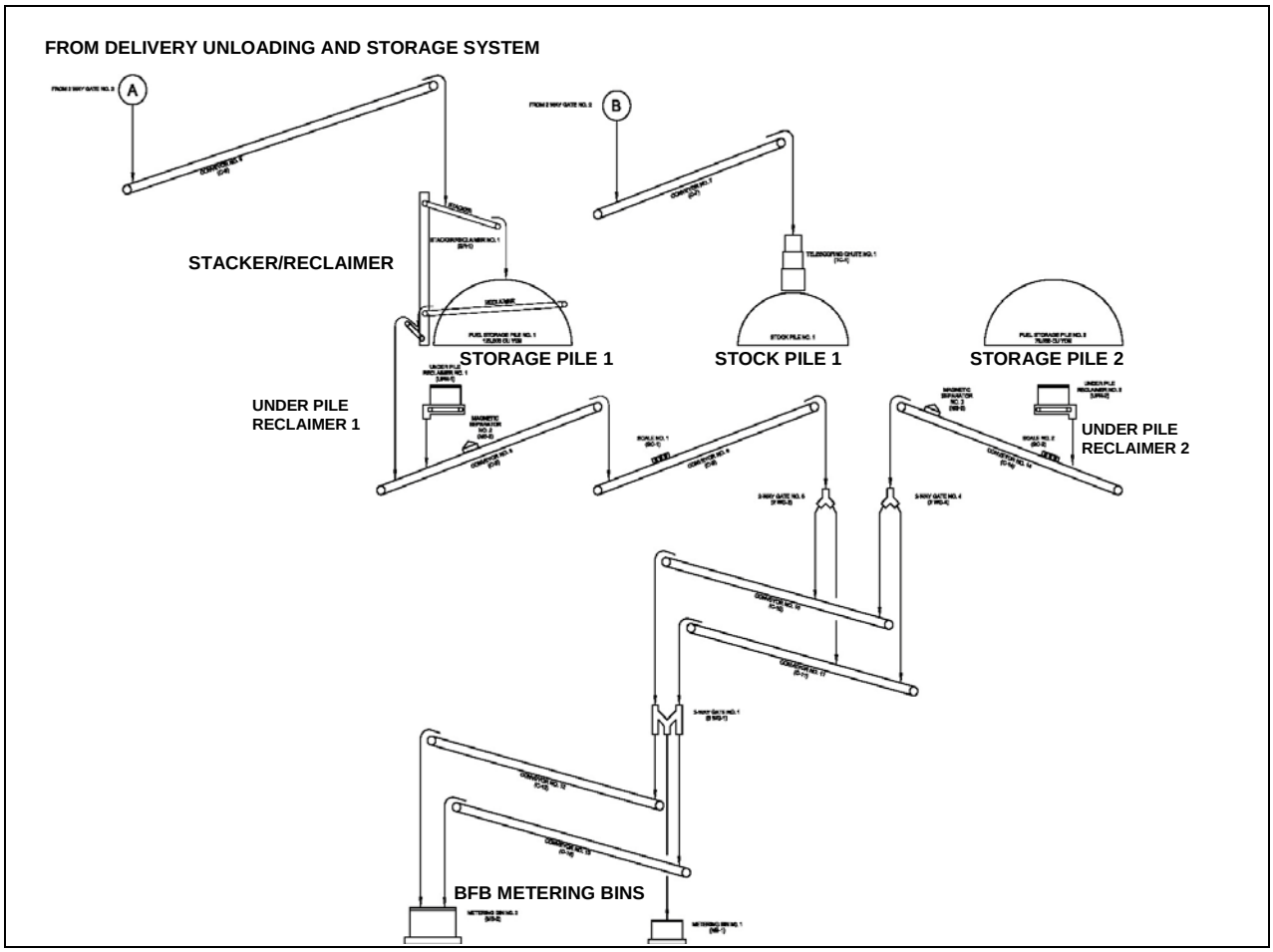


Figure 10 - Biomass Fuel Handling and Storage System

Biomass Combustion and Energy Production

Figure 11 is a diagram of the typical power plant configuration (excluding SCR system) for the HYBEX line of BFB boilers offered by METSO Power of Finland who is the supplier selected for the GREC project. Biomass fuel will be transferred from the fuel bins and combusted in the BFB boiler to generate steam. In a BFB boiler, combustion of biomass fuel takes place in the dense, fluidized sand bed located at the bottom of the furnace as well as above the bed. In addition to biomass fuel, the fluidized bed consists of sieved natural sand maintained in suspension by a fluidizing air system.

Fluidizing (primary) air is introduced into the BFB boiler through a water-cooled, grate air-beam distribution system. Staging (overfire) air (OFA) is introduced through air openings located in the furnace walls. Fluidization results in an expanded combustion zone with high turbulence, intimate solids-to-gas contact, and a high heat transfer rate within the bed. Smaller fuel particles will burn rapidly above the fluidized bed, while the larger particles will be entrained within the bed where they are dried and gasified. Combustion of residual char will occur mainly in the fluidized bed. Combustion of volatile material will occur both within and above the fluidized bed.

OFA is introduced into the furnace above the fluidized bed where final combustion and flue gas oxygen content are controlled. Fuel quality, boiler capacity, and fluidized bed temperature determine air distribution requirements. During the combustion of biomass fuels, the fluidized bed temperature will normally vary between 1,350 and 1,700°F. OFA is injected into the furnace to complete the combustion of volatile gases in the zone above the fluidized bed.

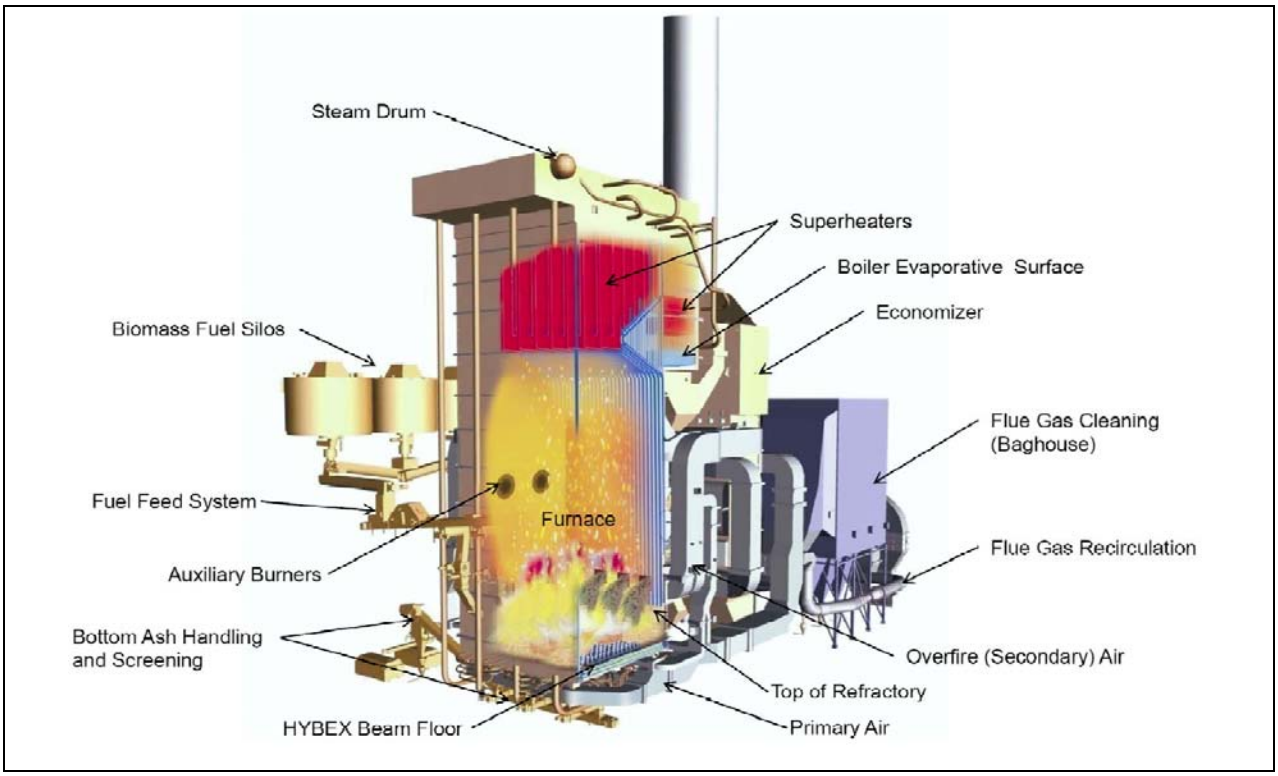


Figure 11 – Schematic of Biomass-fueled BFB Steam Generation Unit including APCS

The furnace temperature is approximately 200°F higher above the fluidized bed where the OFA is introduced. Peak flame temperatures will increase when lower moisture content biomass fuels are combusted and during low load boiler operations. During these periods, flue gas recirculation (FGR) will be employed to lower the peak flame temperatures. The characteristics of the BFB boiler planned for the GREC are given below in Table 8.

Table 8 – BFB Boiler Characteristics for the GREC Project

Parameter	Description
Boiler Type	BFB design
Primary Fuel	Clean woody biomass at maximum design rate of 160 tons per hour (TPH)
Supplemental Fuel	Pipeline natural gas
Ash Removal	From baghouse to ash storage silo via a pneumatic system
Heat Input Rate	Maximum of 1,358 mmBtu/hr (4-hour basis) of which a maximum of 341 mmBtu/hr is from fossil fuels
Thermal Efficiency	To be established
Steam Production	650,000 to 950,000 lb/hour (to be determined based on efficiency)
Stack Parameters	12.0 feet diameter (maximum); 230 feet tall (minimum)
Flue Gas	520,600 actual cubic feet per minute (acfm) at 310 °F
Particulate Control	Fabric filter baghouse greater than 99% efficiency
NO_X Control	Clean side SCR system
SO_2 Control	Dry sorbent injection into ducting before baghouse, low sulfur biomass fuel and low sulfur natural gas for boiler startup
VOC and CO Control	GCP

Flue gas from the boiler will pass through heat recovery and air pollution control systems (APCS) and will discharge to the atmosphere through a 230-ft stack.

Steam generated by the BFB boiler will be sent to a STG for the production of electricity. Electricity will be transmitted from the STG to a switchyard located at the GREC facility, which will be used to increase the voltage. The electricity then will be transmitted through aerial transmission lines to a GRU switchyard for transmission to the electric grid.

Cooling Tower

The cooling tower will be a four cell, counter-flow mechanical draft type tower made from fiberglass material and with high efficiency fill and drift eliminators. Each cell will contain a fan with an electric drive motor. Water obtained from the two onsite Floridan aquifer deep wells will provide makeup water to replace cooling tower evaporation, drift, and blowdown. Cooling tower evaporation loss at maximum load is estimated to be 1.34 million gallons per day (MGD).

Fly Ash and Bottom Ash Handling, Storage and Shipment

Most ash will exit the BFB boiler as fly ash with only a small amount leaving as bottom ash. Fly ash from the boiler convective pass and fabric filter hoppers will be collected dry and transported pneumatically to a single fly ash storage silo by means of two vacuum blowers. The transferred fly ash will first pass through a receiver/collector that separates the fly ash from the conveying air stream. The separated fly ash will then flow through an air lock valve into the storage silo, which will be vented through a baghouse for control of PM/PM_{10} emissions. The clean, filtered outlet air of the fly ash vacuum blowers will be discharged to the atmosphere.

From the silo, the fly ash will either be stabilized using water in a pugmill or loaded dry into a receiving truck. For the fly ash stabilization case, fly ash and water will be mixed in a pug mill and then transferred via a chute into covered trucks and then hauled offsite for reuse or disposal in a properly licensed landfill. During the dry transfer of fly ash, an enclosed process will be utilized to transfer ash from the silo through a chute into sealed trucks. Air displaced from the trucks will be returned to the ash silo via a vacuum system.

Bottom ash from the bed will primarily consist of noncombustible material (i.e., rocks, glass, sand, metal) contained in the biomass fuel. The coarse bottom ash will be removed from the BFB boiler through ash hoppers and chutes. Coarse material will fall from the bed into the ash hoppers, which form a gas tight seal with the furnace bottom. The coarse material will be sieved in a rotating screen prior to being conveyed to the bottom ash container.

Suitable sand fractions recovered by the rotating screen will be transferred pneumatically to the sand silo with the remaining coarse material conveyed to the bottom ash container. The contents of the bottom ash container will be taken offsite for disposal in a properly licensed landfill.

Emergency Support Equipment

The proposed plant will also require:

- One 564 kW emergency electrical generator (or smaller);
- One 275 hp emergency fire water pump (or smaller); and
- Two 1,000 gallon above ground storage tanks for ULSD fuel oil for the emergency equipment.

5. BACT REVIEW

BACT determinations are required for PM/PM_{10}, CO and VOC.

5.1. Definition of BACT

Rule 62-210.200, F.A.C. defines "BACT" as:

An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account:

1. *Energy, environmental and economic impacts, and other costs;*
2. *All scientific, engineering, and technical material and other information available to the Department; and*
3. *The emission limiting standards or BACT determinations of Florida and any other state;*

determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.

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

In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.

5.2. Applicable Standards under 40 CFR 60 and 63

The applicable standards pursuant to 40 CFR 60 and 63 were identified above and are summarized in the following three tables for the BFB boiler, the emergency generator and the emergency fire pump engine.

Table 9 - NSPS Applicable to the BFB Boiler (40 CFR 60, Subpart Da)

Pollutant	**SO_2 [2]**		**PM (filterable) [4]**		**Visible Emissions**	**NO_X [2]**
Units	**lb/MWH [1]**	**Reduction**	**lb/MWH**	**lb/mmBtu [3]**	**Opacity[5]**	**lb/MWH**
BFB Boiler	1.4 or	95%	0.14 or	0.015	20	1.0

1. lb/MWH means pounds per megawatt-hour (gross).
2. 30 day rolling average basis.
3. lb/mmBtu/hr means pounds per million Btu heat input.
4. There is an alternative set of limits of 0.03 lb/mmBtu and 99.9% reduction.
5. Basis 6-minute average, except for one 6-minute period per hour of not more than 27% opacity.

Table 10 - NSPS Applicable to the Emergency Generator (40 CFR 60, Subpart IIII)

Emergency Generator (> 560 kW and ≤ 2,237 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	6.4

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

Table 11 - NSPS Applicable to the Emergency Fire Pump Engine (40 CFR 60, Subpart IIII)

Emergency Pump (175 ≤ hp and < 300 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

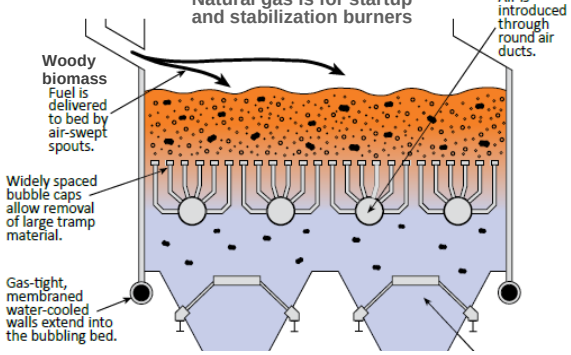
1. g/hp-hr means grams per horsepower-hour.
2. SO_2 emission standard will be met by using ULSD fuel oil in the emergency fire pump engine with a fuel sulfur content of 0.0015% by weight.

5.3. Non-BACT BFB Emission Limits Requested by the Applicant

NO_X Emissions

NO_X Formation and Primary Control. NO_X formation in the boiler may occur by three different mechanisms: fuel NO_X is formed from nitrogen compounds contained in fuel (fuel nitrogen); thermal NO_X is formed from molecular or atomic nitrogen (N_2) and oxygen (O_2) present in combustion air; and prompt NO_X is formed in the proximity of the flame front as intermediate combustion products.

Details of the bed portion of a Babcock and Wilcox (B&W) BFB are provided in Figure 12. Figure 13 is an internal diagram for the typical furnace configuration of a HYBEX BFB biomass boiler such as offered by METSO Power, who according to GREC LLC is providing the project performance guarantees.



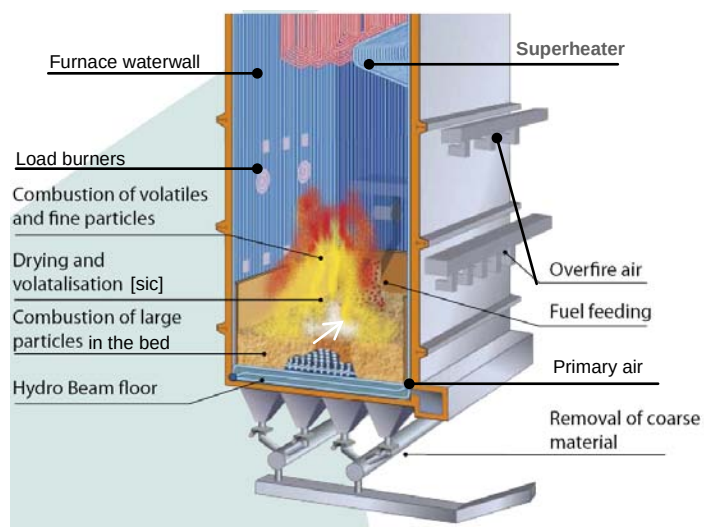


Figure 12 – Bed Description for B&W BFB Boiler **Figure 13 – Typical METSO HYBEX BFB Boiler**

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

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

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

$$CHi^* + NO \rightarrow HCN + ... \qquad \text{Eq. 1}$$

Where:

i = 1, 2, 3

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

$$HCN + NO \rightarrow N_2 + CO + CO_2 + H_2O + ... \quad \text{Eq. 2}$$

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

$$NHi* + NO \rightarrow N_2 + ... \quad \text{Eq. 3}$$

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

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

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

$$CharC + NO \rightarrow N_2 + CO + CO_2 + ... \quad \text{Eq. 4}$$

$$CharN + O_2 \rightarrow N_2 + O_2 + ... \quad \text{Eq. 5}$$

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

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

$$NH_3 + O_2 \rightarrow NO + ... \quad \text{Eq. 6}$$

$$HCN + O_2 \rightarrow NO + ... \quad \text{Eq. 7}$$

$$CharC + O_2 \rightarrow NO + ... \quad \text{Eq. 8}$$

$$CharN + O_2 \rightarrow NO + ... \quad \text{Eq. 9}$$

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

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

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

Following are additional details and opinions provided by B&W when comparing the emission characteristics of a typical stoker furnace with a FBC furnace and, more specifically, a BFB.

[In a stoker boiler] "The combustion zone temperature is typically neither measured nor controlled and can range from 2200 to over 3000 °F. The BFB bed temperature is both measured and controlled to an optimum temperature of approximately 1500 °F.

"Due to the improved combustion process previously described for a BFB, the uncontrolled (upstream of any post combustion air quality control systems) NO_X, CO and VOC emissions for a BFB are typically 10 to 25% less for a given biomass fuel than for a stoker."

For reference, the applicant estimated that the exhaust gas leaving the furnace will contain 0.15 lb NO_X/mmBtu would be a performance even superior to that described above by B&W and would (without add-on control) rival the performance of a stoker incorporating SNCR. B&W further adds:

The BFB emissions are also less susceptible to variations in fuel properties that are inherent with any biomass plant. Under normal steady state operating conditions, both the BFB and stoker can be operated reliably within permitted emission limits. However, normal day-to-day operations in a typical plant are anything but steady state. Fuel variability is a fact of life, even when a conscious effort is made in the fuel yard to keep the fuel homogeneous. The large mass of bed material in the BFB creates a "flywheel effect," which is better suited to minimize spikes in emissions due to any changes in fuel characteristics. Conversely, the relatively low fuel inventory on a grate will typically be much more susceptible to an upset and potential emissions spikes, under changing fuel conditions."

The Department agrees with the stated opinion, but notes that a stoker boiler incorporating more extensive add-on controls than a BFB boiler can also achieve low emissions.

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

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

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

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

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

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

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

Similar simplified reactions describe the destruction of NO_2.

One drawback with SNCR is that some of the NH_3 can be converted to NO_X and excessive NH_3 injection is occasionally required to effect good reduction. Excess NH_3 (called slip) can combine with chloride and sulfate species in the exhaust and cause visible emissions. Additionally good CO control is necessary when employing SNCR due to interference with the reaction as described.

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

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

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

In most Florida coal-fueled power plants (e.g. Stanton Energy Center, Progress Energy Crystal River, St. John River Power Park, Tampa Electric Big Bend and others), the SCR unit is located in a dusty environment ahead of other pollution control equipment. Notwithstanding the severe atmosphere, NO_X reduction on the order of 90% is achieved at some of the most recent installations.

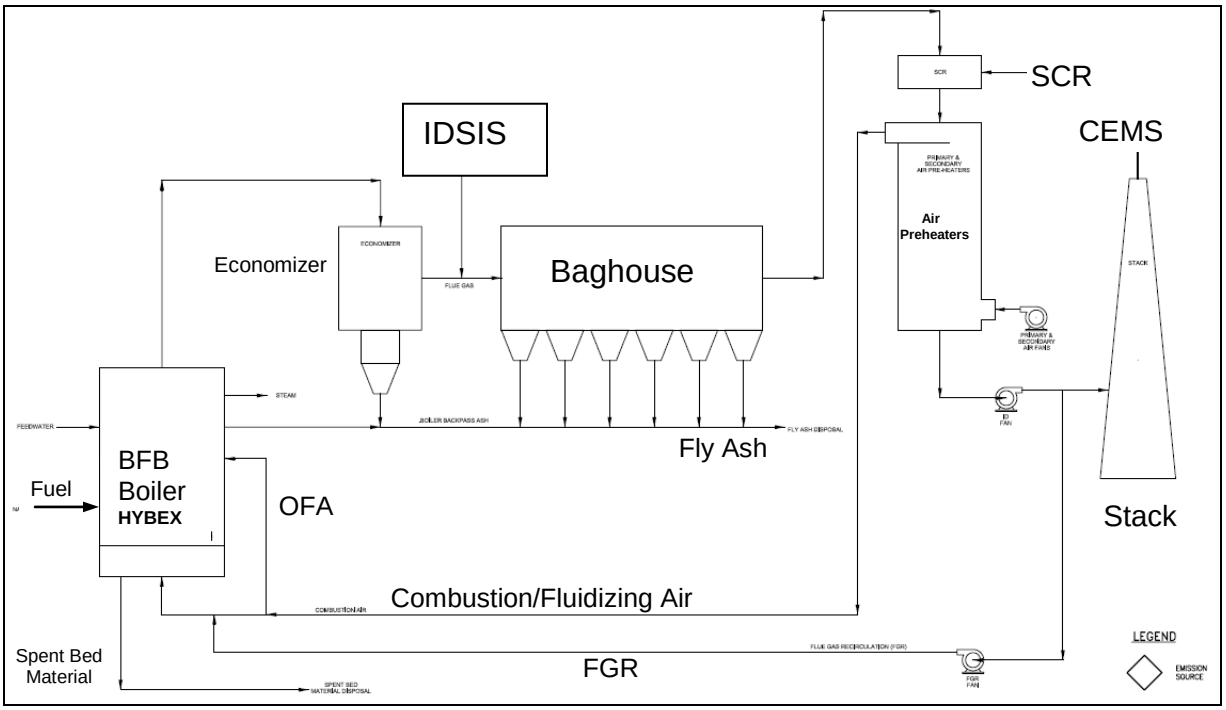


Figure 14 - GREC BFB Boiler Emission Control Technologies

Refer to Figure 14 above. More recently, a number of SCR systems have been specified or actually installed on biomass boilers. The catalyst for the GREC project will be located in the clean, medium temperature zone after all other control equipment and before the air preheaters. In contrast to common perceptions, no reheat of the exhaust gas is required in order to use such a SCR system at a biomass installation. However, the particulate control equipment must be designed for a relatively high temperature environment.

When the PM control devices operate at low temperature, then clean side SCR applications require reheating of the exhaust gases prior to the SCR unit. The improvement of the reheat efficiency is an area of ongoing innovation and is exemplified by regenerative SCR (RSCR) systems such as specified for a number of biomass projects (particularly existing stokers), in the northeast part of the country.

According to the initial application, the SCR reduction target was only 53% compared with the exhaust gases leaving the furnace. The possible reductions by SCR are greater than the targeted reductions for NO_X, which was not subject to PSD or a BACT determination. According to recent literature, SCR will also help to destroy VOC. [1] It is also a well-documented strategy for dioxin furan control.[2]

<u>Proposed NO_X Limits</u>. As previously discussed, GRU requested a NO_X emission cap for DGS Unit 2 to insure that emission increases from GREC are offset by permanent and enforceable reductions at Unit 2. Therefore a BACT determination is not required for NO_X. Accordingly, NO_X emissions from the BFB must be limited to 416.5 TPY (418.1 from all of the GREC).

The applicant proposed a BACT emission limit of 0.070 lb NO_X/mmBtu on a <u>24-hour</u> basis. This short-term limit is not necessary because (considering the enforceable reductions at Unit 2) the project does not trigger PSD. However, the applicant has requested that it be retained and it will provide additional assurance of compliance with the applicable AAQS. Compliance with the concentration and mass emission limits shall be demonstrated by continuous emissions monitoring systems (CEMS).

The emissions cap will be satisfied by the requested NO_X concentration limit and the short-term heat input limit as follows:

(0.070 lb/mmBtu)x(1,358 mmBtu/hr)x(8,760 hr/year)x(ton/2,000 lb) = 416.4 TPY

For reference, some biomass projects comparable to the GREC project are listed in Table 12 below.

Table 12 - Emissions in lb/mmBtu – Boilers with Uses or Capacities Similar to Proposed Project

Project Location	CO	VOC	NO_X	PM/PM_{10} [b]	SO_2
GREC, Alachua County, FL BFB – woody biomass 1,358 mmBtu/hr	**0.12/0.08** [c] 30-day GCP	**~0.010/0.009** [c] stack test GCP	**0.070** 24-hour SCR	**0.015, 0.042 (f, f+c)** stack test fabric filter	**~0.029** 24-hour sorbent in ducts
Yellow Pine, Ft. Gaines, GA BFB - woody biomass, tires 1529 mmBtu/hr (2010)	0.15 30-day GCP	0.02 stack test GCP	0.10 30-day SNCR	0.018 (f+c) stack test fabric filter	0.14 30-day dry scrubber
Southern Power, Nacogdoches, TX BFB – woody biomass ~1,374 mmBtu/hr (2008)	0.15 30-day GCP	0.013 stack test GCP	0.10 30-day SNCR	0.032 (f+c) stack test fabric filter	0.046 12-month sorbent in ducts
ADAGE, Hamilton County, FL BFB – woody biomass ~758 mmBtu/hr (2010)	~0.074 (eq) 12-month GCP	~0.017 (eq) stack test GCP	~0.070 (eq) 12-month SCR	0.029 (f+c) stack test fabric filter	~0.045 (eq) 12-month sorbent in ducts
FBE, Manatee County, FL grate boiler – woody biomass ~757 mmBtu/hr (2010)	~0.0295 (eq) 12-month Ox-cat	~0.003 (eq) stack test Ox-cat	~0.020 (eq) 12-month SCR	0.01 (f) stack test ESP	~0.016 12-month sorbent in ducts
Palmer Renewable, MA grate boiler – woody biomass 509 mmBtu/hr (draft 2009)	0.070 4-hour Ox-cat	0.010 stack test Ox-cat	0.060 1-hour RSCR	0.012, 0.02 (f, f+c) stack test fabric filter	0.02 1-hour dry scrubber
Lindale, Smith Co., TX grate boiler – woody biomass ~684 mmBtu/hr (2009)	0.31 30-day GCP	0.017 stack test GCP	0.15 30-day SNCR	0.02, 0.026 (f, f+c) stack test fabric filter	0.025 30-day low sulfur fuel
HEF Ethanol, Highlands County, FL BFB - stillage, wood, gas, ULSD FO ~198 mmBtu each (2010)	0.10 30-day GCP	0.005 stack test GCP	0.075 30-day SNCR	0.01 (f) Stack test fabric filter	0.06 30-day BFB limestone
U.S. Sugar Clewiston, FL grate boiler - bagasse ~1,000 mmBtu/hr (2003)	0.38 12-month GCP	0.05 Stack test GCP	0.14 30-day SNCR	0.26 (f) stack test fabric filter	0.06 30-day no control
Wheelabrator, Auburndale, FL grate boiler – wood and tires ~630 mmBtu/hr (1990s)	0.32 30-day GCP	0.035 stack test GCP	0.14 30-day SNCR	0.02 (f) stack test fabric filter	0.10 30-day lime spray
NSPS Subpart Da NG, wood, ULSD fuel oil $\geq$ 250 mmBtu/hr	No standard	No standard	~0.085 based on heat rate	0.015 (f) or 0.03 and 99.9% 20% opacity	~0.12 or 95% reduction
Draft NESHAP Subpart DDDDD	~0.031	No standard	No standard	0.008 (f)	No standard

a. In certain cases, the enforceable limits are in terms of lb/hr or TPY and the lb/mmBtu denoted by "eq" are for comparison purposes only.

b. "f" denotes filterable fraction and "c" denotes condensible fraction. GREC also proposes a 0.029 f+c limit.

c. The higher CO and VOC limits at GREC apply an initial period of testing and optimization and the lower limits apply thereafter.

The lowest numerical value (0.02 lb NO_X/mmBtu, 12-month basis) is for the recently permitted FBE project which is a grate stoker project that will incorporate SCR. The Palmer Renewable project NO_X limit that will incorporate a RSCR is nearly as stringent as the FBE NO_X limit when considering the 1-hour averaging time for the 0.070 lb/mmBtu limit.

For reference, the 24-hour concentration limit proposed for the GREC equates to 0.82 lb NO_X/MWH and is more stringent than the 30-day NSPS limit given Table 12 of 1.0 lb NO_X/MWH.

SO_2 Emissions

SO_2 Formation and Primary Control. SO_2 is formed from the oxidation of sulfur compounds contained in biomass. Preventing SO_2 formation by using inherently clean fuels is an important component of a SO_2 control strategy. The clean woody biomass to be used by GREC will be typically low in S content. Characteristics of typical biomass and fossil fuels are given in Table 13.

Table 13 – Typical Characteristics of Biomass and Fossil Fuels – Heating Value, Ash and Sulfur (S)

Fuel Class	Fuel	Gross Heating Value Btu/lb	Ash (%)	S (%)
Bioenergy Feedstocks	**GREC woody biomass[1]**	**8,529**	**0.98**	**0.018**
	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	<0.05
Fossil Fuels	coal (low rank)	6,400-8,100	5-20	1.0-3.0
	coal (high rank)	11,500-12,800	1-10	0.5-1.5
	ULSD fuel oil	18,150	negligible	<0.0015
	natural gas	1,030 Btu/cubic foot	negligible	< 0.002
1. GREC estimated the Cl content of its fuel at approximately 0.003%.				

The S content of the GREC woody biomass will be about two orders of magnitude less than the sulfur content of the coal such as used at the GRU DGS.

Some SO_2 removal occurs due to adsorption on and reaction with the alkaline constituents of fly ash that is subsequently collected in the PM control equipment.

Add-on SO_2 Control. Various kinds of scrubbers are available whereby the exhaust gases are cleaned in a wet or dry FGD scrubber. As described above, the GREC project will incorporate an IDSIS based on injection of hydrated lime (CaO) or trona [$Na_3(CO_3)(HCO_3)\bullet 2(H_2O)$] to augment the alkaline properties of the fly ash collected in the fabric filter baghouse.

Proposed SO_2 Limits. As previously discussed, GRU requested a SO_2 emission cap for DGS Unit 2 to insure that emission increases from GREC are offset by permanent and enforceable reductions at Unit 2. Therefore, a BACT determination is not required for SO_2. Accordingly, SO_2 emissions from the BFB must be limited to 170.7 TPY. Emissions from other sources at the GREC will be minimal.

The emissions cap will be satisfied by a mass emission limit on the BFB boiler of 39.0 lb/hr on a 12-month basis, rolled monthly. The emission cap will be achieved by IDSIS system as discussed above in conjunction with the fabric filter baghouse.

The applicant proposed a BACT emission limit of 0.029 lb SO_2/mmBtu on a 24-hour basis. This short-term limit is not necessary because (considering the enforceable reductions at Unit 2) the project does not trigger PSD. However, the applicant has requested that it be retained and it will provide additional assurance of compliance with the applicable AAQS. Compliance with the concentration and mass emission limits shall be demonstrated by CEMS.

The lowest numerical value (0.016 lb SO_2/mmBtu, 12-month basis) is for the recently permitted FBE project which is a grate stoker project that will also incorporate an IDSIS. Again, the limit for the Palmer Renewable project that will incorporate a dry scrubber is probably as stringent as the FBE NO_X limit considering the 1-hour averaging time for the 0.02 lb/mmBtu limit.

For reference, the 24-hour concentration limit proposed for the GREC is much more stringent than the 30-day NSPS limit given in Table 12 above of approximately 0.12 lb SO_2/mmBtu (actual NSPS is 1.4 lb/MWH).

SAM Emissions

SO_2 Formation and Primary Control. 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).

The primary control is by controlling SO_2 formation and its subsequent conversion to SAM. One primary control strategy is to limit to the extent feasible the excess air available in the furnace. The other relies on reaction with fly ash as described for SO_2 removal.

Add-on SAM Control. The add-on controls described for SO_2, including the IDSIS and the fabric filter constitute the add-on SAM control strategy for the GREC project.

SAM Limits. The applicant does not propose a limit for SAM. According to the application, the BFB biomass boiler is expected to emit 1.4 lb SAM/hr and 5.9 TPY. The Department will establish an actual SAM limit because annual emissions are estimated close to the applicable SER of 7 TPY. The Department will establish a limit of 1.5 lb SAM/hr (equivalent to 6.6 TPY) and will require initial and annual stack tests to determine compliance.

5.4. BACT Determinations for the BFB Boiler

CO and VOC Emissions

CO and VOC Formation and Primary Control. Refer to the previous descriptions of the BFB boiler bed and furnace operation. CO and VOC are products of incomplete combustion.

As discussed, the combustion in the BFB boiler bed and lower furnace occurs in substoichiometric conditions. As a result, a great deal of CO is evolved as well as VOC (including hydrocarbon radicals and other species). The CO, hydrocarbon radicals and reduced nitrogen compounds (as previously mentioned) participate in reactions that assist in primary NO_X control.

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

This fact can be appreciated in Figure 15 from a Babcock and Wilcox publication that demonstrates the modeled relative effects upon CO when switching to a low NO_X control strategy. Under the low NO_X strategy (newly designed air system including higher OFA ports) moderate levels of CO (and presumably VOC) persist at greater heights within the furnace compared with the previous combustion strategy.

According to the article, *"in favor of achieving low NO_X emissions, higher CO values were accepted in the Precision Jet air system. However, these CO emissions were well within the acceptable range to meet state and federal requirements"*. [3]

In summary, the GCP incorporated within the BFB design consists of: intimate contact between the bed material and the fuel and sufficient turbulence, temperature and residence time above the OFA ports to the extent allowed by a low NO_X strategy.

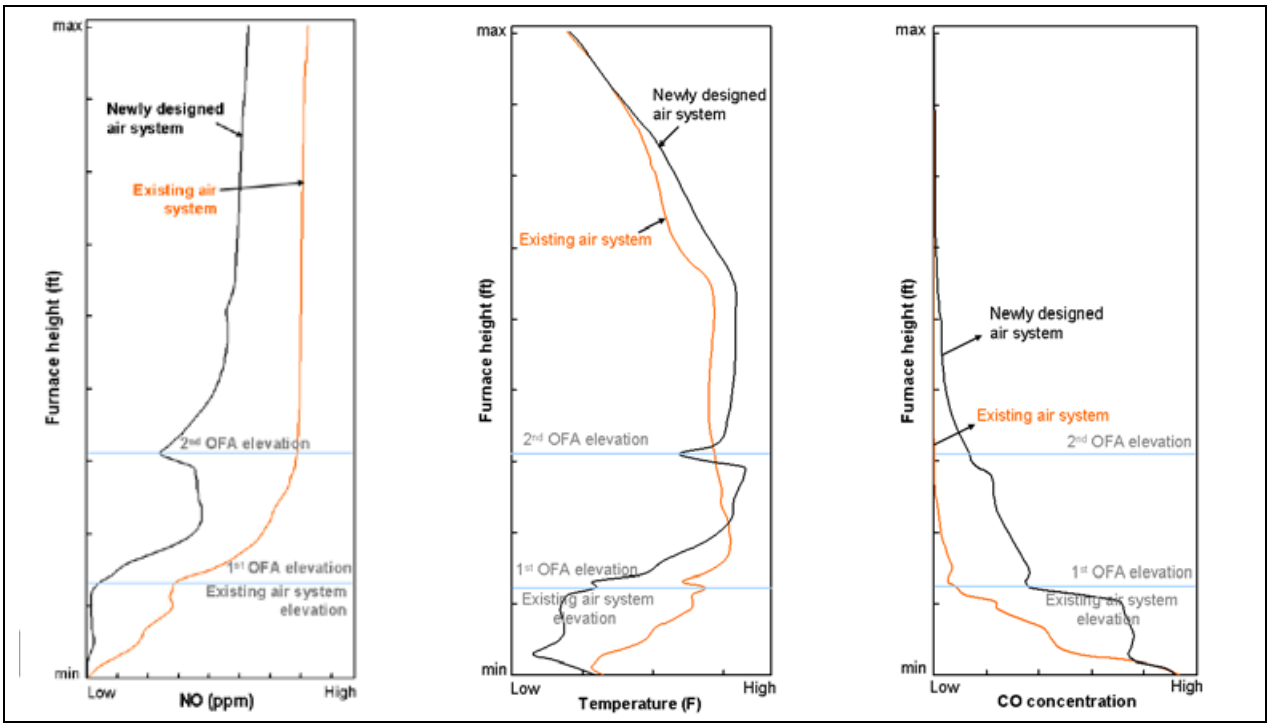


Figure 15. Modeled NO_X, Temperature and CO a BFB Boiler after Switching to Low NO_X strategy.

Add-on CO and VOC Control. If GCP are not sufficient to achieve low CO and VOC emissions, oxidation catalyst (Ox-cat) is an option. As in the case of SCR catalyst, the preferred location of an Ox-cat system is after the PM control device (i.e. the fabric filter baghouse).

CO and VOC Limits. The applicant originally proposed BACT emission limits of 0.12 lb CO/mmBtu and 0.013 lb VOC/mmBtu which equate to approximately 714 TPY of CO and 77 TPY of VOC. A comparison of the proposed values for the GREC project with other biomass projects is given in Table 12 above. The proposed values for the GREC appear to be based on or represent small improvements in the BACT limits set for the Southern Power Nacogdoches (SPN), TX project. Approval for the SPN project, like the GREC project, was pursued by American Renewables and is based on METSO BFB technology.

With the SCR system (versus SNCR at the SPN project), it is possible to make some adjustments in the furnace low NO_X strategy (while compensating with the add-on SCR) so that CO and VOC emissions can be reduced without the need for Ox-cat.

GREC has since agreed to tiered limits of 0.12 and 0.010 lb/mmBtu of CO and VOC respectively during the first year of operation and 0.08 and 0.009 lb/mmBtu of CO and VOC respectively thereafter. This will provide time to optimize the GCP strategy for CO, VOC and NO_X given the existence of a SCR unit (which will operate at a greater efficiency than initially planned). Lowering the CO and VOC emission limits will have a beneficial effect on fine PM emissions, i.e. $PM_{2.5}$.

Compliance with the CO limits shall be demonstrated by a CO-CEMS. Compliance with the VOC limit shall be demonstrated by an annual test.

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

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

Add-on $PM/PM_{10}/PM_{2.5}$ and VE Controls. The most well-known controls include cyclones, electrostatic precipitators (ESP), fabric filters and wet scrubbers. Supplementary controls include strategies such as minimization of $PM_{2.5}$ and VE precursors by limiting SO_2, NO_X, NH_3, VOC and chlorides.

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

$PM/PM_{10}/PM_{2.5}$ and VE Limits. The applicant's BACT proposal for PM/PM_{10} is the NSPS value of 0.015 lb/mmBtu (equal to 89 TPY) for filterable (f) PM/PM_{10} based on a fabric filter baghouse. The applicant also estimated emissions of 0.027 for condensible (c) PM/PM_{10} and 0.042 lb/mmBtu for total PM/PM_{10} (250 TPY) including filterable and condensible (f+c) PM/PM_{10}.

Given the controls (BFB boiler, baghouse, IDSIS, SCR unit, GCP) the Department does not expect emissions of f+c PM/PM_{10} emissions as high as estimated by the applicant. For example, the f+c limit at the similarly configured Nacogdoches facility is 0.032 lb/mmBtu and the f+c emission limit at the Yellow Pine project in Georgia is 0.018 lb/mmBtu. The two projects cited will have SNCR systems, greater NO_X and SO_2 limits and have with arguably higher expectations of f+c PM/PM10 emissions.

The Department will specify a PM/PM_{10} (f) limit based on the existing limit in 40 CFR 60, Subpart Da. It is possible that that the project will eventually need to comply with a PM (f) limit based on 40 CFR 63, Subpart DDDDD that was initially proposed at 0.008 lb/mmBtu. Compliance shall be demonstrated by 3-hour initial and annual stack tests using EPA Methods 5 (or 17). The applicant will be required to test for (f+c) PM/PM_{10} using EPA Method 202 in order to quantify f+c emissions.

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

The Department will establish a NH_3 limit of 10 parts per million (ppm) at 7% O_2 to minimize direct NH_3 emissions that can form ammoniated compounds (such as NH_4Cl and ammoniated sulfates) in the exhaust stream and in the environment. The limit will also provide reasonable assurance of proper control equipment operation. The NH_3 emission limit will be readily controlled by the SCR system. Compliance shall be demonstrated by initial and annual tests using EPA Method CTM-027.

The Department has reviewed $PM_{2.5}$ and believes that measures have been incorporated into the overall BACT for the project that will adequately address this pollutant. These measures include:

- BACT emission limits for PM/PM_{10} CO and VOC;
- Low emission limits and add-on controls for SO_2 and NO_X that tend to form $PM_{2.5}$ in the environment;
- Enforceable reductions in $PM_{2.5}$ precursors from GRU DGS Unit 2;
- The VE limit that directly controls the fraction of $PM_{2.5}$ that interferes with light transmission; and
- Limits on NH_3 and also on HCl as discussed further below.

5.5. HAP Emission Limits for the BFB Boiler

The applicant estimated the PTE of all HAP (aggregate) at 24.7 TPY. Because the PTE of certain individual HAP (HCl and HF) will be close to 10 TPY and the aggregate PTE of all HAP will be close to 25 TPY, it is necessary to establish emission limitations.

HCl Emissions

HCl is formed from chloride (Cl) contained in biomass. According to the applicant, the woody biomass to be used by GREC will be very low in Cl content at 0.003% on a wet basis. According to the application, the BFB biomass boiler has the potential to emit 9.72 TPY of HCl.

If the PTE of HCl is equal to or greater than 10 TPY, then the BFB boiler by itself would be a major source of HAP and subject to a case-by-case determination of MACT per 40 CFR 63, Subpart B. Such a

determination would result in emission limitations patterned on the recent EPA proposal for 40 CFR 63, Subpart DDDDD including a very low CO emission limit.

The Department will set a limit of 9.72 TPY of HCl on a 12-month rolling average, rolled monthly. The control method will be the same as previously discussed for SO_2 (i.e. removal by fly ash, the IDSIS and the fabric filter baghouse). Compliance shall be demonstrated by a HCl-CEMS.

The 12-month limit equates to 2.22 lb/hr HCl (<0.002 lb/mmBtu compared with the draft Subpart DDDDD proposal of 0.004 lb/mmBtu). The limit, the IDSIS, the fabric filter and the continuous measurement requirement will provide reasonable assurance that HCl will be emitted at a rate less than 10 TPY.

HF Emissions

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.). According to the application, the BFB biomass boiler has the potential to emit 9.72 TPY of HCl.

If the PTE of HF is equal to or greater than 10 TPY, then the BFB boiler by itself would be a major source of HAP and a case-by-case determination of MACT would be required. The Department will set a limit of 9.72 TPY of HCl on a 12-month rolling average, rolled monthly. The control method will be the same as previously discussed for SO_2 (i.e. removal by fly ash, the IDSIS and the fabric filter baghouse). Compliance shall be demonstrated by a HF-CEMS.

The 12-month limit equates to 2.22 lb HF/hr. The limit, the IDSIS, the fabric filter and the continuous measurement requirement will provide reasonable assurance that HF will be emitted at a rate less than 10 TPY.

Other HAP Emissions

The applicant estimates emissions of 3.59 TPY of metal HAP of which 2.2 TPY consists of phosphorus (P). The other metals are that contribute to the value are chromium (Cr), manganese (Mn) and lead (Pb).

According to the March 2010 RAI response, no single organic HAP will be emitted at a level approaching 10 TPY. According to the applicant, total organic HAP will equal approximately 1.64 TPY. Table 14 is a list of the PTE of the key organic HAP for the GREC BFB boiler.

Table 14 – Applicant's Estimated PTE of Organic HAP from the BFB Boiler in TPY

Pollutant [1]	**C_3H_4O**	**C_6H_6**	**CH_2O**	**C_8H_{10}**	**C_2H_4O**	**CH_3Cl**	**CH_3CCl_3**	**C_7H_8**	**PAH/POM**	**Total**
Emissions	0.025	0.37	0.8	0.092	0.043	0.15	0.039	0.06	0.06	1.64

1. C_3H_4O (acrolein); C_6H_6 (benzene); CH_2O (formaldehyde); C_8H_{10} (xylene isomers plus ethyl benzene); CH_3Cl (methyl chloride); CH_3CCl_3 (methyl chloroform); C_2H_4O (acetaldehyde); C_7H_8 (toluene); PAH/POM (polycyclic aromatic hydrocarbon/polycyclic organic matter)

Rather than setting individual limits for each of the categories of metal and organic HAP identified above, the Department will limit their total annual HAP emissions to 24.7 TPY. This limit will complement the enforceable limits of 9.72 TPY limits for HCl and HF emissions.

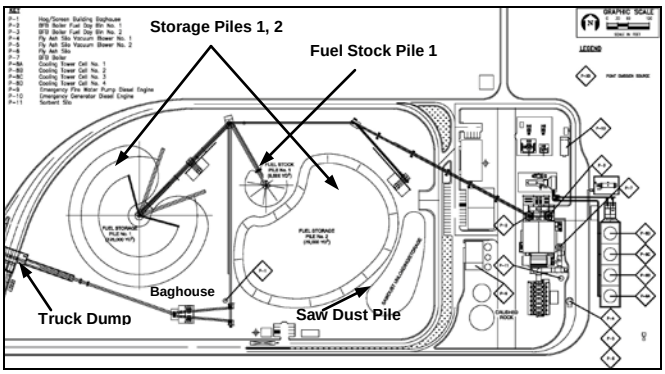
The demonstration of compliance with 24.7 TPY limitation will be determined on a fiscal year basis, based on the initial and annual stack tests conducted for the identified metal and organic HAP stack tests coupled with the totalized HCl and HF-CEMS data for the given fiscal year.

5.6. BACT Review for Biomass Fuel Delivery, Preparation, Storage and Handling (EU 001)

Refer to the previous discussions in Sections 4.3 and Figures 9 and 10 for descriptions of these operations. The expanse of material storage and handling can be seen in the following drawing for a standard American Renewables (owner of GREC, LLC) plant. A truck can be seen in the tilted position above one of the truck dump/pit bridge receiving hoppers. Large storage piles and conveyers are also visible.

Figure 16 - Early Rendition of an American Renewables Woody Biomass Plant

Figure 17 is a preliminary layout of the GREC plant, subject to final optimization. The approximate locations of future Storage Piles 1 and 2, Stock Pile 1, Saw Dust Pile and the screen/hog building baghouse are shown. An example of a FIFO storage pile with stacker/reclaimer is shown in Figure 18.



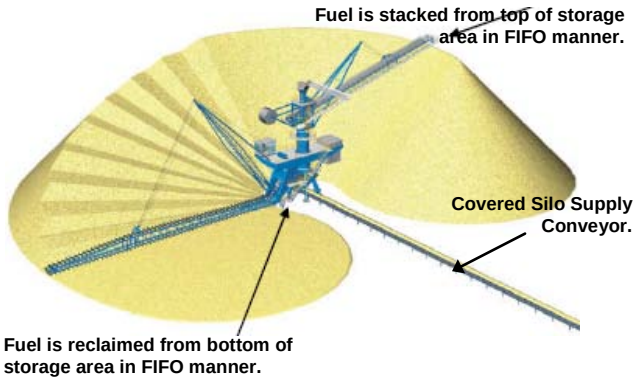


Figure 17 – Preliminary Layout of Plant **Figure 18 – Storage Pile with Stacker/Reclaimer**

Table 15 is a listing of the estimated fugitive emissions from the project. 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.

Table 15 - Estimated Potential to Emit (PTE) Criteria Air Pollutants (TPY)

Source Operation	PM	PM_{10}	$PM_{2.5}$
Biomass Transfer Operations	0.17	0.081	0.012
In-plant Paved Roads	11.0	2.1	0.32
Biomass Pile Processing - Dozer Operations	0.44	0.027	0.0037
Biomass Pile Wind Erosion	0.039	0.020	0.0029
Project Total Fugitive Sources	11.6	2.2	0.3

Accordingly, the applicant submitted a Best Management Practices (BMP) plan that describes storage pile

management, minimization of fugitive dust, fire prevention and spontaneous combustion minimization and quality assurance of clean woody biomass to comply with the rule and other conditions of the permit.

GREC and the City of Gainesville included very specific measures within their Power Purchase Agreement (GREC PPA) related to fuel procurement and forest management. The PPA conditions will not be incorporated into the air permit, but provide additional assurances regarding the nature of the fuel sources and types.

The first part of the BMP to be included in the permit relates to the woody biomass identified in Table 7 above for use at the GREC. The additional parts of the BMP are provided in Tables 16, 17, 18 and 19 below. The BMP will be updated and finalized prior to startup of the GREC.

Table 16 - BMP for Storage Pile Management

1. Woody biomass storage areas shall be managed and maintained to avoid excessive wind erosion.
2. A woody biomass storage area fugitive dust management plan shall be developed and maintained onsite. Plan shall identify warning signs and train plant personnel regarding conditions that could result in excessive fugitive dust formation. The plan shall be submitted to the compliance authority 90 days after the plant becomes operational.
3. Mechanical moving of woody biomass by front end loaders and other supporting equipment shall be minimized on high wind event days. Wetting of the biomass will be utilized when necessary to minimize fugitive dust emissions when the biomass is being manipulated by front end loaders and other supporting equipment.
4. Daily visual observations of the woody biomass storage areas shall be performed and if conditions are favorable for fugitive dust formation, procedures from the storage area fugitive dust plan shall be implemented.

Table 17 - BMP for Minimization of Fugitive Dust Emissions

1. Conveyor systems and associated drop points for biomass material shall be covered or partially enclosed.
2. The incoming trucks will dump into in ground receiving hoppers which are covered for dust control. The receiving hoppers will be covered by a divided enclosure equipped with roll up entry doors, slitted curtains at the exit doors and stilling curtains in the upper roof area.
3. Equipment inside the enclosed fuel processing building (Screen/Hog Building), including screens and hogs will be equipped with local ventilation and ducted to a fabric filter dust collector.
4. Drop points to woody biomass storage areas shall be designed to minimize the overall exposed drop height by utilizing telescoping discharge spouts to minimize the clearance between the spout outlet and the top of the storage pile.
5. Periodic equipment maintenance shall be performed to maintain conveyor systems and associated drop point integrity. Appropriate plant records shall be maintained on equipment maintenance performed.
6. Boiler fuel bins will be equipped with bin vent filters.
7. Daily observations of the conveyor systems and associated drop point integrity will be conducted to identify any equipment abnormalities.
8. Plant personnel shall be trained on identification of warning signs for potential equipment malfunction.
9. Signs shall be posted identifying potential warning signs of equipment malfunction.
10. All major roadways at the plant shall be paved.
11. Excessive mud, dirt or similar debris shall be removed promptly from the paved roads.
12. Plant personnel shall be trained on what constitutes excessive dust on paved roads.
13. All paved roadways and gravel areas at the plant shall be wetted as necessary to minimize fugitive dust emissions.

Table 18 - BMP for Fire Prevention / Spontaneous Combustion Minimization Practice

1. Plant personnel will contact the City of Gainesville Fire Department to develop a Fire Management Plan (FMP). The FMP shall be maintained on site.
2. The FMP will include a requirement to train onsite personnel to handle incipient fires and training on the identification of potential fire hazards. In addition, GREC will install and maintain equipment for plant personnel to handle incipient fires. The City of Gainesville Fire Department shall be invited to participate in onsite training.
3. Daily observations 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.
4. Spontaneous combustion and odor problems will be minimized by rotation of the fuel in the live storage pile and in the manual pile.
5. Signs shall be posted at GREC, which identify potential fire hazards.
6. The stacker reclaimer being used shall maximize the removal of older material in order to minimize the stacking of newer material on top of older material. The automatic stacker/reclaimer will be divided into multiple zones that can be managed to allow simultaneous stacking and reclaiming so that the storage piles are managed on a first in first out basis. The manual pile will be managed by the fuel yard manager and be divided into zones. Each day fuel will be added to new zones and removed from the oldest zones.
7. Compaction of woody biomass materials in the storage areas shall be minimized.

Table 19 - BMP for Quality Assurance of Clean Woody Biomass

1. The feedstock for the BFB boiler will consist of clean woody biomass that will be processed principally off site and then sorted, screened, and sized as necessary on site and then placed in the storage areas or sent directly to the BFB boiler.
2. The permittee will contract for woody biomass that specifically meets the definition of woody biomass as identified in the permit. The woody biomass will consist of clean untreated wood or untreated wood products including clean untreated lumber, tree stumps (whole or chipped), tree limbs (whole or chipped) and slash. This also includes, but is not limited to, wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sander dust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.
3. The woody biomass feedstock will be delivered to the GREC facility in vehicles designed to prevent release.
4. For each shipment of woody biomass, the permittee shall record the date, quantity and a description of the material received.
5. The permittee shall inspect each shipment of woody biomass upon receipt for any material not specifically identified in this plan (see below). If the permittee identifies any such material, the material shall be rejected and/or marshaled in specified areas until proper disposal can be arranged. Rejected materials shall be moved off site in a logistically reasonable time period.
6. The permittee shall maintain records of rejected shipments and disposition thereof. Such records shall be made available to the Department upon request.
7. The following items are not considered woody biomass and are expressly prohibited: those materials that are prohibited by state or federal law; plastics; woody biomass that has been chemically treated or processed; yard trash; municipal solid waste; paper; treated wood such as CCA or creosote; painted wood; and wood wastes from landfills.

5.7. BACT Review Emergency Equipment

The Department is adopting the requirements of 40 CFR 60, Subpart IIII as BACT for the minimal use emergency generator and emergency fire pump.

5.8. Cooling Tower

The 4-cell mechanical draft cooling tower will be 53 feet in height with a circulating water flow rate of 78,000 gallons per minute (gpm). The design air flow will be approximately 2,425,000 acfm. The tower will be equipped with drift eliminators to meet a proposed drift rate of 0.0005%.

The Department determines the draft BACT to be a design drift rate of no more than 0.0005% of the circulating water flow rate. At this level, maximum potential PM and PM_{10} emissions from the cooling tower are expected to be on the order of 1.5 and 1 TPY respectively. $PM_{2.5}$ emissions will be minimal.

6. STARTUP, SHUTDOWN AND MALFUNCTIONS – PROPOSED BFB BOILER

The boiler will be designed to accommodate natural gas for boiler startup, shutdown and boiler bed stabilization only. The maximum burner heat input will be limited to 341 mmBtu/hr.

The applicant requested excess emissions resulting from startup, shutdown, and documented malfunctions shall be permitted, provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents.

The applicant requests that excess emissions resulting from startup, shutdown, or documented malfunctions be permitted but not to exceed two hours in a 24-hour block except for the following specific cases.

a. BFB Boiler Startup: For startup of the BFB boiler, excess emissions shall not exceed twelve (12) hours in any 24-hour period. "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. [Rule 62-210.200(245), F.A.C.]

b. BFB Boiler Shutdown: For any BFB boiler shutdown excess emissions shall not exceed three (3) hours in any 24-hour period.

c. BFB Malfunctions: For any BFB boiler documented malfunction, excess emissions shall not exceed two (2) hours in any 24-hour period. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

The applicable CEMS-based HCl and HF emissions limits (9.72 TPY) are 12-month rolling limits that do not provide for data exclusion given their nature, which is to provide reasonable assurance that annual emissions will be less than 10 TPY of each. 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 for HCl, HF, PM/PM_{10} and VOC.

Data exclusions are acceptable as requested for calculation of the 24-hour NO_X and SO_2 concentrations and the 30-day CO concentration. No data exclusions are permissible when calculating the 12-month rolling total emissions of NO_X and SO_2.

The 30-day NO_X and SO_2 limits are from 40 CFR 60, Subpart Da and are less stringent than the 24-hour limits set pursuant to the state implementation plan (SIP) process for the same pollutants. No exclusions are indicated other those provided in Subpart Da.

The only other limit for which the excess emission rule could apply is opacity. In the case of the NSPS Subpart Da 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 as requested by the applicant by applying a standard of 20% during startups, shutdown and malfunctions expect for one 6-minute period per hour of not more than 27% opacity during periods of startup, shutdown and malfunction.

7. AMBIENT AIR QUALITY

7.1. Introduction

The proposed project will increase emissions of three pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, CO and VOC. PM_{10} is a criteria pollutant and is subject to national and state ambient air quality standards (AAQS), PSD increments, significant impact levels (SIL) and de minimis monitoring levels. CO is a criteria pollutant and is subject only to AAQS, SIL and de minimis monitoring levels. There are no applicable PSD increments, AAQS, SIL or de minimis monitoring levels for VOC.

The applicant used PM_{10} as a surrogate for the criteria pollutant $PM_{2.5}$. The applicant provided a detailed analysis regarding the reasoning in making this determination. The Department concurs that it is reasonable to use PM_{10} as a surrogate for $PM_{2.5}$ for this project, especially in view of the required reduction of surrogates (SO_2 and NO_X) at the contiguous GRU DGS.

7.2. Major Stationary Sources Near the GREC

The proposed project is in Alachua County. Tables 20 to 24 below are lists of the largest stationary sources, by pollutant, in Alachua County and adjacent Putnam County. The facilities listed here are approximately within 60 miles of each other. The information is from annual operating reports (AOR) submitted by the operators to the Department for 2009 or acid rain data submitted to the U.S. EPA. Some data is from 2008 due to incomplete data from 2009 or for comparison purposes. The future GREC emissions are also included for comparison purposes. Note that the GREC SO_2 and NO_X emissions will be offset by permanent and enforceable reductions required at the contiguous GRU DHS following recent installation and start up of new air pollution control systems (APCS) in 2009.

Table 20 - Largest Sources of NO_X

Owner	Site Name, County	TPY
Seminole Electric Cooperative	Seminole Generating Station (2008/2009)	16,468/4,402
City of Gainesville	GRU DGS (2008/2009)	3,540/1,445
Florida Power & Light (FPL)	FPL Putnam Power Plant	2,203
Georgia Pacific	Palatka Pulp and Paper Mill (2008)	1,356
Florida Rock Industries	Thompson S. Baker Cement Plant, Alachua	642
GREC, LLC	**GREC (Proposed)**	**418 (net = 0)**
Progress Energy	University of Florida (UF) Cogen	115
Georgia Pacific	Hawthorne Plywood Plant (2008), Alachua	107

Table 21 - Largest Sources of SO_2

Owner	Site Name, County	TPY
Seminole Electric Cooperative	Seminole Generating Station	20,577
City of Gainesville	GRU DGS (2008/2009)	7,622/5,816
Georgia Pacific	Palatka Pulp and Paper Mill (2008)	1,493
GREC, LLC	**GREC (Proposed)**	**171 (net = 0)**
City of Gainesville	John R. Kelly Power Plant	5

Table 22 - Largest Sources of PM/PM_{10}

Owner	Site Name, County	TPY
Seminole Electric Cooperative	Seminole Generating Station (2008/2009)	759
Georgia Pacific	Palatka Pulp and Paper Mill (2008/2009)	608
GREC, LLC	**GREC (Proposed)**	**281**
City of Gainesville	GRU DGS (2008)	140
Lafarge North America	Lafarge North America Putman County	80

Table 23 - Largest Sources of CO

Owner	Site Name, County	TPY
Seminole Electric Cooperative	Seminole Generating Station (2008/2009)	5,990
Georgia Pacific	Palatka Pulp and Paper Mill (2008)	2,234
Florida Power & Light (FPL)	FPL Putnam Power Plant	774
GREC, LLC	**GREC (Proposed)**	**716**
Florida Rock Industries	Thompson S. Baker Cement Plant, Alachua	676
Georgia Pacific	Hawthorne Plywood Plant (2008) , Alachua	298
City of Gainesville	GRU DGS (2008)	232
Progress Energy	UF Cogen	102

Table 24 - Largest Sources of VOC

Owner	Site Name	TPY
Georgia Pacific	Palatka Pulp and Paper Mill (2008)	402
Ball Container	Ball Container Alachua County	164
Seminole Electric Cooperative	Seminole Generating Station (2008)	132
GREC, LLC	**GREC (Proposed)**	**78**
Georgia Pacific	Hawthorne Plywood Plant (2008) , Alachua	74
Sivance	Sivance Alachua County	40

The most notable feature regarding the emissions is that they are decreasing in Alachua County due to the reductions at GRU DGS following installation of the APCS (SCR and FGD scrubber). Furthermore, the emissions of NO_X were drastically reduced at the Seminole Electric coal-fueled power plant between 2008 and 2009 following installation of new SCR systems.

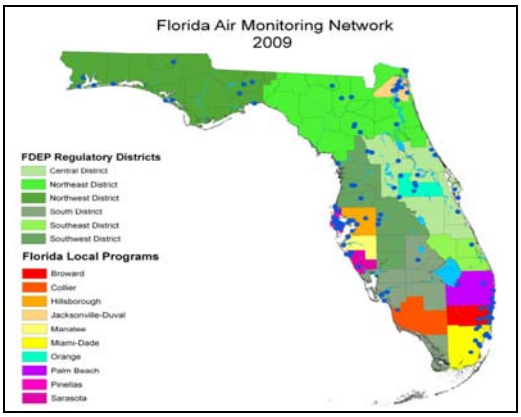
A further review of emissions from other regional coal-fueled power plants indicates that significant reductions in both NO_X and SO_2 occurred as a result of APCS projects at Jacksonville Electric Authority (JEA) St. Johns River Power Park (SCR), Progress Energy Crystal River (SCR and initial operation of a FGD scrubber). The result is that SO_2 emissions from the four mentioned coal-fueled power plants decreased by approximately 18,000 tons while NO_X emissions decreased by 38,000 tons. Further reductions are expected from the group as the APCS are completed and the full benefits are realized by their long term operation.

By comparison, the SO_2 and NO_X expected from GREC are small and are readily offset by the enforceable reductions at GRU DGS and overwhelmed by the reductions at the regional coal-fueled power plants.

7.3. Ambient Air Monitoring Network

The State ambient air monitoring network operated by the Department and its partners (local air pollution control programs) includes monitors in counties containing over 90% of the population. As Figure 19 indicates, the ambient air monitoring sites are concentrated in areas of high population density, along the coasts and near major highways in the interior portion of the state. The Department's Northeast District

operates two monitoring sites in Gainesville, Alachua County and one monitoring site in Putnam County for the measurement of SO_2, PM_{10}, ozone and $PM_{2.5}$ as shown in Figure 20.



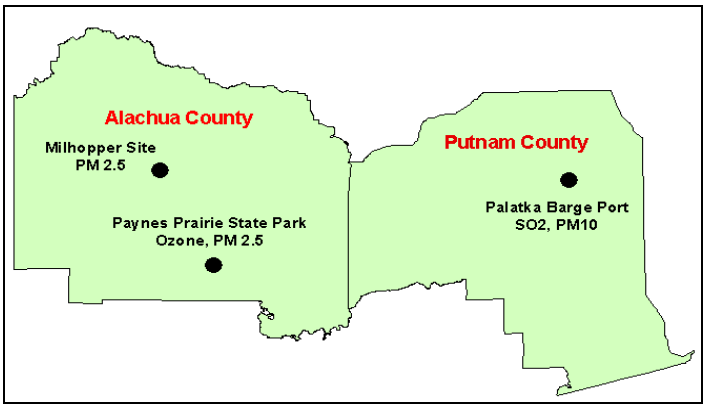


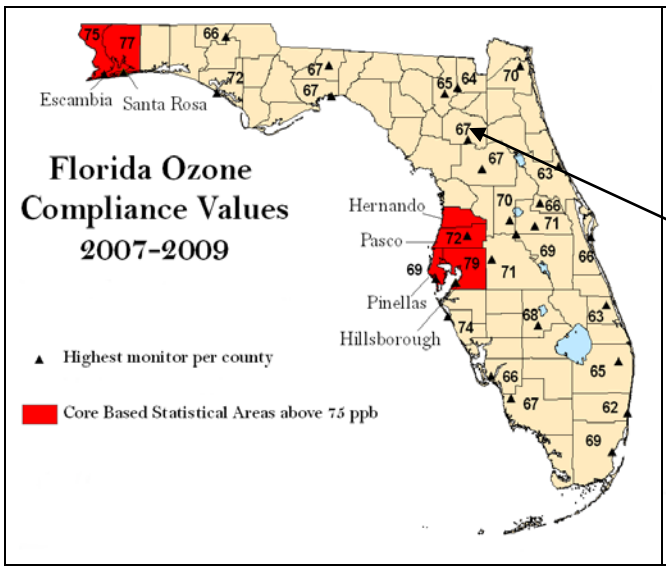
Figure 19 – Air Monitoring Network **Figure 20. Monitors in Alachua and Putnam Counties**

7.4. Existing Ambient Air Quality – $PM_{2.5}$ and Ozone

Ozone is a key indicator of the overall state of regional air quality. It is not emitted directly from combustion processes. Rather it is formed from VOC and NO_X emitted primarily from regional industrial and transportation sources. VOC is also emitted from 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.

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

The Alachua County ozone compliance value is 67 parts per billion (ppb). It is shown in Figure 21, which shows the highest compliance values measured in each county where at least one ozone station is located.



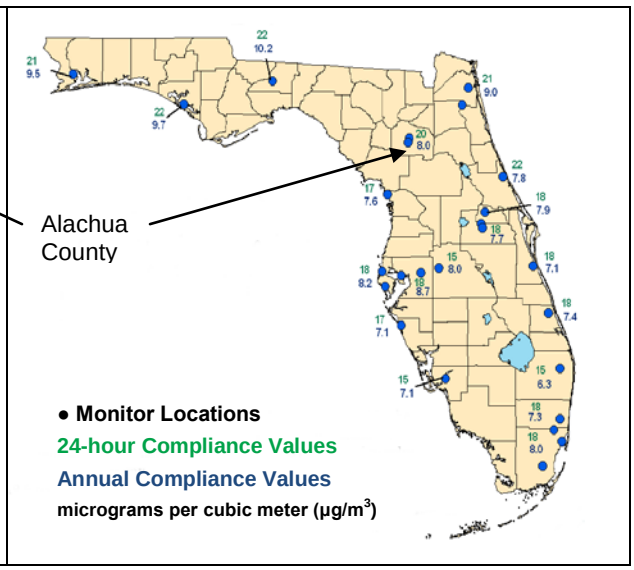


Figure 21 – Florida Ozone Compliance Values **Figure 22 – Florida $PM_{2.5}$ Compliance Values**

$PM_{2.5}$ (also known as PM_{fine}) is another key indicator of the overall state of regional air quality. Some $PM_{2.5}$ is directly emitted as a product of combustion from transportation and industrial sources as well as

fires. Much of it consists of particulate nitrates and sulfates formed through chemical reactions between gaseous precursors such as SO_2 and NO_X from combustion sources and ammonia (NH_3) naturally present in the air or added by other industrial sources.

$PM_{2.5}$ limits and measurements are summarized on three year blocks, rolled annually. The reported 24-hour compliance value for $PM_{2.5}$ is 20 μg/m^3, shown in Figure 22 above for the Gainesville site, and was calculated by taking the average 24-hour readings recorded each day during the three years (2007-2009). The value for each year that exceeds 98% of all daily measurements within each given year was identified and then the average of those three numbers was reported as the 24-hour compliance value and compared with the standard of 35 μg/m^3.

The simple average of all $PM_{2.5}$ measurements within each three years (2007-2009) was also calculated and then the mean of the three averages (8 μg/m^3) was reported as the annual compliance value and compared with the standard of 15 μg/m^3.

The results indicate that Alachua County is in attainment with the applicable ozone and $PM_{2.5}$ AAQS.

7.5. PM$_{2.5}$ Precursor Emissions from Power Plants in the Southeastern U.S.

There is a regional effort underway through the CAIR and other regulatory programs to reduce emissions of $PM_{2.5}$ precursors including NO_X and SO_2. Regional SO_2 emission reductions from existing power plants between 2007 and 2009 are listed in Table 25. SO_2 emissions from power plants in Florida were reduced by nearly 120,000 TPY and regional SO_2 emissions were reduced by over 1.25 million TPY.

Table 25 - SO_2 Emission Reductions from Power Plants in the Southeast between 2007 and 2009

State	2007 (TPY)	2009 (TPY)	Reduction (TPY)	Reduction (%)
Alabama	447,189	277,971	169,218	38
Florida	317,582	197,682	119,900	38
Georgia	635,484	262,258	373,226	59
Kentucky	379,837	252,001	127,836	34
Mississippi	69,796	40,160	29,636	43
North Carolina	370,826	110,948	259,878	70
South Carolina	172,726	97,940	74,786	43
Tennessee	237,231	108,042	129,189	12
Total	**2,630,671**	**1,347,002**	**1,283,669**	**49**

The state and regional SO_2 reduction trends will continue as coal-fueled power plants continue to install scrubbers to control SO_2 emissions. Regional NO_X emission reductions from existing power plants between 2007 and 2009 are listed in Table 26.

Table 26 - NO_X Emission Reductions from Power Plants in the Southeast between 2007 and 2009

State	2007 (TPY)	2009 (TPY)	Reduction (TPY)	Reduction (%)
Alabama	122,374	49,610	72,764	59
Florida	184,171	84,252	99,919	54
Georgia	107,471	57,566	49,905	46
Kentucky	174,840	78,767	96,073	55
Mississippi	48,546	26,601	21,945	45
North Carolina	59,417	38,782	20,635	35
South Carolina	46,062	21,213	24,849	54
Tennessee	102,886	27,911	74,975	73
Total	**845,767**	**384,702**	**461,065**	**55**

NO_X emissions from power plants in Florida were reduced by nearly 100,000 TPY and regional NO_X emissions were reduced by well over 460,000 TPY. The state and regional NO_X reduction trends will continue as coal-fueled power plants operators throughout the southeastern states continue to install SCR systems to control NO_X.

The contribution of 171 TPY of SO_2 and 418 TPY of NO_X from the GREC (without even considering the reductions at the GRU DGS) will not affect the general, overwhelming and continuing downward trend in $PM_{2.5}$ precursors. Similarly, it will not have a measurable effect on local or regional $PM_{2.5}$ concentrations.

7.6. Exceptional Events Affecting $PM_{2.5}$ Concentrations

Certain $PM_{2.5}$ events are driven by wildfires in North Florida and South Georgia during periods of drought. Following is one description from The Christian Science Monitor (May 30, 2007).

"Sparked in mid-April (2007) by a combination of downed wires and lightning, the amalgam of fires now known as the Georgia Bay Complex – Bugaboo Scrub, Sweat Farm, Big Turnaround, and Kneeknocker – has already burned more than a half-million acres, exceeding the enormous fires that burst through the region in 1953 and 1954. The latest fires were declared a federal disaster April 17, entitling the state to federal aid. In an average year, wildfires burn 8,000 acres in Georgia; the Sweat Farm fire alone burned 10,000 acres in one night last week."

The same complex fires caused cancellation of the 3-day Florida Folk Festival in White Springs, held annually at the Stephen Foster Folk Culture Center State Park managed by the Department. Figure 23 is a ground level photograph of the Georgia side of the fire. Figure 24 is a satellite Moderate Resolution Imaging Spectroradiometer (MODIS) image taken on May 11, 2007 after the fire(s) had raged for a month.

Figure 23 – Georgia Bay/Okefenokee Complex Fire

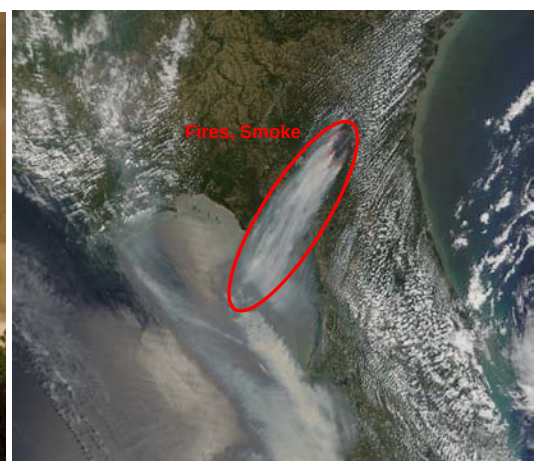


Figure 24 – May 11, 2007 Satellite Image

EPA approved removal of some of the data associated with this exceptional event. The data represented the highest measurements encountered during all of 2007. However, Alachua County would have been in attainment with the $PM_{2.5}$ standards whether or not the data were excluded. The event is nevertheless important because it actually produced a great deal of $PM_{2.5}$ measured and felt by residents throughout North Florida.

The larger regional NO_X and SO_2 sources in the Southeastern U.S. as well as fires are much more significant in their contributions to local ozone and $PM_{2.5}$ than the proposed GREC. The massive reductions in NO_X and SO_2 from regional power plants (including GRU DGS) in the past two years and expected similar reductions in the coming years are having and will continue to have an ameliorative effect on regional ozone and will ultimately be reflected in lower $PM_{2.5}$ as well. Finally the recent availability of improved transportation fuels (e.g. ULSD FO) will also improve air quality (including $PM_{2.5}$) locally and regionally.

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

Nitrogen dioxide (NO_2), SO_2, CO and PM_{10} are directly emitted or quickly formed from combustion sources. PM_{10} is also generated from material processing operations and entrained by wind, traffic, farming and other human activities. These criteria pollutants are monitored near areas of large stationary sources, large population centers or high traffic areas where both emissions and monitored concentrations of pollutants would generally be highest.

There are no active monitors for these four pollutants in Alachua County. A PM_{10} monitor was operated through 2008 and was replaced by the $PM_{2.5}$ monitor discussed above. There is a SO_2 and a PM_{10} monitor in nearby Putnam County within 60 miles of the GREC site. Table 27 includes concentrations from key ozone, PM_{10} and $PM_{2.5}$ monitors in Alachua County as well as values from PM_{10}, CO, NO_2 and SO_2 monitors located in counties where there is an expectation of equal or greater values than measured in Alachua County.

Table 27 - Ambient Air Quality Measurements Nearest to the Project Site (2009)

Pollutant	Location	Averaging Period	Ambient Concentration			
			Compliance Period	Value	Standard	Units [g]
Ozone	Paynes Prairie	8-hour	2007-09	67 [a]	75 [a]	ppb
$PM_{2.5}$	Milhopper	24-hour	2007-09	20 [b]	35 [b]	μg/m^3
		Annual	2007-09	8 [c]	15 [c]	μg/m^3
PM_{10}	Milhopper	24-hour	2006-2008	57 [d]	150 [d]	μg/m^3
		Annual	2008	16.9 [e]	50 [e]	μg/m^3
PM_{10}	Palatka	24-hour	2007-2009	71 [d]	150 [d]	μg/m^3
		Annual	2009	19 [e]	50 [e]	μg/m^3
SO_2	Palatka	3-hour	2009	65	1300 [f]	μg/m^3
		24-hour	2009	21	260 [f]	μg/m^3
		Annual	2009	4	60 [f]	μg/m^3
NO_2	Jacksonville	Annual	2009	19	100 [f]	μg/m^3
CO	Jacksonville	1-hour	2009	3,450	40,000 [f]	μg/m^3
		8-hour	2009	1,610	10,000 [f]	μg/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 3-year period. Report 2nd high average.
e. Arithmetic mean.
f. Not to be exceeded more than once per year.
g. Units are in: micrograms per cubic meter (ug/m3) or parts per billion (ppb).

7.8. Air Quality Impact Analysis

Significant Impact Analysis

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

In order to conduct a SIA, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described below. The modeled concentrations 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, initial modeling consisted of a combination of fence line, near field and far field receptors 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 100m from the property line out to 3km, 500m from 3km out to 6km, and 1000m from 6km out to 15km. This initial modeling of the boiler indicated that the maximum impacts were contained within 1km. Therefore, the PM_{10} modeling where maximum concentrations are typically close to the fence-line due to fugitive emissions, had an alternate receptor grid which included fence-line receptors at 50m apart and receptors spaced at 100m out to 2km from the property line.

If this modeling at worst-load conditions shows ground-level increases less than the SIL, the applicant is exempted from conducting any further modeling. If the modeled concentrations from the project exceed the SIL, then additional modeling including emissions from all major facilities or projects in the region (multi-source modeling) is required to determine the proposed project's impacts compared to the AAQS and PSD increments.

The results of applicant's CO and PM/PM_{10} air quality Class II SIA analysis for this project are shown below in Table 28. Maximum predicted impacts from CO emissions are less than the applicable SIL whereas maximum predicted impacts from PM_{10} emissions are greater than the applicable SIL for the Class II area. These values are tabulated in the table below and compared with existing ambient air quality measurements from the local ambient monitoring network. It is clear that maximum predicted impacts from the project are much less than the respective AAQS.

Table 28 - Maximum Predicted Air Quality Impacts from the GREC for Comparison to the PSD Class II SILs

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	2009 Baseline Concentrations ($\mu g/m^3$)	Ambient Air Standards ($\mu g/m^3$)	Significant Impact?
PM_{10}	Annual	5	1	~19	50	Yes
	24-Hour	20	5	~71	150	Yes
CO	1-hour	421	2,000	~3,450	40,000	No
	8-hour	160	500	~1,610	10,000	No

For the Class I analysis, the applicant provided a SIL analysis for two Class I areas that are within 110km of the proposed project. The nearest Class I area is the Okefenokee NWA, which is approximately 93km to the north of the proposed project. The Chassahowitzka NWA is approximately 110 km southwest of the proposed project. The receptor grids consisted of 500 receptors for the Okefenokee NWA and 113 for the Chassahowitzka NWA. The receptors for both Class I areas were obtained from the National Park Service.

The results of applicant's PM/PM_{10} air quality Class I SIA analysis for this project are shown below in Table 29. The results are from the Okefenokee analysis because impacts were greater there than at the Chassahowitzka. Maximum predicted impacts from all pollutants are less than the applicable SIL for the Class I area.

Table 29 - Maximum Air Quality Impacts from the GREC Project for Comparison to the PSD Class I SILs

Pollutant	Averaging Time	Max. Predicted Impact µg/m^3)	Class I SIL (µg/m^3)	Significant Impact?
PM_{10}	Annual	0.003	0.2	No
	24-hour	0.06	0.3	No

Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is performed for those pollutants with listed de minimis impact levels. These are levels, which, if exceeded, would require pre-construction ambient monitoring. For this analysis, as was done for the SIA, the applicant used the proposed project's emissions at worst load conditions as inputs to the models. As shown in Table 30 below, the maximum predicted impacts for PM/PM_{10} were greater than listed de minimis impact levels. Therefore, a pre-construction monitoring analysis is required for PM/PM_{10}.

Table 30. - Maximum Air Quality Impacts for Comparison to the De Minimis Ambient Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (µg/m^3)	De Minimis Level (µg/m^3)	2009 Baseline Concentrations (µg/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	20	10	~70	Yes
CO	8-hour	160	575	~1,610	No

There is no longer a PM_{10} monitor in Alachua County. However, there is a PM_{10} monitor in Putnam County, less than 60 miles from the proposed project near larger sources of particulate such as Seminole Generating Station. The Putnam County PM_{10} monitor indicates attainment with the PM_{10} AAQS.

There is a $PM_{2.5}$ monitors located in Alachua County which is also in attainment with the NAAQS. The previous PM_{10} monitor in Alachua County also indicated attainment. These monitors provide sufficient data to satisfy preconstruction monitoring needs. Given the low emissions from the future predicted GREC operation, preconstruction monitoring at the site would yield little useable information.

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

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

Models and Meteorological Data Used in the Foregoing Air Quality Analysis

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

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

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

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

PSD Class I Area: The California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Class I ENP beyond 50 km from the proposed project. Meteorological MM4 and MM5 data used in this model was from 2001 to 2003.

CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources.

The CALPUFF model has the capability to treat time-varying sources, is suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanism.

Multi-source PSD Class II Increment Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration. The maximum predicted annual and maximum predicted high, second high short term average PSD Class II area impacts from this project and other increment-consuming sources in the vicinity of the proposed facility are shown in Table 31 below.

Table 31 - PSD Class II Increment Analysis

Pollutant	Averaging Time	Max Predicted Impact ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Impact Greater Than Allowable Increment?
PM_{10}	24-hour	17	30	No
	Annual	5	17	No

AAQS Analysis

For pollutants subject to an AAQS review, the total impact on ambient air quality is obtained by adding a "background" concentration to the modeled concentration based on the averaging time for the standard. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The predicted annual and short term averages for the AAQS analysis are summarized in Table 32 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 32 - Ambient Air Quality Impacts

Pollutant	Averaging Time	Major Sources Impact ($\mu g/m^3$)	Background Conc. ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Total Impact Greater Than AAQS?	Florida AAQS ($\mu g/m^3$)
PM_{10}	24-hour	35	70	105	No	150
	Annual	5	20	25	No	50

7.9. Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife

The GREC proposed project will not contribute to a violation of the PSD Increment or AAQS. Further, the applicant provided a modeling screening analysis using AERMOD to demonstrate that the proposed project will not have an adverse impact on soils, wildlife and vegetation. According to the applicant, the modeling results show that impacts are much less than the threshold levels for injury to wildlife, soils and vegetation. Additionally, any impacts will be less than the expected ameliorative effects from the APCS projects at the contiguous GRU DGS, other nearby coal-fueled power plants and throughout the southeast region of the U.S.

Air Quality Related Values (AQRV)

Due to the low emissions expected from the proposed project, the U.S Fish and Wildlife Service did not require an AQRV analysis, including deposition and visibility analyses. Additionally any impacts will be less than the expected ameliorative effects from the APCS projects at the contiguous GRU DGS, other nearby coal-fueled power plants and throughout the southeast region of the U.S.

Growth-Related Impacts Due to the Proposed Project

According to the applicant, the proposed project will provide up to 44 new permanent employees and up to 168 short term employees during the 34 month construction of the facility. The applicant states that this increase in workers will not significantly impact the air quality in the region since this growth is minimal when compared to the population of Alachua County.

Growth-Related Air Quality Impacts since 1977

The population of Alachua County has increased by 64% between 1980 and 2007. The applicant also provided information regarding industrial growth in Alachua County. According to the applicant, there has been "little industrial growth since 1977." The applicant noted that the latest PSD permit issued in Alachua County was for the Florida Rock cement plant in Newberry. This source is noted in the largest stationary sources tables above.

8. CONCLUSION

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

References

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

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

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