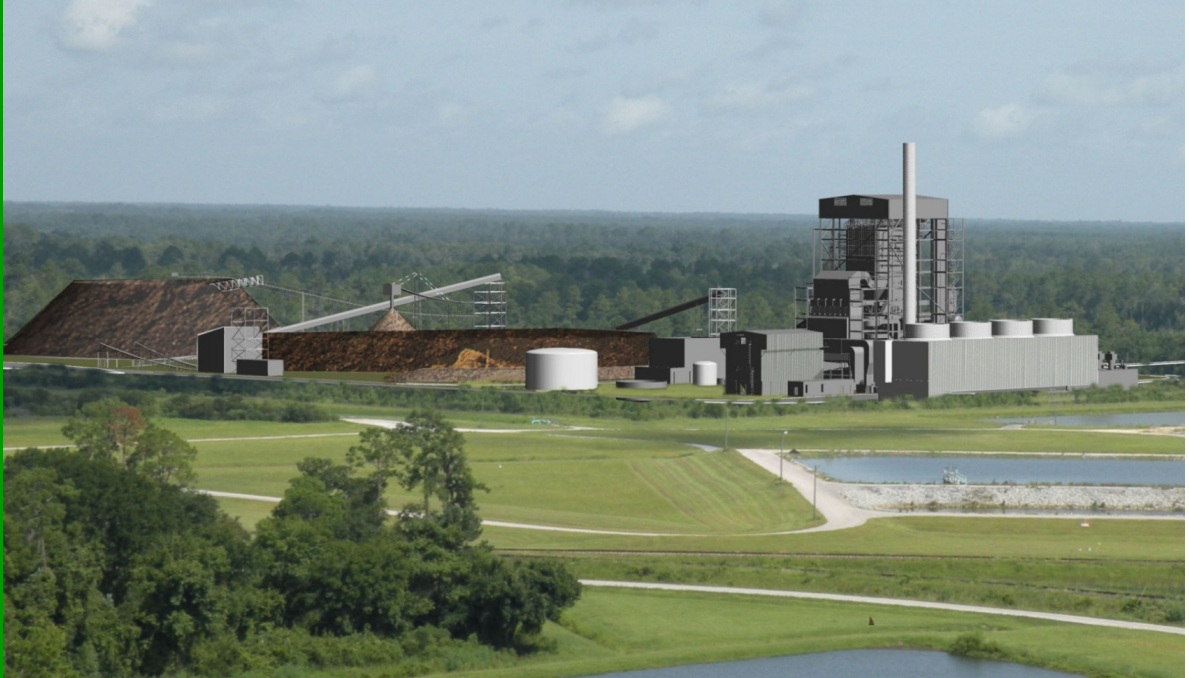


Gainesville Renewable Energy Center Site Certification Application



Gainesville
Renewable Energy Center
An American Renewables Company

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Volume 3

November 2009

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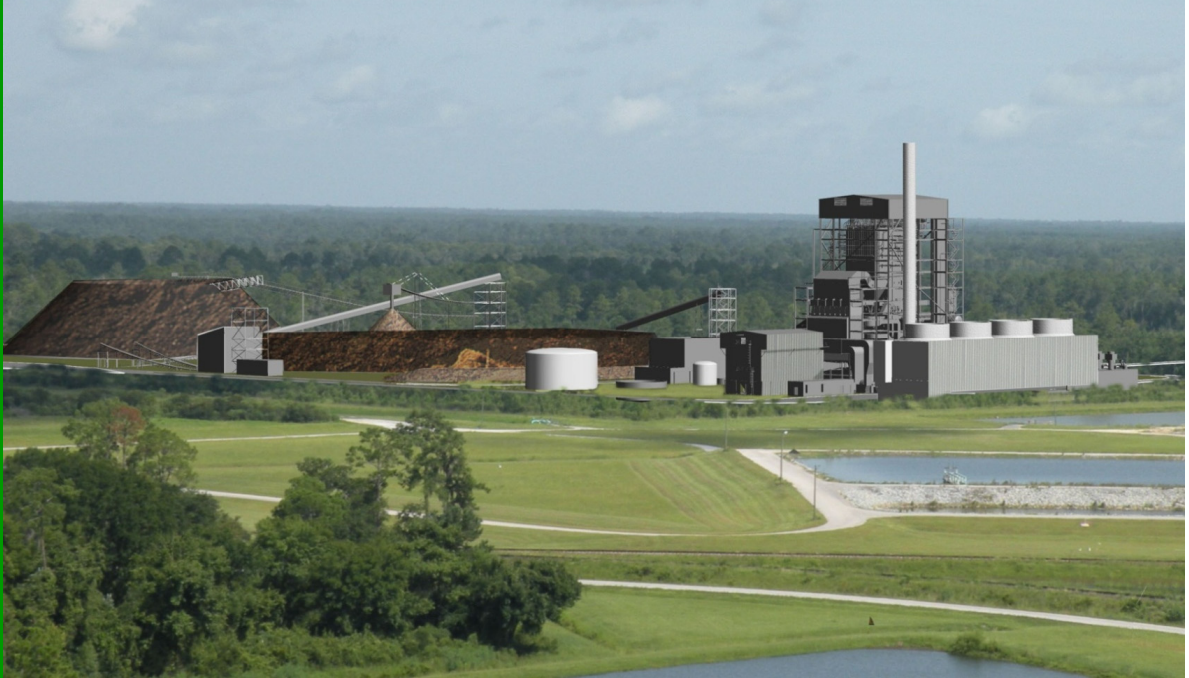
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10.2.5 PREVENTION OF SIGNIFICANT DETERIORATION/AIR CONSTRUCTION PERMIT APPLICATION
--

APPENDIX 10.2.5

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION

Gainesville Renewable Energy Center Prevention of Significant Deterioration/ Air Construction Permit Application



Gainesville
Renewable Energy Center
An American Renewables Company

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November 2009

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LIST OF ACRONYMS AND ABBREVIATIONS

°	degree
°F	degree Fahrenheit
µg/g	microgram per gram
µg/m ² /yr	microgram per square meter per year
µg/m ³	microgram per cubic meter
10 ⁶ Btu/hr	million British thermal units per hour
AAQS	ambient air quality standard
acfm	actual cubic foot per minute
AERMAP	AERMOD modeling system terrain preprocessing program
AERMET	AERMOD modeling system meteorological preprocessing program
AERMOD	AMS/EPA regulatory model
AMS	American Meteorological Society
AQRV	air quality related values
ARP	acid rain program
ASME	American Society of Mechanical Engineers
AST	aboveground storage tank
BACT	best available control technology
BFB	bubbling fluidized bed
bhp	brake horsepower
bhp	brake horsepower
BPIP	Building Profile Input Program
Btu/ft ³	British thermal unit per cubic foot
Btu/gal	British thermal unit per gallon
Btu/lb	British thermal unit per pound
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CBL	convectively generated boundary layer
CDS	circulating dry scrubber
CEC	cation exchange capacity
CEMS	continuous emissions monitoring system
cfm-ft ²	cubic feet per minute-square foot
CFR	Code of Federal Regulations
CI	compression ignition
CMAQ	Community Multiscale Air Quality
CO	carbon monoxide
CO ₂	carbon dioxide
COMS	continuous opacity monitoring system
DC	District of Columbia
DGS	Deerhaven Generation Station
DSI	dry sorbent injection

LIST OF ACRONYMS AND ABBREVIATIONS
(Continued, Page 2 of 4)

EAB	EPA's Environmental Appeals Board
ECT	Environmental Consulting & Technology, Inc.
EPA	U.S. Environmental Protection Agency
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
F.A.C.	Florida Administrative Code
F.R.	Federal Register
FAA	Federal Aviation Authority
FDEP	Florida Department of Environmental Protection
FGD	flue gas desulfurization
FGR	flue gas recirculation
FIP	federal implementation plan
FLAG	Federal Land Manager Air Quality Related Values Workgroup
FLM	Federal Land Manager
ft	foot
ft/sec	foot per second
ft ²	square foot
ft-agl	feet above ground level
ft-msl	feet above mean sea level
g/bhp-hr	gram per brake horsepower-hour
g/kWh	grams per kilowatt-hour
g/s	gram per second
GACT	generally available control technology
GAQM	EPA's Guideline on Air Quality Models
GeoTIFF	geo-referenced tagged image file format
GEP	good engineering practice
gpm	gallon per minute
gr/100 dscf	grain per 100 dry standard cubic foot
gr/dscf	grain per dry standard cubic foot
GRA	Gainesville Regional Airport
GREC	Gainesville Renewable Energy Center
GREC LLC	Gainesville Renewable Energy Center, LLC
GRU	Gainesville Regional Utilities
H ₂ SO ₄	sulfuric acid
ha	hectare
HAP	hazardous air pollutant
HHV	higher heating value
hp	horsepower
hr/yr	hour per year
HSH	highest of the second- highest

LIST OF ACRONYMS AND ABBREVIATIONS (Continued, Page 3 of 4)

ICE	internal combustion engine
IDSIS	in-duct sorbent injection system
IWAQM	Interagency Workgroup on Air Quality Modeling
JBR	jet bubbling reactor
JIA	Jacksonville International Airport
K	Kelvin
kg/ha/yr	kilogram per hectare per year
km	kilometer
kW	kilowatt
LAER	lowest achievable emission rate
lb/10 ⁶ Btu	pound per million British thermal units
lb/hr	pound per hour
lb/MMBtu	pound per million British thermal units
lb/MW	pound per megawatt
lb/MWh	pound per megawatt-hour
lb/MWh	pound per megawatt-hour
LSFO	limestone-forced oxidation
m/sec	meter per second
MACT	maximum achievable control technology
MEL	magnesium enhanced lime
mg/L	milligram per liter
mg/m ³	milligram per cubic meter
MGD	million gallons per day
MMBtu/hr	million British thermal units per hour
MW	megawatt
NAAQS	national ambient air quality standard
NED/SRTM	National Elevation Dataset/Shuttle Radar Topography Mission
NESHAP	national emission standard for hazardous air pollutant
NGR	natural gas reburn
NH ₃	ammonia
NMHC	nonmethane hydrocarbon
NO	nitric oxide
NO ₂	nitrogen dioxide
NO _x	nitrogen oxides
NPS	National Park Service
NRCS	National Resources Conservation Service
NSPS	new source performance standard
NSR	new source review
NWA	National Wilderness Area
NWS	National Weather Service

LIST OF ACRONYMS AND ABBREVIATIONS (Continued, Page 4 of 4)

OAQPS	Office of Air Quality Planning and Standards
OFA	overfire air
OSHA	Occupational Safety and Health Administration
PM	particulate matter
PM ₁₀	particulate matter less than or equal to 10 micrometers
PM _{2.5}	fine particulate matter less than or equal to 2.5 micrometers
ppmvd	part per million by dry volume
ppmw	part per million by weight
PRIME	Plume Rise Model Enhancements
PSD	Prevention of Significant Deterioration
QA	quality assurance
RACT	reasonably available control technology
RACT	reasonably available control technology
RBLC	RACT/BACT/ LAER Clearinghouse
RICE	reciprocating internal combustion engine
RO	reverse osmosis
SBL	stable boundary layer
SCR	selective catalytic reduction
SDA	spray dryer absorber
SIL	significant impact level
SIP	state implementation plan
SNCR	selective noncatalytic reduction
SO ₂	sulfur dioxide
SO ₃	sulfur trioxide
STG	steam turbine generator
TDS	total dissolved solids
tph	ton per hour
tpy	ton per year
TSP	total suspended particulate
ULSD	ultra-low sulfur diesel
USDA	U.S. Department of Agriculture
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey (USGS)
VOC	volatile organic compound
WBAN	Weather-Bureau-Army-Navy
WESP	wet electrostatic precipitator
yd ³	cubic yard
ZLD	zero liquid discharge

1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Gainesville Renewable Energy Center, LLC (GREC, LLC) plans to construct, own, and operate a nominal 100-megawatt (MW) net biomass-fired electric generating unit and associated facilities, including state-of-the-art emission control systems. The Gainesville Renewable Energy Center (GREC) will be located on approximately 131 acres of property in northwest Gainesville that GREC LLC will lease from the City of Gainesville (d/b/a Gainesville Regional Utilities [GRU]).

The main GREC plant facilities and systems will include a bubbling fluidized bed (BFB) boiler, conventional steam turbine generator, mechanical draft cooling tower, process and potable water supply systems, wastewater treatment systems (including a zero liquid discharge [ZLD] crystallizer), biomass fuel and byproduct handling and storage systems, BFB boiler air quality control systems, electrical interconnection facilities, and other balance-of-plant systems and equipment. The facilities will include a 230-foot (ft) BFB boiler exhaust stack, natural gas supply for use during BFB boiler startups, emergency generator and firewater pump diesel engines fired with ultra low sulfur diesel (ULSD) fuel oil, ground water supply well system, administration building, and various maintenance and equipment storage warehouses.

The BFB boiler will be capable of accommodating a wide range of clean, woody biomass fuels. GREC will use clean, chipped/ground, woody biomass material as its primary fuel. The biomass will consist of logging residue, mill residue, and urban wood waste. Urban wood waste typically consists of woody tree trimmings created by land clearing, right-of-way maintenance, and other nonforestry sources of woody debris. GREC will use limited quantities of natural gas as fuel during start-up. Emissions from the BFB boiler will be controlled using best available control technologies (BACT). Proposed BACT control technologies include:

- BFB boiler technology to minimize nitrogen oxides (NO_x) production via combustion staging.
- Selective catalytic reduction (SCR) technology to control NO_x emissions.

- BFB boiler technology combined with dry sorbent injection (DSI) and naturally occurring calcium in the wood ash to reduce sulfur dioxide (SO₂), sulfuric acid (H₂SO₄) mist, hydrogen chloride, and hydrogen fluoride emissions.
- Fabric filter baghouse for control of particulate matter (PM).

Operation of GREC will result in airborne emissions. Therefore, a permit is required prior to the beginning of facility construction, per Rule 62-212.300(1)(a), Florida Administrative Code (F.A.C.). This submittal, including the required permit application forms and supporting documentation included in the appendices, constitutes the GREC LLC application for authorization to commence construction in accordance with the Florida Department of Environmental Protection (FDEP) permitting rules contained in Chapter 62-212, F.A.C.

GREC will have potential emissions greater than 100 tons per year (tpy) of a Prevention of Significant Deterioration (PSD) pollutant and is one of the named major stationary source categories (i.e., fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour [MMBtu/hr]) listed in Section 169 of the Clean Air Act (CAA) and Rule 62-210.200(193)(a)1., F.A.C. Accordingly, GREC will be classified as a new *major stationary source* subject to the PSD New Source Review (NSR) requirements of Section 62-212.400, F.A.C., for those pollutants that are emitted at or above the specified PSD significant emission rate levels. Therefore, this report and application is also submitted to satisfy the permitting requirements contained in the FDEP PSD rules and regulations.

This report is organized as follows:

- Section 1.2 provides an overview and summary of the key regulatory determinations.
- Section 2.0 describes the proposed facility and associated air emissions.
- Section 3.0 describes the NSR requirements and discusses applicability of these requirements to the proposed project.

- Section 4.0 describes the applicable state and federal emission standards.
- Section 5.0 provides an analysis of BACT.
- Section 6.0 provides an analysis of maximum achievable control technology (MACT).
- Sections 7.0 (Dispersion Modeling Methodology) and 8.0 (Dispersion Modeling Results) address ambient air quality impacts.
- Section 9.0 discusses current ambient air quality in the vicinity of the project and preconstruction ambient air quality monitoring.
- Section 10.0 addresses other potential air quality impact analyses.
- Section 11.0 provides an assessment of impacts on Class I areas located within 300 kilometers (km) of GREC.

Appendices A and B provide emission rate calculations and the FDEP Application for Air Permit—Long Form, respectively. Appendix C contains the dispersion modeling protocol and agency comments. Appendix D provides the dispersion modeling input and output files for the ambient impact analyses.

1.2 SUMMARY

The primary source of GREC emissions will result from the combustion of biomass fuels in the BFB boiler. Emissions from the main boiler comprise 95 percent of total estimated GREC annual emissions. Principal air contaminants that will be emitted from the BFB boiler stack include NO_x, SO₂, carbon monoxide (CO), volatile organic compounds (VOC), PM/particulate matter less than or equal to 10 micrometers (PM₁₀), hydrogen fluoride, hydrogen chloride, and H₂SO₄. The BFB boiler will also emit trace amounts of metallic and organic compounds. Ancillary GREC emission sources include a mechanical draft cooling tower, emergency generator and firewater pump diesel engines, and material (biomass fuels and byproducts, and DSI sorbent) storage and handling systems.

The planned GREC construction start date is December 2010 with initial operation planned for December 2013.

Based on an evaluation of anticipated worst-case annual operating scenarios, GREC will have the potential to emit 418.1 tpy of NO_x, 715.6 tpy of CO, 130.4 tpy of PM (filterable), 281.2 tpy of PM₁₀ (filterable and condensable), 243.9 tpy of SO₂, 78.1 tpy of VOCs, 0.12 tpy of lead, 0.0084 tpy of mercury, and 5.9 tpy of H₂SO₄. Based on these potential annual emission rates, NO_x, CO, PM/PM₁₀, SO₂, and VOC emissions are subject to PSD review.

The analyses required for this permit application have resulted in the following conclusions. Since the primary GREC emission source is the BFB boiler, the conclusions primarily address this emission unit.

- BFB boiler technology and SCR represents BACT for NO_x. The proposed NO_x BACT emission limit for the BFB boiler of 0.07 pound per million British thermal units (lb/MMBtu) (30-day rolling average) reflects the expected performance of the most efficient control technologies available.
- Use of low sulfur biomass fuel, BFB boiler technology, and DSI represents BACT for SO₂. Use of ULSD fuel oil represents SO₂ BACT for the emergency generator and firewater pump diesel engines. The proposed SO₂ BACT emission limit for the BFB boiler of 0.041 lb/MMBtu (30-day rolling average) reflects the expected performance of the most efficient control technologies available.
- Good combustion design and operation represent BACT for CO and VOC. Boiler combustion design and operation requires a balancing of the competing goals to minimize the formation of both NO_x and CO/VOC. The proposed CO BACT emission limit of 0.12 lb/MMBtu (30-day rolling average), and VOC BACT emission limit of 0.013 lb/MMBtu (stack test average) reflect this balance and the aggressive NO_x BACT emission limit proposed for the GREC BFB boiler.
- BFB boiler technology, DSI, and a fabric filter represent BACT for H₂SO₄ mist. The proposed H₂SO₄ mist BACT emission limit for the BFB boiler of 0.0010 lb/MMBtu (stack test average) reflects the expected performance of

the most efficient control technologies available and stack test method constraints.

- A fabric filter (i.e., baghouse) represents BACT for filterable PM/PM₁₀. The proposed filterable PM/PM₁₀ BACT emission limit of 0.015 (stack test average) reflects the expected performance of the most efficient control technology available. Water suppression, enclosure, and fabric filter technology will be used to control PM/PM₁₀ emission from the material handling, processing, and storage activities. The mechanical draft cooling tower will employ high efficiency drift eliminators to achieve a drift loss rate of no more than 0.0005 percent of the cooling tower recirculating water flow.
- With the exception of PM₁₀, the ambient impact analysis demonstrates that GREC impacts will be below the PSD Class II significant impact levels (SILs) defined in Rule 62-210.200(281), F.A.C. Accordingly, a multisource cumulative assessment of national ambient air quality standards (NAAQS) attainment and PSD Class II increment consumption was only required for PM₁₀. The cumulative modeling analysis demonstrates that GREC and off-site emission source total PM₁₀ impacts will be below the NAAQS and PSD Class II increments.
- GREC is projected to emit NO_x, PM₁₀, SO₂, CO, and VOC in greater than significant amounts. The ambient impact analysis demonstrates that GREC impacts will be below the PSD *de minimis* monitoring significance levels for all of these pollutants with the exception of PM₁₀. Accordingly, GREC qualifies for the Rule 62-212.400(3)(e), F.A.C., exemption from PSD preconstruction ambient air quality monitoring requirements for all PSD pollutants except for PM₁₀. Current (2004 through 2008) quality-assured ambient air data collected at a nearby FDEP PM₁₀ monitoring site located 4.5 miles south of GREC was used to satisfy the PSD preconstruction ambient air monitoring requirements for PM₁₀.
- Class I areas located within 300 km of GREC include the Okefenokee and Wolf Island National Wilderness Areas (NWAs) in Georgia and the Bradwell Bay, St. Marks, and Chassahowitzka NWAs in Florida. Application of

the Federal Land Manager Air Quality Related Values Workgroup (FLAG) initial screening criteria demonstrates that GREC will not have any adverse impact on air quality-related values (AQRVs) at each of these PSD Class I areas.

- The ambient impact analysis demonstrates that GREC impacts will be below the U.S. Environmental Protection Agency (EPA) proposed PSD Class I SILs for all PSD pollutants and averaging period for the Class I areas evaluated. Accordingly, a multisource cumulative assessment of PSD Class I increment consumption was not required.
- Based on refined dispersion modeling, GREC will not cause, nor contribute to, an exceedance of any NAAQS, Florida ambient air quality standards (AAQS), or PSD increment for Class I or Class II areas.

2.0 PROJECT DESCRIPTION

2.1 PROJECT LOCATION, AREA MAP, AND PLOT PLAN

GREC will be built on leased property at the existing GRU Deerhaven Generation Station (DGS), which is located approximately 8 miles northwest of downtown Gainesville and approximately 7 miles southeast of the city of Alachua. The Site is located within the City of Gainesville and is bordered by Northwest 128th Lane on the north, the existing GRU DGS on the east, U.S. 441 on the south, and the Alachua County Public Works Department Complex on the west.

Figure 2-1 shows the GREC location within the state of Florida and within Alachua County. Figure 2-2 illustrates the leased property boundaries of the 131-acre GREC Site on a U.S. Geological Survey (USGS) 1:24,000-scale topographic quadrangle map. Figure 2-3 depicts the Site leased property and the GRU DGS certified site boundaries on a recent (January 2008) aerial photograph.

The Site is currently undeveloped. Historically, the Site has been used for agriculture and pine silviculture. Most of the Site is actively managed for timber production and has been altered by land preparation (furrowing) and periodic harvesting of timber. The adjacent property to the east of the Site is part of the GRU DGS, a nominal 440-MW coal-, oil-, and natural gas-fired electrical power generating facility. Facilities associated with the DGS located immediately adjacent to the Site include a stormwater treatment pond, a brine disposal area, and an ash disposal/storage area. Facilities of the Alachua County Public Works Department, a radio tower, and undeveloped land are situated to the west of the Site. Undeveloped, wooded land is located north of the Site. U.S. 441 and commercial uses, including plumbing and construction supply stores, a carwash, retail shed sales, and boat sales and storage, are located south of the Site.

Figure 2-4 provides the GREC general arrangement overlaid on the January 2008 aerial photograph. Figure 2-5 presents a conceptual rendering of the major GREC facilities.

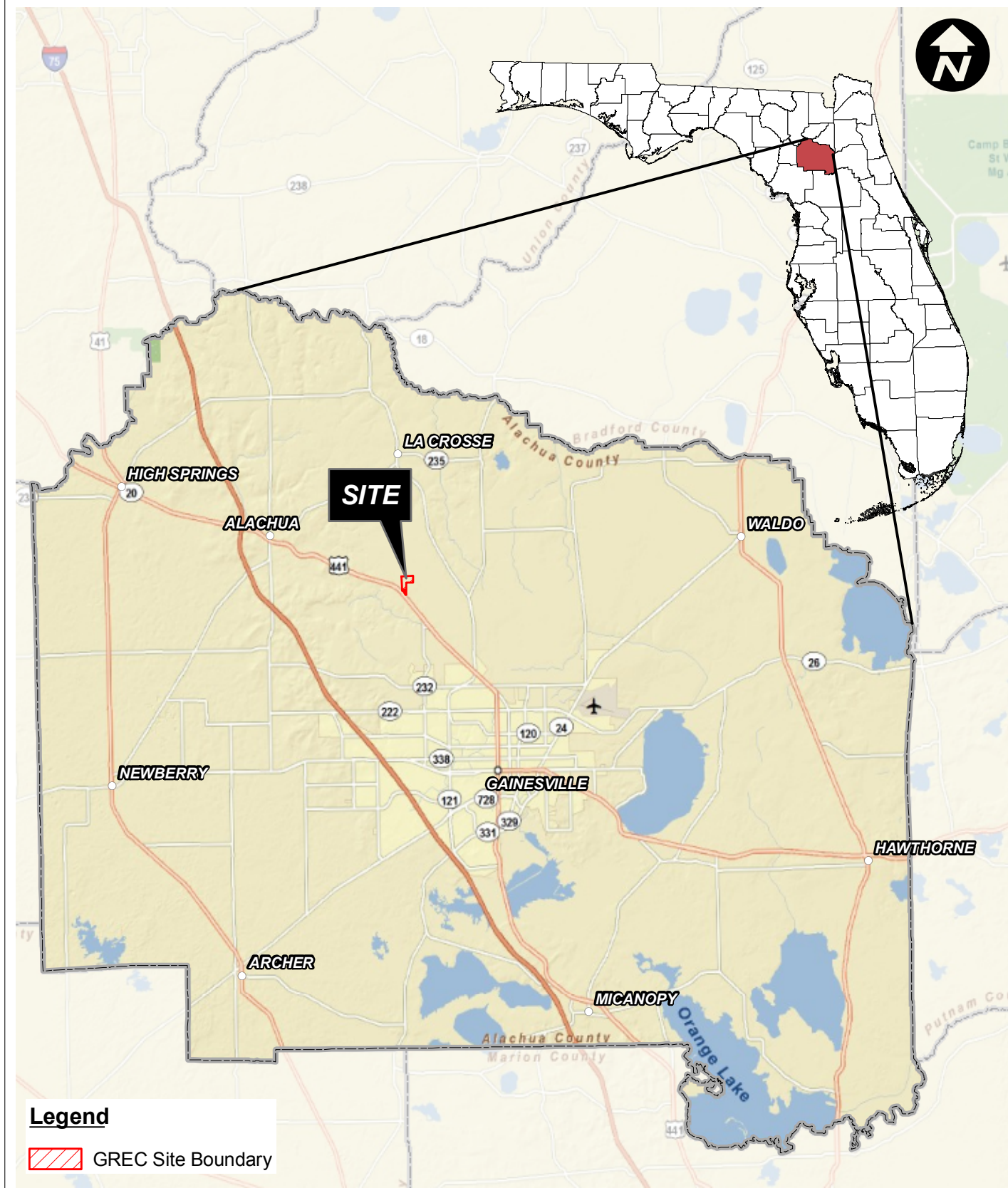


FIGURE 2-1.

GREC SITE LOCATION WITHIN FLORIDA AND ALACHUA COUNTY

Sources: ERSI, 2009; US Census, 2000; ECT, 2009.

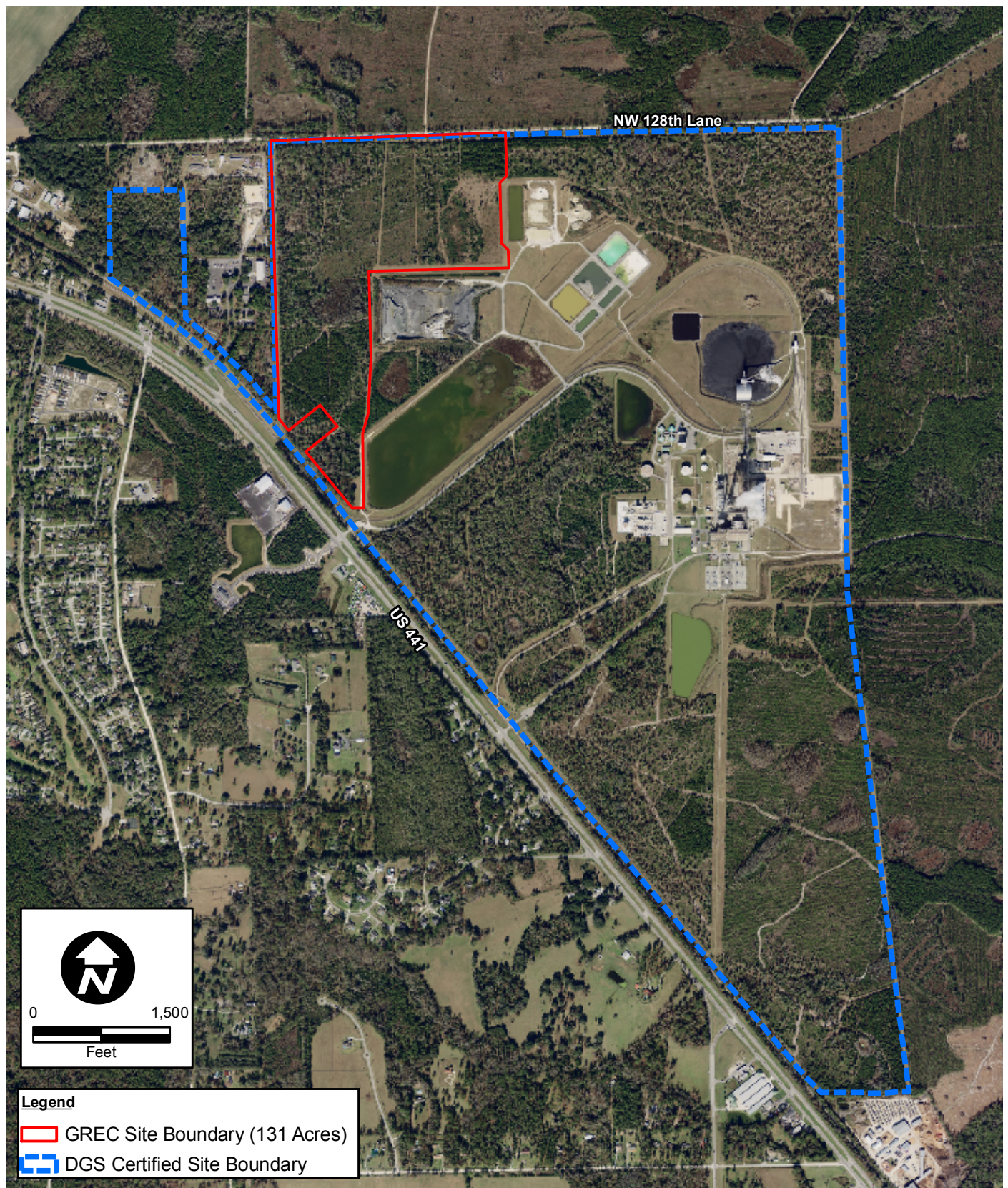


FIGURE 2-3.

GREC SITE

Sources: GRU, 2009; FDOT, 2008; GENESIS, 2009; ECT, 2009.

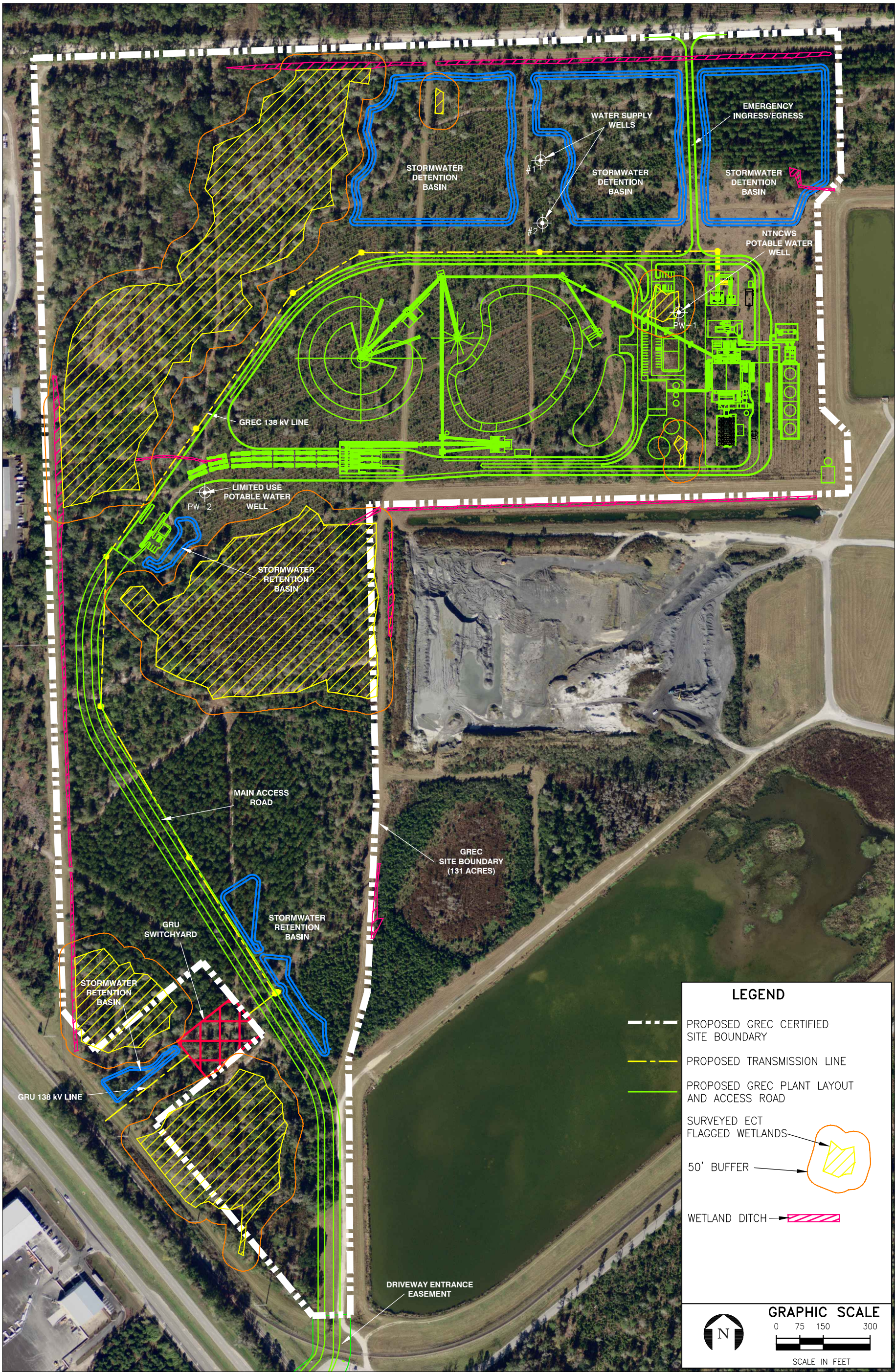


FIGURE 2-4.
LAYOUT OF PROPOSED FACILITIES
WITHIN GREC SITE

Source: FDOT, 2008; EDA, 2009; Zachary, 2009; Genesis, 2009; ECT, 2009.



FIGURE 2-5.
CONCEPTUAL RENDERING OF GREG FACILITY

Source: Zachry, 2009; ECT, 2009.

The main access road to the Site will run north from U.S. 441 to the fuel storage and power block areas. The Site main access road intersection with U.S. 441 will be approximately 0.5 mile north of the main entrance to the GRU DGS. An emergency access road will run north from the fuel storage/power block area to Northwest 128th Lane.

The main power block facilities (i.e., BFB biomass boiler, steam turbine, emission control equipment, boiler stack, cooling tower, etc.) will be located in the northern portion of the Site approximately 3,200 ft (0.6 mile) north of U.S. 441, 2,200 ft (0.4 mile) west of the Alachua County Public Works Department Complex, and 1,100 ft (0.2 mile) south of Northwest 128th Lane. The biomass fuel storage areas will be situated immediately to the west of the power block area. Facilities of the existing GRU DGS are located east and southeast of the GREC power block area. The planned locations of the GREC power block area and biomass fuel storage areas will provide a significant buffer between plant operations and adjoining land uses.

Additional GREC facilities will include an administration building, warehouse, scale house, water and wastewater treatment facilities, BFB boiler sand and fly ash handling and storage, two emergency diesel engines, and several stormwater runoff basins. Construction laydown and parking areas will be located to the north and east of the power block area. GREC construction activities will impact approximately 65 acres of the Site, including temporary activities such as construction parking that will be located south of the plant area.

2.2 PROJECT FUELS

2.2.1 BIOMASS FUELS

The primary fuel for the GREC BFB boiler will be clean, woody biomass material consisting of forest residue (i.e., tops, limbs, and other material left from traditional logging operations), mill residue (i.e., sawdust, bark, sander dust, and processed butt cuts), pre-commercial tree thinnings, used pallets, and urban wood waste, which includes woody tree trimmings that are generated by landscaping contractors, power line clearance contractors, and other nonforestry related sources of woody debris. Supplementary fuels may include herbaceous plant matter, clean agricultural residues (i.e., rice hulls, straw, etc.; no

animal wastes or manure), diseased trees, woody storm debris, whole tree chips, and pulpwood chips. These biomass fuels will principally be obtained within a 75-mile radius of GREC from a variety of sources. The facility will not use as fuel any form of treated or coated wood, municipal solid waste, construction and demolition waste, coal, petroleum coke, or tires. Natural gas will be used as the startup fuel for the BFB boiler.

GREC has been designed to be capable of using the variety of biomass materials mentioned previously, even though the materials may vary in moisture content, species, size, and age. The biomass materials will be primarily processed (i.e., sorted, chipped/ground, and screened to design-specified size) at offsite fuel preparation locations in the fuel procurement region prior to being delivered to the facility. The delivered biomass material will be further screened and processed onsite and mixed in the fuel yard prior to entering the boiler to achieve a homogenous fuel mixture with an expected average moisture content of approximately 50 percent. The flexibility to use a wide range of biomass materials will enable GREC to source its fuel from multiple, regional locations and, therefore, take advantage of competitive fuel pricing and availability opportunities.

Biomass fuel will be delivered to GREC in covered trucks with an average capacity of 25 tons per load. Fuel delivery trucks will access the GREC Site via the main facility entrance road, entering from either northbound or southbound U.S. 441. Typically, fuel deliveries will occur over a 15-hour (i.e., 5 a.m. to 8 p.m.) period per day, 6 days (i.e., Monday through Saturday) per week. To meet the facility's annual fuel requirements, approximately 130 to 150 truckloads of fuel will be delivered to the Site daily. To accommodate peak delivery periods, three drive-through truck dumpers will be capable of unloading 24 trucks per hour. The average fuel delivery rate is expected to be approximately 12 trucks per hour.

Table 2-1 provides typical constituent analyses of the GREC biomass fuels.

2.2.2 NATURAL GAS

Natural gas will be used as the startup fuel for the BFB boiler. After establishment of a minimum bed temperature of 900 degrees Fahrenheit (°F), biomass fuel will be

Table 2-1. Typical Constituent Analysis of Wood Fuel

	Percent by Weight Dry (Unless Otherwise Noted)				
	Slash Pine	Loblolly Pine	Sand Pine	Hard- wood	Weighted Average
Percent of Fuel Mix	59	9	4	28	100
Carbon	50.0	47.3	48.6	47.3	49.0
Sulfur	0.017	0.018	0.016	0.020	0.018
Hydrogen	6.9	5.1	4.4	5.5	6.3
Oxygen	42.1	46.6	45.9	44.5	43.3
Nitrogen	0.16	0.24	0.25	0.20	0.18
Chlorine (ppmw)	36	40	28	54	41
Ash	0.78	0.763	0.76	1.46	0.98
Gross heating value (Btu/lb)	8,624	8,835	8,985	8,166	8,529

Note: Btu/lb = British thermal unit per pound.
ppmw = part per million by weight.

Sources: GREC, 2009.
ECT, 2009

introduced, and the ignition burners will be shut down. Table 2-2 shows the typical composition of natural gas.

2.2.3 ULTRA-LOW SULFUR DIESEL FUEL OIL

The two GREC emergency diesel engines (i.e., emergency generator and emergency firewater pump diesel engines) will be fired with ULSD fuel oil containing no more than 15 parts per million by weight (ppm) of sulfur. Small day storage tanks for ULSD fuel oil will be located within secondary containment areas near each diesel engine. Excluding emergencies, each diesel engine will operate for approximately 96 hours per year (hr/yr) for routine testing and maintenance. Table 2-3 shows the typical composition of ULSD fuel oil.

2.3 PROJECT DESCRIPTION AND FLOW DIAGRAMS

Major components of GREC facility will include: (a) biomass fuel receiving, processing, handling, and storage areas; (b) one biomass-fired BFB steam boiler; (c) one steam turbine generator (STG); and (d) systems used for the handling and storage of sand, fly ash, and bottom ash. Ancillary equipment will include a process water treatment system, a four-cell mechanical draft cooling tower, a ZLD treatment system, and two diesel engines that will be used for the emergency fire water pump and the generator. Descriptions of the major GREC process areas are provided in the following subsections.

2.3.1 BIOMASS FUEL HANDLING, PROCESSING, AND STORAGE

The biomass fuel receiving, processing, handling and storage system will consist of three truck dumpers, two sets of screens and hogs (i.e., machines used to size wood chips), and automatic and manual stacker/reclaimers to maintain an average 15- to 20-day supply of biomass fuel for the BFB boiler based on full-load operation and average biomass fuel moisture content. Figures 2-6 and 2-7 show flow diagrams of the biomass fuel handling, processing, and storage systems.

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

Table 2-2. Typical Natural Gas Composition

Component	Mole Percent (by volume)
<u>Gas Composition</u>	
Pentane	<0.1
Propane	0.3
I-butane	0.1
N-butane	0.1
Nitrogen	0.3
Methane	96.8
Carbon dioxide	0.8
Ethane	1.6
<u>Other Characteristics</u>	
Heat content (HHV)	1,020 Btu/ft ³
Sulfur content	2.0 gr/100 dscf

Note: HHV = higher heating value.
 Btu/ft³ = British thermal units per cubic foot.
 gr/100 dscf = grain per 100 dry standard cubic foot.

Source: ECT, 2009.

Table 2-3. Typical ULSD Composition

Component	Maximum
Carbon residue on 10-percent bottoms	0.25 weight percent
Water and sediment	0.50 percent volume
Vanadium	1.5 ppm
Calcium	4.0 ppm
Sulfur	0.0015 weight percent
Ash	100 ppm
Lead	1.0 ppm
Heat content (HHV)	138,000 Btu/gal

Note: Btu/gal = British thermal unit per gallon.
HHV = higher heating value.

Source: ECT, 2009.

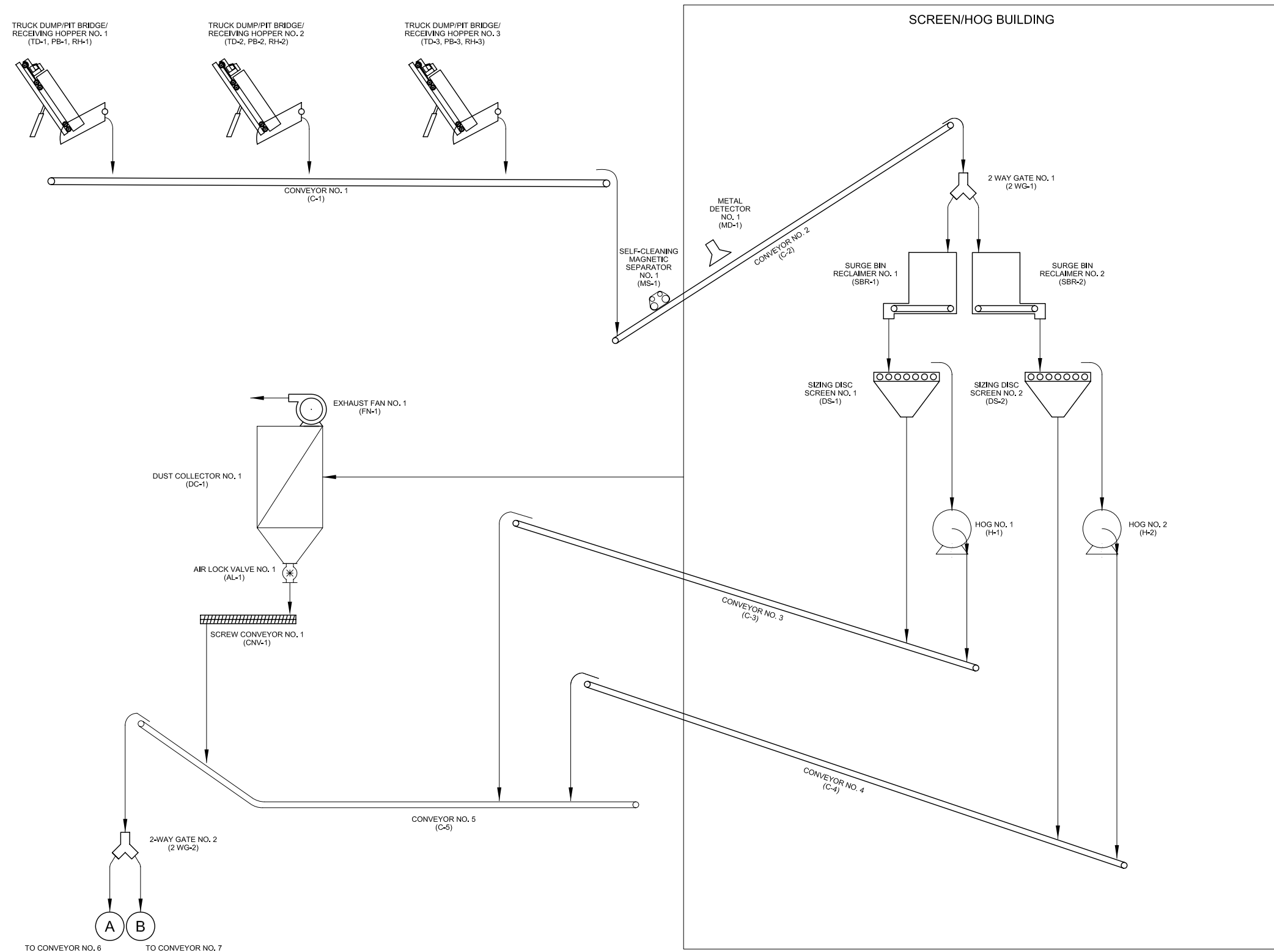


FIGURE 2-6.

BIOMASS FUEL DELIVERY, UNLOADING, AND PROCESSING SYSTEM

Source: Zachry, 2009; ECT, 2009.

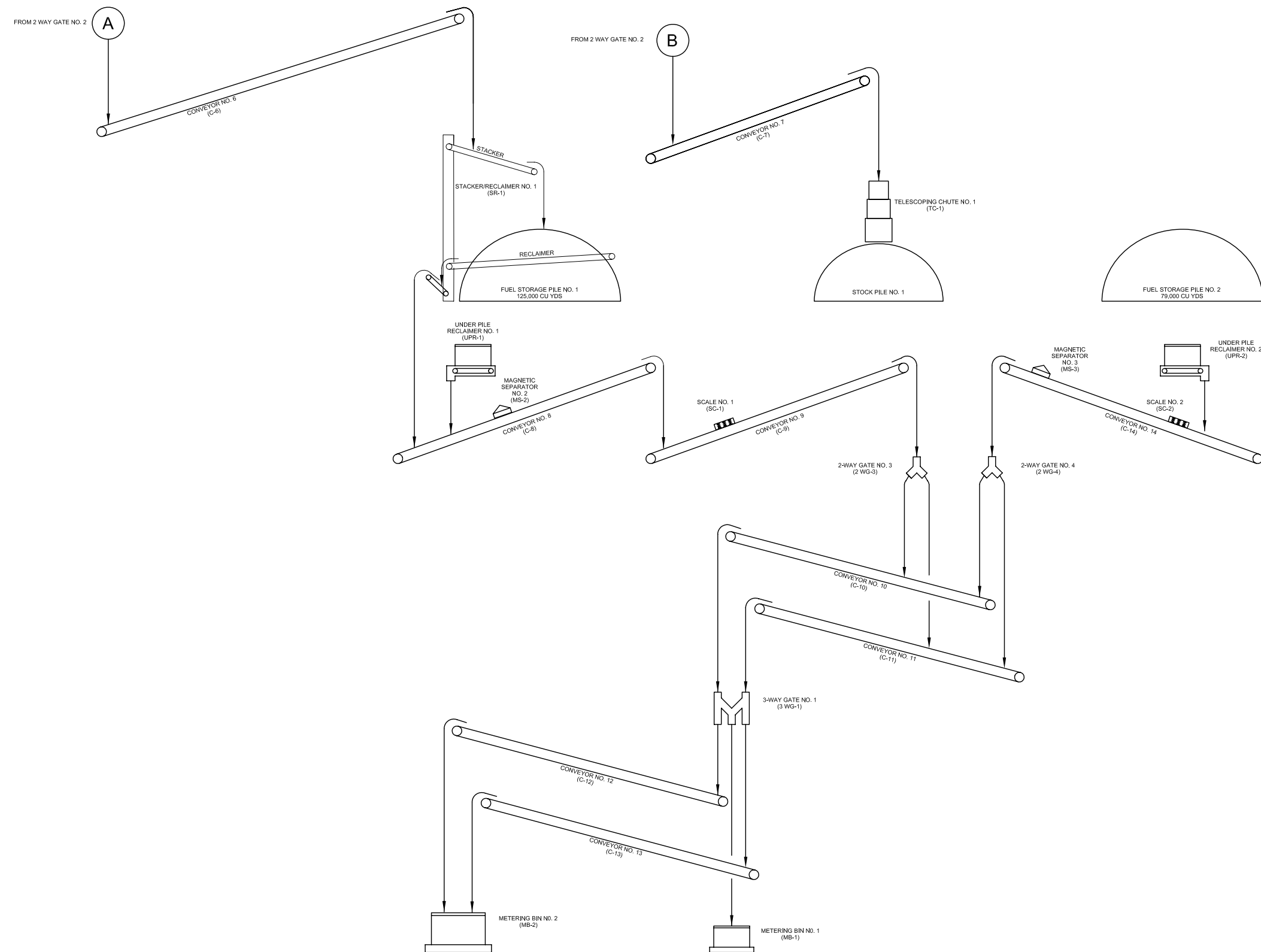


FIGURE 2-7.

BIOMASS FUEL HANDLING AND STORAGE SYSTEM

Source: Zachry, 2009; ECT, 2009.

rate/average moisture content and a 6-day-per-week delivery. During peak delivery periods, the delivery facilities will be capable of unloading 24 truckloads of fuel per hour. The GREC biomass fuel handling system will include scales to weigh each truck entering and departing to determine the delivered fuel weight.

The trucks will proceed from the scales to the receiving structure that covers the three truck dumpers, pit bridges, and receiving hoppers. Three truck dumpers will be located within the single three-sided (two walls and a roof) receiving structure that the trucks will enter from one end and exit from the other. The three truck dumpers are a drive-through design with a 63-degree (°) tilt. Within the receiving structure, a hydraulic dumper will tilt each truck to cause its contents to drop into belowgrade receiving hoppers, which will be covered by hydraulic lids when not in use. The truck will dump into the in-pit receiving hopper, which has a chain conveyor to move the material onto the conveyor that will transport the fuel to the biomass fuel processing system. Some of the biomass fuel that is presized, such as sawdust, will be delivered by self-unloading trucks and unloaded directly in the storage area.

Prior to entering the fully enclosed biomass fuel processing building, the biomass fuel will first pass under a metal detector and magnet to remove ferrous metals. A metal detector located above the conveyor will be used to detect ferrous metals, upstream of the disc screen/hammer hog sizing system. The biomass fuel will then be fed onto one of two disc screens at a rate of up to 300 tons per hour (tph). Fuel that is 3 inches or less in size will drop through the disc screen and onto a conveyor below. A small fraction (typically less than 15 percent) of the biomass fuel will be oversized and will not pass through the disc screen slots and will travel over the end of the screen for additional sizing by one of the two electric motor driven hammer hogs. Each of the hammer hogs is capable of reducing the oversized fuel to a 3-inch minus product at the rate of 100 tph. The properly sized biomass fuel and the fuel resized in the hogging system will be transferred from the fuel processing building by conveyor for delivery to either the automatic stacker/reclaimer or the fixed stacker fuel yard storage areas. The fully enclosed biomass fuel processing building will be vented to a baghouse for abatement of PM/PM₁₀ emissions. The biomass fuel will be stored in one of four storage areas. The first (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 ft high and will have a storage capacity of approximately 125,000 cubic yards (yd³) of fuel. Fuel will be distributed with an articulated stacker boom that rotates up to 240°. The stacker boom can also tilt downward so that the conveyor head is within 20 ft of the ground to minimize the distance that the fuel will drop when the pile is empty. The fuel from the pile will be reclaimed with an over-pile drag bar conveyor that can operate at an angle between 0° to 60° and rotate up to 300° horizontally. During the reclaim process, the over-pile reclaim conveyor will transfer the fuel onto a stationary belt conveyor for delivery to the BFB boiler. The second storage area (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 yd³ of fuel. Rolling stock (i.e., bulldozer or front-end loader) will be used to remove fuel from the fixed stacker pile and deliver it to the third manual reclaim storage pile (Storage Pile No. 2). The manual reclaim storage pile will be approximately 35 ft high with a storage capacity of approximately 79,000 ft³. Grooming of the manual pile will be performed with rolling stock. A front-end loader will reclaim the material to the BFB boiler feed conveyor system. The main storage piles will have the capacity to store sufficient fuel for an average of 15 to 20 days of plant operations.

In addition to the chipped/ground biomass fuel, moist sawdust (typically obtained from sawmill operations) will be received at the Site for use as a supplementary fuel in the BFB boiler. Sawdust will be delivered with self-unloading trucks and deposited in an open area adjacent to Storage Pile 2 in a fourth, small pile. The front-end loaders used to manually reclaim fuel from Storage Pile 2 will also be used to reclaim sawdust. The reclaimed sawdust will be blended with the chipped/ground biomass fuel and transferred to the BFB boiler fuel bins. The sawdust storage pile will be watered, as necessary, to control wind-blown fugitive PM/PM₁₀ emissions.

The reclaimed biomass fuel from Storage Piles 1 and 2 will be transferred via a series of covered conveyors and hoppers to the main conveyor belt that will transfer the biomass fuel to the BFB boiler fuel bins. The biomass fuel conveyor belts will be covered and

transfer points enclosed, as practicable, to reduce fugitive PM/PM₁₀ emissions. Telescoping chutes will be employed on both the automatic and fixed stackers to reduce fugitive PM/PM₁₀ emissions during the transfer of biomass fuel to the storage piles. The delivered biomass fuel will have an average moisture content of 50 percent, which will minimize dust from the storage piles. The storage areas will also be equipped with water sprays to further control potential wind-blown fugitive PM/PM₁₀ emissions dust, as needed. Generally, GREC will operate on a first-fuel-in, first-fuel-out basis to minimize potential odor and spontaneous combustion fire issues. The storage facilities will also be equipped with a manual fire protection system consisting of hoses and hydrants.

The two BFB boiler biomass fuel bins will each provide storage of biomass fuel sufficient to fuel the boiler for approximately 45 minutes. The BFB boiler biomass fuel bins will be equipped with bin vent filters for control of PM/PM₁₀ emissions.

2.3.2 BFB BOILER

Biomass fuel will be transferred from the fuel bins and combusted in the BFB boiler to generate steam. The selection of BFB boiler technology will allow the use of a wide range of biomass fuels. 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. Figure 2-8 provides a schematic of the BFB boiler.

Fluidizing (primary) air is introduced into the BFB boiler through a water-cooled, grate air-beam distribution system. Staging (overfire) air 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.

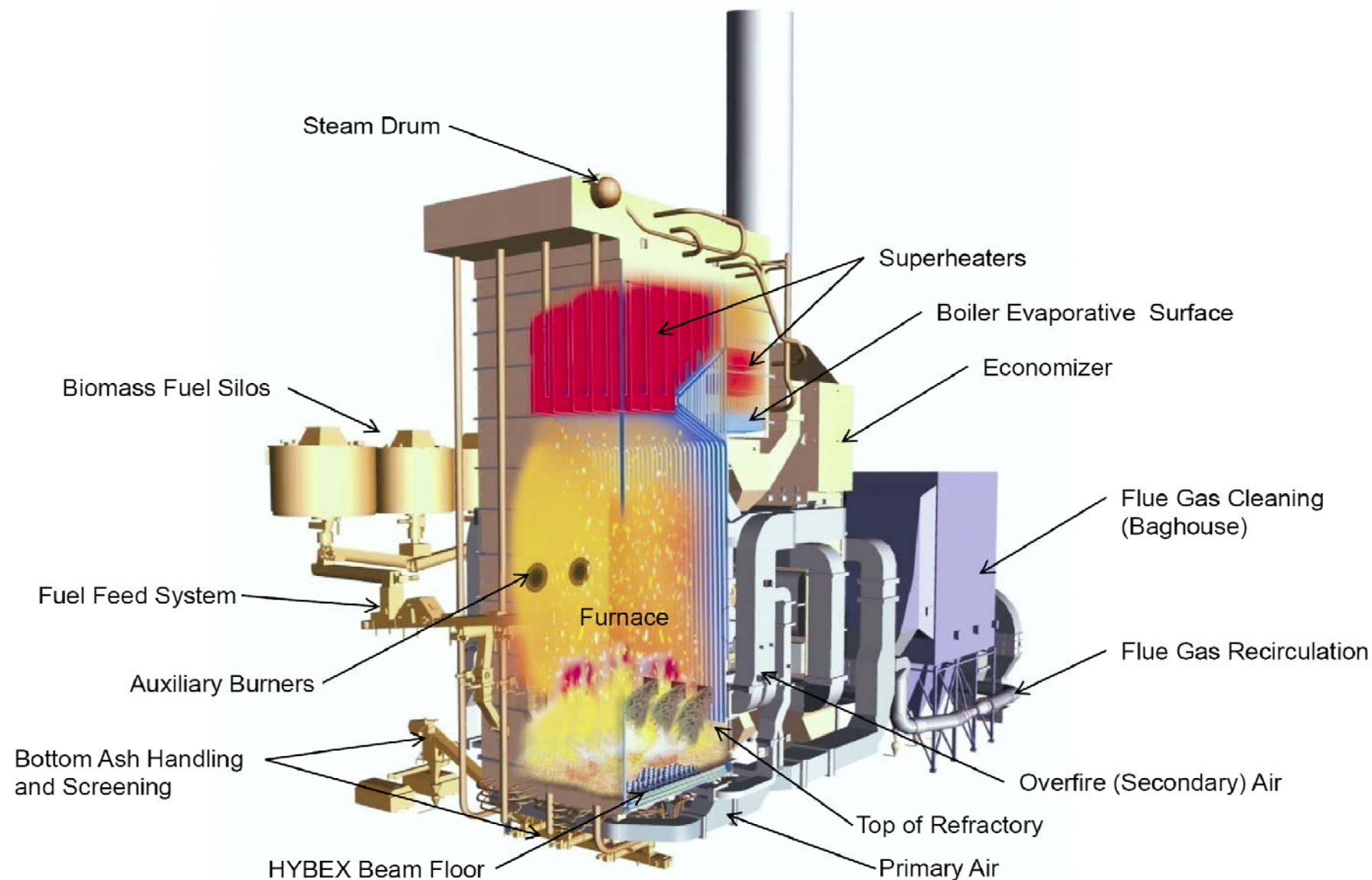


FIGURE 2-8.

SCHEMATIC OF BFB BOILER

Source: Metso, 2009.

Overfire air 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. Overfire air is injected into the furnace to complete the combustion of volatile gases (such as CO and VOCs) in the zone above the fluidized bed. The furnace temperature is approximately 200°F higher above the fluidized bed where the overfire air is introduced. NO_x emissions are limited by staging the combustion in the fluidized bed and in the lower furnace area (freeboard). Due to the reduced flame temperatures that occur with combustion staging, the formation of thermally generated NO_x is reduced. 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.

Flue gas from the boiler will pass through state-of-the-art air emission control equipment and discharge to the atmosphere through one 230-ft stack. Regulated emissions from the boiler will be reduced to low levels using BACT. Proposed BACT control technologies include:

- BFB boiler technology to minimize NO_x production via combustion staging.
- SCR system to control NO_x emissions.
- BFB boiler technology combined with DSI and naturally occurring calcium in the biomass ash to reduce SO₂, H₂SO₄ mist, hydrogen chloride, and hydrogen fluoride emissions.
- Fabric filter baghouse for control of PM/PM₁₀ emissions.

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.

The BFB boiler will normally operate between 70- and 100-percent load, with commensurate STG load.

2.3.3 FLY ASH AND BOTTOM ASH HANDLING AND STORAGE

The majority of ash created by the combustion of biomass fuel 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/PM₁₀ 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. 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.

2.3.4 BFB BOILER SAND AND DSI SORBENT HANDLING AND STORAGE

The BFB boiler will use sieved natural sand as a fluidization and heat transfer media. Sand will be delivered to the Site by truck and pneumatically conveyed to a sand storage silo. The sand silo will be vented to the boiler to control PM/PM₁₀ emissions.

Hydrated lime will be used as the absorbent in the DSI system to reduce BFB boiler acid gas emissions. The sorbent will be delivered to the Site by truck and pneumatically conveyed to a sorbent storage silo. The sorbent silo will be equipped with a bin vent filter to control PM/PM₁₀ emissions.

2.3.5 AQUEOUS AMMONIA HANDLING AND STORAGE

Liquid aqueous ammonia for use in the BFB boiler SCR NO_x emission control system will be delivered to the Site by truck. The aqueous ammonia, containing 19-percent ammonia by volume will be stored in one outdoor 30,000-gallon tank designed and fabricated in accordance with U.S. Department of Labor Chapter 29, Part 1910.111, Code of Federal Regulations (CFR), American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, ANSI K 61.1, and applicable requirements of Chapter 67-762, F.A.C., Aboveground Storage Tank (AST) Systems. The aqueous ammonia storage tank will be located within a secondary containment basin. A fire hydrant will be located within 100 ft of the storage area, and emergency showers and eyewash stations will be located both inside and outside of the tank containment basin.

Aqueous ammonia will be transferred to the storage tank by pumps located on the delivery truck trailer. Aqueous ammonia flow rate at full BFB boiler load is estimated to be approximately 350 pounds per hour (lb/hr). On a weekly basis, approximately two trucks (6,500 gallons per truck) of 19-percent aqueous ammonia will be delivered to the Site.

From the storage tank, the liquid aqueous ammonia will be pumped to a vaporizer skid. The vaporizer heats the liquid ammonia and vaporizes it to a gas. Ammonia vapor leaving the vaporizer is mixed with dilution air and transported to the injection grid in the BFB boiler flue gas upstream of the SCR reactor. Occupational Safety and Health Administration (OSHA) standards require that a hydrostatic relief valve or equivalent shall

be installed in each section of piping between shutoff valves to relieve pressure that could be developed by trapped liquid ammonia. The concentration of ammonia required for NO_x reduction is regulated by the ammonia control system. As the BFB boiler NO_x emission levels increase or decrease, the ammonia supply pump output level changes accordingly.

2.3.6 COOLING TOWER

The GREC cooling tower will be a four cell, counter-flow mechanical draft type tower. The structure will be made from fiberglass material and will have high efficiency fill and drift eliminators. Each cell will contain a fan with an electric drive motor. The structure will be erected over a concrete basin. 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). A blowdown of approximately 0.18 MGD will result in approximately nine cycles of concentration and a maximum total dissolved solids (TDS) concentration in the cooling tower recirculating water closed loop system of 1,700 milligrams per liter (mg/L). Cooling tower blowdown will be treated with a sidestream softener/clarifier. A portion of the treated blowdown water will be further treated by a two-pass reverse osmosis system (RO) and a brine concentrator/crystallizer. The remainder of the treated cooling tower blowdown will be recycled as makeup to the cooling tower.

PM/PM₁₀ emissions from the GREC cooling tower will be controlled using high efficiency drift eliminators. The cooling tower will achieve a drift loss rate of no more than 0.0005 percent of the cooling tower recirculating water flow.

2.3.7 EMERGENCY DIESEL ENGINES

An emergency diesel engine-driven generator will be provided to supply power to essential service motor control centers during an interruption of electrical power supply to the Site. Typical essential service loads include plant control systems, turbine turning gear motors, critical oil pumps, plant communication systems, and essential emergency light-

ing. Based on preliminary design criteria, the emergency generator will have a design generation capacity of approximately 500 kilowatts (kW) and will be driven by an approximate 760 horsepower (hp) diesel engine. Excluding operation during emergency conditions, it is estimated that the emergency generator will be operated for a maximum of 96 hr/yr for routine testing and maintenance. The emergency generator diesel engine will fire ULSD fuel and be designed with advanced combustion modifications, including retarded timing, to minimize potential NO_x emissions.

GREC will also include an emergency diesel engine-driven firewater pump to provide water to the plant firewater system in the event of an emergency that makes the primary electric motor-driven firewater pump inoperable. Based on preliminary design criteria, it is estimated that the firewater pump will be driven by a 275 hp diesel engine to provide water at a rate of 2,000 gallons per minute (gpm). The firewater pump diesel engine will be fired with ULSD fuel and will only be used in case of an emergency and for periodic testing. Excluding operation during emergency conditions, it is estimated that the firewater pump will be operated a maximum of 96 hr/yr for routine testing and maintenance.

The emergency generator and firewater pump diesel engines will comply with the applicable emission limits of New Source Performance Standard (NSPS) Subpart IIII for new nonroad compression ignition (CI) engines.

2.4 EMISSIONS AND STACK PARAMETERS

GREC will include the following emission sources:

- Material (i.e., biomass fuel, BFB boiler sand, fly ash, bottom ash, DSI sorbent, aqueous ammonia, and miscellaneous chemicals) truck traffic on paved facility roads (fugitive source of PM/PM₁₀)
- Biomass fuel receiving, processing, handling, and storage areas and systems (fugitive and point sources of PM/PM₁₀)
- BFB boiler (point source of NO_x, CO, VOC, SO₂, and PM/PM₁₀)
- Fly ash handling, storage, and truck loading systems (fugitive and point sources of PM/PM₁₀)

- Material (i.e., BFB boiler sand and DSI sorbent) receiving, handling, and storage (point sources of PM/PM₁₀)
- Mechanical draft cooling tower (point source of PM/PM₁₀)
- Emergency diesel engines (point sources of NO_x, CO, VOC, SO₂, and PM/PM₁₀)

Figures 2-9 and 2-10 show the locations of the GREC point and fugitive emission sources, respectively.

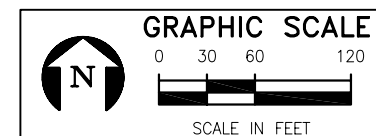
The primary GREC emission source will be the BFB boiler. Excluding startups, shutdowns, and malfunctions, the BFB boiler will operate between 70 and 100 percent of its design capacity. The GREC dispersion modeling analysis will evaluate air quality impacts for the BFB boiler at both 70- and 100-percent load conditions.

The primary source of GREC emissions will be the combustion of biomass fuels in the BFB boiler. Principal air contaminants that will be emitted from the BFB boiler stack will include NO_x, SO₂, CO, VOC, PM/PM₁₀, hydrogen fluoride, hydrogen chloride, and H₂SO₄ mist. The BFB boiler will also emit trace amounts of metallic and organic compounds. Table 2-4 provides a summary of maximum criteria pollutant (NO_x, SO₂, CO, VOC, PM/PM₁₀, and lead) emission rates for the BFB boiler. This table provides maximum emission rates for the BFB boiler for the various averaging periods of interest in units of pounds per million British thermal units (lb/10⁶ Btu), pounds per megawatt-hour (lb/MWh), lb/hr, and tpy.

Table 2-5 provides estimates of main boiler hydrogen fluoride, hydrogen chloride, H₂SO₄, mercury, and ammonia emissions. Although carbon dioxide (CO₂) is currently not a regulated pollutant, estimates of CO₂ emissions are also included in Table 2-5 for informational purposes. Tables 2-6 and 2-7 provide BFB boiler organic and metallic hazardous air pollutant (HAP) emission rates, respectively.

KEY

- P-1 Hog/Screen Building Baghouse
- P-2 BFB Boiler Fuel Day Bin No. 1
- P-3 BFB Boiler Fuel Day Bin No. 2
- P-4 Fly Ash Silo Vacuum Blower No. 1
- P-5 Fly Ash Silo Vacuum Blower No. 2
- P-6 Fly Ash Silo
- P-7 BFB Boiler
- P-8A Cooling Tower Cell No. 1
- P-8B Cooling Tower Cell No. 2
- P-8C Cooling Tower Cell No. 3
- P-8D Cooling Tower Cell No. 4
- P-9 Emergency Fire Water Pump Diesel Engine
- P-10 Emergency Generator Diesel Engine
- P-11 Sorbent Silo



LEGEND

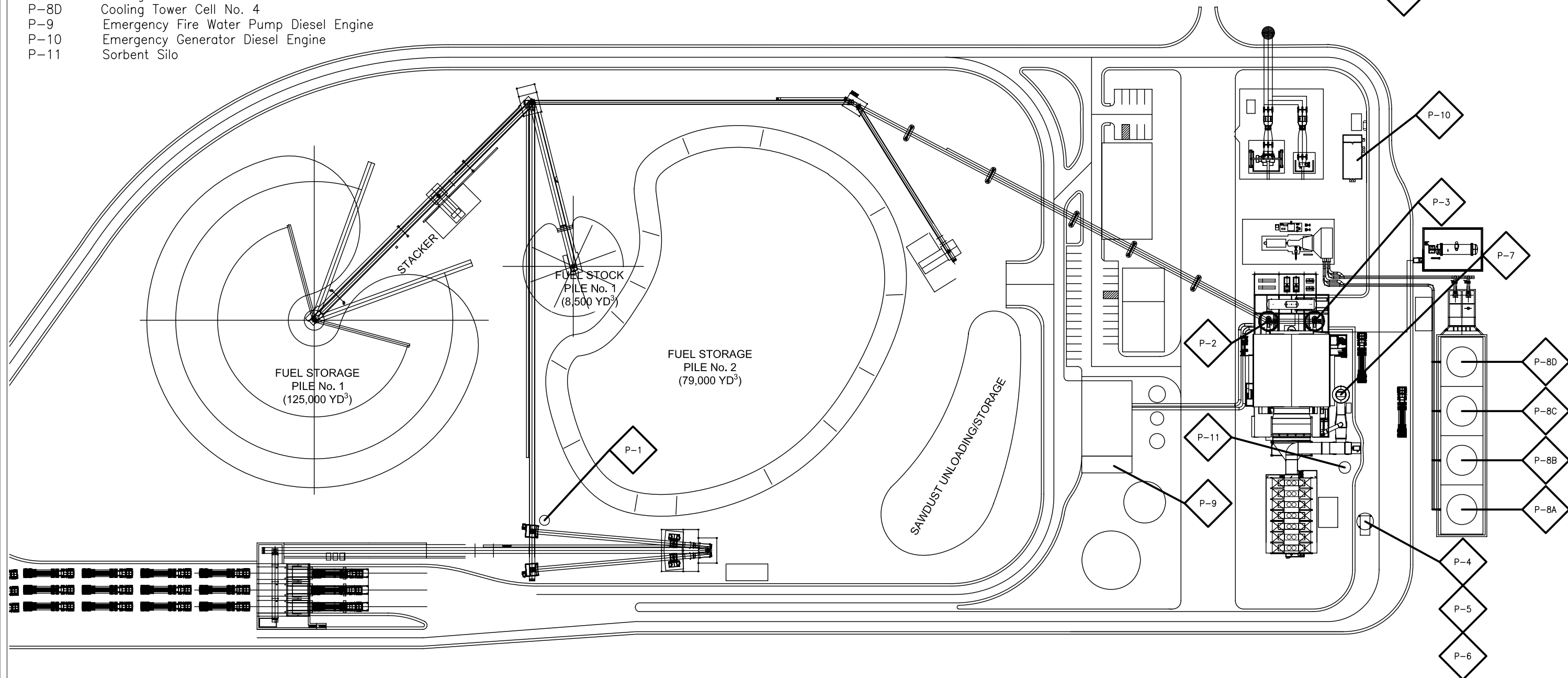


FIGURE 2-9.

LOCATIONS OF POINT (STACK) EMISSION SOURCES

Sources: Zachry Engineering, 2009; ECT, 2009.

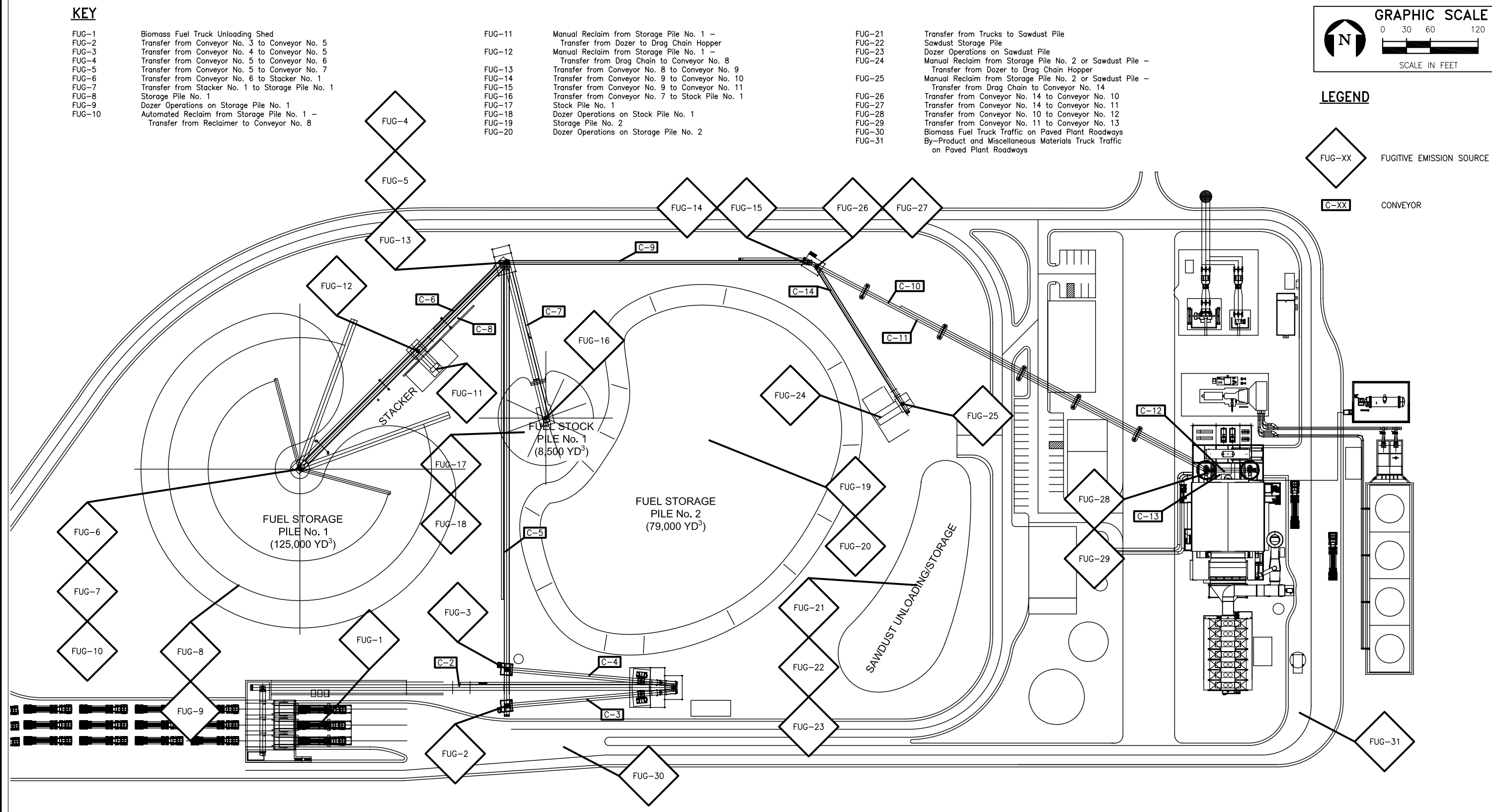


FIGURE 2-10.

LOCATIONS OF FUGITIVE PM/PM₁₀ EMISSION SOURCES

Sources: Zachry Engineering, 2009; ECT, 2009.

Table 2-4. BFB Boiler—Criteria Pollutant Emission Rates

Parameter	Averaging Period	Units	Maximums
Operating hours	Annual	hr/yr	8,760
Output (100-percent load)	Maximum hourly	MW, gross	116
Heat input (100-percent load)	Maximum hourly	10 ⁶ Btu/hr (HHV)	1,358
NO _x	24-Hour and annual	lb/10 ⁶ Btu	0.070
		lb/MWh	0.82
		tpy	416.4
		lb/hr	95.1
		g/s	12.0
SO ₂	24-Hour and annual	lb/10 ⁶ Btu	0.041
		lb/MWh	0.48
		tpy	243.9
		lb/hr	55.7
		g/s	7.0
CO	24-Hour and annual	lb/10 ⁶ Btu	0.120
		lb/MWh	1.4
		tpy	713.8
		lb/hr	163.0
		g/s	20.5
VOC	3-Hour and annual	lb/10 ⁶ Btu	0.013
		lb/MWh	0.15
		tpy	77.3
		lb/hr	17.7
		g/s	2.2
PM/PM ₁₀ (filterable)	3-Hour and annual	lb/10 ⁶ Btu	0.015
		lb/MWh	0.18
		tpy	89.2
		lb/hr	20.4
		g/s	2.6

Table 2-4. BFB Boiler—Criteria Pollutant Emission Rates (Page 2 of 2)

Parameter	Averaging Period	Units	Maximums
PM/PM ₁₀ (condensable)	3-Hour and annual	lb/10 ⁶ Btu	0.027
		lb/MWh	0.32
		tpy	160.6
		lb/hr	36.7
		g/s	4.6
PM/PM ₁₀ (total)	3-Hour and annual	lb/10 ⁶ Btu	0.042
		lb/MWh	0.49
		tpy	249.8
		lb/hr	57.0
		g/s	7.2
Lead	3-Hour and annual	lb/10 ⁶ Btu	0.000021
		lb/MWh	0.00025
		tpy	0.12
		lb/hr	0.029
		g/s	0.0037

Note: 10⁶ Btu/hr = million British thermal units per hour.
 lb/10⁶ Btu = pound per million British thermal units.
 lb/MWh = pound per megawatt-hour.
 tpy = ton per year.
 lb/hr = pound per hour.
 g/s = gram per second.

Sources: GREC, 2009.
 ECT, 2009.

Table 2-5. BFB Boiler—Hydrogen Fluoride, Hydrogen Chloride, H₂SO₄ Mist, Mercury, and CO₂ Emission Rates

Parameter	Averaging Period	Units	Maximums
Hydrogen fluoride	3-Hour and annual	lb/10 ⁶ Btu	0.012
		lb/MWh	0.14
		tpy	71.4
		lb/hr	16.3
		g/s	2.1
Hydrogen chloride	3-Hour and annual	lb/10 ⁶ Btu	0.0060
		lb/MWh	0.070
		tpy	35.7
		lb/hr	8.1
		g/s	1.0
H ₂ SO ₄ mist	3-Hour and annual	lb/10 ⁶ Btu	0.0010
		lb/MWh	0.012
		tpy	5.9
		lb/hr	1.4
		g/s	0.18
Mercury	Annual	lb/10 ⁶ Btu	0.0000014
		lb/MWh	0.000016
		tpy	0.0084
		lb/yr	16.7
Ammonia	Annual	lb/10 ⁶ Btu	0.0063
		lb/MWh	0.073
		tpy	37.3
		lb/hr	8.5
CO ₂	Annual	lb/10 ⁶ Btu	195
		lb/MWh	2,283
		tpy	1,159,868
		lb/hr	264,810

Sources: GREC, 2009.
ECT, 2009.

Table 2-6. BFB Boiler—Organic Hazardous Air Pollutant Emission Rates

Pollutant	Units	Maximums
Heat input (100-percent load)	10^6 Btu/hr (HHV)	1,358
Acetaldehyde	lb/ 10^6 Btu lb/hr tpy	1.44×10^{-5} 0.0196 0.0857
Acrolein	lb/ 10^6 Btu lb/hr tpy	8.52×10^{-6} 0.0116 0.0507
Benzene	lb/ 10^6 Btu lb/hr tpy	1.23×10^{-4} 0.1670 0.7316
Dibenzofurans	lb/ 10^6 Btu lb/hr tpy	1.62×10^{-9} 0.0000022 0.0000096
Dioxins (equivalent)	lb/ 10^6 Btu lb/hr tpy	2.38×10^{-9} 0.0000032 0.0000142
Ethylbenzene	lb/ 10^6 Btu lb/hr tpy	9.52×10^{-6} 0.0129 0.0566
Formaldehyde	lb/ 10^6 Btu lb/hr tpy	2.70×10^{-4} 0.3667 1.6060
Methyl chloroform	lb/ 10^6 Btu lb/hr tpy	1.30×10^{-5} 0.0177 0.0773
Methylene chloride	lb/ 10^6 Btu lb/hr tpy	4.90×10^{-5} 0.0665 0.2915

Table 2-6. BFB Boiler—Organic Hazardous Air Pollutant Emission Rates (Continued,
Page 2 of 2)

Pollutant	Units	Maximums
o-Xylenes	lb/10 ⁶ Btu	1.57 × 10 ⁻⁵
	lb/hr	0.0213
	tpy	0.0934
16-PAH (POM)	lb/10 ⁶ Btu	2.16 × 10 ⁻⁵
	lb/hr	0.0293
	tpy	0.1285
Toluene	lb/10 ⁶ Btu	2.10 × 10 ⁻⁵
	lb/hr	0.0285
	tpy	0.1249
Xylenes	lb/10 ⁶ Btu	5.59 × 10 ⁻⁶
	lb/hr	0.0076
	tpy	0.0332

Note: 16-PAH = acenaphthene, acenaphthylene, anthracene, benz(a)anthracene, benzo(b)fluoranthene, benzo(e)pyrene, benzo(g,h,i)perylene, benzo(k)fluoranthene, chrysene, dibenz(ah)anthracene, fluoranthene, fluorene, ideno(1,2,3-cd)pyrene, naphthalene, phenanthrene, and pyrene.

POM = polycyclic organic matter.

Sources: GREC, 2009.

EPA, 2002.

ECT, 2009.

Table 2-7. BFB Boiler—Metallic Hazardous Air Pollutant Emission Rates

Pollutant	Units	Maximums
Heat input (100-percent load)	10^6 Btu/hr (HHV)	1,358
Arsenic	lb/ 10^6 Btu	5.01×10^{-6}
	lb/hr	0.0068
	tpy	0.0298
Beryllium	lb/ 10^6 Btu	1.57×10^{-6}
	lb/hr	0.0021
	tpy	0.0093
Cadmium	lb/ 10^6 Btu	3.54×10^{-6}
	lb/hr	0.0048
	tpy	0.0211
Chromium	lb/ 10^6 Btu	1.28×10^{-4}
	lb/hr	0.1738
	tpy	0.7613
Lead	lb/ 10^6 Btu	2.10×10^{-5}
	lb/hr	0.0285
	tpy	0.1249
Manganese	lb/ 10^6 Btu	5.89×10^{-5}
	lb/hr	0.0800
	tpy	0.3503
Mercury	lb/ 10^6 Btu	1.41×10^{-6}
	lb/hr	0.0019
	tpy	0.0084
Nickel	lb/ 10^6 Btu	1.35×10^{-5}
	lb/hr	0.0208
Phosphorus	lb/ 10^6 Btu	3.68×10^{-4}
	lb/hr	0.4997
	tpy	2.1889

Sources: GREC, 2009.
EPA, 2002.
ECT, 2009.

The emergency generator and firewater pump diesel engines will be fired with ULSD fuel oil. Table 2-8 summarizes maximum criteria pollutant emission rates for these emergency diesel engines.

The mechanical draft cooling tower will be equipped with high efficiency drift eliminators. PM/PM₁₀/fine particulate matter less than or equal to 2.5 micrometers (PM_{2.5}) will also be emitted by the material handling emission sources. Table 2-9 provides a summary of the PM/PM₁₀/PM_{2.5} point and fugitive emissions for the cooling tower and material handling emission sources.

In addition to the emissions that will occur during GREC operation, there will be temporary emissions that will occur during the construction phase of the project. PM/PM₁₀ emissions will occur due to earthmoving activities associated with site preparation, wind erosion from disturbed areas, and vehicular traffic on unpaved roadways. The use of diesel engine heavy equipment will result in emissions of diesel fuel oil combustion products including NO_x, SO₂, CO, and VOC.

Reasonable precautions will be taken to minimize construction related emissions including watering of unpaved surfaces, as necessary, and use of ULSD by the heavy equipment. Idling of the heavy equipment, to the extent reasonable, will be minimized. Table 2-10 provides estimates of the construction related emissions.

An overall summary of maximum annual criteria and HAP pollutant emission rates for GREC is provided in Tables 2-11 and 2-12, respectively. Appendix A provides detailed emission rate calculations.

Table 2-13 provides stack parameters for the BFB boiler for 100- and 70-percent loads. Table 2-14 presents stack parameters for the material handling baghouses. Table 2-15 provides stack parameters for the cooling tower and emergency generator and firewater pump diesel engines.

Table 2-8. Emergency Diesel Engines—Criteria Pollutant Emission Rates

Pollutant	Units	Generator Engine	Firewater Pump Engine
Operating hours	hr/yr	500	500
Engine output (100-percent load)	kW	564	275
	bhp	757	205
NO _x	g/bhp-hr	3.4	2.1
	tpy	1.4	0.32
	lb/hr	5.6	1.3
	g/s	0.71	0.16
SO ₂	g/bhp-hr	0.0047	0.0051
	tpy	0.0020	0.00078
	lb/hr	0.0078	0.0031
	g/s	0.00098	0.00039
CO	g/bhp-hr	3.5	2.6
	tpy	1.5	0.39
	lb/hr	5.8	1.6
	g/s	0.73	0.20
VOC	g/bhp-hr	1.4	0.90
	tpy	0.60	0.14
	lb/hr	2.4	0.55
	g/s	0.30	0.069
PM/PM ₁₀	g/bhp-hr	0.15	0.15
	tpy	0.063	0.023
	lb/hr	0.25	0.091
	g/s	0.032	0.015
Lead	g/bhp-hr	Negligible	Negligible
	tpy	Negligible	Negligible
	lb/hr	Negligible	Negligible
	g/s	Negligible	Negligible

Note: bhp = brake horsepower.
 g/bhp-hr = gram per brake horsepower-hour.

Sources: GREC, 2009.
 ECT, 2009.

Table 2-9. Cooling Tower and Material Handling/Storage—Annual PM/PM₁₀/PM_{2.5} Emission Rates

Source	Annual Emission Rates (tpy)		
	PM	PM ₁₀	PM _{2.5}
Cooling tower	1.5	1.0	0.0032
Material transfer Baghouses	29.1	29.1	29.1
Material transfer Biomass fuel	0.17	0.081	0.012
Biomass fuel Storage piles Wind erosion	0.039	0.020	0.0029
Biomass fuel Storage piles Dozer operations	0.44	0.027	0.0037
Truck traffic Paved roads	11.0	2.1	0.32

Sources: GREC, 2009.
ECT, 2009.

Table 2-10. Temporary Construction-Related Emission Rate Summary

Criteria Pollutant	Estimated Annual Emissions (tons)					Project Totals
	Soil Transfer and Fill	Grading Activities	Traffic on Unpaved Roads	Wind Erosion	Heavy Equipment Diesel Engines	
NO _x	N/A	N/A	N/A	N/A	117.1	117.1
CO	N/A	N/A	N/A	N/A	90.6	90.6
VOC	N/A	N/A	N/A	N/A	50.2	50.2
SO ₂	N/A	N/A	N/A	N/A	1.3	1.3
PM	0.013	4.1	30.8	0.062	5.2	84.6
PM ₁₀	0.0061	1.7	8.8	0.031	5.2	15.7
PM _{2.5}	0.00092	0.89	0.88	0.0047	5.2	7.0
Lead	N/A	N/A	N/A	N/A	Negligible	Negligible

Note: N/A = not applicable.

Sources: GREC, 2009.
ECT, 2009.

Table 2-11. Annual Criteria Pollutant Emission Rate Summary

Criteria Pollutant	Potential Annual Emissions (tpy)						Project Totals
	BFB Boiler*	Material Handling Point Sources	Material Handling Fugitive Sources	Cooling Tower	Generator Diesel Engine	Firewater Pump Diesel Engine	
NO _x	416.4	N/A	N/A	N/A	1.4	0.32	418.1
CO	713.8	N/A	N/A	N/A	1.5	0.39	715.6
VOC	77.3	N/A	N/A	N/A	0.60	0.14	78.1
SO ₂	243.9	N/A	N/A	N/A	Negligible	Negligible	243.9
PM†	89.2	28.0	11.6	1.5	0.063	0.023	130.4
PM ₁₀	249.8	28.0	2.3	1.0	0.063	0.023	281.2
PM _{2.5}	249.8	28.0	0.34	0.0032	0.063	0.023	278.3
Lead	0.12	N/A	N/A	N/A	Negligible	Negligible	0.12

Note: N/A = not applicable.

*Based on 8,760 hr/yr at 100-percent load. Annual emissions including shutdown, maintenance outages, and startups will be lower.

†Filterable PM.

Sources: GREC, 2009.
ECT, 2009.

Table 2-12. Annual HAPs Emission Rate Summary

HAPs	Potential Annual Emissions (tpy)			Project Totals
	BFB Boiler	Generator Diesel Engine	Firewater Pump Diesel Engine	
<u>Organic HAPS</u>				
Acetaldehyde	0.086	0.000032	0.00039	0.086
Acrolein	0.051	0.000010	0.000047	0.051
Benzene	0.73	0.00099	0.00047	0.73
1,3-Butadiene	Negligible	0.000050	0.000020	0.000069
Dibenzofurans (total PCDD/PCDF)	0.000010	Negligible	Negligible	0.000010
Dioxins	0.000014	Negligible	Negligible	0.000014
Ethyl benzene	0.057	Negligible	Negligible	0.057
Formaldehyde	1.6	0.00010	0.00060	1.6
Methyl chloroform	0.077	Negligible	Negligible	0.077
Methyl chloride	0.29	Negligible	Negligible	0.29
PAH/POM	0.13	0.00043	0.00013	0.13
Toluene	0.12	0.00036	0.00021	0.12
o-Xylenes	0.093	Negligible	Negligible	0.093
Xylenes	0.033	0.00014	0.00025	0.033
<u>Acid Gases</u>				
Hydrogen chloride	35.7	Negligible	Negligible	35.7
Hydrogen fluoride	71.4	Negligible	Negligible	71.4
<u>Metallic HAPS</u>				
Arsenic	0.030	Negligible	Negligible	0.030
Beryllium	0.0093	Negligible	Negligible	0.0093
Cadmium	0.021	Negligible	Negligible	0.021
Chromium	0.76	Negligible	Negligible	0.76
Lead	0.12	Negligible	Negligible	0.12
Manganese	0.35	Negligible	Negligible	0.35
Mercury	0.0084	Negligible	Negligible	0.0084
Nickel	0.091	Negligible	Negligible	0.091
Phosphorus	2.2	Negligible	Negligible	2.2

Sources: GREC, 2009.
ECT, 2009.

Table 2-13. BFB Boiler Stack Parameters

Parameter	Units	Boiler Load	
		100 Percent	70 Percent
Height above grade	ft	230	230
	meter	70.1	70.1
Exit diameter	ft	12.0	12.0
	meter	3.66	3.66
Stack area	ft ²	113.1	113.1
Flow rate	acfm	520,600	359,900
Exit velocity	ft/sec	76.7	53.0
	m/sec	23.4	16.2
Exit temperature	°F	310.0	302.0
	K	427.6	423.2

Note: ft² = square foot.
acfm = actual cubic foot per minute.
ft/sec = foot per second.
m/sec = meter per second.
K = Kelvin.

Sources: GREC, 2009.
ECT, 2009.

Table 2-14. Material Handling Baghouse Stack Parameters

Parameter	Units	Emission Source					
		Screen/Hog Building	BFB Fuel Bin #1	BFB Fuel Bin #2	Fly Ash Silo Blowers (each)	Fly Ash Silo Bin Vent	Sorbent Silo Bin Vent
Height above grade	ft	50	100	100	70	77	51
	meter	15.2	30.5	30.5	21.3	23.5	15.5
Exit diameter	ft	3.3	1.5	1.0	1.5	1.0	1.0
	meter	1.0	0.46	0.30	0.46	0.30	0.30
Stack area	Ft ²	8.3	1.8	0.79	1.8	0.79	0.79
Flow rate	acfm	36,000	4,000	2,000	3,500	2,000	2,000
Exit velocity	ft/sec	72.33	37.7	42.4	33.0	42.4	42.4
	m/sec	22.0	11.5	12.9	10.1	12.9	12.9
Exit temperature	°F	77.0	77.0	77.0	100.0	100.0	100.0
	K	298.2	298.2	298.2	310.9	310.9	310.9

*Per cell.

Sources: GREC, 2009.
ECT, 2009.

Table 2-15. Emergency Diesel Engines and Cooling Tower Stack Parameters

Parameter	Units	Emission Source		
		Generator Diesel Engine	Firewater Pump Diesel Engine	Cooling Tower*
Height above grade	ft	15	10	53.1
	meter	4.6	3.1	16.2
Exit diameter	ft	0.67	0.50	36.8
	meter	0.20	0.15	11.2
Stack area	Ft ²	0.35	0.20	1,061
Flow rate	acfm	3,899	2,250	2,425,000
Exit velocity	ft/sec	186.2	191.0	38.1
	m/sec	56.7	58.2	11.6
Exit temperature	°F	893.0	855.0	93.0
	K	751.4	730.4	307.0

*Per cell.

Sources: GREC, 2009.
ECT, 2009.

2.5 EXCESS EMISSIONS

The GREC BFB boiler may have up to approximately 20 cold startups per year due to forced and unforced outages. Natural gas will be used during the startup cycle to raise the BFB boiler fluidized bed to its minimum effective operating temperature. The duration of each startup will depend on the temperatures of the BFB boiler and STG following the outages. The BFB boiler baghouse will be in service throughout the startup cycle. However, the DSI and SCR control systems cannot be placed in service until the boiler flue gas temperature reaches the minimum operating temperatures required for the effective operation of these emission control technologies. Excess emissions will occur until the BFB boiler attains a steady-state generation load of approximately 70 percent when firing biomass fuels, at which time the unit will be in compliance with all proposed emission limits. Based on a cold startup duration of 14 hours per event, there will be an estimated 280 hr/yr of excess emissions due to startup events. Hourly mass (i.e., lb/hr) emission rates during startup events for all pollutants with short-term AAQS (i.e., SO₂, PM₁₀, and CO) will all be lower than the rates that will occur at 100-percent load. Table 2-16 provides a summary of estimated startup emissions for the BFB boiler.

Similarly, excess emissions associated with BFB boiler shutdowns will also occur due to the temperature constraints of the DSI and SCR control systems. Based on a shutdown duration of 3 hours per event, there will be an estimated 60 hr/yr of excess emissions due to shutdown events. Hourly mass (i.e., lb/hr) emission rates during shutdown events for all pollutants with short-term ambient air quality standards will all be lower than the rates that will occur at 100-percent load. Table 2-17 provides a summary of estimated shutdown emissions for the BFB boiler.

Unless specifically authorized by FDEP for a longer duration, Rule 62-210.700(1), F.A.C., allows excess emissions for up to 2 hours in any 24-hour period provided best operational practices to minimize emissions are adhered to and the duration of excess emissions are minimized. GREC will be a base load unit with an estimated capacity factor of greater than 80 percent. The frequency of unit startups will therefore be low. Each unit startup will also be preceded by a period of time when the unit is offline, during which there will be no emissions from the BFB boiler. Startups of the BFB boiler will be

Table 2-16. BFB Boiler—Cold Startup Emissions*

Pollutant	Units	Value
Number of startups	Annual	20
Duration of startups	hr/event	14
	hr/yr	280
NO _x	lb/hr (average)	113.4
	tpy	15.9
SO ₂	lb/hr (maximum)	11.2
	tpy	0.59
CO	lb/hr (maximum)	159.7
	tpy	9.4
VOC	lb/hr (average)	6.0
	tpy	0.84
PM/PM ₁₀	lb/hr (maximum)	11.7
	tpy	0.96

*Emissions from initial firing to steady-state operation at 70-percent load firing biomass fuels.

Sources: GREC, 2009.
ECT, 2009.

Table 2-17. BFB Boiler—Shutdown Emissions*

Pollutant	Units	Value
Number of shutdowns	Annual	20
Duration of shutdowns	hr/event	3
	hr/yr	60
NO _x	lb/hr (average)	95.6
	tpy	2.9
SO ₂	lb/hr (maximum)	11.2
	tpy	0.29
CO	lb/hr (maximum)	89.9
	tpy	2.4
VOC	lb/hr (average)	7.2
	tpy	0.22
PM/PM ₁₀	lb/hr (maximum)	11.7
	tpy	0.31

*Emissions from steady-state operation at 70-percent load to cessation of fuel firing.

Sources: GREC, 2009.
ECT, 2009.

conducted using best operational practices to minimize emissions and duration consistent with process and safety considerations. GREC estimates up to 14 hours of excess emissions per startup. Accordingly, allowances for excess emissions are requested for: (a) startup events for up to 14 hours in any 24-hour period, and (b) shutdown events for up to 3 hours in any 24-hour period.

3.0 NEW SOURCE REVIEW REQUIREMENTS

3.1 NATIONAL AND STATE AAQS

The U.S. Environmental Protection Agency (EPA) has enacted primary and secondary NAAQS for six air pollutants (40 CFR 50). Primary NAAQS are intended to protect the public health, and secondary NAAQS are intended to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Florida has also adopted AAQS (see Section 62-204.240, F.A.C.). Table 3-1 presents the current national and Florida AAQS.

On July 18, 1997, EPA revised the NAAQS for PM to add new standards for PM_{2.5} particles. The PM NAAQS were again revised by EPA on October 17, 2006. This revision reduced the existing 24-hour average PM_{2.5} NAAQS from 65 to 35 micrograms per cubic meter ($\mu\text{g}/\text{m}^3$), retained the existing 15- $\mu\text{g}/\text{m}^3$ annual PM_{2.5} NAAQS, retained the existing 150- $\mu\text{g}/\text{m}^3$ 24-hour average PM₁₀ NAAQS, and revoked the existing 50- $\mu\text{g}/\text{m}^3$ annual PM₁₀ NAAQS.

An 8-hour ozone NAAQS replacing the existing 1-hour standard was promulgated in July 1997. In March 2008, EPA lowered the 8-hour ozone NAAQS from 0.08 to 0.075 part per million (ppm). Although the Florida rules currently include a 1-hour ozone AAQS, on the federal level, EPA revoked this standard in Florida effective June 15, 2005. FDEP is in the process of adopting both the 8-hour ozone and PM_{2.5} NAAQS and removing the current 1-hour ozone NAAQS.

On July 15, 2009, EPA proposed revising the nitrogen dioxide (NO₂) NAAQS to include an hourly standard in the range of 0.080 to 0.010 ppm. The current annual average NO₂ standard (i.e., 0.053 ppm) would remain unchanged. The new hourly NO₂ standard will be based on the 3-year average of the 4th highest 1-hour daily maximum concentrations. EPA plans to promulgate revised NO₂ NAAQS by January 2010.

Table 3-1. National and Florida Air Quality Standards
($\mu\text{g}/\text{m}^3$ unless otherwise stated)

Pollutant (units)	Averaging Periods	National Standards		Florida Standards
		Primary	Secondary	
SO ₂	3-hour ¹		1,300	1,300
	24-hour ¹	365		260
	Annual ²	80		60
PM ₁₀	24-hour ³	150	150	150
	Annual ⁴			50
PM _{2.5}	24-hour ⁵	35	35	
	Annual ⁶	15	15	
CO	1-hour ¹	40,000		40,000
	8-hour ¹	10,000		10,000
Ozone (ppmv)	1-hour ⁷			0.12
	8-hour ⁸	0.075	0.075	
NO ₂	Annual ²	100	100	100
Lead	Rolling quarterly average	0.15	0.15	
	Calendar quarter arithmetic mean	1.5	1.5	1.5

¹Not to be exceeded more than once per calendar year.

²Arithmetic mean.

³Standard attained when the expected number of days per calendar year with a 24-hour average concentration above the standard, as determined in accordance with 40 CFR 50, Appendix K, is equal to or less than 1.

⁴Expected annual arithmetic mean concentration, determined in accordance with 40 CFR 50, Appendix K.

⁵98th percentile concentration, determined in accordance with 40 CFR 50, Appendix N.

⁶Arithmetic mean concentration, determined in accordance with 40 CFR 50, Appendix N.

⁷Not to be exceeded an average of more than 1 day per year.

⁸3-year average of the annual 4th-highest daily maximum 8-hour average, determined in accordance with 40 CFR 50, Appendix P.

Sources: 40 CFR 50.

Section 62-204.240, F.A.C.

Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements. GREC will be located in northwestern Alachua County. Alachua County, the surrounding counties, and the entire state of Florida are currently designated attainment for all AAQS.

Alachua County is presently designated in 40 CFR 81.310 as better than national standards (for total suspended particulates [TSPs], SO₂, and NO₂), unclassifiable/attainment (for CO, 8-hour ozone, and PM_{2.5}), and not designated (for lead). Alachua County is designated attainment (for ozone, SO₂, CO, and NO₂) and unclassifiable (for PM₁₀ and lead) by Section 62-204.340, F.A.C.

In December 2008, EPA designated Alachua County attainment with respect to the revised 2006 PM_{2.5} NAAQS. In its March 2009 submittal to EPA, Florida recommended that Alachua County be designated attainment with respect to the revised 2008 8-hour ozone NAAQS. EPA plans to designate geographic areas as attaining or not attaining the 2008 ozone NAAQS by March 12, 2010.

3.2 NONATTAINMENT NSR APPLICABILITY

GREC will be located in Alachua County. As noted previously, Alachua County is presently designated as either better than national standards or unclassifiable/attainment for all criteria pollutants. Accordingly, GREC is not subject to the nonattainment new source review (NSR) requirements of Section 62-212.500, F.A.C.

3.3 PSD NSR APPLICABILITY

GREC will have potential emissions greater than 250 tpy of a PSD) pollutant. Accordingly, GREC will be classified as a *major* facility subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for those pollutants that are emitted at or above the specified PSD significant emission rate levels. Comparisons of GREC estimated potential annual emission rates and the PSD significant emission rate thresholds are provided in Table 3-2. As shown in this table, potential emissions of NO_x, CO, PM, PM₁₀, SO₂, and VOC are

each projected to exceed the applicable PSD significant emission rate level. These pollutants are, therefore, subject to the PSD NSR requirements of Section 62-212.400, F.A.C. Appendix A provides detailed GREC emission rate estimates.

3.4 PSD REQUIREMENTS

3.4.1 CONTROL TECHNOLOGY REVIEW

Pursuant to Rule 62-212.400(4)(c), F.A.C., an analysis of BACT is required for each pollutant emitted by GREC in amounts equal to or greater than the PSD significant emission rate levels. As defined by Rule 62-210.200(40), F.A.C., BACT is:

“an emission limitation, including a visible emission standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, 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, 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”

BACT determinations are made on a case-by-case basis as part of the FDEP NSR process and apply to each pollutant that exceeds the PSD significant emission rate thresholds shown in Table 3-2. All emission units, which emit or increase emissions of the applicable pollutants, involved in a major modification or a new major source must undergo BACT analysis. Because each applicable pollutant must be analyzed, particular emission units may undergo BACT analysis for more than one pollutant.

BACT is defined in terms of a numerical emissions limit. This numerical emissions limit can be based on the application of air pollution control equipment; specific production processes, methods, systems, or techniques; fuel cleaning; or combustion techniques. BACT limitations may not exceed any applicable federal NSPS, national emission standard for hazardous air pollutants (NESHAPs), or any other emission limitation established by state regulations.

Table 3-2. Projected GREC Emissions Compared to PSD Significant Emission Rates

Pollutant	Projected Maximum Annual Emissions (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO _x	418.1	40	Yes
CO	715.6	100	Yes
PM (filterable)	130.4	25	Yes
PM ₁₀ (filterable and condensable)	281.2	15	Yes
SO ₂	243.9	40	Yes
Ozone/VOC	78.1	40	Yes
Lead	0.12	0.6	No
Mercury	0.0084	0.1	No
Total fluorides	Not present	3	No
Sulfuric acid mist	5.9	7	No
Total reduced sulfur (including hydrogen sulfide)	Not present	10	No
Reduced sulfur compounds (including hydrogen sulfide)	Not present	10	No
Municipal waste combustor acid gases (measured as SO ₂ and hydrogen chloride)	Not present	40	No
Municipal waste combustor metals (measured as PM)	Not present	15	No
Municipal waste combustor organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	Not present	3.5×10^{-6}	No
For the pollutants listed above, and for major stationary sources locating within 10 km of a Class I area having an impact equal to or greater than 1 µg/m ³ , 24-hour average	Not applicable	Any amount	No

*Excludes hydrogen fluoride.

Sources: Rule 62-210.200(280), F.A.C.
 GREC, 2009.
 ECT, 2009.

BACT analyses must be conducted using the following five step *top-down* approach:

1. All available control technology alternatives are identified based on knowledge of the particular industry of the applicant, control technology vendors, technical journals and reports, and previous control technology permitting decisions for other identical or similar sources.
2. The identified available control technologies are evaluated for technical feasibility. If a control technology has been installed and operated successfully on the type of source under review, it is considered demonstrated and technically feasible. An undemonstrated control technology may be considered technically feasible if it is available and applicable. A control technology is considered available if it can be obtained commercially (i.e., the technology has reached the licensing and commercial sales phase of development). An available control technology is applicable if it can reasonably be installed and operated on the source type under consideration. Undemonstrated available control technologies that are determined to be technically infeasible, based on physical, chemical, and engineering principles, are eliminated from further consideration.
3. The technically feasible technology alternatives are rank-ordered by stringency into a control technology hierarchy.
4. The hierarchy is evaluated starting with the *top*, or most stringent alternative, to determine economic, environmental, and energy impacts and to assess the feasibility or appropriateness of each alternative as BACT based on site-specific factors. If the top control alternative is accepted as BACT from an economic and energy standpoint, evaluation of energy and economic impacts is not required since the only reason for conducting these assessments is to document the rationale for rejecting an alternative technology as BACT. Instead, the applicant proceeds to evaluate the top case control technology for impacts of unregulated air pollutants or impacts in other media (i.e., collateral environmental impacts). If there are no issues regarding collateral environmental impacts, the BACT analysis is complete, and the top case control technology alternative is proposed as BACT. If the top control

alternative is not applicable due to adverse energy, environmental, or economic impacts, it is rejected as BACT and the next most stringent control alternative is then considered.

5. This evaluation process continues until an applicable control alternative is determined to be both technologically and economically feasible, thereby defining the emission level corresponding to BACT for the evaluated pollutant.

This five-step procedure for conducting a BACT analysis is described in Chapter B of EPA's Draft New Source Review Manual dated October 1990.

The BACT emission limit established during the initial permitting process will be enforceable over the life of the unit. As a result, the BACT analysis must take into account the full range of possible fuels, operating conditions, operating system fluctuations, and normal wear-and-tear on the units and control systems. EPA's Environmental Appeals Board (EAB) has recognized that "permitting agencies have the discretion to set BACT limits at levels that do not necessarily reflect the highest possible control efficiencies but, rather will allow permittees to achieve compliance on a consistent basis" (Three Mountain Power, PSD Appeal No. 01-05 at 21 [May 30, 2001] citing: In re Masonite Corp., 5 E.A.D. 560-61 [EAB 1994] ["There is nothing inherently wrong with setting an emission limitation that takes into account a reasonable safety factor."]; and In re Knauf Fiber Glass, GmbH, PSD Appeal Nos. 99-8 to -72, slip op. at 21 [EAB, Mar. 14, 2000] ["The inclusion of a reasonable safety factor in the emission limitation is a legitimate method of deriving a specific emission limitation that may not be exceeded."])).

Section 5.0 provides an analysis of BACT for the GREC emission sources.

3.4.2 AMBIENT AIR QUALITY MONITORING

In accordance with the PSD requirements of Rule 62-212.400(7), F.A.C., any application for a PSD permit must contain, for each pollutant subject to review, an analysis of ambient air quality data in the area affected by the proposed major stationary source or ma-

major modification. The affected pollutants are those which the source would potentially emit in significant amounts (i.e., those that exceed the PSD significant emission rate thresholds shown in Table 3-2).

Preconstruction ambient air monitoring for a period of up to 1 year is generally required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance (QA) requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided by EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (1987a).

Rule 62-212.400(3)(e), F.A.C., provides an exemption that excludes or limits the pollutants for which an air quality monitoring analysis is conducted. This exemption states that a proposed facility will be exempt from the monitoring requirements of Rule 62-212.400(7), F.A.C., with respect to a particular pollutant if the emissions increase of the pollution from the new source would cause, in any area, air quality impacts less than the PSD *de minimis* ambient impact levels presented in Rule 62-212.400(3)(e)1., F.A.C. (see Table 3-3). In addition, an exemption may be granted if the air quality impacts due to existing sources in the area of concern are less than the PSD *de minimis* ambient impact levels.

Section 8.2 discusses applicability of the PSD preconstruction ambient monitoring requirements to for GREC.

3.4.3 AMBIENT IMPACT ANALYSIS

An air quality or source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the significant emission rates (see Table 3-2). FDEP rules specifically require the use of applicable EPA atmospheric dispersion models in determining estimates of ambient concentrations (refer to Rule 62-204.220[4], F.A.C.). Guidance for the use and application of dispersion models is presented in the EPA *Guideline on Air Quality Models* (GAQM) as published in Appendix W to 40 CFR 51. Criteria pollutants may be exempt from the full source

Table 3-3. PSD *De Minimis* Ambient Impact Levels

Averaging Time	Pollutant	<i>De Minimis</i> Level (µg/m ³)
Annual	NO ₂	14
Quarterly	Lead	0.1
24-Hour	PM ₁₀	10
	SO ₂	13
	Mercury	0.25
	Fluorides	0.25
8-Hour	CO	575
1-Hour	Total reduced sulfur	10
	Hydrogen sulfide	0.2
	Reduced sulfur compounds	10
NA	Ozone	100 tpy of VOC emissions

Source: Rule 62-212.400(3)(e)1., F.A.C.

impact analysis if the net increase in impacts due to the new source or modification is below the appropriate Rule 62-210.200(281), F.A.C., SIL, as presented in Table 3-4. EPA has proposed SILs for Class I areas; these levels are provided in Table 3-5.

Ozone is one pollutant for which a source impact analysis is not normally required. Ozone is formed in the atmosphere as a result of complex photochemical reactions. Models for ozone generally are applied to entire urban areas.

Various lengths of record for meteorological data can be used for impact analyses. A 5-year period can be used with corresponding evaluation of the highest of the second-highest (HSH) short-term concentrations for comparison to AAQS or PSD increments. The term *highest, second-highest* refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term PSD increments specify the standard should not be exceeded at any location more than once per year. If less than 5 years of meteorological data are used, the highest concentration at each receptor must be used.

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality baseline concentration level for SO₂ and TSP would constitute significant deterioration. The magnitude of the increment that cannot be exceeded depends on the classification of the area in which a new source (or modification) will have an impact. Three classifications were designated based on criteria established in the CAA Amendments. Initially, Congress promulgated areas as Class I (international parks, national wilderness areas, and memorial parks larger than 2,024 hectares [ha] [5,000 acres], and national parks larger than 2,428 ha [6,000 acres]) or Class II (all other areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. However, the states were given the authority to redesignate any Class II area to Class III status, provided certain requirements were met. EPA then promulgated, as regulations, the requirements for classifications and area designations.

Table 3-4. FDEP Significant Impact Levels

Pollutant	Averaging Period	Concentration ($\mu\text{g}/\text{m}^3$)
SO ₂	Annual	1
	24-Hour	5
	24-Hour (Class I Areas)	1
	3-Hour	25
PM ₁₀	Annual	1
	24-Hour	5
	24-Hour (Class I Areas)	1
NO ₂	Annual	1
CO	8-Hour	500
	1-Hour	2,000
Lead	Quarterly	0.03

Source: Rule 62-210.200(281), F.A.C.

Table 3-5. EPA Significant Impact Levels—Class I Areas

Pollutant	Averaging Period	Concentration ($\mu\text{g}/\text{m}^3$)
SO ₂	Annual	0.1
	24-Hour	0.2
	3-Hour	1.0
PM ₁₀	Annual	0.2
	24-Hour	0.3
NO ₂	Annual	0.1

Source: EPA Proposed, 1996; 61FR 38249.

On October 17, 1988, EPA promulgated PSD increments for NO₂; the effective date of the new regulation was October 17, 1989. However, the baseline date for NO₂ increment consumption was set at February 8, 1988; new major sources or modifications constructed after this date will consume NO₂ increment.

On June 3, 1993, EPA promulgated PSD increments for PM₁₀; the effective date of the new regulation was June 3, 1994. The increments for PM₁₀ replace the original PM increments that were based on TSP. Baseline dates and areas that were previously established for the original TSP increments remain in effect for the new PM₁₀ increments. Revised NAAQS for PM, which include revised NAAQS for PM₁₀ and PM_{2.5}, became effective on October 17, 2006. On May 16, 2008, EPA issued a final rule implementing the NSR program with respect to the 1997 PM_{2.5} NAAQS. This rule, which became effective July 15, 2008, requires states with approved state implementation plan (SIP) PSD programs to submit revised PSD programs implementing the PM_{2.5} NSR requirements within 3 years of the effective date of EPA's final rule. Accordingly, Florida (which has a SIP-approved PSD program) is required to submit its PM_{2.5} NSR SIP revision no later than July 15, 2011.

On October 23, 1997, EPA issued guidance regarding interim implementation of NSR for PM_{2.5}. The 1997 guidance stated that sources should continue to implement an approved PM₁₀ NSR program as a surrogate for meeting PM_{2.5} NSR requirements until certain issues were resolved. As discussed in the preamble to the May 16, 2008, EPA final rule, during the 3-year PM_{2.5} NSR SIP development period states may continue to implement a PM₁₀ program as a surrogate to meet the PSD program for PM_{2.5} pursuant to the 1997 guidance.

Current Florida PSD allowable increments are specified in Section 62-204.260, F.A.C., and shown on Table 3-6.

Table 3-6. PSD Allowable Increments ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Time	Class		
		I	II	III
PM ₁₀	Annual arithmetic mean	4	17	34
	24-Hour maximum*	8	30	60
SO ₂	Annual arithmetic mean	2	20	40
	24-Hour maximum*	5	91	182
	3-Hour maximum*	25	512	700
NO ₂	Annual arithmetic mean	2.5	25	50

*Maximum concentration not to be exceeded more than once per year at any one location.

Source: Section 62-204.260, F.A.C.

The term *baseline concentration* evolved from federal and state PSD regulations and denotes a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition in the PSD regulations, as amended, *baseline concentration* means the ambient concentration level that exists in the baseline area at the time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established based on:

- The actual emissions representative of sources in existence on the applicable minor source baseline date.
- The allowable emissions of major stationary sources that commenced construction before the major source baseline date but were not in operation by the applicable minor source baseline date.

The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s) (i.e., allowed increment consumption):

- Actual emissions from any major stationary source on which construction commenced after the major source baseline date.
- Actual emissions increases and decreases at any stationary source occurring after the minor source baseline date.

It is not necessary to make a determination of the baseline concentration to determine the amount of PSD increment consumed. Instead, increment consumption calculations need only reflect the ambient pollutant concentration *change* attributable to emission sources that affect increment. *Major* source baseline date means January 6, 1975, for PM (TSP/PM₁₀) and SO₂ and February 8, 1988, for NO₂. *Minor* source baseline date means the earliest date after the trigger date on which the first complete application was submitted by a major stationary source or major modification subject to the requirements of 40 CFR 52.21 or Section 62-212.400, F.A.C. The trigger dates are August 7, 1977, for PM (TSP/PM₁₀) and SO₂ and February 8, 1988, for NO₂.

The ambient impact analyses for GREC are provided in Sections 7.0 (Methodology), 8.0 (PSD Class II areas), and 11.0 (PSD Class I areas).

3.4.4 ADDITIONAL IMPACT ANALYSES

Rule 62-212.400(8), F.A.C., requires additional impact analyses for three areas: associated growth, soils and vegetation impact, and visibility impairment. The level of analysis for each area should be commensurate with the scope of the project. A more extensive analysis would be conducted for projects having large emission increases than those that will cause a small increase in emissions.

The growth analysis generally includes:

- A projection of the associated industrial, commercial, and residential growth that will occur in the area.
- An estimate of the air pollution emissions generated by the permanent associated growth.
- An air quality analysis based on the associated growth emission estimates and the emissions expected to be generated directly by the new source or modification.

The soils and vegetation analysis is typically conducted by comparing projected ambient concentrations for the pollutants of concern with applicable susceptibility data from the air pollution literature. For most types of soils and vegetation, ambient air concentrations of criteria pollutants below the NAAQS will not result in harmful effects. Sensitive vegetation and emissions of toxic air pollutants could necessitate a more extensive assessment of potential adverse effects on soils and vegetation.

The visibility impairment analysis pertains particularly to Class I area impacts and other areas where good visibility is of special concern. A quantitative estimate of visibility impairment is conducted, if warranted by the scope of the project. Section 10.0 provides information on the GREC additional impact analyses.

3.5 HAZARDOUS AIR POLLUTANT REQUIREMENTS

Florida relies on the requirements of the CAA with respect to the regulation of hazardous (also known as toxic) air pollutants. These federal requirements include a comprehensive set of technology-based emission standards referred to as NESHAPs. These standards establish hazardous air pollutant emission limitations for a wide variety of industrial source categories. Recent NESHAPs (i.e., those adopted after the 1990 amendments to the CAA) reflect MACT. Section 4.2 provides a discussion of the NESHAPs program and its applicability to GREC. Section 6.0 provides an analysis of MACT for the GREC emission sources.

4.0 STATE AND FEDERAL EMISSION STANDARDS

4.1 NEW SOURCE PERFORMANCE STANDARDS (NSPS)

EPA is required to establish federal emission standards for source categories that cause or contribute significantly to air pollution pursuant to Section 111 of the CAA, Standards of Performance of New Stationary Sources. These standards are intended to promote use of the best air pollution control technologies, taking into account the cost of such technology and any other non-air quality, health, and environmental impact and energy requirements. These standards apply to sources that have been constructed or modified since the proposal of the standard. Since December 23, 1971, EPA has promulgated more than 75 standards. The NSPS are codified in 40 CFR 60.

Major GREC components include: (a) biomass fuel receiving, processing, handling and storage areas; (b) a biomass-fired BFB steam boiler; (c) a STG; and (d) systems used for the handling and storage of sand, fly ash, bottom ash, sorbent, and aqueous ammonia. Ancillary equipment will include a process water treatment system, a four-cell mechanical draft cooling tower, a ZLD treatment system, and two diesel engines that will be used for the emergency firewater pump and generator. NSPS applicable to GREC are discussed in the following subsections.

4.1.1 NSPS SUBPART DA—ELECTRIC UTILITY STEAM GENERATING UNITS

The maximum BFB boiler heat input when firing natural gas during startup and shutdown events is 340.5 MMBtu/hr. Accordingly, the BFB boiler will: (a) be capable of combusting more than 250 MMBtu/hr heat input of fossil fuel (either alone or in combination with any other fuel), (b) meet the definition of an *electric utility steam generating unit*, and (c) commence construction after September 18, 1978. The BFB boiler will therefore be subject to the applicable requirements of NSPS Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. NSPS Subpart Da was amended on February 27, 2006 to include

emission standards for steam generating units that commence construction after February 28, 2005.

NSPS Subpart Da specifies emission limitations, monitoring, reporting, and recordkeeping requirements for PM, NO_x, SO₂, and opacity. NSPS Subpart Da emission standards applicable to the BFB boiler are summarized as follows:

- PM—0.14 pound per megawatt-hour (lb/MWh) gross energy output or 0.015 lb/MMBtu. Alternatively, units that commence construction after February 28, 2005, may elect to comply with a PM emission limit of 0.03 lb/MMBtu and a 99.9-percent reduction from uncontrolled emission rates. Opacity is limited to 20 percent (6-minute average), except for one 6-minute period per hour of no more than 27 percent.
- SO₂—1.4 pounds per megawatt (lb/MW) gross energy output on a 30-day rolling average basis, or 95-percent reduction on a 30-day rolling average basis.
- NO_x—1.0 lb/MW gross energy output, on a 30-day rolling average basis.

The NSPS Subpart Da PM and NO_x emission limits do not apply during periods of startup, shutdown, or malfunction. The NSPS Subpart Da SO₂ emission limit applies at all times except emergency conditions.

The BFB boiler will be required to install a continuous opacity monitoring system (COMS) and continuous emissions monitoring systems (CEMS) for SO₂, and NO_x pursuant to 40 CFR 60.49Da(a), (b), and (c), respectively. Continuous monitoring of oxygen or CO₂ pursuant to 40 CFR 60.49Da(d) is also required. Initial performance tests will be required to demonstrate compliance with the NSPS Subpart Da PM, opacity, NO_x, and SO₂ emission standards in accordance with the test methods specified in 40 CFR 60.48Da. Subpart Da compliance provisions for PM require the use of opacity monitoring equipment as an indicator of continuous PM control device performance and a continuous bag leak detection system for units equipped with fabric filters. Alternatively, a PM CEMS may be used to demonstrate compliance with the Subpart Da PM stan-

dard. Compliance with the Subpart Da NO_x and SO₂ standards will be determined based on a 30-day rolling average as measured by the NO_x and SO₂ CEMS.

The GREC BFB boiler will comply with the applicable requirements of NSPS Subpart Da.

4.1.2 NSPS SUBPART OOO—NONMETALLIC MINERAL PROCESSING PLANTS

NSPS Subpart OOO is applicable to equipment that processes nonmetallic minerals including crushers, grinding mills, screening operations, bucket elevators, belt conveyors, bagging operations, storage bins, and enclosed truck or railcar loading stations. Based on the preliminary GREC design, hydrated lime will be used as the reagent for the in-duct DSI system used to reduce SO₂ and H₂SO₄ mist emissions from the BFB boiler. Hydrated lime is classified as a nonmetallic mineral since it is a calcium compound, and therefore the hydrated lime storage and handling activities planned for GREC will be subject to the applicable provisions of NSPS Subpart OOO. As alternatives to hydrated lime, GREC may use other alkaline reagents such as trona (natural sodium sesquicarbonate) or sodium bicarbonate. These alternative reagents will also be subject to the applicable provisions of NSPS Subpart OOO.

NSPS Subpart OOO specifies emission limitations, monitoring, reporting, and record-keeping requirements for PM and opacity. Applicable NSPS Subpart OOO emission standards for the GREC hydrated lime storage and handling equipment are summarized as follows:

- PM—0.022 grain per dry standard cubic foot (gr/dscf) and 7-percent opacity for stack emissions (i.e., PM that is released from a capture system), 10-percent opacity for fugitive emissions (i.e., PM that is not collected by a capture system and released to the atmosphere at the point of generation), and 7-percent opacity from any baghouse that controls emissions from only an individual enclosed storage bin.

Initial compliance with the NSPS Subpart OOO PM emission standards is determined using EPA Reference Method 5 or 17 (for stack emissions) and EPA Reference Methods 9 and/or 22 (for opacity determinations). Reporting and recordkeeping requirements are specified in 40 CFR 60.676.

The GREC DSI reagent storage and handling equipment will comply with the applicable requirements of NSPS Subpart OOO.

4.1.3 NSPS SUBPART III—STATIONARY COMPRESSION IGNITION INTERNAL COMBUSTION ENGINES

NSPS Subpart III is applicable to owners and operators of stationary CI internal combustion engines (ICE) that commence construction after July 11, 2005, where the CI ICE are manufactured after April 1, 2006 (and are not fire pump engines), or manufactured after July 1, 2006 (for certified National Fire Protection Association fire pump engines).

NSPS Subpart III specifies emission limitations, monitoring, reporting, and recordkeeping requirements for NO_x, CO, nonmethane hydrocarbons (NMHC), and PM. Applicable NSPS Subpart III emission standards for the GREC emergency diesel generator and diesel-driven firewater pump CI ICEs are summarized as follows:

- Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in 40 CFR 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE. The GREC 757-hp emergency generator diesel engine will be required to meet the EPA Tier 2 emission limits for nonroad CI engines.
- Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in Table 4 to NSPS Subpart III, for all pollutants. The GREC 275-hp emergency firewater pump diesel engine will be required to meet the EPA Tier 3 emission limits for nonroad CI engines.

The GREC emergency generator and firewater pump diesel engines will comply with the applicable requirements of NSPS Subpart IIII.

4.2 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAPs)

The CAA Amendments of 1970 required EPA to identify and list all air pollutants (not already identified as criteria pollutants) that “may reasonably be anticipated to result in an increase in mortality or an increase in serious irreversible or incapacitating reversible illness.” For each pollutant identified, EPA was then required to promulgate NESHAPs at levels that would ensure the protection of the public health with an ample margin of safety and to prevent any significant and adverse environmental effects, which may reasonably be anticipated, on wildlife, aquatic life, or other natural resources. The approach used by EPA to promulgate NESHAPs was based primarily on health considerations with the objective of establishing numerical emission limits that would protect human health from any adverse effects. EPA found it difficult to establish these standards because of the uncertainty in assessing health risk. In the 20 years following enactment of the 1970 legislation, EPA identified only eight pollutants as HAPs and regulated sources of seven of them (asbestos, benzene, beryllium, inorganic arsenic, mercury, radionuclides, and vinyl chloride).

The passage of the 1990 CAA Amendments changed the approach to regulating HAPs to one based on available control technology rather than health effects. A list of 189 compounds was provided by the Congress to be controlled by EPA as HAPs. With the removal of caprolactam, the current list includes 188 compounds. Examples of listed air toxics include dioxin, asbestos, toluene, and metals such as cadmium, mercury, chromium, and lead compounds. The majority of the HAPs are VOCs.

In the first regulatory phase of the HAPs program, the CAA defines two types of emissions standards for promulgation: MACTs and generally available control technologies (GACTs). MACTs are emission standards that achieve “the maximum degree of reduction in emissions of the HAPs,” taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy

requirements. MACT is determined differently for new and existing sources of HAPs. For new sources, MACT is equivalent to the best-controlled similar source in a given industry. For existing sources, MACT represents the average emission limit achieved by the best performing 12 percent of the existing sources for which EPA has information. GACTs are less stringent emission standards based on the use of more standard technologies and work practices. In the second regulatory phase of the HAPs program, EPA is required to conduct an assessment of and report on the residual risk due to HAPs that is likely to remain after attainment of the MACT and GACT standards.

The provisions of the CAA that address the control of HAPs are found in Section 112. Section 112 of the CAA includes provisions for the promulgation of NESHAPs (i.e., MACT standards) as well as several related programs to enhance and support the NESHAPs program. Section 112 requires EPA to publish and regularly update (at least every 8 years) a listing of all categories and subcategories of major and area sources that emit HAPs. The Section 112(c) list of source categories was initially published in the Federal Register on July 16, 1992, and has been periodically revised thereafter. EPA must promulgate regulations NESHAPs for each category or subcategory of major sources and area sources of HAPs that are listed pursuant to Section 112(c). NESHAPs relevant to GREC are discussed in the following subsections.

4.2.1 NESHAPS SUBPART DDDDD—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS AND PROCESS HEATERS

NESHAPS Subpart DDDDD (commonly referred to as the boiler MACT) was promulgated by EPA on September 13, 2004. This NESHAPS contains emission limits for PM (or selected metals), hydrogen chloride, mercury, and CO applicable to new boilers and process heaters that commenced construction after January 13, 2003. Pursuant to 40 CFR 63.7491(c), Subpart DDDDD is not applicable to electric utility steam generating units. In addition, Subpart DDDDD was vacated by the District of Columbia (DC) Circuit Court of Appeals on June 18, 2007. This vacatur became final by a DC Circuit Court of Appeals mandate issued on July 30, 2007. Accordingly, NESHAPS Subpart DDDDD is not applicable to the GREC BFB boiler.

4.2.2 NESHAPS SUBPART ZZZZ—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES

NESHAPs Subpart ZZZZ is applicable to owners and operators of stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. The GREC emergency generator diesel engine qualifies as a *new* stationary RICE since construction of the engine will commence on or after December 19, 2002, and the engine has a site rating of more than 500 brake horsepower (bhp). The emergency firewater pump diesel engine will also qualify as a new stationary RICE since construction of the engine will commence on or after June 12, 2006, and the engine has a site rating equal to or less than 500 bhp.

In accordance with the provisions of 40 CFR 63.6590(b)(i), the GREC emergency generator diesel engine is not subject to the requirements of NESHAPs Subpart A (General Provisions) and Subpart ZZZZ since the engine is an *emergency* stationary RICE with a site rating of more than 500 bhp and will be located at a major HAP source. Emergency stationary RICE are RICE whose operation is limited to emergency situations and required testing and maintenance. Emergency stationary RICE with a site rating of more than 500 bhp located at a major source of HAP emissions that were installed on or after June 12, 2006, must comply with the following requirements specified in NSPS Subpart IIII 60.4243(d):

“Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. Emergency stationary ICE may operate up to 50 hours per year in nonemergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for nonemergency situations cannot be used for peak shaving or to generate income for a facility to supply

power to an electric grid or otherwise supply power as part of a financial arrangement with another entity. For owners and operators of emergency engines, any operation other than emergency operation, maintenance and testing, and operation in nonemergency situations for 50 hours per year, as permitted in this section, is prohibited.”

The GREC emergency firewater pump diesel engine will be a new stationary CI RICE located at a major HAP source with a site rating less than or equal to 500 bhp. For this category of RICE, Subpart ZZZZ 63.6590(c) requires compliance with the applicable requirements of NSPS Subpart IIII. There are no further NESHAPs Subpart ZZZZ requirements for this category of RICE.

The GREC emergency diesel engines will comply with applicable requirements of NESHAPs Subpart ZZZZ.

4.2.3 SECTION 112(G) CASE-BY-CASE MACT DETERMINATIONS

As previously noted, EPA must promulgate regulations establishing NESHAPs for each category or subcategory of major sources and area sources of HAPs that are listed pursuant to Section 112(c). The standards must require the maximum degree of emission reduction that EPA determines to be achievable by each particular source category.

Section 112(g) of the CAA requires a case-by-case MACT determination to ensure that emissions of toxic air pollutants do not increase if a facility is constructed or reconstructed before EPA issues a MACT or air toxics regulation for that particular category of sources or facilities. The 112(g) provision is essentially a transitional measure to ensure that facilities adequately protect the public from toxic air pollutants until EPA issues a MACT standard that applies to the facility in question.

On December 20, 2000, EPA added coal- and oil-fired electric utility steam generating units to the list of source categories to be regulated by MACT standards. On March 29, 2005, EPA reversed its earlier decision and issued a final agency action delisting electric utility steam generating units from the CAA Section 112(c) source category list. Instead of regulating electric utility steam generating unit HAP emissions under the NESHAPs

program, EPA decided to limit emissions of mercury (the only electric utility steam generating unit HAP considered by EPA to warrant regulation) from coal-fired units using the authority of the NSPS program; i.e., by NSPS Subpart Da. Accordingly, on May 18, 2005, EPA promulgated the Clean Air Mercury Rule (CAMR), which established mercury emission limits from coal-fired units under NSPS Subpart Da. However, on February 8, 2008, the DC Circuit Court of Appeals vacated CAMR and invalidated EPA's delisting of coal- and oil-fired electric utility steam generating units from the Section 112(c) source category list. To date, EPA has not proposed any MACT standards for the electric utility steam generating unit category.

As discussed previously, NESHAPs Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants: Industrial, Commercial, and Institutional Boilers and Process Heaters, was vacated by a DC Circuit Court of Appeals mandate issued on July 30, 2007.

Accordingly, there are presently no proposed or final MACT standards that apply to the GREC BFB boiler. Since GREC will be a major source of HAPs (i.e., will have potential HAP emissions of 10 tpy or more for any individual HAP, and 25 tpy or more for aggregate HAPs), GREC will be subject to a Section 112(g) case-by-case MACT review. Section 6.0 provides the analysis of MACT requirements for GREC emission sources.

4.3 ACID RAIN PROGRAM

The overall goal of the acid rain program (ARP) is to achieve significant environmental and public health benefits through reductions in emissions of SO₂ and NO_x, the primary causes of acid rain. To achieve this goal at the lowest cost to society, the program employs both traditional and innovative, market-based approaches for controlling air pollution. In addition, the program encourages energy efficiency and pollution prevention.

Title IV of the CAA sets a goal of reducing annual SO₂ emissions by 10 million tons below 1980 levels. To achieve these reductions, the law required a two-phase tightening of the restrictions placed on fossil fuel-fired power plants. Phase I began in 1995 and affected 263 units at 110 mostly coal-burning electric utility plants located in 21 eastern

and midwestern states. An additional 182 units joined Phase I of the program as substitution or compensating units, bringing the total of Phase I affected units to 445. Phase II, which began in the year 2000, tightened the annual emissions limits imposed on these large, higher emitting plants and also set restrictions on smaller, cleaner plants fired by coal, oil, and gas, encompassing more than 2,000 units in all. The program affects existing utility units serving generators with an output capacity of greater than 25 MW and all new utility units.

For SO₂, the ARP introduced an allowance trading system that harnesses the incentives of the free market to reduce pollution. Under this cap-and-trade program, affected existing utility units (i.e., those in operation prior to November 15, 1990) are allocated allowances based on their historical fuel consumption and a specific emission rate. Each allowance permits a unit to emit 1 ton of SO₂ during or after a specified year. For each ton of SO₂ emitted in a given year, one allowance is retired, that is, it can no longer be used. Allowances may be bought, sold, or banked. Anyone may acquire allowances and participate in the trading system. However, regardless of the number of allowances a source holds, it may not emit at levels that would violate federal or state limits set under Title I of the CAA to protect public health. During Phase II of the program (now in effect), the CAA set a permanent ceiling (or cap) of 8.95 million allowances for total annual SO₂ allowance allocations to utilities. This cap firmly restricts emissions and ensures that environmental benefits will be achieved and maintained. New utility units (i.e., those that commence operation on and after November 15, 1990) are not allocated any SO₂ allowances and must obtain such allowances annually from the ARP SO₂ allowance market in amounts equal to their actual SO₂ emission rates.

The CAA also required a 2-million-ton reduction in NO_x emissions by the year 2000. A significant portion of this reduction has been achieved by coal-fired utility boilers that will be required to install low NO_x burner technologies and to meet new emissions standards. The ARP NO_x emission reduction requirements are only applicable to existing utility units (i.e., those in operation prior to November 15, 1990).

The GREC BFB boiler will be subject to the ARP since it is a *new utility unit* (i.e., will commence operation after November 15, 1990) and will serve a generator that produces electricity for sale. As noted previously, new utility units do not receive any SO₂ allowance allocations. Accordingly, GREC will need to obtain SO₂ allowances annually from the ARP SO₂ allowance market in amounts equal to the BFB boiler's actual SO₂ emission rates. The NO_x component of the ARP does not apply to new utility units.

4.4 CLEAN AIR INTERSTATE RULE

On March 10, 2005, EPA issued the final Clean Air Interstate Rule (CAIR). The objective of CAIR is to assist states with PM_{2.5} and 8-hour ozone nonattainment areas to achieve attainment by reducing precursor emissions at sources located in 28 states (including Florida) situated upwind of these nonattainment areas. Based on regional dispersion modeling, EPA determined that these 28 upwind states significantly contribute to PM_{2.5} and 8-hour ozone nonattainment in downwind areas. Florida emission sources are projected to significantly contribute to PM_{2.5} nonattainment areas located in Georgia (Macon and Atlanta) and Alabama (Birmingham) and to an 8-hour ozone nonattainment area in Georgia (Atlanta).

The CAIR reductions of precursor emissions address annual SO₂ and NO_x emissions (for reductions in annual and daily average ambient PM_{2.5} impacts) and ozone season (May through September) NO_x emissions (for reductions in 8-hour average ambient ozone impacts). The SO₂ and NO_x reductions will be implemented by means of a regional two-phase cap-and-trade program. For SO₂, the first cap begins in calendar year 2010 and extends through 2014. For NO_x, the first cap begins in calendar year 2009 and also extends through 2014. The second phase cap for both pollutants becomes effective in calendar year 2015 and thereafter. The SO₂ caps will reduce current ARP SO₂ emissions by 50 percent in Phase I and by 65 percent in Phase II. The NO_x caps reflect NO_x emission rates of 0.15 and 0.125 lb/MMBtu for the first and second phase caps, respectively.

For each phase cap, CAIR assigns SO₂ and NO_x emission budgets (in units of tpy) and in units of tons per ozone season) to each affected upwind state. These state emission budgets were developed by EPA based on the application of cost-effective control technologies (i.e.,

FGD) for SO₂ and SCR for NO_x. The affected states were required to submit revised SIPs within 18 months (i.e., by September 11, 2006) for EPA review and approval. Florida's proposed SIP revisions implementing CAIR were submitted to EPA Region 4 on March 16, 2007, for review and approval in accordance with EPA's abbreviated SIP approval process. The submitted SIP revisions provided details as to the procedures that will be used by Florida to allocate the state's NO_x and SO₂ budgets to individual sources. Florida's revised SIP incorporating the CAIR requirements was approved by EPA on October 12, 2007.

Following allocation of the state SO₂ and NO_x budgets to individual emission sources, emission units at these sources must possess sufficient SO₂ and NO_x allowances such that actual emissions (as measured by CEMS) do not exceed the allocations for each control period beginning in 2009 (for NO_x) and 2010 (for SO₂). Sources that have actual emissions in excess of their allocation will need to reduce actual emission rates or purchase additional allowances on the open market. Emission sources that have surplus allowances may bank the allowances for use in any future control period or sell the surplus allowances on the open market.

Petitions for review of the CAIR and CAIR federal implementation plans (FIPs), including their provisions establishing the CAIR NO_x annual and ozone season and SO₂ trading programs, were filed with the U.S. Court of Appeals for the DC Circuit. On July 11, 2008, the Court issued an opinion vacating and remanding these rules; however, parties to the litigation requested rehearing of aspects of the Court's decision, including the vacatur of the rules. On December 23, 2008, the Court granted rehearing only to the extent that it remanded the rules to EPA without vacating them. The December 23, 2008, Court ruling leaves CAIR and the CAIR FIPs, including the CAIR trading programs, in place until EPA issues a new rule to replace CAIR in accordance with the July 11, 2008, decision. EPA informed the Court that development and finalization of a replacement rule could take approximately 2 years.

Florida has adopted EPA's 40 CFR 96 CAIR NO_x and SO₂ trading programs for SIPs by reference in Section 62-204.800, F.A.C. Florida's implementation of the Federal CAIR is set forth at Section 62-296.470, F.A.C.

EPA's model NO_x trading program includes provisions for allocating NO_x allowances to new utility units (those that are placed in service in 2001 or later) such as the GREC BFB boiler (i.e., a new source set-aside). Similar to the ARP, there are no provisions for a new source set-aside with respect to CAIR SO₂ allowances. For NO_x allowances, new units will be allocated allowances from the new source set-aside until they have established a baseline and are included in the shared pool. NO_x allowance allocations from the new source set-aside pool will be made to new utility units on a pro-rata basis.

4.5 FLORIDA EMISSION STANDARDS

FDEP emission standards for stationary sources are contained in Chapter 62-296, Stationary Sources—Emission Standards, F.A.C. General pollutant emission limit standards are included in Section 62-296.320, F.A.C. Sections 62-296.401 through 62-296.417, F.A.C., specify emission standards for 17 categories of sources. Sections 62-296.470 and 62-296.480 address CAIR and CAMR requirements, respectively. Sections 62-296.500 through 62-296.570, F.A.C., establish reasonably available control technology (RACT) requirements for VOC and NO_x emitting facilities. RACT requirements for lead and PM are found in Sections 62-296.600 through 62-296.605 and 62-296.700 through 62-296.712, F.A.C., respectively. FDEP emission standards applicable to GREC are discussed in the following sections.

4.5.1 SECTION 62-296.320—GENERAL POLLUTANT EMISSION LIMITING STANDARDS

General Rule 62-296.320 (2), F.A.C. (Objectionable Odor Prohibited), will apply to all GREC emission sources and activities. The general Rule 62-296.320(4)(b), F.A.C. (General Particulate Emission Limiting Standards), visible emission limitation of 20-percent opacity will apply to all GREC point (i.e., stack) emission sources. Reasonable precautions to prevent unconfined PM emissions (e.g., biomass storage piles) will be required pursuant to Rule 62-296.320(4)(c), F.A.C. (Unconfined Emissions of Particulate Matter).

4.5.2 SECTION 62-296.405—FOSSIL FUEL STEAM GENERATORS WITH MORE THAN 250 MMBTU/HR HEAT INPUT

Rule 62-296.405(2), F.A.C., (New Emission Units) will apply to the GREC BFB boiler since the boiler will be capable of combusting more than 250 MMBtu/hr heat input of natural gas during startup, shutdown, and malfunction events. This section requires compliance with applicable NSPS requirements for visible, PM, SO₂, and NO_x emissions (e.g., NSPS Subpart Da).

4.5.3 SECTION 62-296.410—CARBONACEOUS FUEL BURNING EQUIPMENT

For new emission units with a heat input greater than 30 MMBtu/hr, Rule 62-296.410(2), F.A.C. (New Emission Units), limits PM emissions to 0.2 lb/MMBtu for carbonaceous fuels plus 0.1 lb/MMBtu for fossil fuels. Visible emissions are limited to 30-percent opacity, except that 40-percent opacity is permissible for not more than 2 minutes in any 1 hour.

GREC will comply with all of the applicable FDEP emission standards discussed above. None of the remaining emission standards specified in Sections 62-296.401 through 62-296.417, F.A.C., are applicable to GREC. GREC will also comply with the applicable requirements of Section 62-296.470, F.A.C., Implementation of Federal CAIR. The VOC, NO_x, lead, and PM RACT requirements of Sections 62-296.500 through 62-296.570, F.A.C., Sections 62-296.600 through 62-296.605, and 62-296.700 through 62-296.712 do not apply to emission units that are subject to NSR permitting and therefore are not applicable to GREC.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY

5.1 METHODOLOGY

BACT analyses were performed in accordance with the EPA top-down method. As previously described in Section 3.4.1, the top-down methodology consists of the following five steps:

- Step 1—Identify all available control technologies for each PSD pollutant subject to review.
- Step 2—Eliminate all technically infeasible control technologies.
- Step 3—Rank the remaining control technologies by control effectiveness.
- Step 4—Evaluate the feasible control technologies, beginning with the most efficient, with respect to economic, energy, and environmental impacts.
- Step 5—Select as BACT the most effective control technology that is not rejected based on adverse economic, environmental, and/or energy impacts.

The first step in the top-down BACT procedure is the identification of all available control technologies. Alternatives considered included process designs and operating practices that reduce the formation of emissions, postprocess stack controls that reduce emissions after they are formed, and combinations of these two control categories. Sources of information used to identify control alternatives included:

- EPA reasonably available control technology (**RACT**)/**BACT**/lowest achievable emission rate (**LAER**) Clearinghouse (**RBLC**) via the RBLC Information system database.
- Recent permits for biomass-fired power projects.
- FDEP BACT determinations for similar facilities.
- Environmental Consulting & Technology, Inc.'s (ECT's) experience for similar projects.

Following the identification of available control technologies, the next step in the analysis is to determine which technologies may be technically infeasible. Technical feasibility was evaluated using the criteria contained in Chapter B of the EPA NSR Workshop Ma-

nual (EPA, 1990a). The third step in the top-down BACT process is the ranking of the remaining technically feasible control technologies from high to low in order of control effectiveness.

If the top-case control technology with the highest removal efficiency is selected as BACT, an assessment of collateral environmental impacts is conducted to determine whether such impacts would deem the control technology unacceptable. If the most efficient control technology is not selected as BACT, an assessment of energy, environmental, and economic impacts is then performed. If assessed, the economic analysis employed the procedures found in the Office of Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual, Sixth Edition (EPA, 2002).

The fifth and final step is the selection of a BACT emission limitation corresponding to the most stringent, technically feasible control technology that was not eliminated based on adverse energy, environmental, or economic grounds.

As defined by Rule 62-210.200(40), F.A.C., BACT emission limitations must be no less stringent than any applicable NSPS (40 CFR 60), NESHAPs (40 CFR 61 and 63), and FDEP emission standards (Chapter 62-296, Stationary Sources—Emission Standards, F.A.C.). The NSPS, NESHAPs, and Florida emission standards applicable to GREC were previously discussed in Sections 4.1, 4.2, and 4.5, respectively. All of the BACT emission limitations proposed for GREC are more stringent than the applicable federal and state standards cited in these sections.

As shown in Table 3-2 of Section 3.3, annual GREC emissions of NO_x, SO₂, CO, VOC, and PM/PM₁₀ are projected to exceed the PSD significance rates for these pollutants. A BACT analysis is therefore required for each GREC emission source that will emit these pollutants. Accordingly, BACT analyses were conducted for the following GREC emission sources:

- BFB boiler.
- Emergency firewater pump and generator diesel engines.

- Mechanical draft cooling tower.
- Biomass fuel and material (fly ash and DSI sorbent) storage and handling systems.

The BFB boiler and emergency diesel engines will emit pollutants associated with fuel combustion including NO_x, SO₂, CO, VOC, and PM/PM₁₀. BACT analyses were therefore conducted for each of these combustion-related PSD pollutants for the BFB boiler and emergency diesel engines. The mechanical draft cooling tower and material storage and handling systems will only emit PM/PM₁₀. The BACT analysis for these GREC emission sources was therefore confined to PM/PM₁₀.

The principal GREC emission source is the BFB boiler. Emissions from the BFB boiler comprise approximately 95 percent of total estimated GREC project annual emissions. Accordingly, the primary emphasis of the BACT analysis conducted for GREC was directed to the BFB boiler. The BFB boiler will be equipped with a comprehensive state-of-the-art emission control system that includes the inherent emission reduction benefits of the bubbling fluidized bed process, DSI for acid gas control, fabric filter for PM/PM₁₀ control, and a SCR system for NO_x control.

Control technology analyses using the five-step top-down BACT method are provided for in Section 5.3 (NO_x), Section 5.4 (SO₂), Section 5.5 (CO and VOC), and Section 5.6 (PM/PM₁₀). CO and VOC are addressed in one section since these pollutants have a common origin (i.e., both are products of incomplete fuel combustion) and similar available control technologies.

5.2 BACT ANALYSIS FOR STARTUP AND SHUTDOWN EVENTS

GREC will be a base load unit with an estimated capacity factor of 90 percent. The frequency of unit startups and shutdowns will therefore be low. Each unit startup will also be preceded by a period of time when the unit is offline, during which there will be no emissions from the BFB boiler. Startups and shutdowns of the BFB boiler will be conducted using best operational practices to minimize emissions and have a duration consis-

tent with process and safety considerations. The fabric filter will be used at all times, i.e. during startup and shutdown. However, the DSI and SCR control systems cannot be placed in service until the boiler flue gas conditions reach specific criteria for each control system. Excess emissions associated with startup and shutdown events were previously discussed in Section 2.5.

5.3 EVALUATION OF ALTERNATIVE ELECTRICAL GENERATION TECHNOLOGIES

As discussed in Section 5.1, the first step in a BACT determination process is to identify all available control technologies that could potentially be used to minimize the emissions for the pollutant under evaluation. Control technologies typically considered in a BACT analysis include process modifications that reduce the formation of pollutants and postprocess emission control systems that reduce emissions after the pollutants are formed. An example of the former is the use of staged combustion to alter the combustion process and reduce the formation of NO_x. The use of SCR to reduce NO_x following its formation in the combustion process is an example of a postprocess emission control system. These types of control technologies, when applicable, are appropriately considered in a BACT analysis.

Evaluation of process alternatives that would involve completely redefining the design of the proposed process are not required to be considered (reference the 1990 Draft NSR Workshop Manual, Section IV.A.3). Alternative electrical generating processes, such as natural gas-fired, coal-fired, or IGCC plants, represent completely different power generation plant designs compared to the biomass-fired BFB combustion technology selected for GREC. While all electrical generation technologies generate electricity, the technical basis for the BFB combustion technology is substantially different from a natural gas-fired, coal-fired, or IGCC plant. Since a natural gas-fired, coal-fired, or IGCC electrical generating plant represents a completely different process compared to biomass-fired BFB combustion technology, a BACT analysis of these alternative electrical generation technologies is not required because these process alternatives would redefine the design of GREC.

5.4 BACT ANALYSIS FOR NO_x

5.4.1 BUBBLING FLUIDIZED BED (BFB) BOILER

NO_x emissions from combustion sources consist of two components: oxidation of atmospheric nitrogen contained in the combustion air (thermal NO_x and prompt NO_x) and conversion of chemically bound fuel nitrogen (fuel NO_x). Thermal NO_x results when atmospheric nitrogen is oxidized at the high temperatures occurring in the boiler firebox to yield nitric oxide (NO), NO₂, and other oxides of nitrogen. Most thermal NO_x is formed in high-temperature areas where combustion air has mixed sufficiently with the fuel to produce a peak temperature. The rate of formation of thermal NO_x is a function of residence time and free oxygen and varies exponentially with peak flame temperature. Prompt NO_x forms within the combustion flame and is usually negligible when compared to the amount of thermal NO_x formed. Fuel-related NO_x is formed from oxidation of chemically bound nitrogen present in the fuel. Most boiler NO_x emissions originate as NO. NO generated by the combustion process is subsequently further oxidized downstream of the combustion zone or in the atmosphere to the more stable NO₂ molecule.

5.4.1.1 Available NO_x Control Technologies

Available technologies for controlling NO_x emissions from BFB boilers include combustion process modifications and postcombustion exhaust gas treatment systems. Available combustion process modifications include staged combustion using overfire air (OFA), natural gas reburn (NGR), and FGR. Available postcombustion controls include selective noncatalytic reduction (SNCR), EMx™ (formerly SCONOx™), and SCR. A description of each of these control technologies is provided in the following subsections.

Staged Combustion

Staged combustion is the process of partially delaying the combustion process for the purpose of more complete combustion and lower NO_x emissions. BFB boilers reduce NO_x by completing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame and results in one or more of the following conditions: (a) reduced oxygen in the primary flame zone; (b) reduced flame tempera-

ture; and (c) reduced residence time at peak temperature. The lower oxygen levels, flame temperatures, and residence times will suppress the formation of thermal NO_x . NO_x emission reductions of 30 to 50 percent have been achieved with staged combustion.

OFA is a form of staged combustion. In the primary combustion zone, combustion air is diverted from the BFB creating a fuel-rich zone in the lower section of the boiler. This oxygen-deficient zone decreases the conversion of fuel-bound nitrogen to NO_x . Additional combustion air is injected above the primary combustion zone to complete the combustion process. The resulting reduction in temperature decreases the production of thermal NO_x .

Natural Gas Reburn

NGR is a process that diverts some of the heat input from the main boiler combustion zone to an area above the main boiler burners. This diversion creates a secondary *reburn* combustion zone. Natural gas is injected in the reburn zone producing a slightly fuel-rich section. OFA is then added above the reburn zone to complete the combustion process. As NO_x formed in the main combustion zone is reduced by hydrocarbon fragments (free radicals) due to the combustion of natural gas in the reburn zone, it is converted to molecular nitrogen.

Flue Gas Recirculation

FGR recirculates boiler exhaust gas from the boiler outlet to the furnace, where it is reintroduced into the combustion process. Fuel/air mixing in the combustion region is increased by the recirculated flue gas during the early stages of combustion. This increased mixing results in a higher fuel/air ratio, and reduction in peak flame temperatures results in lower thermal NO_x formation. The amount of NO_x reduction is dependent upon the burner and furnace design. FGR has been demonstrated as a technically feasible technology on biomass-fired boilers.

Selective Non-Catalytic Reduction

The SNCR process involves the gas phase reaction, in the absence of a catalyst, of NO_x in the exhaust gas stream with injected ammonia (NH₃) or urea to yield nitrogen and water vapor. The two commercial applications of SNCR include the Electric Power Research Institute's (EPRI's) NO_xOUT and Exxon's Thermal DeNO_x processes. The two processes are similar in that either ammonia (Thermal DeNO_x) or urea (NO_xOUT) is injected into a hot exhaust gas stream at a location specifically chosen to achieve the optimum reaction temperature and residence time. Simplified chemical reactions for the Thermal DeNO_x process are as follows:



The NO_xOUT process is similar with the exception that urea is used in place of ammonia.

The critical design parameter for both SNCR processes is the reaction temperature. At temperatures below 1,600°F, rates for both reactions decrease allowing unreacted ammonia to exit with the exhaust stream. Temperatures between 1,600 and 2,000°F will favor Equation (1) resulting in a reduction in NO_x emissions. Equation (2) will dominate at temperatures above approximately 2,000°F, causing an increase in NO_x emissions. Due to reaction temperature considerations, the SNCR injection system must be located at a point in the exhaust duct where temperatures are consistently between 1,600 and 2,000°F.

Since Equations (1) and (2) are theoretical, some of the injected ammonia will not react completely to form nitrogen and water. This unreacted ammonia will be emitted into the atmosphere as ammonia slip. Excess ammonia in the atmosphere may produce ammonium salts and further develop into PM_{2.5} or PM₁₀ particles. The amount of ammonia slip emitted will depend on three factors: (1) the extent of mixing of the injected ammonia and fuel combustion products; (2) temperature in the mixing zone; and (3) residence time. Therefore, ammonia slip formation is related to the physical characteristics of the boiler and achievable NO_x control efficiency. SNCR typically achieves NO_x control efficiencies of 40 to 60 percent.

Selective Catalytic Reduction

In contrast to SNCR, SCR reduces NO_x emissions by reacting ammonia with exhaust gas NO_x to yield nitrogen and water vapor in the presence of a catalyst. Ammonia is injected upstream of the catalyst bed where the following primary reactions take place:



The catalyst serves to lower the activation energy of these reactions, which allows the NO_x conversions to take place at a lower temperature (i.e., in the range of 600 to 750°F). Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the volume of the catalyst bed), ammonia/NO_x molar ratio, catalyst reactivity, catalyst age, and catalyst bed temperature. Space velocity is a function of catalyst bed depth. Decreasing the space velocity (increasing catalyst bed depth) will improve NO_x removal efficiency by increasing residence time but will also cause an increase in catalyst bed pressure drop. The reaction of NO_x with ammonia theoretically requires a 1:1 molar ratio. Ammonia/NO_x molar ratios greater than 1:1 are necessary to achieve high-NO_x removal efficiencies due to imperfect mixing and other reaction limitations. However, ammonia/NO_x molar ratios are typically maintained at 1:1 or lower to prevent excessive ammonia slip emissions.

As is the case for SNCR, reaction temperature is critical for proper SCR operation. The optimum temperature range for SCR operation is dependent on the type of catalyst used. The two main groups of catalyst are base metal (vanadium-platinum or –titanium) and zeolite. The optimum temperature range for a vanadium-platinum catalyst is less than 500°F while the optimum temperature range for a vanadium-titanium catalyst is to 550 to 800°F. The zeolite catalyst is used for higher temperature applications and can operate effectively at temperatures as high as 1,000°F. At temperatures below the optimum range

for the specified catalyst, reduction Equations (3) and (4) will not proceed. At temperatures exceeding the optimal range, oxidation of ammonia will take place resulting in an increase in NO_x emissions.

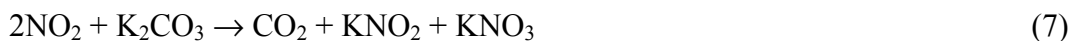
SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principle poisons include arsenic, sulfur, potassium, sodium, and calcium. The catalyst life does not include this potential for degradation that could cause early replacement of the catalyst.

Ammonia slip becomes a greater issue as the catalyst degrades because of the increased amount of ammonia injected to achieve the appropriate NO_x control. Vendors typically can provide SCR systems that have the ability to limit the concentration of ammonia slip to 10 parts per million by dry volume (ppmvd) throughout the life of the catalyst. SCR systems typically achieve NO_x control efficiencies of 70 to 80 percent.

EMx™ (SCONO_x™)

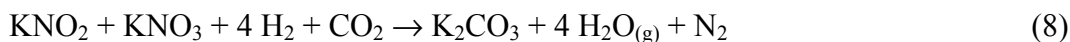
EMx™ (formerly referred to as SCONO_x™) is a multipollutant reduction catalytic control system offered by EmeraChem. EMx™ is a complex technology that is designed to simultaneously reduce NO_x, VOC, and CO through a series of oxidation/absorption catalytic reactions.

The EMx™ system employs a single catalyst to simultaneously oxidize CO to CO₂ and NO to NO₂. NO₂ formed by the oxidation of NO is subsequently absorbed onto the catalyst surface through the use of a potassium carbonate absorber coating. The EMx™ oxidation/absorption cycle reactions are:



CO₂ produced by Equations (5) and (7) is released to the atmosphere as part of the exhaust stream.

As shown in Equation (7), the potassium carbonate catalyst coating reacts with NO₂ to form potassium nitrites and nitrates. Prior to saturation of the potassium carbonate coating, the catalyst must be regenerated. This regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of oxygen. Hydrogen in the reducing gas reacts with the nitrites and nitrates to form water and elemental nitrogen. CO₂ in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate; this compound is the catalyst absorber coating present on the surface of the catalyst at the start of the oxidation/absorption cycle. The EMx™ regeneration cycle reaction is:



Water vapor and elemental nitrogen are released to the atmosphere as part of the exhaust stream. Following regeneration, the EMx™ catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again. There is no net gain or loss of potassium carbonate after both the oxidation/absorption and regeneration cycles have been completed.

The EMx™ operates at a temperature range of 300 to 700°F and, therefore, must be installed in an appropriate temperature section of the exhaust stream. For installations above 450°F, the EMx™ catalyst is regenerated by introducing a small quantity of natural gas with a carrier gas, such as steam, over a steam reforming catalyst and then to the EMx™ catalyst. The reforming catalyst initiates the conversion of methane to hydrogen, and the conversion is completed over the EMx™ catalyst. The reformer catalyst works to partially reform the methane gas to hydrogen (2 percent by volume) to be used in the regeneration of the EMx™ catalysts. The reformer converts methane to hydrogen by the steam reforming reaction as shown by the following equation:



The reformer catalyst is placed upstream of the EMx™ catalyst in a steam reformer reactor. The reformer catalyst is designed for a minimum 50-percent conversion of methane to hydrogen.

The EMx™ system has not been installed on any biomass combustion process and there are no current plans to install the EMx™ system on any biomass combustion process. Accordingly, EMx™ technology has never been demonstrated and therefore is not considered technically feasible for GREC.

5.4.1.2 Technical Feasibility and Ranking

The staged combustion process modifications described previously are technically feasible with the exception of NGR. NGR has not been demonstrated on a biomass-fired BFB boiler and, therefore, is not considered feasible for the GREC BFB boiler. Staged combustion is integral to the design of BFB technology.

Of the available postcombustion control technologies, both SNCR and SCR are feasible. The EMx™ technology has not been demonstrated on biomass-fired boilers and therefore is not considered technically feasible.

Table 5-1 provides a summary of the technical feasibility and ranking of the available NO_x control technologies. As shown, SCR in combination with staged combustion offers the highest control efficiency.

5.4.1.3 Evaluation of Control Technologies

GREC proposes to install the NO_x control technologies identified as having the highest control efficiency—staged combustion (integral to BFB technology), FGR, and SCR. Peak flame temperatures will increase when lower moisture content biomass fuels are combusted and during partial load boiler operations. During these periods, FGR will be employed to lower the peak flame temperatures. BFB technology includes several combustion design features that will inherently reduce the formation of NO_x including:

Table 5-1. Ranking of Available NO_x Control Technologies—BFB Boiler

Control Technology	Technically Feasible (Yes/No)	Control Efficiency Range (%)
Staged combustion, FGR, SCR	Yes	80 to 90
SCR	Yes	70 to 90
SNCR	Yes	40 to 60
FGR	Yes	40 to 60
Staged combustion	Yes	30 to 50
NGR	No	Not applicable

Source: ECT, 2009.

- Operation of the bed in a reducing atmosphere of approximately 30 to 40 percent of theoretical air requirements (i.e., substoichiometric combustion), which reduces the bed temperature. Bed temperature is controlled within a temperature range of approximately 1,350 to 1,700°F, which minimizes the formation of thermal NO_x.
- Combustion staging (i.e., use of OFA) to reduce peak bed combustion temperatures and formation of thermal NO_x.
- Large mass of bed material and fluidization achieves high combustion efficiency (approximately 99 percent) and stable combustion to minimize emissions, including potential excess emissions due to a change in fuel characteristics.

The economic and energy impacts associated with the installation and operation of this combination of control technologies are considered reasonable. There are also no significant collateral environmental issues that would justify rejection of these control technologies as BACT.

5.4.1.4 Proposed NO_x BACT

Table 5-2 provides a summary of biomass-fired utility and industrial size boiler (greater than 250 MMBtu/hr) NO_x BACT and LAER determinations for the past 5 years. The proposed GREC BFB boiler NO_x emission limit of 0.070 lb/MMBtu is equal to the two most recent draft LAER determinations, i.e. Concord Steam Corporation and Clean Power Berlin, LLC, which were updated on June 16, 2009, and October 26, 2009, respectively. Since LAER does not take into account economic factors, LAER is more stringent than BACT. Both of these draft LAER determinations were based on using SCR and staged combustion. Therefore, GREC LLC proposes a NO_x emission rate of 0.070 lb/MMBtu on a 30-day rolling average basis. NO_x BACT proposed for the BFB boiler is summarized as follows:

- Emission Limit—0.070 lb/MMBtu.
- Averaging Period—30-day rolling average.

Table 5.2. Summary of Biomass-Fired Power Plant NO_x BACT/LAER Determinations

RBLC ID	Facility Name	Permit Dates		Process Description	Fuel	Throughput	Control Description	Emission Limit	Basis
		Issuance	Update						
*NH-0016	Clean Power Berlin LLC	09/25/09	10/26/09	Boiler 1	Wood chips	40.75 ton/hr wood	SCR with staged combustion	0.065 lb/MMBtu	LAER
*NH-0015	Concord Steam Corporation	02/27/09	06/16/09	Boiler #1	Biomass	32.62 tons/hr	SCR system	0.065 lb/MMBtu	LAER
WA-0329	Darrington Energy Cogeneration Power Plant	02/11/05	07/05/06	Wood waste-fired boiler	Wood waste	403 MMBtu/hr	SNCR	0.12 lb/MMBtu	BACT-PSD
MN-0074	Koda Energy	08/23/07	01/26/09	Biomass boiler 4			SNCR	0.18 lb/MMBtu	BACT-PSD
WA-0335	Simpson Tacoma Kraft Company, LLC	05/22/07	08/21/07	Utility and large industrial sized boilers/furnaces	Wood waste	595 MMBtu/hr	Proper combustion controls with OFA	0.2 lb/MMBtu	BACT-PSD
ND-0022	Northern Sun	05/01/06	02/13/07	Wood/hull fired boiler	Biomass		Combustion controls	0.2 LB/MM BTU	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Heat energy systems for pellet processing	Wood/woodpaste	77 MMBtu/hr	Thermal oxidizers and CEMS	0.22 lb/MMBtu	BACT-PSD
MN-0074	Koda Energy	08/23/07	01/26/09	Biomass boiler 3			SNCR	0.25 lb/MMBtu	BACT-PSD
WA-0337	Boise White Paper LLC	02/01/06	08/21/07	Utility-and large industrial-size boilers/furnaces (greater than 250 MMBtu/hr)	Wood/bark	343 MMBtu/hr	OFA system added to improve boiler combustion system; boiler has an ESP	0.3 lb/MMBtu	Other
FL-0301	Clewiston Sugar Mill and Refinery	12/06/07	12/15/08	Boiler 7 industrial sugar mill boiler firing bagasse	Bagasse	738 MMBtu/hr	Boiler design and operation (includes OFA system)	0.31 lb/MMBtu	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Wood thermal oxidizers for wood pellant process	Wood/wood paste	43 MMBtu/hr	Thermal oxidizers and CEMS	18.9 lb/hr	BACT-PSD
OH-0307	South Point Biomass Generation	04/04/06	08/16/07	Wood fired boilers (7)	Wood	318 MMBtu/hr	SCR	27.98 lb/hr	BACT-PSD
WA-0327	Skagit County Lumber Mill	01/25/06	06/11/09	Wood-fired cogeneration unit	Bark & waste wood	430 MMBtu/hr	SNCR	56 lb/hr	BACT-PSD
LA-0188	Bogalusa Mill	11/23/04	06/02/06	No. 12 hogged fuel boiler	Bark	787.5 MMBtu/hr	Existing OFA system with low NO _x burners in the under grate air heater system, plus good combustion practices	351.38 lb/hr	BACT-PSD

Source: ECT, 2009.

- Compliance Method—Continuous emissions monitoring in accordance with 40 CFR 75.

Table 5-3 provides a summary of the preliminary BFB boiler SCR design criteria.

5.4.2 EMERGENCY DIESEL ENGINES

GREC will include a diesel engine-driven emergency generator rated at 500 kW and a diesel engine-driven emergency firewater pump. The design power output ratings for the emergency generator and firewater pump diesel engines are 757 and 275 bhp, respectively. Excluding emergencies, each diesel engine will operate no more than 96 hr/yr for routine testing and maintenance purposes. This limit is less than the 100-hr/yr requirement for emergency engines as specified in NSPS Subpart IIII. Potential emissions for each diesel engine are based on each engine operating 500 hr/yr. Potential NO_x emission rates for the emergency generator and firewater pump diesel engines are 1.4 and 0.3 tpy, respectively.

The emergency diesel engines will be subject to the applicable emission standards of NSPS Subpart IIII for stationary compression ignition ICEs. Subpart IIII limits the combination of NO_x and NMHC emissions to 6.4 grams per kilowatt-hour (g/kWh) for a 2007 model year or later emergency generator diesel engines with an output greater than 750 bhp. For 2009 and later model year emergency firewater pump diesel engines between 175 and 300 bph, Subpart IIII limits the combination of NO_x and NMHC emissions to 4.0 g/kWh. Both of the emergency diesel engines purchased for GREC will comply with the applicable emission standards of NSPS Subpart IIII.

Compliance with the stringent NSPS Subpart IIII emission standards and limited annual operating hours are proposed as NO_x BACT for the GREC emergency generator and firewater pump diesel engines. NO_x BACT proposed for the GREC emergency diesel engines is summarized as follows:

Table 5-3. Preliminary SCR Design Criteria

Parameter	Unit	Estimated Design Value	Notes
Catalytic reaction temperature	°F	460 to 575	Alternate lower temperature may be considered
Inlet gas temperature	°F	460 to 550	Alternate lower temperature may be considered
Inlet gas flow rate	lb/hr	1,463,200	
Reducing agent		Aqueous ammonia	
Ammonia feed rate	lb/hr	350	
NO _x inlet concentration	ppmvd at 7-percent oxygen	92 (0.15 lb/MMBtu)	
NO _x outlet concentration	ppmvd at 7-percent oxygen	43 (0.07 lb/MMBtu)	
NO _x control efficiency	%	53	
Ammonia slip	ppmvd at 7-percent oxygen	10 ppm	
Catalyst life	Years	2 to 3	

Source: GREC, 2009.

- Emission Limit—Applicable standards of NSPS Subpart IIII.
- Averaging Period—Per NSPS Subpart IIII.
- Compliance Method—Engine manufacturer certification in accordance with NSPS Subpart IIII.
- Annual Operating Hours—96 hr/yr (excluding emergencies).
- Averaging Period—Calendar year.
- Compliance Method—Monitoring of operating hours using engine run-time meters

5.5 BACT ANALYSIS FOR SO₂

5.5.1 BUBBLING FLUIDIZED BED BOILER

Emissions of sulfur oxides from BFB boilers result from the oxidation of sulfur present in the fuel. Sulfur oxides formed during combustion are primarily SO₂, with minor amounts of sulfur trioxide (SO₃) and gaseous sulfates. These sulfur compounds form as the sulfur contained in the fuel is oxidized during the combustion process. Uncontrolled sulfur oxide emissions from biomass-fired boilers vary directly with the sulfur content. Due to the naturally occurring alkaline (i.e., calcium) content of woody biomass fuel, a significant portion of the SO₂ will react within the bed to form calcium sulfate compounds.

5.5.1.1 Available SO₂ Control Technologies

Available control technologies for reducing SO₂ emissions from BFB boilers include the inherent benefits of the BFB boiler, and use of postcombustion wet and dry flue gas desulfurization (FGD).

BFB Boiler

The BFB boiler itself provides inherent SO₂ control through the efficient mixing of the bed materials (i.e., sand and biomass fuel) and the boiler combustion gases. The wood fuel not only contains sulfur which converts to SO₂ during the combustion process, but also contains calcium. In the BFB, calcium oxides will react with the SO₂ to form calcium sulfate compounds and will be removed from the boiler as fly ash.

Wet FGD

Wet FGD systems remove SO₂ from exhaust streams by using an alkaline reagent to form sulfite and sulfate salts. Wet FGD systems typically involve the reaction of limestone and exhaust gas sulfur oxides in a spray absorber tower. Boiler exhaust gas enters at the bottom of the absorber tower, flows vertically through the limestone/water spray, passes through a mist eliminator to remove reentrained limestone slurry droplets, and then exits the tower. Ground limestone in the scrubbing slurry reacts with SO₂ in the flue gas to form calcium sulfite and calcium sulfate (i.e., gypsum). The calcium sulfite to calcium sulfate reaction is a result of oxidation, which can be inhibited or forced (i.e., by blowing compressed air into the slurry in the retention tank in the base of the tower or in an external oxidation tank) depending on the desired byproduct.

Wet FGD systems will generate wastewater and wet sludge streams requiring treatment and disposal. Gypsum slurry from the reaction tank is typically treated in a series of hydroclones. Reclaimed water from the hydroclones will be returned to the scrubber system, and gypsum solids will be sent to a vacuum filtration system. Gypsum solids from the vacuum filter system may be washed to remove contaminants and then loaded into railcars or trucks for shipment as a byproduct or mixed with fly ash, if necessary, and conveyed to a landfill.

Other wet FGD technologies include the use of lime, magnesium enhanced lime (MEL), and dual-alkali reagents and alternative scrubbing equipment such as the Chiyoda jet bubbling reactor (JBR). These wet FGD technologies achieve comparable or lower SO₂ removal efficiencies compared to the previously described limestone-forced oxidation (LSFO) wet FGD technology. Each of these wet FGD technologies is briefly described in the following paragraphs.

Lime Wet FGD

Lime wet FGD technology is similar to that described previously for limestone with hydrated lime used as the alkaline reagent instead of limestone. The primary advantage of limestone versus lime as the wet FGD reagent is the significantly lower cost of limestone.

MEL Wet FGD

In the MEL process, slaked lime containing calcium hydroxide and magnesium hydroxide is used to react with SO₂. The slurry is added to a recycle tank at the bottom of the absorber under pH control to replenish the reagent that is consumed. Calcium hydroxide in the slurry reacts with most of the SO₂ to precipitate calcium sulfite. Magnesium hydroxide reacts with the remainder of the SO₂ to form soluble magnesium salts, magnesium sulfite, and magnesium bisulfite. These soluble magnesium salts increase SO₂ capture and allow reduction in power consumption and equipment costs. Magnesium sulfite is replenished by addition of fresh lime slurry to the reaction tank.

MEL scrubber systems can achieve 98-percent SO₂ removal efficiency using absorber towers significantly smaller than limestone reagent systems. The presence of magnesium effectively increases the dissolved alkalinity and makes removal less dependent on lime dissolution. For the same removal efficiency, limestone based systems require a higher liquid-to-gas ratio. The selection of LSFO or MEL wet FGD technology is generally based on site-specific considerations involving the higher operating cost of lime and the higher capital cost of the larger absorbers and greater pumping costs of LSFO.

Dual-Alkali Wet FGD

Dual-alkali systems employ sodium- and calcium-based reagents to remove SO₂ from the flue gas and regenerate the scrubbing reagent. Due to the relatively high cost of sodium-based reagents and improvements in LSFO wet FGD technology, dual-alkali wet FGD technology is considered an inferior technology to LSFO wet FGD.

Chiyoda JBR

The Chiyoda wet FGD technology uses a unique JBR to react limestone reagent and flue gas. The flue gas is first quenched in a gas cooler prior to entry into the JBR. In the JBR, the flue gas is forced through numerous sparger pipes submerged below the absorbent liquid level. The flow of flue gas through the alkaline absorbent liquid results in mass transfer of SO₂ from the gas phase to the liquid phase. Absorbent liquid and oxidation air

is also introduced into the JBR enhancing the mixing of limestone slurry and flue gas. The treated flue gas proceeds to the upper part of the JBR, passes through a mist eliminator, and then enters the stack. The oxidized gypsum is removed from the JBR for dewatering. The Chiyoda process combines all FGD reactions in the JBR. The overall chemical reactions are identical to those of LSFO wet FGD technology.

In addition to controlling SO₂ emissions, wet FGD systems also have the cobenefit of removing PM, H₂SO₄ mist, hydrogen chloride, hydrogen fluoride, and mercury.

Dry Flue Gas Desulfurization

Dry FGD control systems include spray dryer absorber (SDA), circulating dry scrubber (CDS), and DSI (also termed in-duct sorbent injection system [IDSIS]) control technologies.

In an SDA control system, the combustion process exhaust stream passes through the SDA upstream of a PM control device (typically a fabric filter). An alkaline lime slurry is injected in the SDA using a rotary atomizer or fluid nozzles. The liquid sulfite/sulfate salts that form from the reaction of the alkaline slurry with SO₂ are dried by heat contained in the exhaust stream. If a fabric filter is used as the PM control device, the alkaline lime reagent may further react with SO₂ that passes through the filter cake. This additional reaction in the fabric filter can also aid in the removal of additional pollutants (i.e., H₂SO₄ mist, hydrogen chloride, hydrogen fluoride, and mercury).

CDS technology uses flue gas, ash, and lime sorbent to form a fluidized bed in an absorber vessel. Water is added to the CDS absorber vessel to enhance the lime and SO₂ absorption reactions. Byproducts leave the absorber in a dry form with the flue gas for subsequent removal by a downstream PM collection device.

Dry Sorbent Injection (DSI)

DSI is another once-through dry FGD technology that uses an alkaline reagent (e.g., hydrated lime, trona, limestone, etc.) to absorb SO₂. DSI control technology injects the al-

kaline reagent in the ductwork between the air heater and the particulate collection device. No water is added to the lime or limestone or directly to the process. The sulfite/sulfate salts reaction products are then removed by the particulate collection device.

5.5.1.2 Technical Feasibility and Ranking

All of the postcombustion wet and dry FGD processes are technically feasible technologies for biomass-fired boilers. While technically feasible, wet FGD and the dry FGD SDA and CDS have not been installed on biomass-fired boilers due to the low sulfur of the biomass fuel and thus the low uncontrolled SO₂ flue gas concentrations. The removal efficiency of FGD control systems will decrease with decreasing inlet SO₂ loading. DSI technology has been applied to coal-fired boilers and proposed for biomass-fired boilers to control acid gases such as H₂SO₄ mist, hydrogen chloride, hydrogen fluoride, as well as SO₂.

Table 5-4 provides a summary of the technical feasibility and ranking of the available SO₂ control technologies.

5.5.1.3 Evaluation of Control Technologies

As previously discussed, wet FGD and dry FGD SDA and CDS systems have not been installed on biomass-fired boilers due to their low uncontrolled SO₂ flue gas concentrations. Therefore, GREC LLC proposes BFB technology and DSI as SO₂ BACT. The DSI control system in conjunction with the inherent benefits of BFB technology will provide an estimated 35-percent SO₂ control efficiency. This relatively low overall SO₂ removal efficiency is due to the low sulfur content of the biomass fuel; i.e., the GREC BFB boiler design biomass fuel mix sulfur content is only 0.009 weight percent on an as-received basis. In comparison, coal-fired power plants may combust coals containing more than 2.0 weight percent sulfur or more than 200 times higher than woody biomass. The economic and energy impacts associated with the installation and operation of this control technology are considered reasonable. There are also no significant collateral environmental issues that would justify rejection of this control technology as BACT.

Table 5-4. Ranking of Available SO₂ Control Technologies—BFB Boiler

Control Technology	Technically Feasible (Yes/No)	Control Efficiency Range* (%)
Wet FGD	Yes	90 to 98
Dry FGD—SDA and CDS	Yes	70 to 90
BFB technology and DSI	Yes	30 to 40

*Control efficiencies vary depending on the level of uncontrolled SO₂ emissions. Higher efficiencies shown for wet and dry FGD are typical values for coal-fired power plants with significantly higher fuel sulfur contents compared to woody biomass.

Source: ECT, 2009.

5.5.1.4 Proposed SO₂ BACT

Table 5-5 provides a summary of biomass-fired utility and industrial size boiler (greater than 250 MMBtu/hr) SO₂ BACT determinations for the past 5 years. The lowest BACT determination is 0.025 lb/MMBtu for Skagit County Lumber Mill in Washington. This BACT emission limit is based on the uncontrolled emission factor contained in AP-42 Section 1.6, Wood Residue Combustion in Boilers. There are no control technologies installed at Skagit County Lumber Mill to reduce the uncontrolled SO₂ emissions. GREC proposes an SO₂ BACT emission rate of 0.041 lb/MMBtu on a 30-day rolling average basis.

SO₂ BACT emission limits proposed for the GREC BFB boiler are summarized as follows:

- Emission Limits—0.041 lb/MMBtu.
- Averaging Period—30-day rolling average.
- Compliance Method—Continuous emissions monitoring in accordance with 40 CFR 75.

5.5.2 EMERGENCY DIESEL ENGINES

The emergency generator and firewater pump diesel engines will each be fired with ULSD fuel oil containing no more than 0.0015 percent sulfur by weight. Excluding emergencies, each diesel engine will operate no more than 96 hr/yr for routine testing and maintenance purposes. Potential emissions for each diesel engine are based on each engine operating 500 hr/yr. Potential SO₂ emission rates are for the emergency generator and firewater pump diesel engines are .0002 and 0.0008 tpy, respectively.

The diesel engines will emit SO₂ due to thermal oxidation of sulfur contained in the fuel oil. The only technically and economically feasible technology available to control SO₂ from emergency diesel engines is the use of low-sulfur fuel oil.

Table 5 5. Summary of Coal-Fired Power Plant SO₂ BACT Determinations

RBLC ID	Facility Name	Permit Dates		Process Description	Fuel	Throughput	Control Description	Emission Limit	Basis
		Issuance	Update						
WA-0327	Skagit County Lumber Mill	01/25/06	06/11/09	Wood-fired cogeneration unit	Bark and waste wood	430 MMBtu/hr		0.025 lb/MMBtu	BACT-PSD
ND-0022	Northern Sun	05/01/06	02/13/07	Wood/hull fired boiler	Biomass			0.47 lb/MMBtu	BACT-PSD
VA-0298	International Biofuels, Inc	12/13/05	09/17/07	Wood thermal oxidizers for wood pellet process	Wood/wood paste	43 MMBtu/hr	Thermal oxidizers and CEMS	2.2 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc	12/13/05	09/17/07	Heat energy systems for pellet processing	Wood/woodpaste	77 MMBtu/hr	Thermal oxidizers and CEMS	3.9 lb/hr	BACT-PSD
OH-0307	South Point Biomass Generation	04/04/06	08/16/07	Wood fired boilers (7)	Wood	318 MMBtu/hr	Spray dryer adsorber or dry sodium bicarbonate injection system	22.13 lb/hr	BACT-PSD
AL-0223	Stevenson Mill	07/14/06	07/23/07	No. 2 wood-fired boiler	Biomass	620 MMBtu/hr		93 lb/hr	BACT-PSD
LA-0188	Bogalusa Mill	11/23/04	06/02/06	No. 12 hogged fuel boiler	Bark	787.5 MMBtu/hr	Limit annual fuel oil capacity factor to less than 10 percent	1,209.75 lb/hr	BACT-PSD
WA-0337	Boise White Paper LLC	02/01/06	08/21/07	Kraft pulp and paper processes/recovery furnace	Black liquor solids	3.4 MMlb/day		1301 tpy	BACT-PSD
WA-0337	Boise White Paper LLC	02/01/06	08/21/07	Kraft pulp and paper processes/recovery furnace	Black liquor solids	3.4 MMlb/day		1301 tpy	BACT-PSD

Sources: EPA, 2009.
ECT, 2009.

The exclusive use of ULSD fuel oil and constraints on annual operations for maintenance and testing purposes are proposed as SO₂ BACT for the emergency diesel engines. SO₂ BACT proposed for the GREC emergency diesel engines is summarized as follows:

- Emission Limit—Exclusive use of ULSD fuel oil.
- Compliance Method—Supplier certifications of fuel oil sulfur content.
- Annual Operating Hours—96 hr/yr (excluding emergencies).
- Averaging Period—Calendar year.
- Compliance Method—Monitoring of operating hours using engine run-time meters.

5.6 BACT ANALYSIS FOR CO AND VOC

5.6.1 BFB BOILER

Fuel combustion CO and VOC emissions result from the incomplete combustion of carbon and organic compounds contained in the fuel. Factors affecting CO and VOC emissions include firing temperatures, excess oxygen and residence time in the combustion zone, and combustion area mixing characteristics. An increase in combustion zone residence time and oxygen levels and improved mixing of fuel and combustion air will increase oxidation rates and decrease CO and VOC emission rates. BFB boilers are designed and operated to minimize the formation of CO and VOC by maximizing the combustion area mixing of the biomass fuel and combustion air.

In general, emissions of NO_x and CO/VOC are inversely related (i.e., decreasing NO_x emissions will result in an increase in CO/VOC emissions and vice-versa). Accordingly, boiler combustion controls designed to lower NO_x emissions (e.g., lower combustion temperatures) would also be expected to cause a collateral increase in CO and VOC emissions. Accordingly, boiler combustion design and operation requires a balancing of the competing goals to minimize the formation of both NO_x and CO/VOC.

5.6.1.1 Available CO and VOC Control Technologies

Three control technologies are available for reducing CO and VOC emissions from combustion sources: combustion controls, thermal oxidation, and catalytic oxidation.

Combustion Controls

Optimization of the design, operation, and maintenance of the boiler combustion system is the primary technology available for reducing CO and VOC emissions. Combustion process controls involve boiler combustion designs and operating practices that improve the oxidation process and minimize incomplete combustion. Key combustion design and operating parameters include sufficient excess air, high combustion temperatures, adequate residence time, and good mixing of the combustion air and fuel.

Thermal Oxidation

A thermal oxidizer employs high temperature (approximately 1,500°F) combustion to achieve a 90- to 95-percent oxidization rate of CO and VOC to CO₂ and water. The thermal oxidizer components are subject to fouling by PM. Accordingly, for biomass-fired boilers, the thermal oxidizer would need to be located downstream of the boiler's PM control device. In addition, a thermal oxidizer requires a source of supplemental fuel, typically natural gas, to raise the exhaust stream to the required oxidation temperature.

Catalytic Oxidation

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote the oxidation of CO and VOC to CO₂ and water at temperatures approximately 50 percent lower than would be necessary for oxidation without a catalyst. The operating temperature range for conventional oxidation catalysts is between 650 and 1,150°F.

The efficiency of CO and VOC oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature up to a temperature of approximately 1,100°F; further temperature increases will have little effect on control efficiency. Significant CO and VOC oxidation will occur at any temperature above roughly 500°F. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst that will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time, which is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an in-

crease in pressure drop across the catalyst bed. Oxidation catalyst systems are typically designed for a CO oxidation efficiency of 80 to 90 percent. The efficiency of VOC oxidation is approximately 50 percent.

Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica will all act as catalyst poisons causing a reduction in catalyst activity and pollutant removal efficiencies. Oxidation catalysts are also subject to masking and/or blinding by fly ash contained in the exhaust stream of a pulverized coal boiler. There are no known installations of catalytic oxidation technology to control CO and VOC emissions from biomass-fired boilers.

Table 5-6 provides a summary of the technical feasibility and ranking of the available CO and VOC control technologies.

5.6.1.2 Technical Feasibility

The only CO and VOC control technologies considered technically feasible for biomass-fired boilers is combustion controls and thermal oxidation. Thermal oxidation technology is considered impractical due to the required operating temperature and need for supplemental fuel. Due to naturally occurring biomass fuel contaminants and high flue gas temperature required, oxidation catalyst technology is not considered technically feasible for the GREC BFB boiler.

5.6.1.3 Proposed CO and VOC BACT

Tables 5-7 and 5-8 provide a summary of biomass-fired utility and industrial size boiler (greater than 250 MMBtu/hr) CO and VOC BACT determinations, respectively for the past 5 years. GREC LLC proposes good combustion controls as CO and VOC BACT. The proposed CO BACT emission rate of 0.12 lb/MMBtu is lower than any previous BACT determination, as shown in Table 5-7. Similarly, good combustion controls will result in a VOC emission rate of only 0.013 lb/MMBtu per hour. This proposed VOC BACT emission rate is lower than any previous BACT determination, as shown in Table 5-8.

Table 5-6. Ranking of Available CO and VOC Control Technologies—BFB Boiler

Control Technology	Technically Feasible (Yes/No)	Control Efficiency Range* (%)
Thermal oxidation	Yes	90 to 95
Catalytic oxidation	No	80 to 90
Combustion controls	Yes	25 to 50

*Control efficiencies vary depending on the level of uncontrolled CO and VOC emissions.

Source: ECT, 2009.

Table 5.7. Summary of Biomass-Fired Boiler CO BACT Determinations

RBLC ID	Facility Name	Permit Dates		Process Description	Fuel	Throughput	Control Description	Emission Limit	Basis
		Issuance	Update						
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Heat energy systems for pellet processing	Wood/woodpaste	77 MMBtu/hr	Thermal oxidizers and CEMS	0.19 lb/MMBtu	BACT-PSD
WA-0335	Simpson Tacoma Kraft Company, LLC	05/22/07	08/21/07	Utility and large industrial sized boilers/furnaces	Wood waste	595 MMBtu/hr	OFA system installed in 2006 to improve combustion conditions.	0.35 lb/MMBtu	BACT-PSD
WA-0329	Darrington Energy Cogeneration Power Plant	02/11/05	07/05/06	Wood waste-fired boiler	Wood waste	403 MMBtu/hr	Good combustion practices	0.35 lb/MMBtu	BACT-PSD
MN-0074	Koda Energy	08/23/07	01/26/09	Biomass boiler 4			Good combustion practice	0.43 lb/MMBtu	BACT-PSD
ND-0022	Northern Sun	05/01/06	02/13/07	Wood/hull fired boiler	Biomass		Good combustion practices	0.63 lb/MMBtu	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Wood thermal oxidizers for wood pellet process	Wood/wood paste	43 MMBtu/hr	Thermal oxidizers and CEMS	16.3 lb/hr	BACT-PSD
OH-0307	South Point Biomass Generatic	04/04/06	08/16/07	Wood fired boilers (7)	Wood	318 MMBtu/hr	Oxidation catalyst	31.8 lb/hr	BACT-PSD
WA-0327	Skagit County Lumber Mill	01/25/06	06/11/09	Wood-fired cogeneration unit	Bark and waste wood	430 MMBtu/hr		400 lb/hr	BACT-PSD
LA-0188	Bogalusa Mill	11/23/04	06/02/06	No. 12 hogged fuel boiler	Bark	787.5 MMBtu/hr	Existing OFA system and good combustion practices	491.45 lb/hr	BACT-PSD
WA-0337	Boise White Paper LLC	02/01/06	08/21/07	Utility-and large industrial-size boilers/furnaces (greater than 250 MMBtu/hr)	Wood/bark	343 MMBtu/hr	OFA system added to improve the boiler's combustion system; boiler has an ESP	500 ppmvd	Other

Sources: EPA, 2009.
ECT, 2009.

Table 5-8. Summary of Biomass-Fired Boiler VOC BACT Determinations

RBLC ID	Facility Name	Permit Dates		Process Description	Fuel	Throughput	Control Description	Emission Limit	Basis
		Issuance	Update						
WA-0327	Skagit County Lumber Mill	01/25/06	06/11/09	Wood-fired cogeneration unit	Bark and waste wood	430 MMBtu/hr		0.019 lb/MMBtu	BACT-PSD
AR-0083	Potlatch Corporation - Ozan Unit	07/26/05	12/22/05	Wood fired boiler	Wood chips	110,000 lb/hr	Good combustion practices	0.034 lb/MMBtu	BACT-PSD
AR-0084	Potlatch Corporation - Ozan Unit	07/26/05	12/22/05	Wood fired boiler	Wood chips	110,000 lb/hr	Good combustion practices	0.034 lb/MMBtu	BACT-PSD
AR-0083	Potlatch Corporation - Ozan Unit	07/26/05	12/22/05	Kilns 1 through 4	Steam heated	265 MMbf annually	Proper operation	3.5 lb/MMbf	
AR-0084	Potlatch Corporation - Ozan Unit	07/26/05	12/22/05	Kilns 1 through 4	Steam heated	265 MMbf annually	Proper operation	3.5 lb/MMbf	
OH-0307	South Point Biomass Generation	04/04/06	08/16/07	Wood fired boilers (7)	Wood	318 MMBtu/hr	Good combustion practices and use of oxidation catalyst	4.06 lb/hr	BACT-PSD
WA-0327	Skagit County Lumber Mill	01/25/06	06/11/09	Anti-mold spray system		300 MMf/yr	Drip-free design	9 tpy	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Rotary and fuel dryer processing	Wood	65.6 tph	Wood fired thermal oxidizers for rotary dryers	37.8 lb/hr	BACT-PSD
WA-0327	Skagit County Lumber Mill	01/25/06	06/11/09	7. Dry kilns		300 MM board f/yr	Computerized steam management system	54 tpy	BACT-PSD

Sources: EPA, 2009.
ECT, 2009.

CO and VOC BACT emission limits proposed for the GREC BFB boiler are summarized as follows:

- CO Emission Limit—0.120 lb/MMBtu.
 - Averaging Period—30-day rolling average.
 - Compliance Method— Continuous emissions monitoring in accordance with 40 CFR 60.
- VOC Emission Limit—0.013 lb/MMBtu.
 - Averaging Period—Stack test duration.
 - Compliance Method— Stack test using EPA reference methods.

5.6.2 EMERGENCY DIESEL ENGINES

The formation mechanism of CO and VOC, available control technologies, and control technology technical feasibility described for the BFB boiler also generally apply to the emergency diesel engines. Excluding emergencies, each diesel engine will operate no more than 96 hr/yr for routine testing and maintenance purposes. Potential emissions for each diesel engine are based on each engine operating 500 hr/yr. Potential CO emission rates are for the emergency generator and firewater pump diesel engines are 1.5 and 0.4 tpy, respectively. Potential VOC emission rates are for the emergency generator and firewater pump diesel engines are 0.6 and 0.1 tpy, respectively.

The only CO and VOC control technology considered technically feasible for the GREC ULSD-fired emergency diesel engines is combustion controls.

Good combustion design and operation and constraints on annual operations for maintenance and testing purposes are proposed as CO and VOC BACT for the emergency diesel engines. The emergency diesel engines will be subject to the applicable emission standards of NSPS Subpart IIII for stationary compression ignition internal combustion engines. Subpart IIII limits CO emissions to 3.5 g/kWh for model year 2007 and later emergency generator diesel engines greater than 750 bhp. Subpart IIII limits the combination of NO_x and NMHC emissions to 6.4 g/kWh for model year 2007 or later emergen-

cy generator diesel engines greater than 750 bhp. The Subpart IIII CO and combination NO_x and NMHC emission limits for model year 2009 and later firewater pump diesel engines between 175 and 300 bph are 3.5 and 4.0 g/kWh, respectively. GREC will use emergency diesel engines that comply with the applicable emission standards of NSPS Subpart IIII.

CO and VOC BACT proposed for the GREC emergency diesel engines are summarized as follows:

- Emission Limit—Applicable standards of NSPS Subpart IIII.
- Averaging Period—Per NSPS Subpart IIII.
- Compliance Method—Engine manufacturer certification in accordance with NSPS Subpart IIII.
- Annual Operating Hours—96 hr/yr (excluding emergencies).
- Averaging Period—Calendar year.
- Compliance Method—Monitoring of operating hours using engine run-time meters.

5.7 BACT ANALYSIS FOR PM/PM₁₀

PM is classified by particle size and is defined by the test methods used to measure stack emissions. Filterable PM is measured using EPA Reference Methods 5, 5B, or 17 which capture particles greater than 0.3 micron in size using a filter that is weighed prior to and following the stack test to determine the gain in weight. In Method 5, the filter is located in the sampling train external to the stack and maintained at a temperature of 248°F. A variation of Method 5 is Method 5B, which maintains the filter temperature at 320°F to exclude H₂SO₄ PM. Method 17 places the filter in the stack and therefore collects PM at the prevailing stack temperature. Filterable PM₁₀ is measured using either EPA Reference Methods 201 or 201A. Both of these test methods collect filterable PM with a nominal aerodynamic diameter of 10 microns or less using an in-stack cyclone and filter system. All of the filterable PM test methods, commonly referred to as front-half PM, determine the mass of PM that condenses at or above the filter temperature.

EPA also includes condensable PM as a component of PM₁₀. Condensable PM is collected using EPA Reference Method 202 by passing the filtered sample gas stream through a series of chilled water-filled impingers to maintain an impinger outlet sample gas temperature of 68°F or less. Following sampling, the impinger solution is purged with nitrogen and extracted with methylene chloride. The organic and water fractions are then evaporated and the residues weighed to determine the mass of condensable PM. Since the impingers are located in the sampling train downstream of the filter, condensable PM is also referred to as back-half particulate. As discussed in EPA's May 16, 2008, final rule regarding implementation of NSR for PM_{2.5}, there are technical issues with the current stack test method for condensable PM. For this reason, EPA is not requiring states to address condensable PM for either PM₁₀ or PM_{2.5} in NSR permits until completion of a transition period ending January 1, 2011, to allow for further stack test method research.

In summary, PM includes the filterable portion of PM as measured by EPA Reference Methods 5, 5B, or 17. PM₁₀ includes filterable PM less than 10 microns as measured by EPA Reference Methods 201 or 201A and condensable PM as measured by EPA Reference Method 202. Since PM₁₀ includes condensable particulate and PM does not, PM emission sources will have higher PM₁₀ emissions compared to PM. For biomass-fired combustion sources, PM₁₀ emission rates are more than double that of PM emissions. Accordingly, the distinction between PM and PM₁₀ is important when assessing BACT for biomass-fired combustion sources.

5.7.1 BFB BOILER

PM/PM₁₀ emissions resulting from the combustion of any solid fuel are generally due to the oxidation of ash and sulfur contained in the fuel. Specific PM/PM₁₀ emission rates depend on the composition of the fuel (i.e., ash content), boiler design and operation, and emission control equipment. Uncontrolled PM/PM₁₀ emissions from biomass-fired boilers include the ash from fuel combustion, unburned carbon resulting from incomplete combustion, and condensable compounds. Biomass-fired BFB boilers achieve a high combustion efficiency resulting in PM/PM₁₀ emissions that are primarily comprised of

inorganic ash residues. In the case of a boiler equipped with an SCR and DSI, the loading increases due to the reactions with the sorbent and in the SCR. Additional compounds such as ammonium sulfate and ammonium nitrate are formed.

Ash generated by the combustion of biomass will exit the boiler as either bottom ash or fly ash. Fly ash is entrained in the boiler exhaust gas stream and will be discharged to the atmosphere unless removed by emission control equipment. Bottom ash is the noncombustible slag or residue remaining after the biomass is combusted. Bottom ash is removed mechanically from the boiler and is handled and processed as a solid combustion byproduct.

5.7.1.1 Available PM/PM₁₀ Control Technologies

Available technologies used for controlling PM/PM₁₀ from biomass-fired boilers include the following:

- Centrifugal collectors.
- Electrostatic precipitators (ESPs).
- Wet electrostatic precipitators (WESPs).
- Fabric filters or baghouses.
- Wet scrubbers.

Centrifugal Collectors

Centrifugal (cyclone) separators are primarily used to recover material from an exhaust stream before the stream is ducted to the principle control device since cyclones are effective in removing only large sized (greater than 10 microns) particles.

Electrostatic Precipitators

ESPs remove particles from a gas stream through the use of electrical forces. Discharge electrodes apply a negative charge to particles passing through a strong electrical field. These charged particles then migrate to a collecting electrode having an opposite, or positive, charge. Collected particles are removed from the collecting electrodes by periodic mechanical rapping of the collecting electrodes.

Wet Electrostatic Precipitators

WESPs remove particles from a gas stream using the same mechanisms as described above for ESPs. A WESP, however, removes particles from the collecting electrodes by washing of the collection surface using water, rather than mechanically rapping the collector plates. WESPs are common in applications where the exhaust gas stream has a high moisture content, is below the dew point, or includes particulate that may be difficult to remove from a dry ESP.

Fabric Filter

A fabric filter system consists of a number of filtering elements, bag cleaning system, main shell structure, dust removal system, and fan. PM/PM₁₀ is filtered from the gas stream by various mechanisms (inertial impaction, impingement, accumulated dust cake sieving, etc.) as the gas passes through the fabric filter. Accumulated dust on the bags is periodically removed using mechanical or pneumatic means. In pulse jet pneumatic cleaning, a sudden pulse of compressed air is injected into the top of the bag. This pulse creates a traveling wave in the fabric that separates the cake from the surface of the fabric. The cleaning normally proceeds by row, all bags in the row being cleaned simultaneously. Reverse air pneumatic cleaning isolates a section of the fabric filter and uses a dedicated fan to provide air flow in the opposite direction of normal air flow to remove collected particulate matter. Typical air-to-cloth ratios range from 2 to 8 cubic feet per minute-square foot (cfm-ft²).

Wet Scrubbers

Wet scrubbers remove PM/PM₁₀ from gas streams principally by inertial impaction of the particulate onto a water droplet. Particles can be wetted by impingement, diffusion, or condensation mechanisms. To be wetted, PM/PM₁₀ must either make contact with a spray droplet or impinge upon a wet surface. In a Venturi scrubber, the gas stream is constricted in a throat section. The large volume of gas passing through a small constriction gives a high gas velocity and a high-pressure drop across the system. As water is introduced into the throat, the gas is forced to move at a higher velocity causing the water to shear into droplets. Particles in the gas stream then impact onto the water droplets pro-

duced. The entrained water droplets are subsequently removed from the gas stream by a cyclone separator. Venturi scrubber collection efficiency increases with increasing pressure drops for a given particle size. Collection efficiency will also increase with increasing liquid-to-gas ratios up to the point where flooding of the system occurs. Packed-bed and venturi scrubber collection efficiencies are typically 90 percent for particles smaller than 2.5 microns in size.

5.7.1.2 Technical Feasibility and Ranking

All of the available PM/PM₁₀ control technologies described previously are technically feasible for the biomass-fired BFB boiler. Table 5-9 provides a summary of the technical feasibility and ranking of the available PM/PM₁₀ control technologies. As shown, fabric filter technology provides the highest control efficiency.

5.7.1.3 Evaluation of Control Technologies

GREC LLC proposes to install the PM/PM₁₀ control technology identified as having the highest control efficiency—fabric filter. The economic and energy impacts associated with the installation and operation of this control technology is considered reasonable. There are also no significant collateral environmental issues that would justify rejection of this control technology as BACT.

5.7.1.4 Proposed PM/PM₁₀ BACT

Table 5-10 provides a summary of biomass-fired utility and industrial size boiler (greater than 250 MMBtu/hr) PM/PM₁₀ BACT determinations for the past 5 years.

GREC LLC proposes a PM/PM₁₀ BACT emission rate of 0.015 lb/MMBtu (filterable). This limit reflects the expected performance of the fabric filter. PM/PM₁₀ BACT emission limits proposed for the GREC BFB boiler are summarized as follows:

- Emission Limits—0.015 lb/MMBtu (filterable PM/PM₁₀).
- Averaging Period—Stack test duration.
- Compliance Method—EPA Reference Methods 201 or 201A.

Table 5-9. Ranking of Available PM/PM₁₀ Control Technologies—BFB Boiler

Control Technology	Technically Feasible (Yes/No)	Control Efficiency* (%)
Fabric filter	Yes	99.5
ESP	Yes	99
WESP	Yes	99
Wet Venturi scrubber	Yes	95
Cyclone collector	Yes	80 to 90

*Control efficiencies vary depending on the level of uncontrolled PM/PM₁₀ emissions.

Source: ECT, 2009.

Table 5-10. Summary of Biomass-Fired Boiler PM/PM10 BACT Determinations (Page 1 of 2)

RBLC ID	Facility Name	Permit Dates		Process Description	Fuel	Throughput	Control Description	Emission Limit	Basis
		Issuance	Update						
<u>PM</u>									
MN-0074	Koda Energy	08/23/07	01/26/09	Biomass Boiler 2			Good combustion practices	0.01 lb/MMBtu	BACT-PSD
MN-0074	Koda Energy	08/23/07	01/26/09	Biomass Boiler 1	Natural gas	308 MMBtu/hr	Cyclone and ESP	0.03 lb/MMBtu	BACT-PSD
MN-0074	Koda Energy	08/23/07	01/26/09	Biomass Boiler 3			Cyclone and ESP	0.037 lb/MMBtu	BACT-PSD
ND-0022	Northern Sun	05/01/06	02/13/07	Wood/hull fired boiler	Biomass		ESP	0.08 lb/MMBtu	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Peanut hull unloading	Wood	3 tph		0.6 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Final grind hammermill processing	Wood	52 tph	Baghouse	1 lb/hr	Other Case-by-Case
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Wood thermal oxidizers for wood pellet process	Wood/wood paste	43 MMBtu/hr	Setting chamber and cyclone	3.9 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Heat energy systems for pellet processing	Wood/woodpaste	77 MMBtu/hr	Setting chambers and cyclones	6.9 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Pellet mills processing	Wood	51 tpy	Cyclones	10.2 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Raw material unloading	Wood/wood paste	121 tph		12.1 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Rotary and fuel dryer processing	Wood	65.6 tph	Setting chambers and cyclones CEMS	13.1 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Primary grind hammermills	Wood	121 tph	Setting chambers and cyclones and CEMS	14.5 lb/hr	BACT-PSD
WA-0329	Darrington Energy Cogeneration Power Plant	02/11/05	07/05/06	Cooling tower			Installation of drift eliminators with drift loss of less than 0.001 percent of the recirculating water flow rate.		BACT-PSD
<u>PM₁₀</u>									
WA-0327	Skagit County Lumber Mill	01/25/06	06/11/09	Planer mill bag house		48,000 dscf/min	Bag house	0.005 g/dscf	BACT-PSD
MN-0074	Koda Energy	08/23/07	01/26/09	Biomass boiler 4			Good combustion practice	0.01 lb/MMBtu	BACT-PSD
WA-0335	Simpson Tacoma Kraft Company, LLC	05/22/07	08/21/07	Utility and large industrial sized boilers/furnaces	Wood waste	595 MMBtu/hr	Existing ESP	0.02 lb/MMBtu	BACT-PSD
WA-0327	Skagit County Lumber Mill	01/25/06	06/11/09	Wood-fired cogeneration unit	Bark and waste wood	430 MMBtu/hr	ESP	0.02 lb/MMBtu	BACT-PSD
WA-0329	Darrington Energy Cogeneration Power Plant	02/11/05	07/05/06	Wood waste-fired boiler	Wood waste	403 MMBtu/hr	Dry ESP	0.02 lb/MMBtu	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Peanut hull unloading	Wood	3 tph		0.6 lb/hr	BACT-PSD

Table 5-10. Summary of Biomass-Fired Boiler PM/PM10 BACT Determinations (Page 2 of 2)

RBLC ID	Facility Name	Permit Dates		Process Description	Fuel	Throughput	Control Description	Emission Limit	Basis
		Issuance	Update						
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Final grind hammermill processing	Wood	52 tph	Baghouse	1 lb/hr	Other Case-by-Case
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Wood thermal oxidizers for wood pellet process	Wood/wood paste	43 MMBtu/hr	Setting chamber and cyclones	3.4 lb/hr	BACT-PSD
OH-0307	South Point Biomass Generation	04/04/06	08/16/07	Wood fired boilers (7)	Wood	318 MMBtu/hr	Pulse jet baghouse	3.97 lb/hr	BACT-PSD
WA-0327	Skagit County Lumber Mill	01/25/06	06/11/09	Dry kilns		300 MM board f/yr		4 tpy	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Heat energy systems for pellet processing	Wood/woodpaste	77 MMBtu/hr	Setting chambers and cyclones	6.2 lb/hr	BACT-PSD
OH-0307	South Point Biomass Generation	04/04/06	08/16/07	Wood handling system			Baghouse, one at each transfer point	6.71 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Pellet mills processing	Wood	51 tpy	Cyclones	10.2 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Raw material unloading	Wood/wood paste	121 tph		12.1 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Rotary and fuel dryer processing	Wood	65.6 tph	Setting chambers and cyclones and CEMS	13.1 lb/hr	BACT-PSD
VA-0298	International Biofuels, Inc.	12/13/05	09/17/07	Primary grind hammermills	Wood	121 tph	Setting chambers and cyclones CEMS	14.5 lb/hr	BACT-PSD
WA-0336	Grays Harbor Paper LP	11/17/06	08/21/07	Utility-and large industrial sized boilers	Wood waste	379 MMBtu/hr	Multiclones with 80 14-inch diameter tubes. Two parallel impringement wet scrubber with six top and six bottom showers	52.5 lb/hr	BACT-PSD
WA-0336	Grays Harbor Paper LP	11/17/06	08/21/07	Industrial-size boilers/furnaces 100 to 250 MMBtu/hr	Wood waste	227 MMBtu/hr	Multiclones - western precipitation type 9 vg, size 189-7 Secondary multiclones - 9 14-inch tubes Secondary scrubber packed, wet Venturi	78.4 lb/hr	BACT-PSD
LA-0188	Bogalusa Mill	11/23/04	06/02/06	No. 12 hogged fuel boiler	Bark	787.5 MMBtu/hr	Existing wet scrubber	121.93 lb/hr	BACT-PSD

Source: ECT, 2009.

Table 5-11 provides a summary of the preliminary fabric filter design criteria.

5.7.2 EMERGENCY DIESEL ENGINES

As previously noted, the emergency diesel engines will be fired with ULSD fuel oil and will each operate no more than 96 hr/yr for routine testing and maintenance purposes. Potential PM/PM₁₀ emission rates for the emergency generator and firewater pump diesel engines are 0.06 and 0.02 tpy, respectively.

The emergency diesel engines will be subject to the applicable emission standards of NSPS Subpart IIII for new nonroad ICEs. Subpart IIII limits PM emissions to 0.2 g/kWh for a 2007 model year or later emergency generator diesel engines with an output greater than 750 bhp. For 2009 and later model year emergency firewater pump diesel engines between 175 and 300 bph, the Subpart IIII PM emission limit is also 0.2 g/kWh. Both of the emergency diesel engines purchased for GREC will comply with the applicable emission standards of NSPS Subpart IIII.

Compliance with the stringent NSPS Subpart IIII emission standards and limited annual operating hours for maintenance and testing purposes is proposed as PM/PM₁₀ BACT for the GREC emergency generator and firewater pump diesel engines. PM/PM₁₀ BACT proposed for the GREC emergency diesel engines is summarized as follows:

- Emission Limit—Applicable standards of NSPS Subpart IIII.
- Averaging Period—Per NSPS Subpart IIII.
- Compliance Method—Engine manufacturer certification in accordance with NSPS Subpart IIII.
- Annual Operating Hours—96 hr/yr (excluding emergencies).
- Averaging Period—Calendar year.
- Compliance Method—Monitoring of operating hours using engine run-time meters.

Table 5-11. Preliminary Fabric Filter Design Criteria

Parameter	Unit	Estimated Design Value	Notes
Flue gas flow rate to fabric filter	acfm	720,000	Flue gas flow to the fabric filter is based upon the design wood mix
Inlet gas temperature	°F	465 to 550	
Inlet filterable particulate loading	lb/hr	1,850 (1.36 lb/MMBtu)	Based on design wood mix ash content of 0.98 percent and heating value of 8,529 Btu/lb HHV, dry basis and sorbent
Outlet filterable particulate loading	lb/MMBtu	0.015	Based on maximum heat input of 1,358 MMBtu/hr
	lb/hr	20.4	
Bag material	—	—	To be determined during detailed design
Bag diameter, length, number of bags	—	—	To be determined during detailed design
Number of modules and compartments per module	—	—	To be determined during detailed design
Air to cloth ratio	—	Approximately 4	Final air-to-cloth ratio will be determined during detailed design
Pressure drop across baghouse	inches of water	6 to 8	
Cleaning mechanism and cycle	—	Pulse Jet	

Source: GREC, 2009.

5.7.3 COOLING TOWER

5.7.3.1 Cooling Tower

GREC will include a four-cell mechanical draft cooling tower that will emit PM/PM₁₀. Because of direct contact between the cooling water and ambient air, a small portion of the recirculating cooling water is entrained in the air stream and discharged from the cooling tower as drift droplets. These water droplets contain the same concentration of dissolved solids as found in the recirculating cooling water. Large water droplets quickly settle out of the cooling tower exhaust stream and deposit near the tower. The remaining smaller water droplets may evaporate prior to being deposited in the area surrounding the cooling tower. These evaporated droplets represent potential PM/PM₁₀ emissions because of the fine PM/PM₁₀ formed by crystallization of the dissolved solids contained in the droplet.

5.7.3.2 Available PM/PM₁₀ Control Technologies

The only feasible technology for controlling PM/PM₁₀ from wet cooling towers is the use of drift eliminators. Drift eliminators rely on inertial separation caused by airflow direction changes to remove water droplets from the air stream leaving the tower. The water droplets are returned to the cooling tower. Drift eliminator configurations include herringbone (blade-type), wave-form, and cellular (honeycomb) designs. Drift eliminator materials of construction include ceramics; fiber-reinforced cement; metal; plastic; and wood fabricated into closely spaced slats, sheets, honeycomb assemblies, or tiles.

5.7.3.3 Proposed PM/PM₁₀ BACT

PM/PM₁₀ emissions from the GREC cooling tower will be controlled using high-efficiency drift eliminators. The cooling tower will achieve a drift loss rate of no more than 0.0005 percent of the cooling tower recirculating water flow. This cooling tower drift loss rate is consistent with recent FDEP BACT determinations. PM/PM₁₀ BACT proposed for the GREC cooling tower is summarized as follows:

- Emission Limit—Use of high-efficiency drift eliminators with a drift loss rate of no more than 0.0005 percent.
- Compliance Method—Cooling tower manufacturer certification.

5.7.4 BIOMASS FUEL PROCESSING

The disc screens and hammer hogs will be located within the biomass fuel processing building. This building will be equipped with local exhaust ventilation systems that will be routed to a fabric filter for control of PM/PM₁₀ emissions.

5.7.5 MATERIAL HANDLING AND STORAGE

GREC will include biomass fuel, fly ash, and DSI sorbent receiving, processing, handling, and storage systems. These material handling and storage processes will generate fugitive and point (stack) source PM/PM₁₀ emissions. Fugitive emissions are emissions that cannot reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. In contrast, point source emissions are emissions that can reasonably be collected and subsequently passed through a stack, chimney, vent, or other functionally equivalent opening. Fugitive and point source PM/PM₁₀ emissions from material handling and storage will be generated from three general source categories: transfer points, storage silos and piles, and truck traffic on facility roadways.

5.7.5.1 Available PM/PM₁₀ Control Technologies

Transfer Points

Transfer points include material loading/unloading, conveyor-to-conveyor drops, material transfers from reclaim hoppers to conveyors, and transfers from conveyors to storage silos. Particulate emissions will be generated as material drops through the transfer point. The potential to generate particulate emissions at a transfer point is a function of the rate at which the material flows through the transfer point, exposure to wind, and the material's particle size and moisture content. Potential emissions from a transfer point can be reduced by decreasing the speed at which the material is transferred, decreasing the wind speed to which the material is exposed, or increasing the aggregate's moisture content by watering or chemical wetting agents. Transfer point emissions may be further reduced by enclosing the transfer operations within a structure, and exhausting the air from the structure through a particulate control device (e.g., fabric filter).

Storage Silos and Piles

The transfer of materials (i.e., biomass fuel, fly ash, and sorbent) to storage silos results in point source PM/PM₁₀ emissions due to the displacement of air from the silos. Fabric filters (also referred to as bin vent filters) are commonly used to control PM/PM₁₀ emissions from storage silos.

Fugitive PM/PM₁₀ emissions associated with the biomass fuel storage piles include dust emissions produced by adding/removing material from the pile, routine shaping of the pile and from wind erosion. A combination of material drop controls (e.g., telescopic chutes), compaction, and dust suppression sprays (e.g., wetting) can be used to minimize fugitive emission from the biomass fuel storage piles.

Facility Roadways

Vehicular traffic on paved roads will generate fugitive PM/PM₁₀ emissions. Particulate emissions from roads can be controlled by sweeping, applying water as necessary, and limiting vehicle speeds.

5.7.5.2 Proposed PM/PM₁₀ BACT

A combination of good operating practices and fabric filters are proposed as PM/PM₁₀ BACT for the GREC material handling emission sources. Specific PM/PM₁₀ control measures proposed for the GREC material handling systems are as follows:

- Transfers Points—To the extent practical and appropriate, material handling transfer points will be enclosed. Where complete enclosure is not practical, partial enclosure and/or wet dust suppression systems using water sprays or a chemical wetting agent will be employed. Opacity from each transfer point will not exceed 5 percent.
- Storage Silos—Silos storing dry materials will be equipped with bin vent filters with a design outlet PM/PM₁₀ concentration of no more than 0.015 gr/dscf.
- Storage Piles—Water or chemical dust suppression will be applied to the biomass fuel storage piles, as necessary.

- Roads—All plant roadways will be paved. These roads will be watered or swept, as necessary, to control fugitive PM/PM₁₀ emissions.

5.8 SUMMARY OF PROPOSED BACT

Table 5-12 provides a summary of the BACT proposed for GREC including the emission limit, averaging period, and compliance method.

Table 5-12. Summary of Proposed BACT

Emission Unit	Pollutant	Averaging Period	BACT Emission Limit	Compliance Method
BFB boiler	NO _x	30-day rolling	0.070 lb/MMBtu	CEMS
	SO ₂	30-day rolling	0.041 lb/MMBtu	CEMS
	CO	30-day rolling	0.120 lb/MMBtu	CEMS
	VOC (as CH ₄)	Stack test duration	0.013 lb/MMBtu	EPA Reference Methods 18, 25, 25A
	PM/PM ₁₀ (filterable)	Stack test duration	0.015 lb/MMBtu	EPA Reference Methods 201/201A
Emergency diesel engines	NO _x	N/A	Applicable NSPS Subpart IIII standard	Engine manufacturer certification
	SO ₂	N/A	ULSD fuel oil	Fuel oil supplier certifications
	CO	N/A	Applicable NSPS Subpart IIII standard	Engine manufacturer certification
	VOC (as CH ₄)	N/A	Applicable NSPS Subpart IIII standard	Engine manufacturer certification
	PM/PM ₁₀	N/A	Applicable NSPS Subpart IIII standard	Engine manufacturer certification
Cooling tower	PM/PM ₁₀	N/A	Drift eliminators Drift Loss Rate of 0.0005 percent	Cooling tower manufacturer certification

Table 5-12. Summary of Proposed BACT (Continued, Page 2 of 2)

Emission Unit	Pollutant	Averaging Period	BACT Emission Limit	Compliance Method
Biomass fuel processing				
	PM/PM ₁₀	N/A	Baghouse: 5-percent opacity	EPA Reference Method 9
Material handling sources				
Transfer points	PM/PM ₁₀	N/A	Enclosure, partial enclosure, wet suppression, application of chemical wetting agents Baghouses/bin vents 5-percent opacity	Good operating practices
				EPA Reference Method 9
5-47 Storage silos (dry materials)	PM/PM ₁₀	N/A	Baghouses/bin vents 5-percent opacity	EPA Reference Method 9
	Storage piles	N/A	Wet suppression, application of chemical wetting agents	Good operating practices
	Plant roads	N/A		Good operating practices

Sources: GREC, 2009.
ECT, 2009

6.0 MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY

6.1 METHODOLOGY

GREC will be a major source of HAPs since potential facility emissions exceed 10 tpy for any individual HAP and 25 tpy for total combined HAPs. As a major source of HAPs, the GREC biomass-fired BFB boiler may have been subject to the MACT standards contained in the NESHAP for Industrial, Commercial, and Institutional Boiler and Process Heaters codified as 40 CFR 63, Subpart DDDDD (commonly referred to as the boiler MACT). However, the United States Court of Appeals vacated and remanded this rule effective July 30, 2007. No subsequent rule has been promulgated for industrial, commercial, and institutional boilers or process heaters.

Newly constructed major sources of HAPs without a promulgated 40 CFR 63 NESHAP are subject to a Section 112(g) case-by-case MACT determination in accordance with the provisions of 40 CFR 63.40 through 63.44. Therefore, the GREC BFB boiler, as well as other GREC HAP emission sources, are subject to a case-by-case MACT determination in accordance with 40 CFR 63.42, which states:

“In the event that the permitting authority fails to adopt a program to implement section 112(g) with respect to construction or reconstruction of major sources of HAP...and the permitting authority concludes that it is able to make case-by-case MACT determinations..., the permitting authority may make those determinations.”

Case-by-case MACT determinations for the construction of major sources include the following requirements:

- MACT emission limitations or MACT requirements recommended by the applicant and approved by the permitting authority shall not be less stringent than the emission control, which is achieved in practice by the best controlled similar source; i.e., the MACT *floor*.
- MACT emission limitation and control technology recommended by the applicant and approved by the permitting authority shall achieve the maximum degree of reduction in emissions of HAP, which can be achieved by using those control technologies that can be identified from the available informa-

tion taking into consideration the costs of achieving such emission reductions and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction.

- If the Administrator has either proposed a relevant emission standard pursuant to Section 112(d) or 112(h) of the CAA or adopted a presumptive MACT determination for the source category, which includes the constructed new source, the MACT requirements applied to the constructed major source shall have considered those MACT emission limitations and requirements of the proposed standard or presumptive MACT determinations.

GREC emission sources that will emit HAPs include the biomass-fired BFB boiler and two emergency diesel engines. The emergency diesel engines will only operate up to 96 hr/yr for routine testing and maintenance and will be fired with ULSD diesel fuel oil. Potential HAP emissions associated with the emergency diesel engines will therefore be insignificant; Table A-9 in Appendix A provides HAP emission estimates for the emergency diesel engines. Accordingly, the primary focus of this case-by-case MACT assessment is the BFB boiler.

The case-by-case MACT analysis first established the most stringent emission control achieved in practice by the best controlled similar source. The following sources were reviewed to determine the most stringent emission control achieved in practice:

- Recent FDEP case-by-case MACT or other permit determinations.
- BACT determinations contained in EPA's RBLC database.

Other recent PSD permit determinations that have been issued for similar type facilities and were considered include the following:

- Yellow Pine Energy Company, LLC—Fort Gaines, Georgia.
- Nacogdoches Power, LLC—Sacul, Texas.
- Highlands Ethanol—Brighton, Florida (minor source of HAP emissions).

One additional minor source determination for biomass-fired boilers was identified but not considered since this determination (i.e., Adage Hamilton, LLC, biomass power project proposed for a site in Jasper, Hamilton County, Florida) avoided PSD requirements and thus BACT and MACT review.

The case-by-case MACT analysis evaluated several pollutant categories in establishing MACT emission limitations:

- Inorganic HAP acid gases—Hydrochloric acid and hydrofluoric acid.
- Mercury.
- HAP metals (excluding mercury).
- Organic HAPs.

This grouping of HAPs addresses all of the HAPs regulated by 40 CFR 63.

The information required in an application for a case-by-case MACT determination is contained in 40 CFR 63.43(e) and is summarized as follows:

- Name and physical address of the major source to be constructed.
- Brief description of the major source to be constructed.
- Expected commencement date of construction.
- Expected completion date of construction.
- Anticipated startup date.
- Estimated emission rate of each HAP emitted.
- Any applicable federally enforceable emission limitations.
- Capacity factor and uncontrolled HAP emission rates.
- Controlled HAP emission rates (tpy).
- Proposed emission limitation.
- Proposed control technology.
- Supporting documentation.

GREC emission source descriptions, estimated project milestone dates, and emission rates were previously presented in Section 2.0. Section 4.0 provides a discussion of applicable federal emission limitations. Detailed HAP emission estimates are provided in Appendix A. The following sections provide the proposed emission limitations and control technologies for each group of HAPs evaluated.

6.2 INORGANIC HAP ACID GASES

Inorganic HAP acid gases that will be emitted by the BFB boiler include hydrogen chloride and hydrogen fluoride. Emissions of these two acid gases result from the release of chlorine and fluorine naturally occurring in the biomass fuel.

In general, control technologies used to control emissions of SO₂ will also reduce HAP acid gas emissions. A discussion of available SO₂ emission control technologies was previously provided in Section 5.5 of the BACT analysis. Due to the naturally occurring alkaline (i.e., calcium) content of woody biomass fuel, a portion of the biomass fuel chlorine and fluorine will react within the bed to form chlorine and fluorine compounds that will exit the boiler as fly ash and will be subsequently removed from the boiler flue gas by the fabric filter.

As previously discussed, wet FGD and dry FGD SDA and CDS systems have not been installed on biomass-fired boilers due to their low uncontrolled SO₂ flue gas concentrations. Therefore, GREC LLC proposes BFB technology and DSI as MACT for inorganic HAP acid gases.

For new large solid fuel units, the boiler MACT specified hydrogen chloride as a surrogate for inorganic HAP acid gases with a limit of 0.02 lb/MMBtu. A review of EPA's RBLC database was performed for MACT or BACT determinations for hydrogen chloride and hydrogen fluoride emissions from biomass-fired boilers from 1999 to present. The only MACT determination for hydrogen chloride was for Public Service of New Hampshire Schiller Station and was updated in February 2005. The MACT emission limit was 0.02 lb/MMBtu and was based on using lime injection. There were no other appli-

cable MACT or BACT determinations contained in the RBLC database. Table 6-1 provides a summary of the acid gas (hydrogen chloride and hydrogen fluoride) emission rates for the three recent biomass boiler projects that were considered in this case-by-case MACT analysis. The proposed Highlands Ethanol project is not a major source of HAPs and therefore was not subject to MACT review. However, the hydrogen chloride emission control technology planned for the much smaller Highlands Ethanol BFB boilers is comparable to that proposed for GREC; i.e., injection of an alkaline reagent to neutralize hydrogen chloride followed by a fabric filter. The expected performance of this control technology (i.e., the controlled hydrogen chloride emission rate) is essentially the same for both projects.

Consistent with the approach that was taken for the Boiler MACT, hydrogen chloride is proposed as a surrogate for inorganic HAP acid gases. Hydrogen chloride MACT emission limit proposed for the GREC BFB boiler is summarized as follows:

- Emission Limit—0.006 lb/MMBtu
- Averaging Period—Stack test duration.
- Compliance Method—EPA Reference Methods 26 or 26A (Part 60).

For the emergency diesel engines, limited operation, use of ULSD fuel oil, and compliance with the applicable emission standards of NSPS Subpart IIII is proposed as MACT for inorganic HAP acid gases.

6.3 MERCURY

Mercury emissions from the BFB boiler will be low (i.e., 16.7 lb/yr) due to the low concentration of naturally occurring mercury in the biomass fuels. Due to the low chlorine content of the biomass fuels, mercury in the BFB boiler flue gas is expected to be in the vapor phase as primarily elemental mercury.

Control technologies for mercury include injection of activated carbon followed by a collection device and, for the soluble oxidized forms of mercury, wet scrubbing. Due to the

Table 6-1. Summary of Acid Gas (Hydrogen Chloride and Hydrogen Fluoride) Emission Rates for Similar Biomass-Fired Boilers

Facility	Boiler Type	Fuel	Boiler Rating (MMBtu/hr)	Hydrogen Chloride Emission Rate (lb/MMBtu)	Hydrogen Fluoride Emissions Rate (lb/MMBtu)
Nacogdoches Power, LLC	BFB	Wood chips	1,374	0.0213	None
Yellow Pine Energy Company	FB	Biomass, TDF, ULSD, or propane	1,529	0.006	None
Highlands Ethanol	BFB	Spillage cake and biogas	436	0.0054	None

Source: ECT, 2009.

already low concentration of mercury in the BFB boiler flue gas, neither of these control technologies are considered feasible since removal mercury efficiencies would be low.

For new large solid fuel units, the boiler MACT specified a mercury limit of 3×10^{-6} MMBtu. A review of EPA's RBLC database was performed for MACT or BACT determinations for mercury emissions from biomass-fired boilers from 1999 to present. There are two permit determinations for mercury in the RBLC database. The only MACT determination was 3×10^{-6} lb/MMBtu issued for the Public Service of New Hampshire Schiller Station. The only BACT determination was 0.013 tpy and issued for the South Point Biomass Generation project. Table 6-2 provides a summary of the mercury emission rates for the three recent biomass boiler projects considered in this case-by-case MACT analysis. Estimated GREC BFB boiler mercury emission rates (1.4×10^{-6} MMBtu and 0.0084 tpy) are well below the Boiler MACT and prior MACT/BACT determinations.

Mercury MACT emission limit proposed for the GREC BFB boiler is summarized as follows:

- Emission Limit— 1.4×10^{-6} MMBtu.
- Averaging Period—Stack test duration.
- Compliance Method—EPA Reference Methods 29 (Part 60) or 101A (Part 61).

For the emergency diesel engines, limited operation, use of ULSD fuel oil, and compliance with the applicable emission standards of NSPS Subpart IIII is proposed as MACT for mercury.

6.4 HAP METALS (EXCLUDING MERCURY)

Non-mercury HAP metal emissions will be low due to the relatively low concentration of naturally occurring metals in the biomass fuels. Metal oxides that have condensation temperatures below the BFB boiler flue gas prior to the fabric filter will be removed by the fabric filter as fly ash PM

Table 6-2. Summary of Mercury Emission Rates for Similar Biomass-Fired Boilers

Facility	Boiler Type	Fuel	Boiler Rating (MMBtu/hr)	Mercury Emission Rate (lb/MMBtu)
Nacogdoches Power, LLC	BFB	Wood chips	1,374	2.99×10^{-6}
Yellow Pine Energy Company	FB	Biomass, TDF, ULSD, or propane	1,529	2.50×10^{-6}

Source: ECT, 2009.

Control technologies used to remove filterable PM will also remove particulate metals. A discussion of available PM emission control technologies for the BFB boiler was previously provided in Section 5.7.1 of the BACT analysis. The GREC BFB boiler will be equipped with a fabric filter—the most efficient PM control technology available.

For new large solid fuel units, the boiler MACT specified a filterable PM emission limit of 0.025 lb/MMBtu. A review of EPA's RBLC database was performed for BACT determinations for PM₁₀ emissions from biomass-fired boilers for the past 5 years. The lowest BACT determination for PM₁₀ is 0.01 lb/MMBtu for the Koda Energy project. Table 6-3 provides a summary of the PM₁₀ emission rates for the three recent biomass boiler projects considered in this case-by-case MACT analysis.

Consistent with the approach that was taken for the boiler MACT, PM is proposed as a surrogate for non-mercury HAP metals. PM MACT emission limit proposed for the GREC BFB boiler is summarized as follows:

- Emission Limit—0.015 lb/MMBtu (filterable).
- Averaging Period—Stack test duration.
- Compliance Method—EPA Reference Methods 5 or 17 (Part 60).

The proposed GREC PM emissions rate of 0.015 lb/MMBtu (filterable) is equal to the lowest PM₁₀ emission rate listed in Table 6-3. In addition, the GREC BFB boiler PM emissions will be controlled by a fabric filter, which is considered the highest efficiency control option.

For the emergency diesel engines, limited operation, use of ULSD fuel oil, and compliance with the applicable emission standards of NSPS Subpart IIII is proposed as MACT for non-mercury HAP metals.

6.5 ORGANIC HAPS

The BFB boiler will emit trace amounts of organic HAPs due to incomplete combustion of the biomass fuels; the same mechanism which results in CO and VOC emissions. A

Table 6-3. Summary of PM₁₀ Emission Rates for Similar Biomass-Fired Boilers

Facility	Boiler Type	Fuel	Boiler Rating (MMBtu/hr)	PM ₁₀ Emission Rate (lb/MMBtu)
Nacogdoches Power, LLC	BFB	Wood chips	1,374	0.015
Yellow Pine Energy Company	FB	Biomass, TDF, ULSD, or propane	1,529	0.025

Source: ECT, 2009.

discussion of available CO and VOC emission control technologies was previously provided in Section 5.6.1 of the BACT analysis. For the GREC BFB boiler, good combustion practice (GCP) is the only technically feasible control technology to reduce pollutants resulting from incomplete combustion, including organic HAPs. The large mass of bed material and fluidization achieves high combustion efficiency (approximately 99 percent) and stable combustion to minimize emissions due to incomplete combustion.

For new large solid fuel units, the boiler MACT specified CO as a surrogate for organic HAPs with a limit of 400 ppm corrected to 7-percent oxygen, which is approximately equivalent to 0.3 lb/MMBtu for a woody biomass fired boiler. A review of EPA's RBLC database was performed for BACT determinations for CO emissions from biomass-fired boilers for the past 5 years. The lowest CO emission limit was 0.19 lb/MMBtu for the International Biofuels, Inc., project. Table 6-4 provides a summary of the CO emission rates for the three recent biomass boiler projects considered in this case-by-case MACT analysis. Each of the projects listed in Table 6-4 have proposed the use of GCP to control CO emissions. The expected performance of GCP technology will vary depending on the boiler design (e.g., boiler size, combustion temperatures, residence times, etc.). The proposed Highlands Ethanol BFB boilers heat input rating of 218 MMBtu/hr per boiler is approximately one-sixth the size of the GREC BFB boiler. The CO emission limit proposed for the GREC BFB boiler is slightly lower than the two projects shown in Table 6-4 that are approximately the same size.

Consistent with the approach that was taken for the boiler MACT, CO is proposed as a surrogate for organic HAPs. PM MACT emission limit proposed for the GREC BFB boiler is summarized as follows:

- Emission Limit—0.120 lb/MMBtu.
- Averaging Period—30-day rolling average.
- Compliance Method— Continuous emissions monitoring in accordance with 40 CFR 60.

Table 6-4. Summary of CO Emission Rates for Similar Biomass-Fired Boilers

Facility	Boiler Type	Fuel	Boiler Rating (MMBtu/hr)	CO Emission Rate (lb/MMBtu)
Nacogdoches Power, LLC	BFB	Wood chips	1,374	0.15
Yellow Pine Energy Company	FB	Biomass, TDF, ULSD, or propane	1,529	0.149
Highlands Ethanol	BFB	Spillage cake and biogas	436	0.10

Source: ECT, 2009.

7.0 AIR QUALITY IMPACT ANALYSIS METHODOLOGY

7.1 GENERAL APPROACH

As previously noted in Section 3.1, GREC will be located in an area designated attainment or unclassifiable for all criteria pollutants. All areas of Florida, with the exception of four PSD Class I areas, are designated as PSD Class II areas. Accordingly, the GREC Site and vicinity are classified as a PSD Class II area. This section focuses on the methodology used to determine project air quality impacts with respect to the PSD Class II increments and the NAAQS.

Florida PSD Class I areas include the Everglades National Park and the Chassahowitzka, St. Marks, and Bradwell Bay National Wilderness Areas. GREC air quality impacts with respect to PSD Class I areas are addressed in Section 11.0.

The approach to assessing air quality impacts for a new or modified emission source generally begins by determining the impacts of only the proposed facility. If facility impacts are below the PSD SILs, then no further analysis is required. The PSD Class II SILs were previously presented in Table 3-4. If the impacts of a proposed facility are found to exceed a particular PSD SIL, further analysis considering other existing sources and background pollutant concentrations is required. With the exception of PM₁₀, GREC impacts are predicted to be below the PSD SILs. Accordingly, an analysis of PSD increments and NAAQS was only required for PM₁₀.

The approach used to analyze the potential impacts from the facility, as described in detail in the following subsections, was developed in accordance with applicable federal and state laws and related guidelines. Guidance contained in EPA manuals and user's guides was sought and followed. In addition, an air dispersion modeling protocol was submitted to FDEP in July 2009 for review and comments. The air quality impact analyses conducted for the facility incorporates the comments and suggestions received from FDEP and EPA Region 4 on the modeling protocol. Appendix C contains the proposed modeling protocol and FDEP and EPA comments.

7.2 POLLUTANTS EVALUATED

Based on an evaluation of anticipated worst-case annual operating scenarios, GREC will have the potential to emit 418.1 tpy of NO_x, 715.6 tpy of CO, 130.4 tpy of PM, 281.2 tpy of PM₁₀, 243.9 tpy of SO₂, 78.1 tpy of VOCs, and 5.9 tpy of H₂SO₄ mist. Table 3-2 previously provided the estimated potential annual emission rates for GREC. As shown in that table, potential emissions of NO_x, CO, VOC, PM, PM₁₀, and SO₂ are each projected to exceed the applicable PSD significant emission rates. In accordance with current EPA policy, PM₁₀ was used as a surrogate for PM_{2.5}. Potential GREC emissions are below the applicable PSD significant emission rates for all other regulated pollutants.

GREC is subject to the PSD air quality impact analysis requirements for NO_x (as NO₂), CO, SO₂, and PM₁₀. There are no applicable AAQS or PSD increments for PM and VOC, and, therefore, air quality impact analyses are not required for these pollutants.

7.3 MODEL SELECTION AND USE

For this air quality analyses, the current version of the refined American Meteorological Society (AMS)/EPA regulatory model (AERMOD) modeling system (Version 09292—October 19, 2009), together with 5 years of hour-by-hour National Weather Service (NWS) meteorological data, was used to predict short-term periods (i.e., periods equal to or less than 24 hours) and annual average air quality impacts. Two BFB boiler operational cases (i.e., 70- and 100-percent load) were modeled for each pollutant/averaging period and each year of meteorological data.

Regulatory agency recommended procedures for conducting air quality impact assessments are contained in the EPA's GAQM. In the November 9, 2005, Federal Register (F.R.), EPA approved use of AERMOD as a GAQM Appendix A *preferred* model effective December 9, 2005. AERMOD is recommended for use in a wide range of regulatory applications, including both simple and complex terrain. The AERMOD modeling system consists of meteorological and terrain preprocessing programs (AERMET and AERMAP, respectively), and the AERMOD dispersion model.

7.4 MODEL OPTIONS

Procedures applicable to the AERMOD modeling system specified in the latest version of the User's Guide for the AMS/EPA Regulatory Model—AERMOD (September 2004, currently under revision), the October 2009 Addendum to the User's Guide, and the current GAQM were followed. In addition, guidance from the EPA AERMOD Implementation Guide (updated March 19, 2009) was applied. In particular, the AERMOD control pathway MODELOPT keyword parameters DFAULT and CONC were selected. Selection of the parameter DFAULT, which specifies use of the regulatory default options, is recommended by the GAQM. The CONC option specifies the calculation of concentrations. GREC will be located in an area of Alachua County that is mostly rural with some commercial and industrial use. Accordingly, AERMOD options pertinent to urban areas including increased surface heating (URBANOPT keyword) and pollutant exponential decay (HALFLIFE and DCAYCOEF keywords) were not employed. In addition, the option to use flagpole receptors (FLAGPOLE keyword) was not selected. As previously mentioned, the AERMOD modeling system was used to determine short-term and annual average impacts by using the PERIOD parameter for the AVERTIME keyword.

7.5 NO₂ AMBIENT IMPACT ANALYSIS

For annual NO₂ impacts, the tiered screening approach described in the GAQM, Section 5.2.4, was used. Tier 1 of this screening procedure assumes complete conversion of NO_x to NO₂. Tier 2 applies an empirically derived NO₂/NO_x ratio of 0.75 to the Tier 1 results.

7.6 TERRAIN CONSIDERATION

The GAQM defines *flat* terrain as terrain equal to the elevation of the stack base, *simple* terrain as terrain lower than the height of the stack top, and *complex* terrain as terrain exceeding the height of the stack being modeled. AERMOD contains algorithms for estimating air quality impacts in flat, simple, and complex terrain.

The elevation of GREC is approximately 185 feet above mean sea level (ft-msl). The GREC BFB boiler stack will have a height of 230 feet above ground level (ft-agl). Accordingly, terrain elevations above 415 ft-msl would be classified as complex terrain. USGS National Elevation Dataset/Shuttle Radar Topography Mission (NED/SRTM) terrain data in geo-referenced tagged image file format (GeoTIFF) were examined for terrain features within the GREC impact area. The topography in the vicinity of GREC is mostly flat. Terrain elevations within 15 km of the project site range from 43.5 to 198.5 ft-msl. Based on this examination, terrain in the vicinity of the Site is classified as flat and simple terrain.

In accordance with the latest GAQM recommendations for AERMOD, each modeled receptor was assigned a terrain elevation based on USGS NED/SRTM data and the AERMAP (Version 09040—February 9, 2009) terrain preprocessing program. AERMAP was used in accordance with the latest version of the User's Guide for the AERMOD Terrain Preprocessor (AERMAP), addenda to the User's Guide, and EPA's GAQM.

7.7 BUILDING WAKE EFFECTS

The CAA Amendments require the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds good engineering practice (GEP) or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (40 CFR 51). GEP stack heights for the facility emission sources will comply with EPA promulgated final stack height regulations (40 CFR 51). GEP stack height is defined as the highest of 65 meters (213 ft), or a height established by applying the formula:

$$H_g = H + 1.5 L$$

where: H_g = GEP stack height.

H = height of the structure or nearby structure.

L = lesser dimension (height or projected width) of the nearby structure.

Nearby is defined as a distance up to five times the lesser of the height or width dimension of a structure or terrain feature, but not greater than 800 meters (2,625 ft). While

GEP stack height regulations require that stack height used in modeling for determining compliance with NAAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater. Guidelines for determining GEP stack height have been issued by EPA (1985).

The height proposed for the BFB boiler stack (230 ft-agl) is greater than the maximum regulatory GEP stack height of 213 ft (65 meters). However, based on the height of the boiler (i.e., 180 ft-agl), the BFB boiler stack will be less than GEP as defined by the formula. Since the proposed BFB boiler stack height will comply with the EPA promulgated final stack height regulations and will also comply with applicable Federal Aviation Authority (FAA) requirements, it was used in the modeling analyses.

While the GEP stack height rules address the maximum stack height that can be employed in a dispersion model analysis, a stack having a height lower than GEP stack height can potentially result in higher downwind concentrations due to building downwash effects. AERMOD evaluates the effects of building downwash based on the Plume Rise Model Enhancements (PRIME) building downwash algorithms. For the ambient impact analysis, the downwash analysis implemented by AERMOD was performed using the current version of EPA's Building Profile Input Program (BPIP) for PRIME (BPIP-PRM—Version 04274 [September 30, 2004]). The EPA BPIP-PRM program was used to determine the area of influence for each building, whether a particular stack is subject to building downwash, the area of influence for directionally dependent building downwash, and finally to generate the specific building dimension data required by the model. BPIP-PRM output consists of an array of 36 direction-specific (10° to 360°) building heights (BUILDHGT keyword), lengths (BUILDLN keyword), widths (BUILDWID keyword), and along-flow (XBADJ keyword) and across-flow (YBADJ keyword) distances for the stack suitable for use as input to AERMOD.

Table 7-1 provides dimensions of the buildings/structures evaluated for wake effects. The building/structure dimensions were determined from engineering layouts and specifications. Figure 7-1 shows the buildings/structures in three dimensions.

Table 7-1. Building and Structure Dimensions

Building/Structure	Modeling ID	Height		Length		Width	
		ft	meter	ft	meter	ft	meter
Boiler tier 1	BLD_14T1	179.0	54.6	87.6	26.7	90.2	27.5
Boiler tier 2	BLD_14T2	115.0	35.1	35.4	10.8	90.2	27.5
Truck receiving	BLD_58	54.0	16.5	26.3	8.0	54.9	16.7
Cooling tower	BLD_9	50.0	15.2	60.1	18.3	241.3	73.5
Raw water/firewater tank	BLD_17	50.0	15.2	70.2*	21.4*	—	—
Water treatment and pad	BLD_5	45.0	13.7	49.4	15.1	64.4	19.6
Baghouse PDC	BLD_23	70.0	21.3	60.7	18.5	137.8	42.0
Hog/screen structure	BLD_29	77.0	23.5	50.0	15.2	66.1	20.2
Warehouse	BLD_3	40.0	12.2	62.3	19.0	115.0	35.0
Control room/office	BLD_21	30.0	9.1	49.3	15.0	99.8	30.4
Fire pumps	BLD_20	55.0	16.8	15.4	4.7	49.3	15.0
Steam turbine	BLD_8	40.0	12.2	53.7	16.4	109.6	33.4
Fuel day bins structure	BLD_13	60.0	18.3	47.7	14.5	89.3	27.2
Sorbent silo	67_SORBENT	45.0	13.7	14.1*	4.3*	—	—
Fly ash silo	BLD_22	70.0	21.3	20.0*	6.1*	—	—
Sawdust storage pile	65_SAWDUST	12.0	3.7	211.6	64.5	134.2	40.9
Fuel storage 2	64_FUELSTRG2	35.0	10.7	459.3	140.0	416.7	127.0
Fuel storage 1	50_FUELSTRG1	85.0	25.9	393.7	120.0	393.7	120.0
Stock pile # 1	44_STCKPILE1	60.0	18.3	120*	36.6*	—	—

*Dimension represents structure diameter

Source: ECT, 2009.

7-7



FIGURE 7-1.
BUILDING/STRUCTURE THREE DIMENSIONAL VIEW

Source: Zachry, 2009; ECT, 2009.

7.8 RECEPTOR GRIDS

Receptors were placed at locations considered to be ambient air, which is defined as “that portion of the atmosphere, external to buildings, to which the general public has access.” The entire perimeter of the GREC leased Site will be fenced. Therefore, the nearest locations of general public access are at the facility fence lines. Consistent with GAQM recommendations, the ambient impact analysis used the following receptor grids:

- Fence Line Receptors—Receptors placed on the site fence line spaced 50 meters apart.
- Near-Field Cartesian Receptors—Receptors at 100-meter spacing beyond the fence line extending to approximately 3 km.
- Mid-Field Cartesian Receptors—Receptors at 500-meter spacing extending to approximately 6 km.
- Far-Field Cartesian Receptors—Receptors at 1,000-meter spacing extending to approximately 15 km.

The origin of the above Cartesian receptor grids was located at the approximate center of GREC. Following initial modeling of the BFB boiler, it was determined that maximum impacts will occur within 1 km of the boiler stack. For the assessment of GREC PM₁₀ impacts, a Cartesian receptor grid centered on the GREC power block area with a 100-meter spacing extending to 2 km was employed. The full receptor grid was used to evaluate the GREC CO impacts.

As noted previously, the AERMOD results demonstrate that GREC air quality impacts will be below the PSD SILs for all pollutants and averaging times with the exception of PM₁₀. Accordingly, a receptor grid consisting of the specific GREC emission source receptors that exceeded the PSD Class II PM₁₀ SILs was developed. This grid included any receptor for which an SIL was exceeded for any averaging time, year, or set of meteorological data. These PM₁₀ SIL exceedance receptor grids were subsequently used for the cumulative PM₁₀ PSD Class II increment and NAAQS analyses.

Graphical representations of the receptor grids are provided as follows:

- Figure 7-2. Fence Line Receptors.
- Figure 7-3. Near- to Far-Field Receptors (fence line to 15 km).
- Figure 7-4. Refined 2-km Receptor Grid (GREC PM₁₀ sources).
- Figure 7-5. PM₁₀ SIL Receptor Grid.

7.9 METEOROLOGICAL DATA

The EPA AERMET and AERSURFACE meteorological data preprocessing programs were used to generate the meteorological input files required by AERMOD.

The AERMET meteorological preprocessing program creates two files that are used by AERMOD (i.e. surface and profile files). The surface file contains boundary layer parameters including friction velocity, Monin-Obukhov length, convective velocity scale, temperature scale, convectively generated boundary layer (CBL) height, stable boundary layer (SBL) height, and surface heat flux. The profile file contains multilevel data of windspeed, wind direction, and temperature.

AERMET passes all observed meteorological parameters to AERMOD, including wind direction and speed (at multiple heights, if available), temperature, and, if available, measured turbulence. AERMOD uses this information to calculate concentrations in a manner that accounts for a dispersion rate that is a continuous function of meteorology. The current EPA-approved version of AERMET (Version 06341 – December 7, 2006) was used in accordance with the latest version (November) (EPA, 2004c) of the *User's Guide for the AERMOD Meteorological Preprocessor (AERMET)*, addenda to the User's Guide (EPA, 2006c), and EPA's GAQM.

The AERMET meteorological processor requires the determination of three surface characteristics: surface roughness length (z_0), albedo (α), and Bowen ratio (B_0). Surface roughness length is related to the height of obstacles to the wind flow and is the height at which the mean horizontal wind speed is zero based on a logarithmic profile. Surface roughness length influences the surface shear stress and is an important factor in

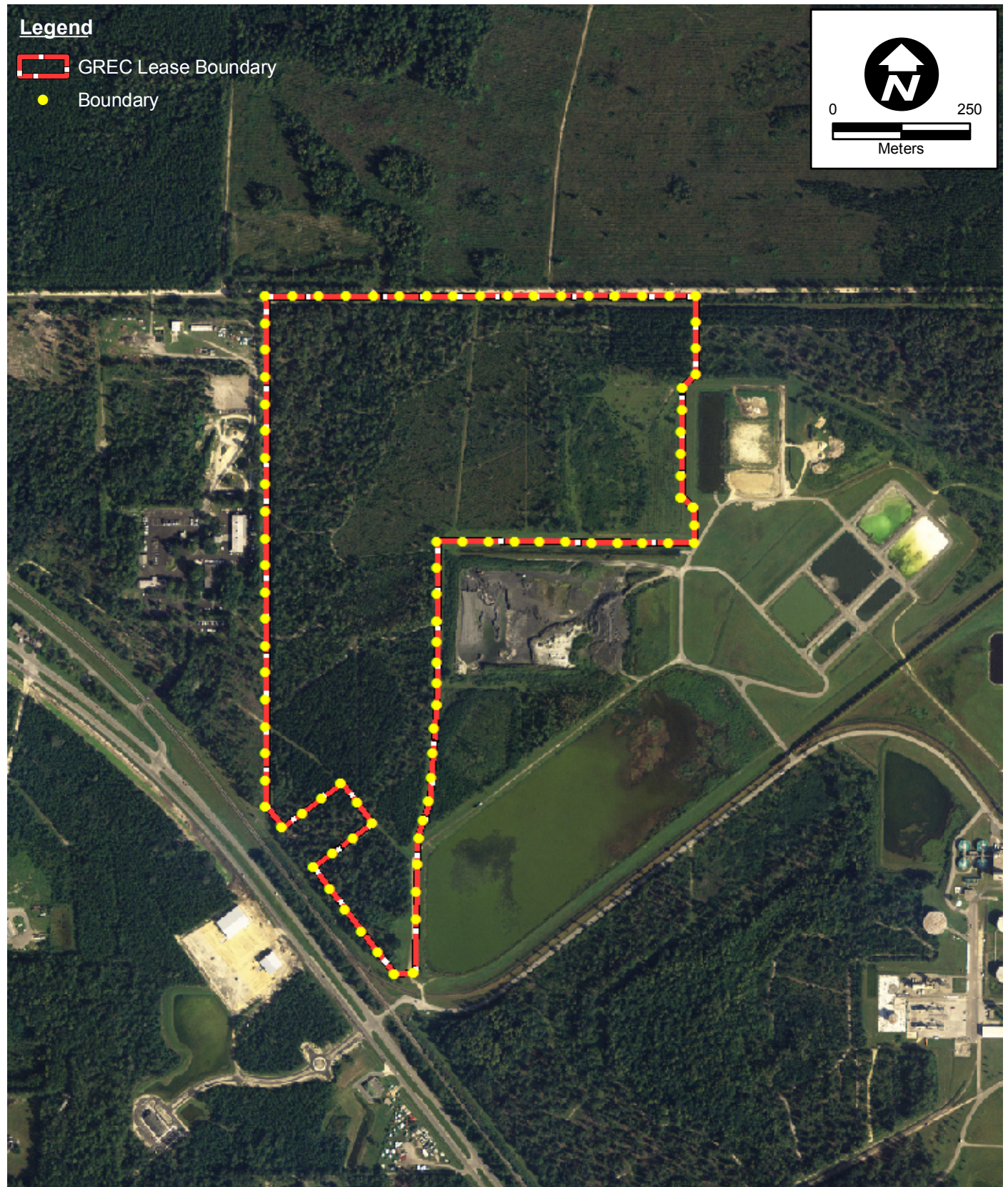


FIGURE 7-2.

FENCE LINE RECEPTOR GRID

Sources: NRCS, 2007; ECT, 2009,

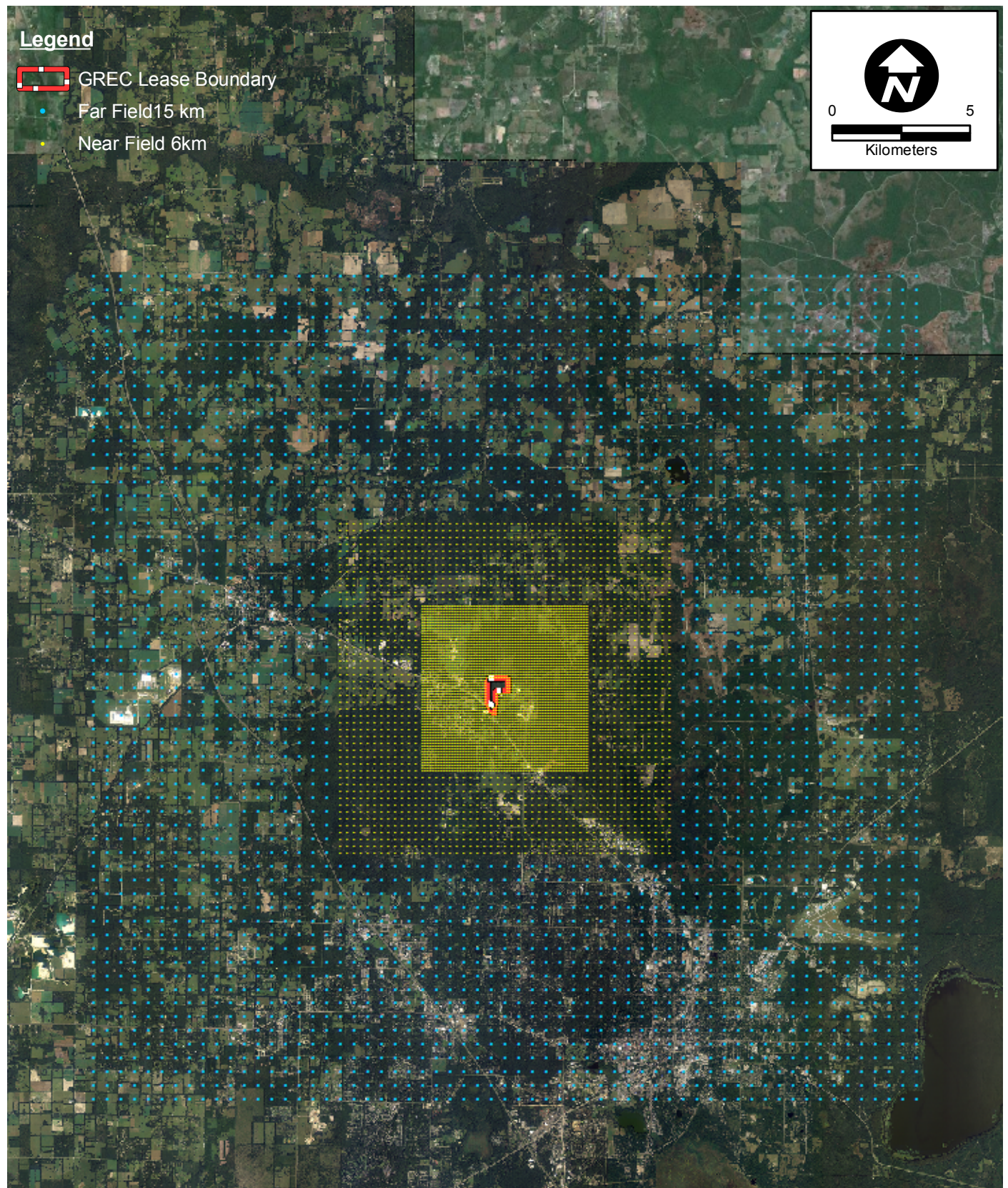


FIGURE 7-3.

NEAR AND FAR FIELD RECEPTOR GRIDS

Sources: NRCS, 2007; ECT, 2009,

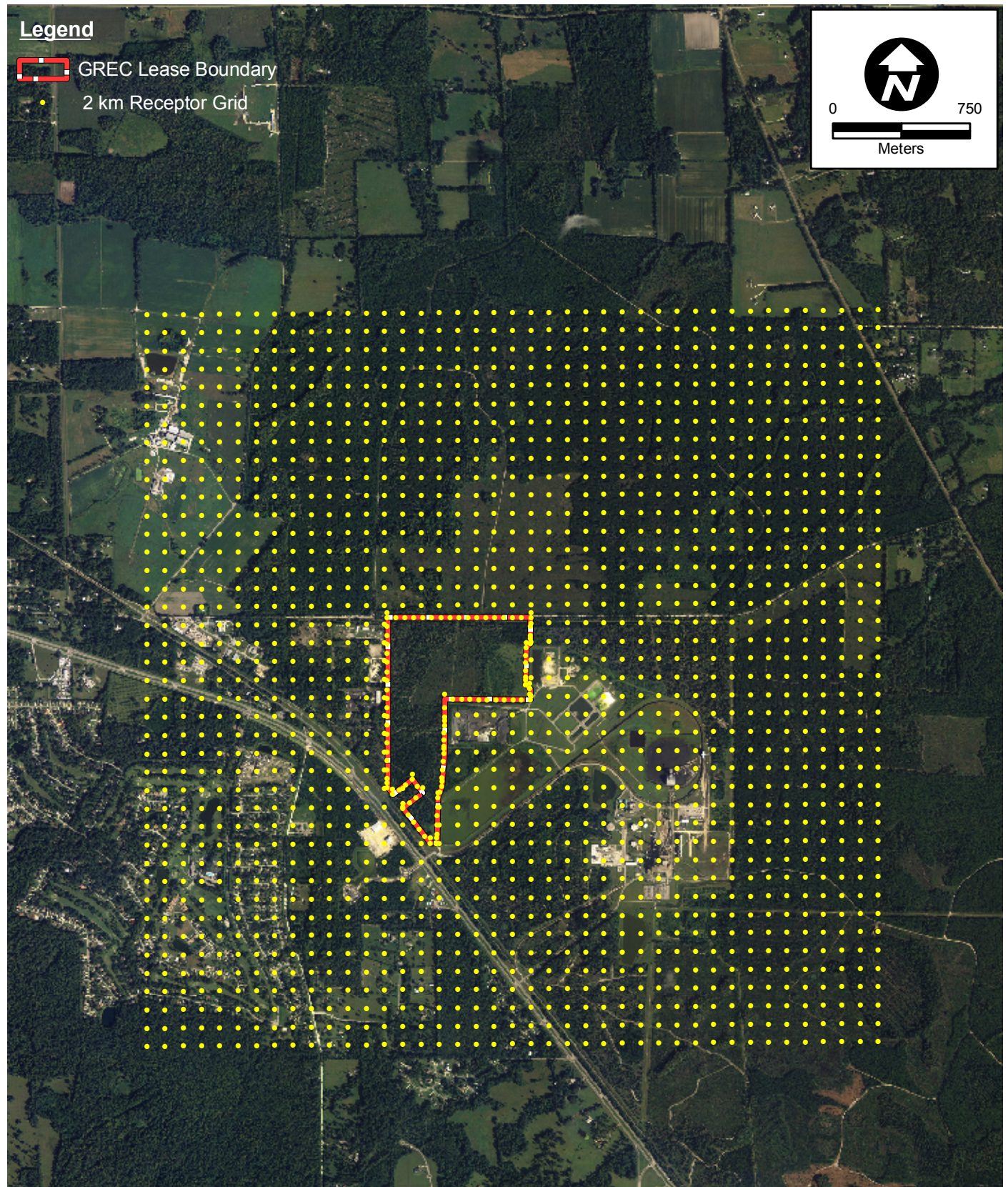


FIGURE 7-4.

2 km RECEPTOR GRID

Sources: NRCS, 2007; ECT, 2009,

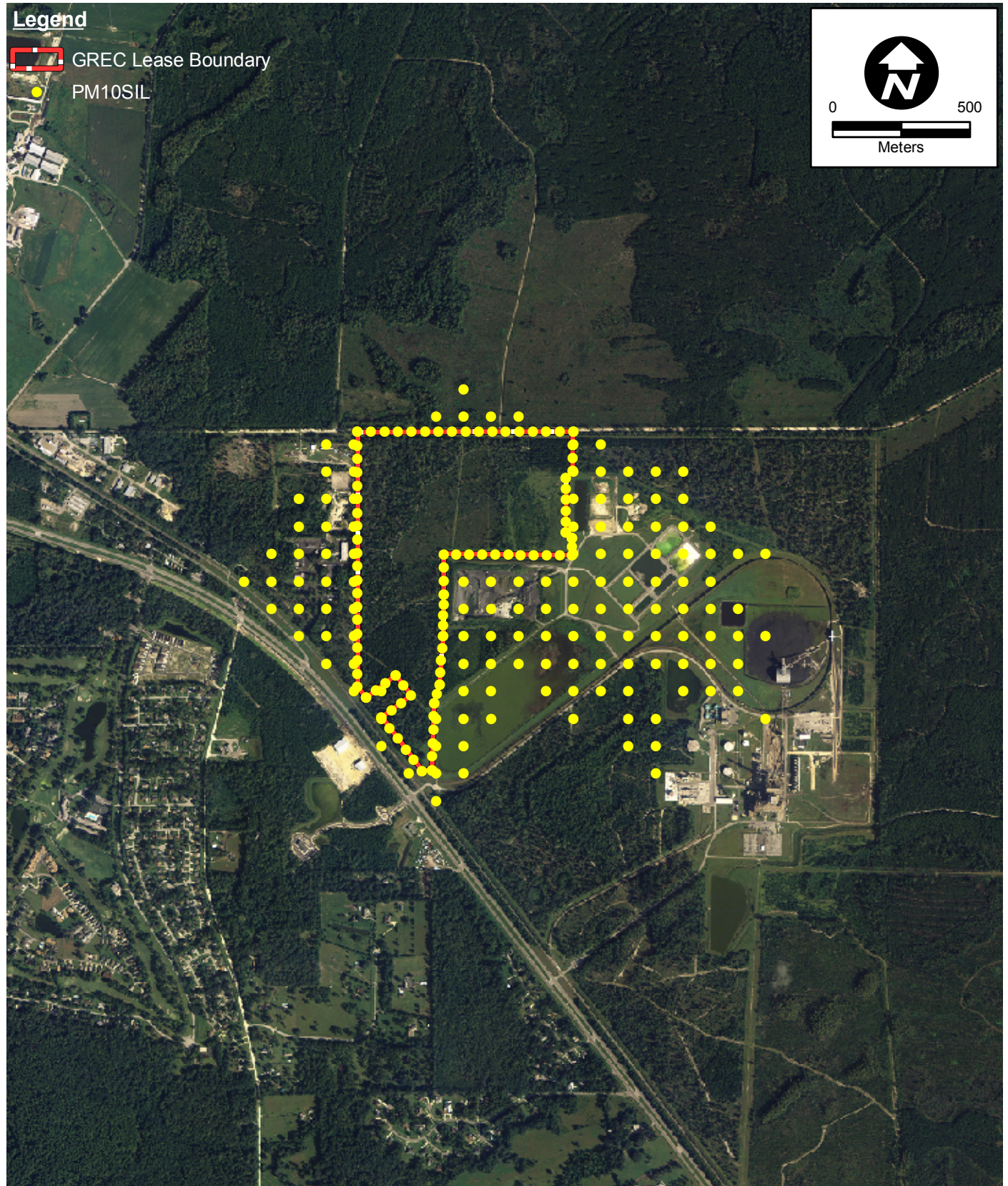


FIGURE 7-5.

PM10 SIL RECEPTOR GRID

Sources: NRCS, 2007; ECT, 2009,

determining the magnitude of mechanical turbulence and the stability of the boundary layer. Albedo is the fraction of total incident solar radiation reflected by the surface back to space without absorption. The daytime Bowen ratio, an indicator of surface moisture, is the ratio of sensible heat flux to latent heat flux and, together with albedo and other meteorological observations, is used for determining planetary boundary layer parameters for convective conditions driven by the surface sensible heat flux. The EPA AERSURFACE program was developed to aid users in obtaining realistic and reproducible surface characteristic values, including albedo, Bowen ratio, and surface roughness length, for input to AERMET. The program uses publicly available national land cover datasets and look-up tables of surface characteristics that vary by land cover type and season. The current EPA-approved version of AERSURFACE (Version 08009 – January 9, 2008) was used in accordance with the latest version (January 2008) of the *AERSURFACE User's Guide*, updates to the User's Guide, and EPA's GAQM.

AERSURFACE contains a set of seasonal surface characteristics which are based on data reported in the literature. Values of seasonal surface characteristics were developed for the continental U.S. for the following five seasonal categories:

- Midsummer with lush vegetation.
- Autumn with un-harvested cropland.
- Late autumn after frost and harvest, or winter with no snow.
- Winter with continuous snow on ground.
- Transitional spring with partial green coverage or short annuals.

These categories are the same as those used by AERMOD for the model's gas deposition algorithms. The user is given the option of assigning specific calendar months to each seasonal category based on site-specific factors. If this option is selected, AERSURFACE will generate monthly or annual surface characteristics for input to AERMET. This option allows for a better evaluation of site-specific surface characteristics compared to the AERSURFACE defaults. For processing the GREC north-central Florida meteorological data, calendar months were assigned to the five seasonal categories as follows.

- Due to short seasonal transition periods in the spring and fall, the months of March and April were assigned to seasonal category 5, and the months of October and November were assigned to seasonal category 2.
- The summer season in north-central Florida is relatively long, starting earlier in the year and ending later than in most of the continental United States. Therefore, the months of May, June, July, August, and September were assigned to seasonal category 1, thus extending the summer season category.
- The months of December, January, and February were assigned to seasonal category 3.
- Since north-central Florida does not experience any periods of winter with continuous snow on the ground, none of the months were assigned to seasonal category 4.

The nearest source of surface meteorological data is the NWS site (Weather-Bureau-Army-Navy [WBAN] Station No. 12816) located at the Gainesville Regional Airport (GRA) approximately 10 miles southeast of GREC. The nearest source of upper air meteorological data is the NWS site (WBAN Station No. 13889) located at the Jacksonville International Airport (JIA) approximately 66 miles northeast of GREC. Based on the proximity of GRA and JIA meteorological stations and in accordance with FDEP guidance, the most recent 5 years (i.e., 2001 through 2005) of readily available surface and upper air meteorological data from GRA and JIA were selected for the GREC air quality impact analysis.

Since surface characteristics influencing dispersion within 1 km of the GRA meteorological station differ from GREC, two sets of meteorological data were prepared for use in the model. Each dataset contains 5 consecutive years (i.e., 2001 through 2005) of GRA surface and JIA upper air meteorological data. The first set used the surface characteristics of the GRA site (see Table 7-2), while the second set employed GREC surface characteristics (see Table 7-3). Figures 7-6 and 7-7 provide aerial views of the GRA and GREC Site, respectively. Both 5-year sets of GRA/JIA meteorological data, in

Table 7-2. Summary of Seasonal AERMET Surface Characteristics for GRA

Sectors	Winter			Spring			Summer			Fall		
	Albedo	Bowen Ratio	Surface Roughness	Albedo	Bowen Ratio	Surface Roughness	Albedo	Bowen Ratio	Surface Roughness	Albedo	Bowen Ratio	Surface Roughness
1	0.14	0.63	0.101	0.14	0.51	0.126	0.14	0.37	0.148	0.14	0.61	0.134
2	0.14	0.63	0.195	0.14	0.51	0.221	0.14	0.37	0.257	0.14	0.61	0.242
3	0.14	0.63	0.472	0.14	0.51	0.514	0.14	0.37	0.561	0.14	0.61	0.549
4	0.14	0.63	1.186	0.14	0.51	1.201	0.14	0.37	1.201	0.14	0.61	1.201
5	0.14	0.63	1.049	0.14	0.51	1.072	0.14	0.37	1.078	0.14	0.61	1.078
6	0.14	0.63	1.093	0.14	0.51	1.103	0.14	0.37	1.105	0.14	0.61	1.105
7	0.14	0.63	1.143	0.14	0.51	1.159	0.14	0.37	1.196	0.14	0.61	1.196
8	0.14	0.63	0.894	0.14	0.51	0.907	0.14	0.37	0.938	0.14	0.61	0.938
9	0.14	0.63	1.166	0.14	0.51	1.173	0.14	0.37	1.182	0.14	0.61	1.182
10	0.14	0.63	0.237	0.14	0.51	0.28	0.14	0.37	0.32	0.14	0.61	0.304
11	0.14	0.63	0.048	0.14	0.51	0.068	0.14	0.37	0.085	0.14	0.61	0.075
12	0.14	0.63	0.041	0.14	0.51	0.056	0.14	0.37	0.07	0.14	0.61	0.06

Source: ECT, 2009.

Table 7-3. Summary of Seasonal AERMET Surface Characteristics for GREC

Sectors	Winter			Spring			Summer			Fall		
	Albedo	Bowen Ratio	Surface Roughness	Albedo	Bowen Ratio	Surface Roughness	Albedo	Bowen Ratio	Surface Roughness	Albedo	Bowen Ratio	Surface Roughness
1	0.14	0.69	1.252	0.14	0.49	1.261	0.14	0.36	1.261	0.14	0.65	1.261
2	0.14	0.69	1.274	0.14	0.49	1.277	0.14	0.36	1.277	0.14	0.65	1.277
3	0.14	0.69	1.122	0.14	0.49	1.128	0.14	0.36	1.128	0.14	0.65	1.128
4	0.14	0.69	0.37	0.14	0.49	0.382	0.14	0.36	0.435	0.14	0.65	0.435
5	0.14	0.69	0.429	0.14	0.49	0.432	0.14	0.36	0.439	0.14	0.65	0.439
6	0.14	0.69	0.166	0.14	0.49	0.167	0.14	0.36	0.17	0.14	0.65	0.17
7	0.14	0.69	0.925	0.14	0.49	0.934	0.14	0.36	0.947	0.14	0.65	0.947
8	0.14	0.69	0.743	0.14	0.49	0.771	0.14	0.36	0.793	0.14	0.65	0.793
9	0.14	0.69	0.715	0.14	0.49	0.806	0.14	0.36	0.87	0.14	0.65	0.87
10	0.14	0.69	0.86	0.14	0.49	0.886	0.14	0.36	0.91	0.14	0.65	0.91
11	0.14	0.69	1.084	0.14	0.49	1.103	0.14	0.36	1.148	0.14	0.65	1.148
12	0.14	0.69	1.211	0.14	0.49	1.226	0.14	0.36	1.226	0.14	0.65	1.226

Source: ECT, 2009.



FIGURE 7-6.
AERIAL VIEW OF GAINESVILLE REGIONAL AIRPORT

Sources: SJRWMD, 2007; ECT, 2009.

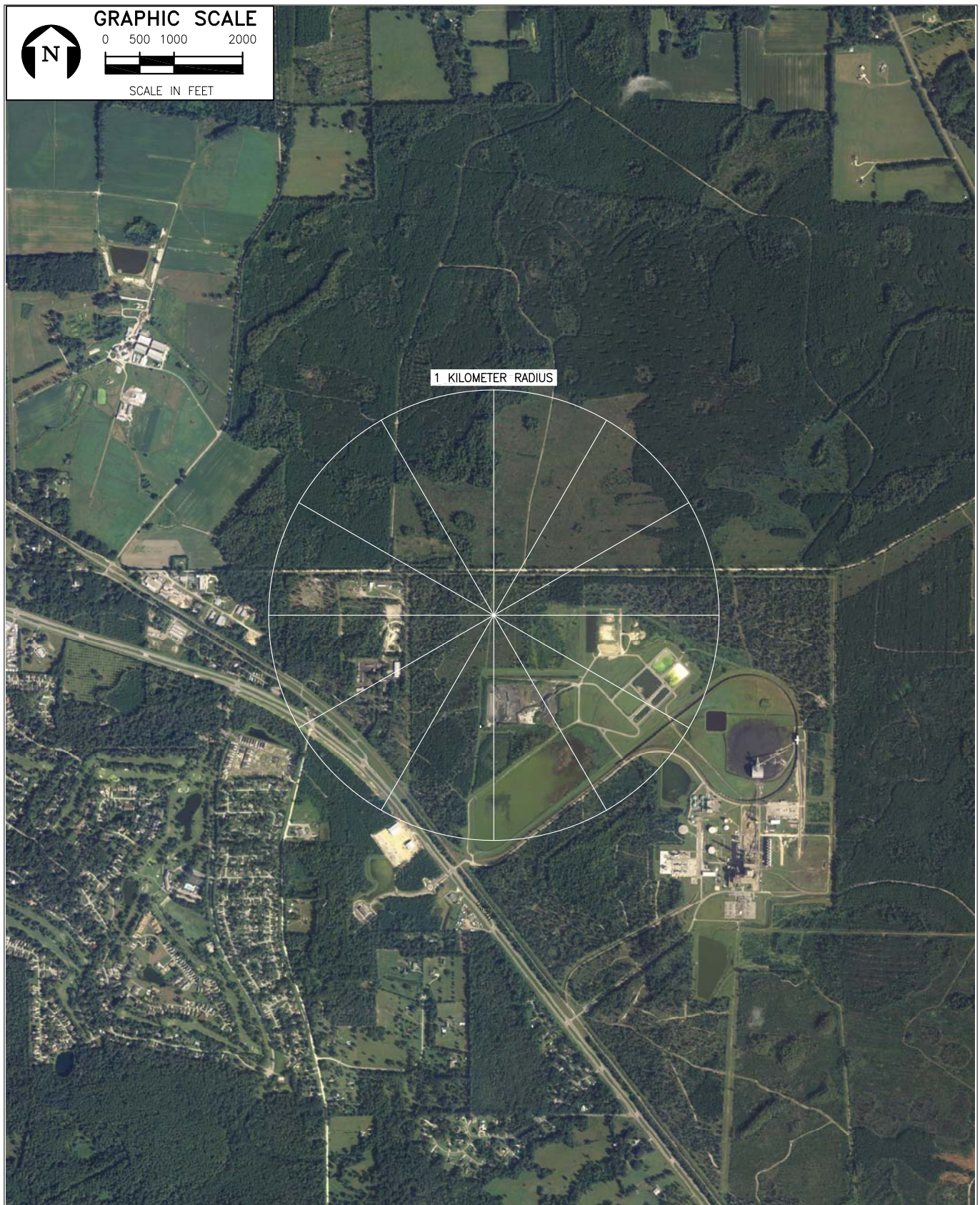


FIGURE 7-7.
AERIAL VIEW OF GREC SITE

Sources: SJRWMD, 2007; ECT, 2009.

 Gainesville
Renewable Energy Center
An American Renewables Company

conjunction with the AERMOD dispersion model, were used to determine maximum GREC air quality impacts.

7.10 MODELED EMISSION INVENTORY

7.10.1 ON-PROPERTY SOURCES

GREC emission sources addressed in the air quality impact analysis include the BFB boiler, material handling point emission sources (i.e., baghouses), mechanical draft cooling tower, emergency diesel engines, and fugitive emission sources associated with material handling and truck traffic roadway emissions. The BFB boiler and emergency diesel engines will emit pollutants associated with fuel combustion. The remaining GREC emission sources will all emit only PM₁₀.

All GREC emissions sources were assessed for PM₁₀ impacts. For evaluating NO_x and SO₂ impacts, detailed modeling was only performed for the BFB boiler stack. While the emergency diesel engines also emit these pollutants, the engines will operate infrequently (up to 96 hr/yr for routine testing and maintenance) and will combust ULSD fuel oil. Accordingly, emergency diesel engine annual average NO₂ and SO₂ impacts will be insignificant. Short-term SO₂ impacts will also be insignificant due to the low SO₂ emission rates resulting from the use of ULSD fuel oil; e.g., the emergency generator diesel engine maximum SO₂ emission rate is only 0.0078 lb/hr. When operated for routine testing and maintenance, the emergency diesel engines may operate for a period of up to 2 hours in a 24-hour period. Accordingly, assessment of GREC CO impacts included the emergency diesel engines as well as the BFB boiler.

The BFB boiler, material handling sources equipped with baghouses, cooling tower, and emergency diesel engines were modeled as point sources. Excluding startups and shutdowns, the BFB boiler will operate between 70 and 100 percent of full load. Emissions from the BFB boiler will decrease with reduced load. However, the BFB boiler exhaust flow rate and stack exit velocity will also decrease. The interaction of these two variables could potentially result in higher impacts at reduced boiler load. Accordingly, the BFB boiler was modeled at the minimum (70 percent) and maximum (100 percent) steady-

state operating loads. The locations, stack parameters, and emissions rates for the GREC point sources were previously provided in Section 2.0 of this report.

The fugitive PM₁₀ material transfer points and plant roadway truck traffic were modeled as volume sources. The initial dispersion parameters associated with the volume sources were based on the physical dimensions of structures at the transfer point or, in the case of the roadways, on the dimensions of the trucks in conjunction with the turbulence produced by their movement. The roadways were depicted in the model as a series of nonadjacent volume sources. The volume source locations and emission rates were previously provided in Section 2.0 of this report.

7.10.2 OFF-PROPERTY SOURCES

Since PM₁₀ impacts from GREC were predicted to exceed the SILs, interactive modeling including other offsite sources was performed to demonstrate compliance with the NAAQS and PSD Class II increments. FDEP supplied a list of industrial sources within 60 km of GREC. In addition to the source locations, the list included other useful information including source description, annual and short-term emission rates, and stack parameters. The FDEP list was supplemented with permit information obtained from FDEP's air permit documents search Web site www.dep.state.fl.us/air/emission/apds/default.asp.

It is regulatory agency policy to include all off-property sources within a radius of 50 km from the maximum distance to any significant receptor. Since the maximum distance to significance is less than 10 km, including off-property sources within a 60-km radius is conservative. In addition, the entire NAAQS inventory was conservatively used for both the NAAQS analysis and the PSD increment analysis; i.e., all sources were assumed to consume PSD increment. To reduce the number of other sources included in the modeling, only sources reasonably expected to significantly impact the SIA were selected. A screening procedure, commonly referred to as the North Carolina 20D Rule, was used. The first step in this procedure is to multiply the distance (D) of the source from the edge of the SIA in km by 20 to obtain the value 20D. This defines the threshold value in tpy

for each pollutant being studied. Facilities with emissions below 20D are assumed to not be able to contribute significantly within the SIA and are eliminated from the inventory. The complete list of facilities and the results of the 20D screening procedure are shown in Table 7-4. Even though the SIA for PM₁₀ was found to be less than 10 km, all sources within 10 km of GREC were included in the modeling, and 10 km was subtracted from the total distance to the source to define the value for D. Also, only stack emissions were included in the inventory, because fugitive PM₁₀ emissions from distant sources would not be expected to impact significantly within the SIA. In addition, it was possible to eliminate sources not having numerical emission limits; i.e., sources whose particulate emissions are controlled by a visible emissions limit.

There were 18 facilities included in the FDEP list for which PM₁₀ emissions rate data were missing and for which additional information could not be located in the FDEP permit documents database. Since it is believed that major sources having PSD and Title V permits are likely to be included in FDEP's permit database, the 14 facilities with missing information and 20D thresholds greater than 100 tpy were felt to be good candidates for elimination; i.e., none of those facilities were likely to have potential PM₁₀ emissions greater than 100 tpy. The Milam Funeral crematorium facility had a 20D threshold of 91.2 tpy. Since it is unlikely that this facility would exceed this threshold, it was also eliminated. Three facilities that did not have available permit information were within 10 km of GREC. Two of the facilities incinerate animal remains, and the third has two natural gas-fired boilers. None of these facilities are expected to have significant PM₁₀ impacts.

Table 7-5 contains the emissions and stack parameters of the sources that were selected to be included in the modeling. Figure 7-8 shows the location of the off-property facilities that were selected for modeling. Following are notes concerning sources of the facilities that were included in the inventory:

- J.R. Kelly Generating Station—Emissions Unit 9 consists of three unregulated combustion turbines and was not included in the modeling since there are no numerical emission rates.

Table 7-4. Selection of Off-Property Sources for Inclusion in Cumulative PM₁₀ Modeling

Facility ID	Owner/Company Name—Site Name	East UTM (km)	North UTM (km)	Distance from GREC (km)	Assumed Edge of PM ₁₀ SIA (km)	Distance from Edge of SIA (km)	Threshold Emissions PM ₁₀ × 20D (tpy)	Potential PM ₁₀ Emissions (tpy)	Modeling Required (Yes/No)
10001	Florida Power Corp D/B/A Progress—UF Cogen	368.78	3,279.25	14.44	10.00	4.44	88.70	13.10	No
10002	Escalade Sports—Fred Bear Archery Equipment	365.71	3,276.50	17.23	10.00	7.23	144.60	29.93	No
10003	Koppers Industries, Inc.	371.70	3,283.30	12.68	10.00	2.68	53.60	48.00	No
10005	Gainesville Regional Utilities—John R. Kelly Power Plant	372.05	3,280.05	15.11	10.00	5.11	102.10	468.00	Yes
10006	Gainesville Regional Utilities—Deerhaven Generating Station	365.81	3,292.88	1.35	10.00	-8.65	—	697.00	Yes
10007	Maddox Foundry and Machine Works, Inc.	352.40	3,267.30	27.99	10.00	17.99	359.80	6.53	No
10013	Cemex—Gainesville Concrete Readymix Plant	370.20	3,279.00	15.66	10.00	5.66	113.20	14.13	No
10037	V.E. Whitehurst and Sons, Inc.	368.75	3,288.80	6.26	10.00	-3.75	—	53.30	Yes
10039	Lamson and Sessions Co.	347.00	3,299.60	18.78	10.00	8.78	175.60	VE only	No
10040	Electro Energy Florida LLC	361.49	3,294.78	3.56	10.00	-6.44	—	NA	No
10041	N. Fla/South Ga Veterans Health System—Gainesville	369.75	3,279.13	15.38	10.00	5.38	107.60	7.76	No
10056	Central Florida Crematorium, aka Milam Funeral	371.80	3,280.30	14.56	10.00	4.56	91.20	NA	No
10057	Forest Meadows Funeral Home, Inc.	371.40	3,283.80	11.20	10.00	1.20	24.00	3.50	No
10061	Florida Rock Industries Inc—High Springs	359.30	3,289.65	17.57	10.00	7.57	151.30	NA	No
10062	University of Florida—Animal Resources Department	369.93	3,279.39	14.82	10.00	4.82	96.40	3.74	No
10064	Southern Pre-Cast, Inc.	359.00	3,295.70	6.17	10.00	-3.83	—	VE only	No
10069	Specialty Construction Brands, Inc.	369.50	3,287.10	8.04	10.00	-1.96	—	10.90	Yes
10070	Williams Colonial Crematory	371.65	3,282.13	12.81	10.00	2.81	56.20	1.24	No
10072	University of Florida Biotechnology Development Institute	355.30	3,295.50	9.74	10.00	-0.26	—	NA	No
10073	Sanvik Minning and Construction LLC USA	355.70	3,295.20	9.29	10.00	-0.71	—	<1.0	No
10087	Florida Rock Industries, Inc.—Thompson S. Baker Cement Plant	347.69	3,286.54	19.94	10.00	9.94	198.79	805.44	Yes
10103	Cherished Memories Inc.	356.84	3,296.35	9.83	10.00	-0.17	—	NA	No
10116	Alachua County Animal Services	375.71	3,286.57	13.05	10.00	3.05	61.00	1.38	No
10118	Electro Energy Florida, LLC	361.40	3,294.80	3.56	10.00	-6.44	—	VE only	No
10125	Crevasse's Pet Cremation Service —Gainesville	369.68	3,287.45	7.14	10.00	-2.86	—	1.47	Yes
10127	Florida Septic, Inc./ Hawthorne Plant	397.31	3,274.30	37.85	10.00	27.85	557.00	NA	No
30001	Northeast Florida State Hospital	391.00	3,345.00	57.24	10.00	47.24	944.80	13.50	No
30004	Insteel Wire Products Inc.—Insteel Wire Products Florida	378.91	3,347.19	55.48	10.00	45.48	909.60	1.78	No
30010	Hanson Roof Tile—Sanderson Facility	379.20	3,347.20	55.38	10.00	45.38	907.60	10.56	No
70001	E.I. Dupont De Nemours and Company, Inc.—Highland	398.39	3,325.00	45.52	10.00	35.52	710.30	19.20	No
70004	Griffin Industries of Florida—Test3	391.66	3,306.06	28.49	10.00	18.49	369.75	10.93	No
70011	Florida Rock Industries, Inc.—Bradford	393.10	3,313.10	34.27	10.00	24.27	485.40	NA	No
70012	Florida Gas Transmission Company—Bradford County Station #16	371.98	3,310.57	17.93	10.00	7.93	158.60	9.36	No
70016	Owen Joist Corporation—SMI Joist of Florida	391.80	3,309.75	30.42	10.00	20.42	408.40	0.73	No
190005	Gilman Building Products Company	400.90	3,336.20	55.80	10.00	45.80	916.00	13.72	No
190011	E.I. Dupont De Nemours and Company—Trailridge	400.19	3,308.70	37.87	10.00	27.87	557.45	19.20	No
190059	W.W.Carter Contracting—Contractmasters Road Property	414.37	3,324.69	57.66	10.00	47.66	953.20	VE only	No
230008	Purina Mills, Inc.	341.20	3,341.40	53.42	10.00	43.42	868.40	VE only	No
230026	Columbia Ready Mix Concrete, Inc.	341.60	3,342.90	54.56	10.00	44.56	891.20	NA	No
230032	Forest Lawn Memorial Gardens	342.91	3,332.65	45.61	10.00	35.61	712.20	NA	No

Table 7-4. Selection of Off-Property Sources for Inclusion in Cumulative PM₁₀ Modeling (Continued, Page 2 of 2)

Facility ID	Owner/Company Name—Site Name	East UTM (km)	North UTM (km)	Distance from GREC (km)	Assumed Edge of PM ₁₀ SIA (km)	Distance from Edge of SIA (km)	Threshold Emissions PM ₁₀ × 20D (tpy)	Potential PM ₁₀ Emissions (tpy)	Modeling Required (Yes/No)
230035	Timco—Lake City Airport	348.30	3,339.00	48.93	10.00	38.93	778.60	VE only	No
230039	Trinity Materials LLC—Plant #37	341.30	3,343.55	55.99	10.00	45.99	919.80	3.47	No
230040	Columbia Block, Inc.	343.24	3,343.06	54.70	10.00	44.70	894.00	NA	No
230043	Bluelinx Corporation	346.52	3,339.35	49.95	10.00	39.95	799.00	31.90	No
410001	Bell Concrete Products, Inc.	319.60	3,294.90	45.23	10.00	35.23	704.60	NA	No
410004	Florida Gas Transmission Company—Station 24, Trenton	321.31	3,282.79	46.59	10.00	36.59	731.70	5.37	No
750001	Trinity Materials, LLC—Williston Concrete Batch Plant	362.81	3,250.80	43.15	10.00	33.15	663.00	NA	No
750026	Bell Concrete Products, Inc.	318.06	3,266.04	53.74	10.00	43.74	874.80	NA	No
750028	Trinity Materials LLC—Plant #38	314.70	3,272.30	54.49	10.00	44.49	889.80	4.98	No
750030	Knauff Crematory	318.98	3,262.26	57.12	10.00	47.12	942.40	NA	No
750085	Freebee Landholdings, Ltd.—Watson Construction Borrow Pit	349.00	3,264.60	33.95	10.00	23.95	479.00	29.10	No
830016	Franklin Industrial Minerals/Lowell	384.54	3,244.15	53.07	10.00	43.07	861.35	11.16	No
830017	Mfm Industries Inc.—Lowell Processing Plant	384.50	3,245.30	51.91	10.00	41.91	838.20	50.40	No
830059	Steven Counts, Inc. Asphalt Plant #1	385.02	3,237.05	59.90	10.00	49.90	998.00	51.74	No
830069	Delta Laboratories—Ocala	385.00	3,238.00	59.38	10.00	49.38	987.60	VE only	No
830091	Dixie Lime and Stone—Cummer Limestone Mine	386.70	3,238.00	59.55	10.00	49.55	991.00	NA	No
1070001	Feldspar Corp—Edgar Plastic Kaolin Division	408.11	3,273.43	46.86	10.00	36.86	737.20	38.96	No
1070007	Florida Rock Industries, Inc.—Keuka Plant	411.30	3,274.20	50.30	10.00	40.30	806.00	NA	No
1070015	Georgia-Pacific Wood Products LLC—Hawthorne Plywood Plant	399.60	3,273.80	39.92	10.00	29.92	598.40	180.00	No
1210465	Suwannee American Cement Company	321.40	3,315.90	50.39	10.00	40.39	807.80	384.91	No
1250005	Gilman Building Products Company	373.50	3,319.70	27.48	10.00	17.48	349.60	24.36	No
1250007	Pride Enterprises—Union Metal	384.90	3,326.60	38.59	10.00	28.59	571.80	VE only	No
7770007	Anderson Columbia, Inc.—Asphalt Plant #9	400.30	3,275.50	38.89	10.00	28.89	577.80	10.10	No
7770037	Apac-Southeast, Inc.—First Coast Division	393.62	3,303.85	29.44	10.00	19.44	388.80	22.01	No
7770079	White Construction Company—Gainesville Asphalt Plant	347.00	3,299.80	18.87	10.00	8.87	177.40	8.98	No
7770123	Trinity Materials, LLC—Plant #35	344.80	3,282.00	24.59	10.00	14.59	291.80	2.11	No
7770130	Venkat's Test Site	362.61	3,272.88	21.17	10.00	11.17	223.40	NA	No
7770237	Anderson Mining Corporation	321.00	3,316.00	49.18	10.00	39.18	783.60	NA	No
7775074	Anderson Columbia Company, Inc.—Panhandle Land and Timber Plant #12	342.40	3,344.26	56.16	10.00	46.16	923.20	11.17	No
7775181	Trinity Materials, LLC—Concrete Plant No. 5	401.70	3,334.20	54.81	10.00	44.81	896.20	11.94	No
7775240	Apac-Se, Inc. First Coast Division—Gainesville Asphalt Plant	368.17	3,288.88	5.81	10.00	-4.20	—	3.94	Yes
7775271	John C. Hipp Construction Equipment Company	361.20	3,296.50	10.19	10.00	0.19	3.80	42.63	Yes
7775304	Trinity Materials, LLC—Temporary Plant at Newberry	344.70	3,282.20	24.58	10.00	14.58	291.60	2.02	No

Note: Distance to facilities was measured from central GREC location; i.e., UTM 3293.865 km north and UTM 364.888 km east.

Source: ECT, 2009.

Table 7-5. Off-Property Source Inventory Modeling Parameters

Facility ID	Emission Unit Description	Model ID	East UTM (meter)	North UTM (meter)	Source Elevation (meter)	PM ₁₀		Stack Height		Exit Temperature		Exit Velocity		Stack Diameter	
						Emission Rate lb/hr	g/s	ft	meter	°F	K	ft/s	m/s	ft	meter
Gainesville Regional Utilities—John R. Kelly Power Plant															
10005	Fossil Fuel-Fired Steam Generator Unit No. 7	Kelly_7	372,100	3,280,100	44.20	27.20	3.43	200	61.0	337	443	40.0	12.19	10.5	3.20
10005	Combined-Cycle Unit No. 1 (CC-1)	Kelly_10	372,000	3,280,000	44.20	10.00	1.26	102	31.1	242	390	62.2	18.96	15.5	4.72
Gainesville Regional Utilities—Deerhaven Generating Station															
10006	Fossil Fuel Fired Steam Generator No. 1	Deer_3	365,789	3,292,851	56.08	96.00	12.10	300	91.4	261	400	47.0	14.33	11.0	3.35
10006	Fossil Fuel Fired Steam Generator No. 2	Deer_5	365,813	3,292,881	56.39	242.80	30.59	350	106.7	275	408	50.0	15.24	18.5	5.64
10006	Simple Cycle Comb Turbine No. 3	Deer_6	365,532	3,292,921	54.86	15.00	1.89	52	15.8	1,100	866	168.0	51.21	14.1	4.30
V. E. Whitehurst & Sons, Inc.															
10037	#4 Asphalt Plant with Baghouse	White_3	368,700	3,289,000	57.61	12.17	1.53	31	9.4	300	422	98.6	30.05	3.8	1.17
Specialty Construction Brands, Inc.															
10069	Motar and Grout Plant - Processes and 7 Silo Dust Collectors	SCB_1	369,500	3,287,100	56.08	8.71	1.10	69	21.0	80	300	50.0	15.24	0.5	0.15
Crevasse's Pet Cremation Service—Gainesville															
10125	Pet Crematory	Crev-1	369,680	3,287,450	56.08	0.33	0.04	15	4.6	1,300	978	18.2	5.55	1.5	0.46
Florida Rock Industries, Inc. —Thompson S. Baker Cement Plant															
10087	Kiln/Raw Mill System Stack	Baker_3	348,350	3,287,040	25.60	22.10	2.78	250	76.2	356	453	47.8	14.57	9.4	2.87
10087	Clinker Cooler and Handling	Baker_4	348,350	3,287,040	25.60	13.00	1.64	115	35.1	480	522	41.9	12.77	9.0	2.74
10087	Raw Mill System—Line 2	Baker_9	346,360	3,285,640	25.60	2.51	0.32	240	73.2	200	366	46.7	14.23	2.6	0.80
10087	Kiln/Raw Mill—Line 2	Baker_10	346,430	3,285,690	25.60	25.00	3.15	315	96.0	356	453	52.6	16.03	9.4	2.87
10087	Clinker Handling System—Line 2	Baker_11	348,350	3,287,040	25.60	10.84	1.37	198	60.4	480	522	45.1	13.75	9.0	2.74
10087	Finish Grinding Operation—Line 2	Baker_12	346,530	3,285,670	25.60	10.16	1.28	131	39.9	158	343	48.3	14.72	7.5	2.29
10087	Cement Loadout Silos 6 and 7	Baker_13	346,660	3,285,770	25.60	0.15	0.02	30	9.1	150	339	28.3	8.63	1.5	0.46
10087	Coal/Coke Handling and Grinding Operation	Baker_14	346,480	3,285,730	25.60	1.27	0.16	198	60.4	150	339	6.3	1.92	9.0	2.74
APRAC - Southeast, Inc. First Coast Div.— Gainesville Asphalt Plant															
7775240	Double Barrel Drum Mix Asphalt Plant	GAP_1	368,150	3,288,960	58.52	9.20	1.16	31	9.4	0	255	0.003	0.001	3.05	1.00
John C. Hipp Construction Equipment Company															
7775271	Drum Mix Asphalt Plant	Hipp_1	356,700	3,296,500	25.60	9.48	1.19	32	9.8	0	255	69.4	21.15	4.1	1.25

Source: ECT, 2009.

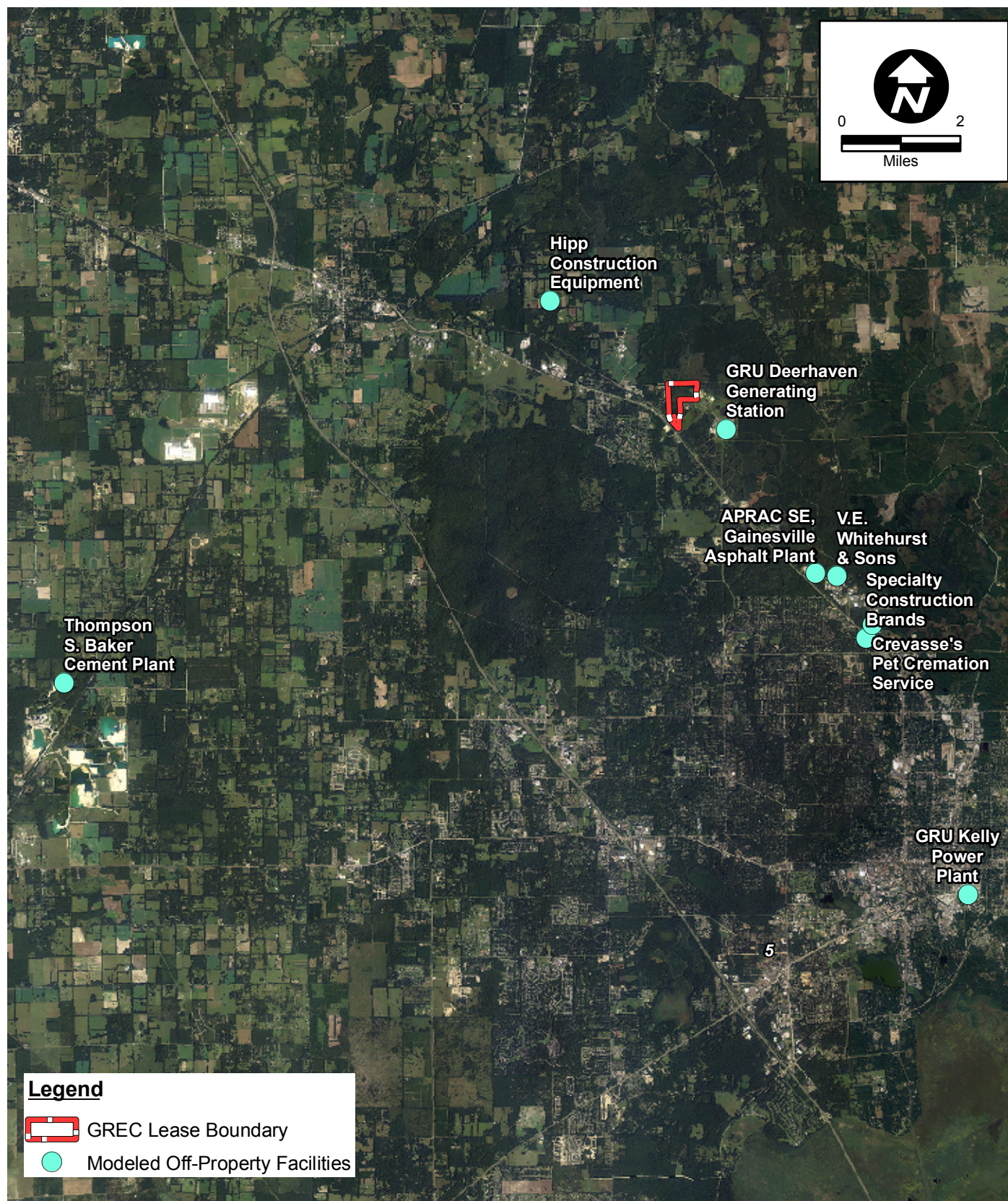


FIGURE 7-8.
LOCATION OF MODELED OFF-PROPERTY PM_{10} FACILITIES

Sources: NRCS, 2007; ECT, 2009,

- Deerhaven Generating Station—The two small 20-MW, simple-cycle combustion turbines 1 and 2 were eliminated from the inventory because they are unregulated sources and emissions or stack data were unavailable. Also, the fugitive emissions (EUs 7 and 8) were not included in the modeling.
- V.E. Whitehurst & Sons, Inc.—Emissions Unit 3 was retained for modeling. The stack emissions were based on the NSPS limit of 0.04 gr/dscf.
- Specialty Construction Brands, Inc.—Stack parameters were only available for the silo filters. Emissions from the seven silos account for approximately 30 percent of the potential hourly emissions. To be conservative, all emissions were summed and modeled using the height and flow rate of the silo filters.
- Crevasse's Pet Cremation Service—The hourly emission rate of the incinerator was based on the flow rate and permit limit of 0.08 gr/dscf.
- Thompson S. Baker Cement Plant—The fugitive emission sources (EUs 1, 5, 6, 7, 8, and 15) were not included in the modeling. Emissions Unit 2 was also eliminated since its emissions are vented to Emissions Unit 3 and are included in that way.
- APAC, Gainesville Asphalt Plant—Emissions Unit 1 was retained for modeling. The stack emissions were based on the NSPS limit of 0.04 gr/dscf.
- John C. Hipp Construction Equipment Company—Emissions Unit 1 was retained for modeling. The stack emissions were based on the NSPS limit of 0.04 gr/dscf.

8.0 AMBIENT IMPACT ANALYSIS RESULTS

8.1 OVERVIEW

Comprehensive dispersion modeling was conducted to assess the air quality impacts resulting from GREC operations in accordance with the methodology described in Section 7.0. This section provides the results of the air quality assessment with respect to PSD Class II area impacts. GREC air quality impacts at the distant PSD Class I areas resulting from long-range transport are addressed in Section 11.0.

8.1 RESULTS

8.1.1 PSD SIGNIFICANT IMPACT LEVEL ANALYSIS

As discussed in Section 7.2, GREC is subject to the PSD air quality impact analysis requirements for NO_x (as NO₂), CO, SO₂, and PM₁₀. The first step in the PSD Class II area analysis was to determine the air quality impacts for these pollutants due to only the GREC emission sources for comparison to the PSD Class II area SILs. Except for low levels of emissions from the emergency diesel engines, the BFB boiler is the principle GREC emission source for SO₂, NO_x, and CO. Therefore, the impact of the BFB boiler alone was evaluated by running AERMOD for each load (i.e., 100- and 70-percent load conditions), each year of meteorology (i.e., 2001 through 2005), and each option for processing the meteorological data (i.e., use of GRA or GREC site characteristics). Normalized concentrations were produced using a 10-g/s emission rate for the BFB boiler stack and proportioning the results based on the potential emission rate for each pollutant. Tables 8-1 through 8-4 provide the results of this analysis of the BFB boiler. As shown on these tables, the predicted impacts of SO₂, NO_x, CO, and PM₁₀ are below the SILs for all averaging times.

Tables 8-5 through 8-8 present details of the maximum BFB boiler impacts that occurred for each modeled year for SO₂ and NO₂. These tables include the maximum air quality impacts for all meteorological data and BFB boiler loads evaluated, location and relative position of these impacts to GREC, time period that the impacts occurred, and comparisons of the impacts to the PSD SILs. In addition, the maximum impacts were compared

Table 8-1. PSD Class II SIL Analysis Summary—BFB Boiler at 100-Percent Load: GRA Surface Characteristics

	Year of Meteorology					Maximum Impact (µg/m³)	SIL (µg/m³)	Exceed SIL? (Yes/No)
	2001	2002	2003	2004	2005			
<u>Nominal 10 g/s Impacts:</u>								
High, 1-hour (µg/m³)	11.36	11.34	10.92	11.66	11.77			
High, 3-hour (µg/m³)	7.16	6.69	7.40	7.83	7.47			
High, 8-hour (µg/m³)	5.29	5.44	5.81	6.56	6.08			
High, 24-hour (µg/m³)	2.51	3.02	2.90	3.36	4.00			
Annual (µg/m³)	0.38	0.39	0.44	0.39	0.34			
<u>SO₂</u>								
Emission rate (g/s)	7.02	7.02	7.02	7.02	7.02			
High, 3-hour (µg/m³)	5.02	4.70	5.19	5.50	5.24	5.50	25	No
High, 24-hour (µg/m³)	1.76	2.12	2.04	2.36	2.81	2.81	5	No
Annual (µg/m³)	0.27	0.27	0.31	0.27	0.24	0.31	1	No
<u>NO_x</u>								
Emission rate (g/s)	11.98	11.98	11.98	11.98	11.98			
Tier 1 annual (µg/m³)*	0.45	0.47	0.53	0.46	0.41	0.53	1	No
Tier 2 annual (µg/m³)†	0.34	0.35	0.39	0.35	0.31	0.39	1	No
<u>CO</u>								
Emission rate (g/s)	20.54	20.54	20.54	20.54	20.54			
High, 1-hour (µg/m³)	23.33	23.29	22.43	23.95	24.17	24.17	2,000	No
High, 8-hour (µg/m³)	10.86	11.18	11.93	13.47	12.49	13.47	500	No
<u>PM₁₀</u>								
Emission rate (g/s)	7.18	7.18	7.18	7.18	7.18			
High, 24-hour (µg/m³)	1.80	2.17	2.08	2.41	2.87	2.87	5	No
Annual (µg/m³)	0.27	0.28	0.31	0.28	0.25	0.31	1	No

*Assumes total conversion of NO to NO₂.†Tier 1 impact multiplied by national default NO₂/NO_x ratio of 0.75.

Source: ECT, 2009.

Table 8-2. PSD Class II SIL Analysis Summary—BFB Boiler at 100-Percent Load: GREC Site Surface Characteristics

	Year of Meteorology					Maximum Impact (µg/m³)	SIL (µg/m³)	Exceed SIL? (Yes/No)
	2001	2002	2003	2004	2005			
<u>Nominal 10 g/s Impacts:</u>								
High, 1-hour (µg/m³)	9.49	9.17	9.28	9.25	9.06			
High, 3-hour (µg/m³)	7.11	7.14	6.93	8.02	7.25			
High, 8-hour (µg/m³)	5.52	5.69	6.13	6.96	6.20			
High, 24-hour (µg/m³)	3.42	2.91	4.19	3.73	4.66			
Annual (µg/m³)	0.39	0.43	0.41	0.37	0.38			
<u>SO₂</u>								
Emission rate (g/s)	7.02	7.02	7.02	7.02	7.02			
High, 3-hour (µg/m³)	4.99	5.01	4.86	5.63	5.09	5.63	25	No
High, 24-hour (µg/m³)	2.40	2.04	2.94	2.62	3.27	3.27	5	No
Annual (µg/m³)	0.27	0.30	0.29	0.26	0.26	0.30	1	No
<u>NO_x</u>								
Emission rate (g/s)	11.98	11.98	11.98	11.98	11.98			
Tier 1 annual (µg/m³)*	0.47	0.51	0.49	0.44	0.45	0.51	1	No
Tier 2 annual (µg/m³)†	0.35	0.38	0.37	0.33	0.34	0.38	1	No
<u>CO</u>								
Emission rate (g/s)	20.54	20.54	20.54	20.54	20.54			
High, 1-hour (µg/m³)	19.49	18.83	19.06	19.00	18.61	19.49	2,000	No
High, 8-hour (µg/m³)	11.34	11.69	12.59	14.28	12.73	14.28	500	No
<u>PM₁₀</u>								
Emission rate (g/s)	7.18	7.18	7.18	7.18	7.18			
High, 24-hour (µg/m³)	2.46	2.09	3.01	2.68	3.35	3.35	5	No
Annual (µg/m³)	0.28	0.31	0.30	0.26	0.27	0.31	1	No

*Assumes total conversion of NO to NO₂.†Tier 1 impact multiplied by national default NO₂/NO_x ratio of 0.75.

Source: ECT, 2009.

Table 8-3. PSD Class II SIL Analysis Summary—BFB Boiler at 70-Percent Load: GRA Surface Characteristics

	Year of Meteorology					Maximum Impact (µg/m³)	SIL (µg/m³)	Exceed SIL? (Yes/No)
	2001	2002	2003	2004	2005			
<u>Nominal 10 g/s Impacts:</u>								
High, 1-hour (µg/m³)	15.44	15.84	15.44	15.68	16.33			
High, 3-hour (µg/m³)	10.83	8.62	9.80	10.16	10.48			
High, 8-hour (µg/m³)	6.79	6.92	7.89	8.46	8.05			
High, 24-hour (µg/m³)	3.24	3.72	3.75	4.46	4.95			
Annual (µg/m³)	0.51	0.52	0.59	0.53	0.47			
<u>SO₂</u>								
Emission rate (g/s)	4.91	4.91	4.91	4.91	4.91			
High, 3-hour (µg/m³)	5.32	4.24	4.82	4.99	5.15	5.32	25	No
High, 24-hour (µg/m³)	1.59	1.83	1.84	2.19	2.43	2.43	5	No
Annual (µg/m³)	0.25	0.25	0.29	0.26	0.23	0.29	1	No
<u>NO_x</u>								
Emission rate (g/s)	8.39	8.39	8.39	8.39	8.39			
Tier 1 annual (µg/m³)*	0.43	0.43	0.50	0.44	0.39	0.50	1	No
Tier 2 annual (µg/m³)†	0.32	0.33	0.37	0.33	0.30	0.37	1	No
<u>CO</u>								
Emission rate (g/s)	14.38	14.38	14.38	14.38	14.38			
High, 1-hour (µg/m³)	22.20	22.77	22.20	22.54	23.48	23.48	2,000	No
High, 8-hour (µg/m³)	9.76	9.95	11.34	12.16	11.57	12.16	500	No
<u>PM₁₀</u>								
Emission rate (g/s)	5.03	5.03	5.03	5.03	5.03			
High, 24-hour (µg/m³)	1.63	1.87	1.89	2.24	2.49	2.49	5	No
Annual (µg/m³)	0.26	0.26	0.30	0.26	0.24	0.30	1	No

*Assumes total conversion of NO to NO₂.†Tier 1 impact multiplied by national default NO₂/NO_x ratio of 0.75.

Source: ECT, 2009.

Table 8-4. PSD Class II SIL Analysis Summary—BFB Boiler at 70-Percent Load: GREC Site Surface Characteristics

	Year of Meteorology					Maximum Impact (µg/m³)	SIL (µg/m³)	Exceed SIL? (Yes/No)
	2001	2002	2003	2004	2005			
<u>Nominal 10 g/s Impacts:</u>								
High, 1-hour (µg/m³)	11.76	11.33	11.68	11.85	11.36			
High, 3-hour (µg/m³)	8.94	9.06	9.03	9.90	9.77			
High, 8-hour (µg/m³)	6.67	7.08	7.68	8.15	8.18			
High, 24-hour (µg/m³)	4.41	3.79	5.21	4.85	6.04			
Annual (µg/m³)	0.50	0.55	0.56	0.51	0.51			
<u>SO₂</u>								
Emission rate (g/s)	4.91	4.91	4.91	4.91	4.91			
High, 3-hour (µg/m³)	4.39	4.45	4.44	4.86	4.80	4.86	25	No
High, 24-hour (µg/m³)	2.17	1.86	2.56	2.38	2.97	2.97	5	No
Annual (µg/m³)	0.25	0.27	0.28	0.25	0.25	0.28	1	No
<u>NO_x</u>								
Emission rate (g/s)	8.39	8.39	8.39	8.39	8.39			
Tier 1 annual (µg/m³)*	0.42	0.46	0.47	0.43	0.43	0.47	1	No
Tier 2 annual (µg/m³)†	0.32	0.35	0.35	0.32	0.32	0.35	1	No
<u>CO</u>								
Emission rate (g/s)	14.38	14.38	14.38	14.38	14.38			
High, 1-hour (µg/m³)	16.91	16.29	16.79	17.04	16.33	17.04	2,000	No
High, 8-hour (µg/m³)	9.59	10.18	11.04	11.72	11.76	11.76	500	No
<u>PM₁₀</u>								
Emission rate (g/s)	5.03	5.03	5.03	5.03	5.03			
High, 24-hour (µg/m³)	2.22	1.91	2.62	2.44	3.04	3.04	5	No
Annual (µg/m³)	0.25	0.28	0.28	0.26	0.25	0.28	1	No

*Assumes total conversion of NO to NO₂.†Tier 1 impact multiplied by national default NO₂/NO_x ratio of 0.75.

Source: ECT, 2009.

Table 8-5. PSD Class II SIL Analysis Details—BFB Boiler Annual Average NO₂ Impacts

	Year of Meteorology				
	2001	2002	2003	2004	2005
Tier 1 maximum predicted NO ₂ impact (µg/m ³)*	0.47	0.51	0.52	0.47	0.45
Tier 2 maximum predicted NO ₂ impact (µg/m ³)†	0.35	0.38	0.39	0.35	0.34
Receptor UTM easting (meter)	364,326	364,326	365,610	365,710	364,614
Receptor UTM northing (meter)	3,293,577	3,293,626	3,294,125	3,294,125	3,293,209
Distance from grid origin (meter)	727	712	671	762	732
Direction from grid origin (degrees)	250	254	63	67	213
Receptor elevation (meter, amsl)	55.42	55.13	55.84	55.84	55.92
PSD modeling SIL (µg/m ³)	1.0	1.0	1.0	1.0	1.0
Exceed PSD modeling SIL? (Yes/No)	No	No	No	No	No
Percent of PSD modeling SIL (%)	35.0	38.0	39.0	35.0	34.0
PSD monitoring <i>de minimis</i> impact level (µg/m ³)	14.0	14.0	14.0	14.0	14.0
Exceed PSD monitoring <i>de minimis</i> impact level? (Yes/No)	No	No	No	No	No
Percent of PSD monitoring <i>de minimis</i> impact level (%)	2.5	2.7	2.8	2.5	2.4

Note: Distance and direction measured from BFB stack at UTM 365,001 meters easting, and 3,293,825 meters northing.

Maximum impact shown in **bold**.

Maximum impact for GRA or GREC Site surface characteristics and for 100-percent or 70-percent loads.

*Assumes total conversion of NO to NO₂.

†Tier 1 impact multiplied by national default NO₂/NO_x ratio of 0.75.

Source: ECT, 2009.

Table 8-6. PSD Class II SIL Analysis Details—BFB Boiler 3-Hour Average SO₂ Impacts

	Year of Meteorology				
	2001	2002	2003	2004	2005
Maximum predicted impact (µg/m ³)	5.32	5.01	5.19	5.63	5.24
Receptor UTM easting (meter)	365,610	365,410	365,510	364,639	365,710
Receptor UTM northing (meter)	3,293,625	3,293,325	3,294,125	3,293,518	3,293,925
Distance from grid origin (meter)	632	640	583	481	707
Direction from grid origin (degrees)	108	141	59	230	82
Receptor elevation (meter, amsl)	55.57	53.59	55.57	56.15	56.15
Date of maximum impact (YYMMDDHH)	01030615	02061212	03051612	04092612	05112124
PSD modeling SIL (µg/m ³)	25.0	25.0	25.0	25.0	25.0
Exceed PSD modeling SIL? (Yes/No)	No	No	No	No	No
Percent of PSD modeling SIL (%)	21.3	20.0	20.8	22.5	21.0

Note: Distance and direction measured from BFB stack at UTM 365,001 meters easting, and 3,293,825 meters northing.

Maximum impact shown in **bold**.

Maximum impact for GRA or GREC Site surface characteristics and for 100-percent or 70-percent loads.

Source: ECT, 2009.

Table 8-7. PSD Class II SIL Analysis Details—BFB Boiler 24-Hour Average SO₂ Impacts

	Year of Meteorology				
	2001	2002	2003	2004	2005
Maximum predicted impact (µg/m ³)	2.40	2.12	2.94	2.62	3.27
Receptor UTM easting (meter)	365,010	364,326	364,710	364,710	364,710
Receptor UTM northing (meter)	3,292,925	3,293,821	3,293,025	3,292,825	3,293,025
Distance from grid origin (meter)	900	683	854	1,044	854
Direction from grid origin (degrees)	180	270	201	197	201
Receptor elevation (meter, amsl)	53.02	54.45	55.46	54.49	55.46
Date of maximum impact (YYMMDDHH)	01111524	02081024	03110924	04111424	05011524
PSD modeling SIL (µg/m ³)	25.0	25.0	25.0	25.0	25.0
Exceed PSD modeling SIL? (Yes/No)	No	No	No	No	No
Percent of PSD modeling SIL (%)	9.6	8.5	11.8	10.5	13.1
PSD monitoring <i>de minimis</i> impact level (µg/m ³)	13.0	13.0	13.0	13.0	13.0
Exceed PSD monitoring <i>de minimis</i> impact level? (Yes/No)	No	No	No	No	No
Percent of PSD monitoring <i>de minimis</i> impact level (%)	18.5	16.3	22.6	20.2	25.2

Note: Distance and direction measured from BFB stack at UTM 365,001 meters easting, and 3,293,825 meters northing.

Maximum impact shown in **bold**.

Maximum impact for GRA or GREC Site surface characteristics and for 100-percent or 70-percent loads.

Source: ECT, 2009.

Table 8-8. PSD Class II SIL Analysis Details—BFB Boiler Annual Average SO₂ Impacts

	Year of Meteorology				
	2001	2002	2003	2004	2005
Maximum predicted impact (µg/m ³)	0.27	0.30	0.31	0.27	0.26
Receptor UTM easting (meter)	364,326	364,326	365,610	365,710	364,614
Receptor UTM northing (meter)	3,293,577	3,293,626	3,294,125	3,294,125	3,293,209
Distance from grid origin (meter)	727	712	671	762	732
Direction from grid origin (degrees)	250	254	63	67	213
Receptor elevation (meter, amsl)	55.42	55.13	55.84	55.84	55.92
PSD modeling SIL (µg/m ³)	25.0	25.0	25.0	25.0	25.0
Exceed PSD modeling SIL? (Yes/No)	No	No	No	No	No
Percent of PSD modeling SIL (%)	1.1	1.2	1.2	1.1	1.0

Note: Distance and direction measured from BFB stack at UTM 365,001 meters easting, and 3,293,825 meters northing.

Maximum impact shown in **bold**.

Maximum impact for GRA or GREC Site surface characteristics and for 100-percent or 70-percent loads.

Source: ECT, 2009.

to the PSD *de minimis* levels used to determine the need for preconstruction ambient air quality monitoring. As shown in Tables 8-5 and 8-7, the predicted concentrations of NO_x and SO₂ are below the PSD *de minimis* levels.

The two GREC emergency diesel engines will combust ULSD fuel oil and will operate infrequently for testing and routine maintenance. Accordingly, the emergency diesel engines will emit minor amounts of SO₂, NO_x, CO, and PM₁₀. As suggested in agency comments on the modeling protocol, the emergency diesel engines were evaluated with respect to those pollutants that have short-term averaging periods of concern; i.e., SO₂, CO, and PM₁₀. Diesel engine SO₂ emissions and air quality impacts will be insignificant since the engines will be fired with ULSD fuel oil; e.g., the maximum SO₂ emission rate for the larger emergency diesel engine is only 0.0020 lb/hr. As discussed in the following, the diesel engines were included in the GREC emission inventory for the assessment of PM₁₀ impacts. Accordingly, the emergency diesel engines along with the BFB boiler were modeled for CO to assess the combined impacts of these GREC emission sources with respect to the PSD CO SILs. Table 8-9 summarizes the results, which confirms the conclusion that GREC CO impacts will not exceed the PSD Class II SILs. The predicted 8-hour CO impacts significantly overestimate the actual GREC impacts, since it was assumed that the diesel engines would operate continuously for the entire 8-hour period. In reality, emergency diesel engines are expected to operate for no more than 2 hours during each periodic maintenance and testing event. Tables 8-10 and 8-11 provide detailed results for the GREC maximum CO impacts for each modeled year. In addition to being below SILs, the predicted CO concentrations were also below the PSD *de minimis* level.

In addition to the BFB boiler and emergency diesel engines, GREC will include material (i.e., biomass fuel, DSI sorbent, and fly ash) handling, processing, and storage activities, and a mechanical draft cooling tower that will emit PM₁₀. Many of these PM₁₀ emission sources will result in fugitive emissions with a low release height (e.g., truck traffic on paved facility roadways and material transfer points) and therefore would be expected to have PM₁₀ air quality impacts much closer to the GREC boundaries than emissions from the 230-ft BFB boiler stack. Accordingly, all GREC PM₁₀ sources were included in the

Table 8-9. Summary of GREC CO PSD Class II SIL Analysis

Pollutant	Averaging Period	Meteorological Site Surface Characteristics	Maximum Predicted Concentration (µg/m³)					Maximum Impact	SIL (µg/m³)	Exceed SIL? (Yes/No)
			Year of Meteorology							
			2001	2002	2003	2004	2005			
CO	1-hour	GRA	418.1	420.5	413.8	418.4	405.2	420.5	2,000	No
		GREC Site	414.2	419.2	410.0	414.1	401.3	419.2	2,000	No
	8-hour	GRA	152.0	157.1	140.9	140.7	122.3	157.1	500	No
		GREC Site	140.4	159.9	143.2	142.7	127.8	159.9	500	No

Note: Maximum impact for 100-percent or 70-percent BFB boiler load.
Maximum impact shown in bold.

Source: ECT, 2009.

Table 8-10. PSD Class II SIL Analysis Details—GREC 1-Hour Average CO Impacts

	Year of Meteorology				
	2001	2002	2003	2004	2005
Maximum predicted impact ($\mu\text{g}/\text{m}^3$)	418.1	420.5	413.8	418.4	405.2
Receptor UTM easting (meter)	365,109	365,109	365,109	365,109	365,109
Receptor UTM northing (meter)	3,294,069	3,294,069	3,294,069	3,294,069	3,294,069
Distance from grid origin (meter)	263	263	263	263	263
Direction from grid origin (degrees)	22	22	22	22	22
Receptor elevation (meter, amsl)	54.94	54.94	54.94	54.94	54.94
Date of maximum impact (YYMMDDHH)	01022601	02092722	03040904	04070421	05083102
PSD modeling SIL ($\mu\text{g}/\text{m}^3$)	2,000	2,000	2,000	2,000	2,000
Exceed PSD modeling SIL? (Yes/No)	No	No	No	No	No
Percent of PSD modeling SIL (%)	20.9	21.0	20.7	20.9	20.3

Note: Distance and direction measured from BFB stack at UTM 365,001 meters easting, and 3,293,825 meters northing.

Maximum impact shown in **bold**.

Maximum impact for GRA or GREC Site surface characteristics and for 100-percent or 70-percent loads.

Source: ECT, 2009.

Table 8-11. PSD Class II SIL Analysis Details—GREC 8-Hour Average CO Impacts

	Year of Meteorology				
	2001	2002	2003	2004	2005
Maximum predicted impact ($\mu\text{g}/\text{m}^3$)	152.0	159.9	143.2	142.7	127.8
Receptor UTM easting (meter)	364,734	365,109	365,109	365,109	365,109
Receptor UTM northing (meter)	3,293,715	3,294,069	3,294,069	3,294,069	3,294,069
Distance from grid origin (meter)	297	263	263	263	263
Direction from grid origin (degrees)	248	22	22	22	22
Receptor elevation (meter, amsl)	56.15	54.94	54.94	54.94	54.94
Date of maximum Impact (YYMMDDHH)	01091108	02092724	03012108	04082724	05031308
PSD modeling SIL ($\mu\text{g}/\text{m}^3$)	500	500	500	500	500
Exceed PSD modeling SIL? (Yes/No)	No	No	No	No	No
Percent of PSD modeling SIL (%)	30.4	32.0	28.6	28.5	25.6
PSD monitoring <i>de minimis</i> Impact Level ($\mu\text{g}/\text{m}^3$)	575	575	575	575	575
Exceed PSD monitoring <i>de minimis</i> impact level? (Yes/No)	No	No	No	No	No
Percent of PSD monitoring <i>de minimis</i> impact level (%)	26.4	27.8	24.9	24.8	22.2

Note: Distance and direction measured from BFB stack at UTM 365,001 meters easting, and 3,293,825 meters northing.

Maximum impact shown in **bold**.

Maximum impact for GRA or GREC Site surface characteristics and for 100-percent or 70-percent loads.

Source: ECT, 2009.

PSD Class II SIL modeling. Table 8-12 provides the summary of the AERMOD results. As can be seen, the PSD Class II SILs for PM₁₀ were exceeded for all averaging times and model years. Tables 8-13 and 8-14 show detailed model results for the GREC maximum PM₁₀ impacts for each modeled year. Plan view drawings showing the spatial distribution of the predicted PM₁₀ concentrations (i.e., concentration isopleths) were prepared for each pollutant and each averaging period for the year in which the highest impact occurred. Figures 8-1 through 8-8 provide these PM₁₀ concentration isopleths.

Although the 24-hour PSD *de minimis* level for PM₁₀ was predicted to be exceeded (see Table 8-13), GREC is not proposing to perform preconstruction ambient air quality monitoring for the following reasons:

- Adequate ambient PM₁₀ monitoring data already exists in Alachua County for establishing background air quality.
- 24-hour PM₁₀ impacts predicted to exceed the *de minimis* level of 10 µg/m³ are highly localized and occur in the DGS site and GRU property adjacent to the GREC site (see Figure 8-7).

Further discussion of ambient air quality monitoring is provided in Section 9.0

8.1.2 PSD CLASS II INCREMENT AND NAAQS ANALYSIS RESULTS

Since GREC 24-hour and annual PM₁₀ impacts are predicted to exceed the PSD Class SILs, a multisource cumulative analysis of air quality impacts with respect to the 24-hour and annual PM₁₀ NAAQS and PSD Class II increments is required. As previously discussed in Section 7.0, only those receptors that were predicted to have an impact above the PSD PM₁₀ significance level for any year or averaging period were assessed in the cumulative analysis (see Figure 7-5).

The maximum distance to significance for PM₁₀, based on the 24-hour and annual averaging periods for all years of meteorological data evaluated, was determined to be 1.1 km. Although it would have been acceptable to only include offsite sources of PM₁₀ emissions within a radius of 51.1 km (i.e., maximum distance to significance plus

Table 8-12. Summary of GREC PM₁₀ PSD Class II SIL Analysis

Pollutant	Averaging Period	Meteorological Site Surface Characteristics	Maximum Predicted Concentration (µg/m³)					Maximum Impact	SIL (µg/m³)	Exceed SIL? (Yes/No)
			Year of Meteorology							
			2001	2002	2003	2004	2005			
PM ₁₀	24-hour	GRA	18.4	17.0	17.6	17.3	20.4	20.4	5	Yes
		GREC Site	15.9	14.4	15.3	13.2	12.1	15.9	5	Yes
	Annual	GRA	5.2	5.3	4.7	4.5	5.0	5.3	1	Yes
		GREC Site	4.1	4.0	3.7	3.5	3.9	4.1	1	Yes

Note: Maximum impact for 100-percent or 70-percent BFB boiler load.
Maximum impact shown in bold.

Source: ECT, 2009.

Table 8-13. PSD Class II SIL Analysis Details—GREC 24-Hour Average PM₁₀ Impacts

	Year of Meteorology				
	2001	2002	2003	2004	2005
Maximum predicted impact (µg/m ³)	18.4	17.0	17.6	17.3	20.4
Receptor UTM easting (meter)	364,967	364,967	364,967	365,061	365,061
Receptor UTM northing (meter)	3,293,714	3,293,714	3,293,714	3,293,714	3,293,714
Distance from grid origin (meter)	119	119	119	122	122
Direction from grid origin (degrees)	201	201	201	155	155
Receptor elevation (meter, amsl)	56.15	56.15	56.15	56.15	56.15
Date of maximum impact (YYMMDDHH)	01102224	02120824	03101324	04110524	05122024
PSD modeling SIL (µg/m ³)	5.0	5.0	5.0	5.0	5.0
Exceed PSD modeling SIL? (Yes/No)	Yes	Yes	Yes	Yes	Yes
Percent of PSD modeling SIL (%)	367.4	339.4	352.6	346.8	407.4
PSD monitoring <i>de minimis</i> impact level (µg/m ³)	10.0	10.0	10.0	10.0	10.0
Exceed PSD monitoring <i>de minimis</i> impact level? (Yes/No)	Yes	Yes	Yes	Yes	Yes
Percent of PSD monitoring <i>de minimis</i> impact level (%)	183.7	169.7	176.3	173.4	203.7

Note: Distance and direction measured from BFB stack at UTM 365,001 meters easting, and 3,293,825 meters northing.

Maximum impact shown in **bold**.

Maximum impact for GRA or GREC Site surface characteristics and for 100-percent or 70-percent loads.

Source: ECT, 2009.

Table 8-14. PSD Class II SIL Analysis Details—GREC Annual Average PM₁₀ Impacts

	Year of Meteorology				
	2001	2002	2003	2004	2005
Maximum predicted impact (µg/m ³)	5.2	5.3	4.7	4.5	5.0
Receptor UTM easting (meter)	364,967	364,920	364,967	364,967	364,967
Receptor UTM northing (meter)	3,293,714	3,293,715	3,293,714	3,293,714	3,293,714
Distance from grid origin (meter)	119	142	119	119	119
Direction from grid origin (degrees)	201	219	201	201	201
Receptor elevation (meter, amsl)	56.15	56.15	56.15	56.15	56.15
PSD modeling SIL (µg/m ³)	1.0	1.0	1.0	1.0	1.0
Exceed PSD modeling SIL? (Yes/No)	Yes	Yes	Yes	Yes	Yes
Percent of PSD modeling SIL (%)	519.0	525.0	474.0	445.0	495.0

Note: Distance and direction measured from BFB stack at UTM 365,001 meters easting, and 3,293,825 meters northing.

Maximum impact shown in **bold**.

Maximum impact for GRA or GREC Site surface characteristics and for 100-percent or 70-percent loads.

Source: ECT, 2009.

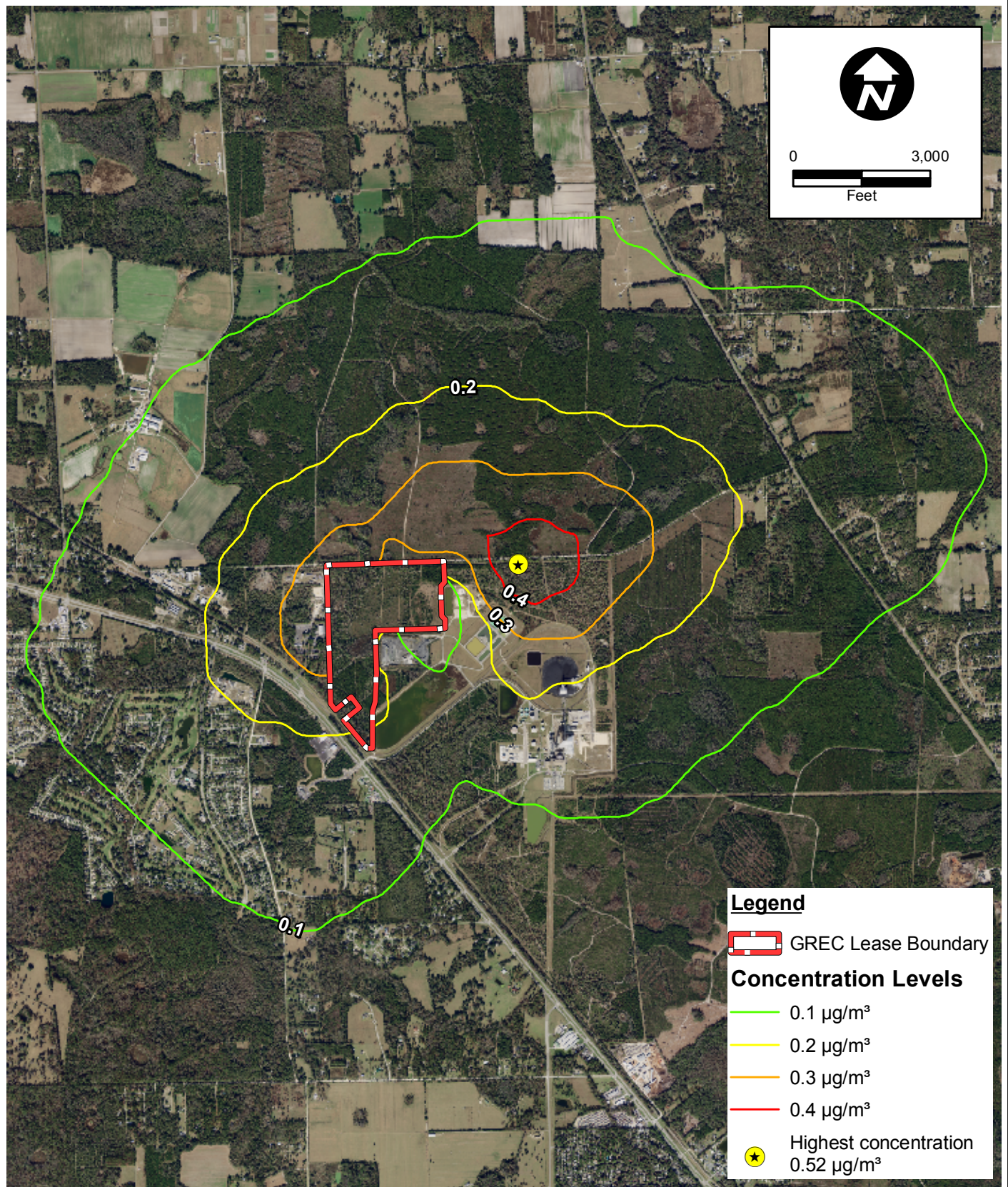


FIGURE 8-1.

GREC MAXIMUM ANNUAL NO₂ IMPACT
MODEL YEAR 2003

Sources: FDOT, 2008; ECT, 2009,

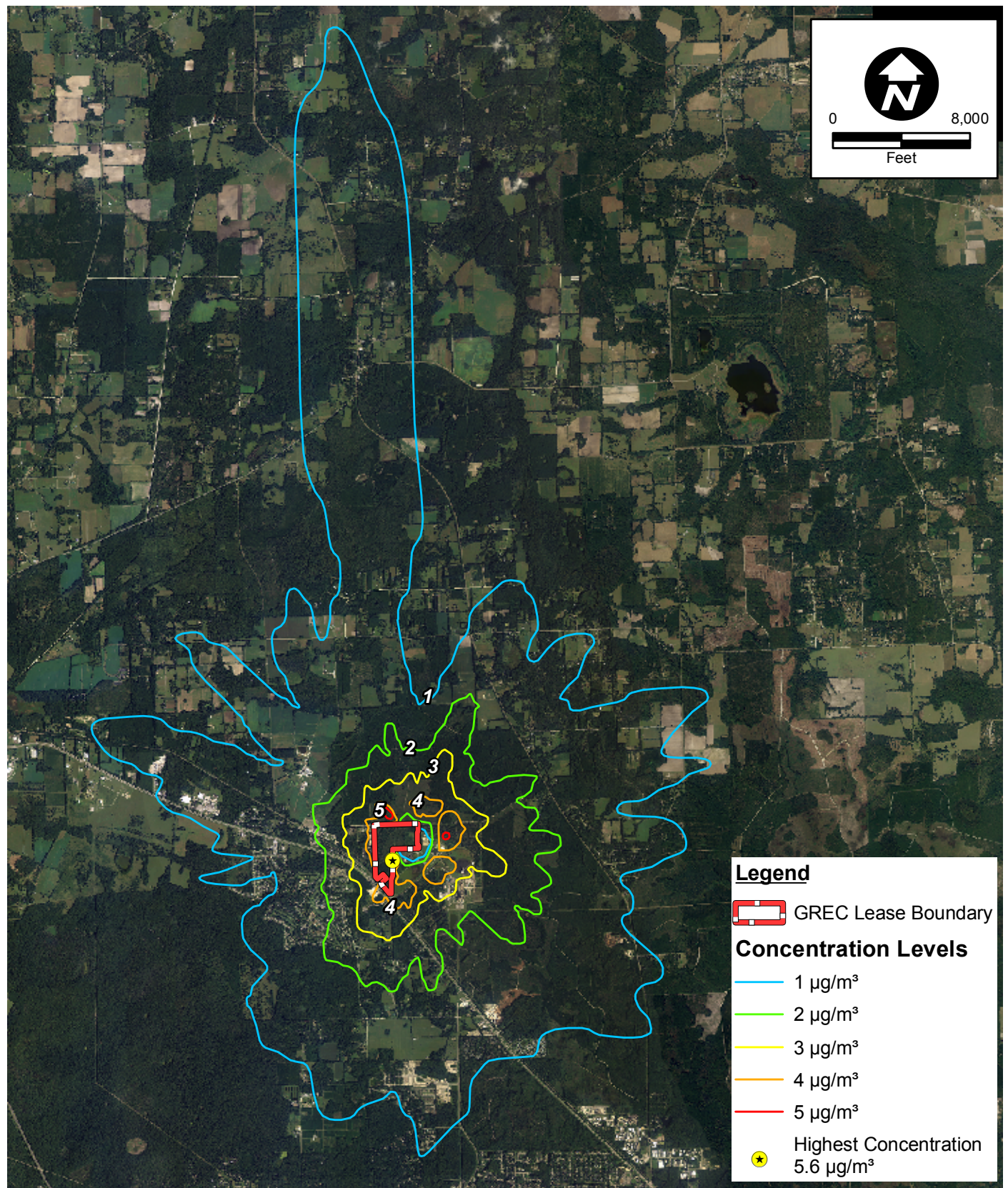


FIGURE 8-2.

GREC MAXIMUM 3- HOUR SO_2 IMPACT
MODEL YEAR 2004

Sources: FDOT, 2008; ECT, 2009,

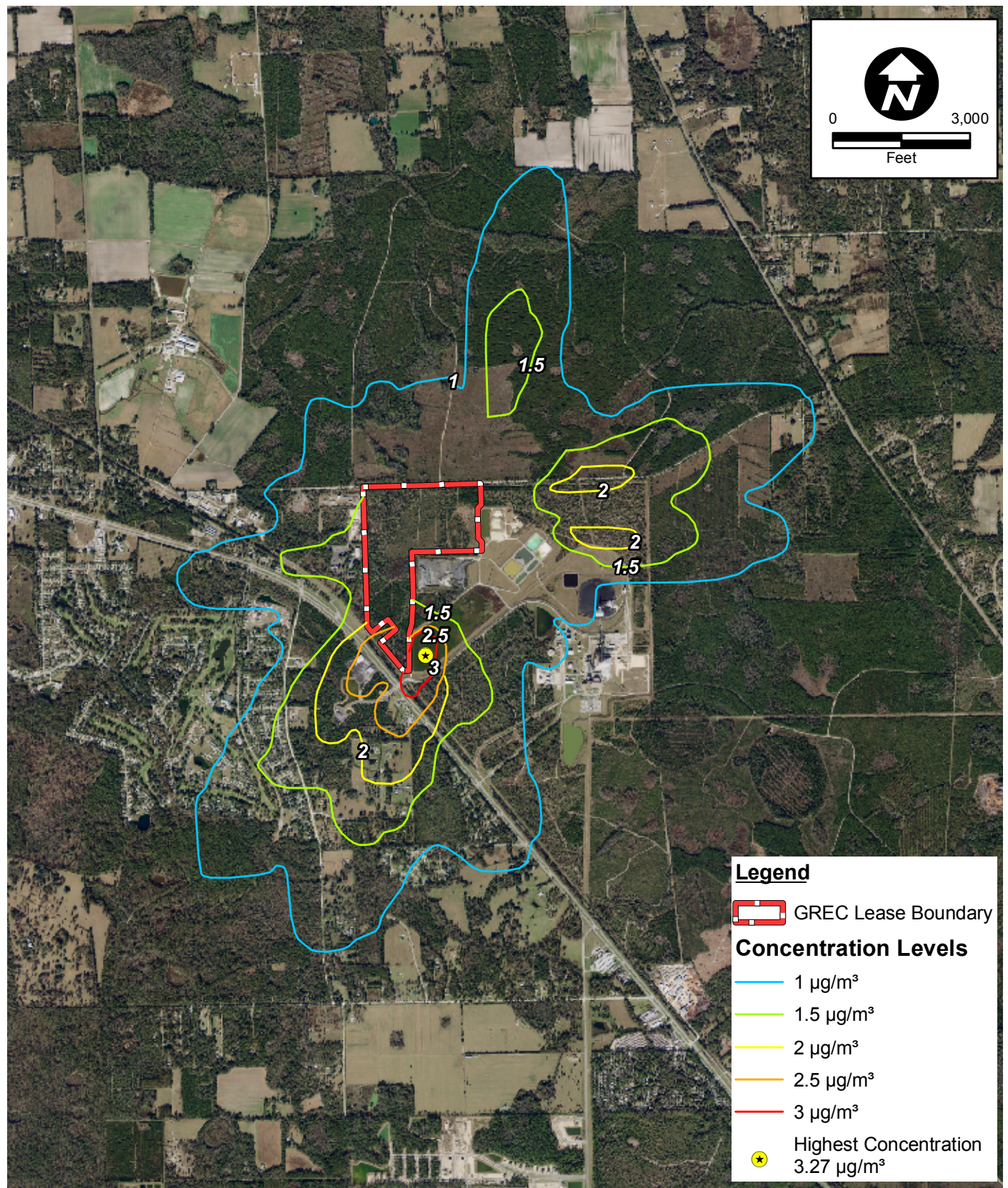


FIGURE 8-3.

GREC MAXIMUM 24-HOUR SO_2 IMPACT
MODEL YEAR 2005

Sources: FDOT, 2008; ECT, 2009,

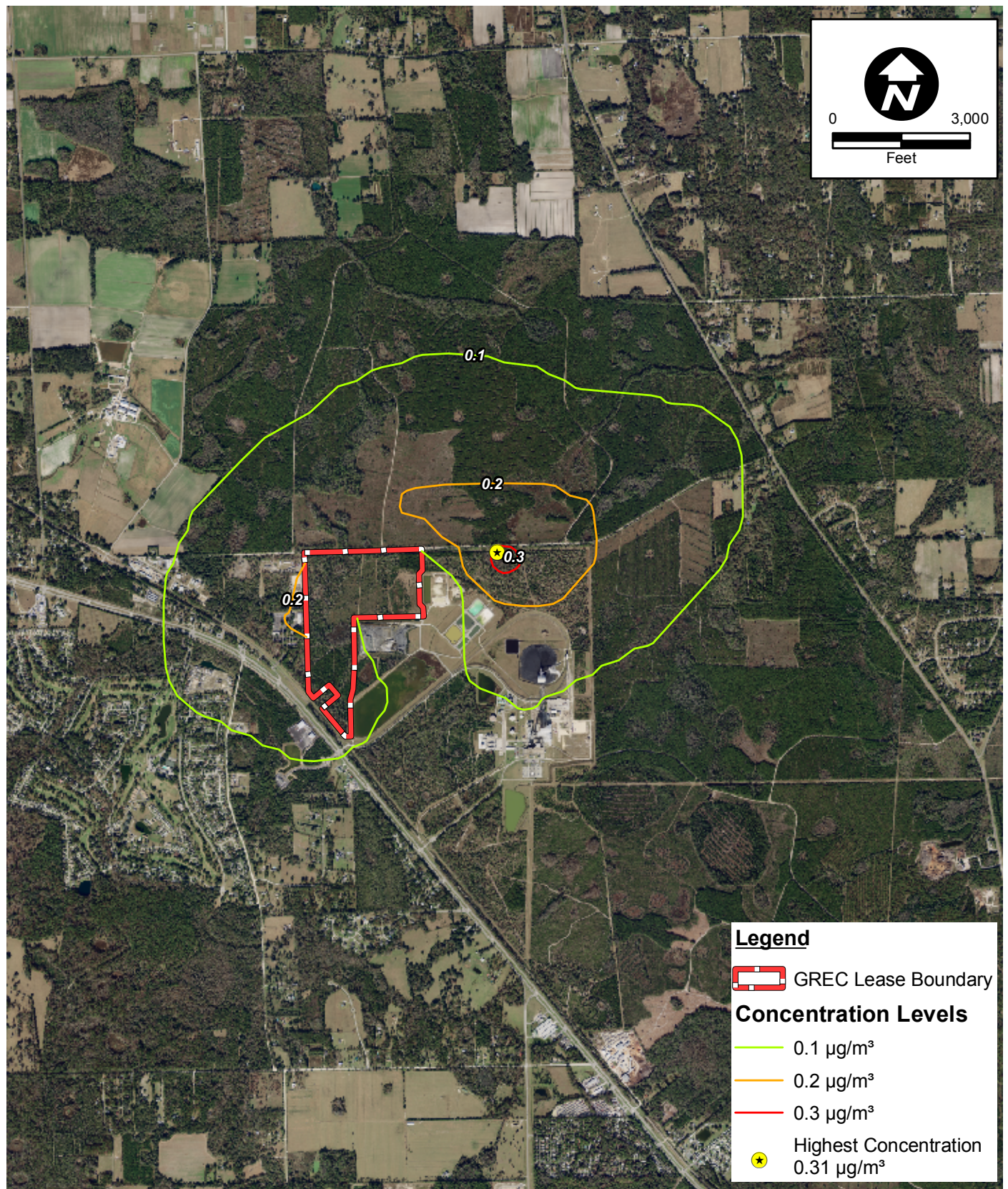


FIGURE 8-4.

GREC MAXIMUM ANNUAL SO₂ IMPACT
MODEL YEAR 2003

Sources: FDOT, 2008; ECT, 2009,

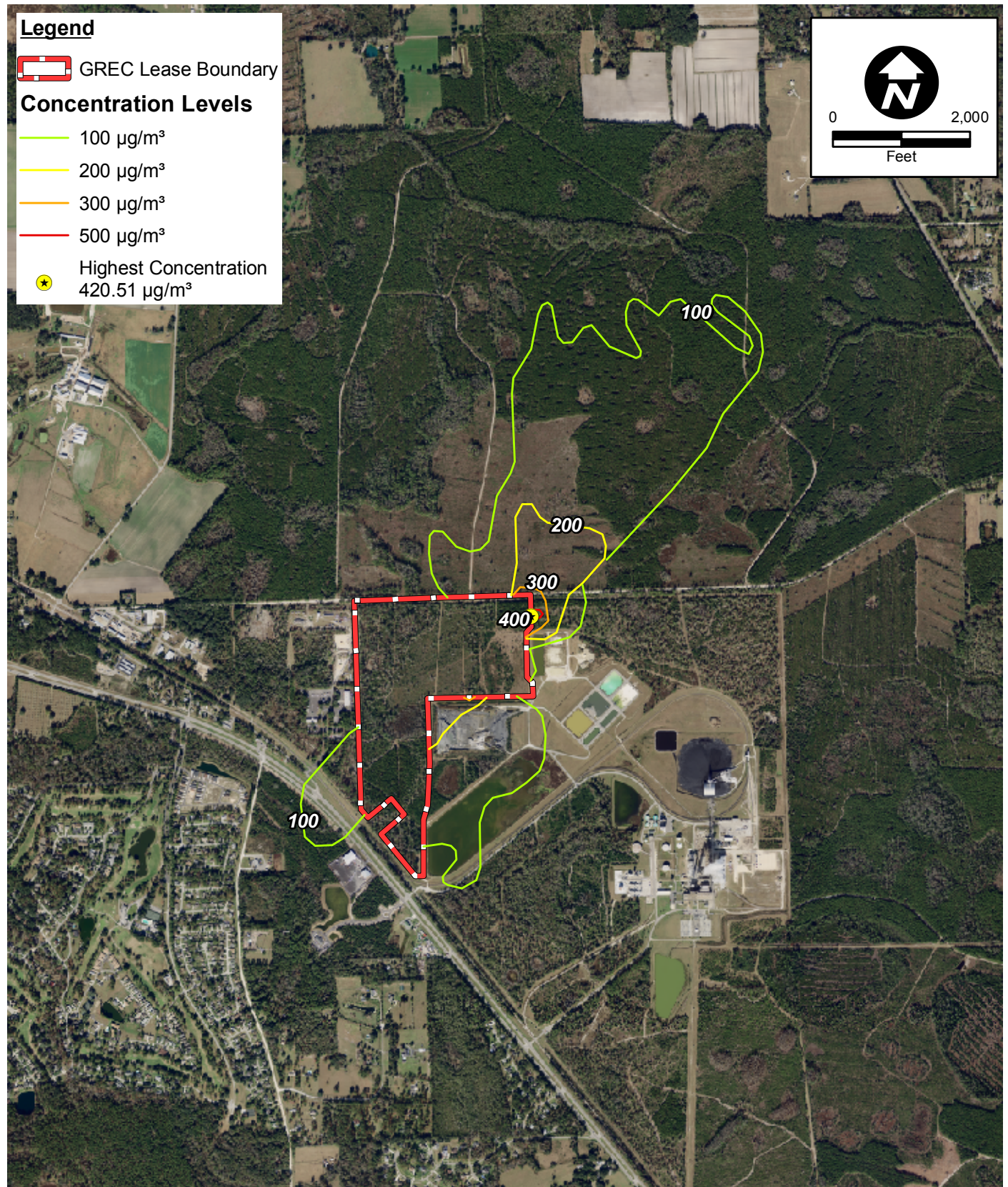


FIGURE 8-5.

MAXIMUM 1-HOUR CO IMPACT
FROM GREC FOR MODEL YEAR 2002

Sources: FDOT, 2008; ECT, 2009,

ECT
Environmental Consulting & Technology, Inc.

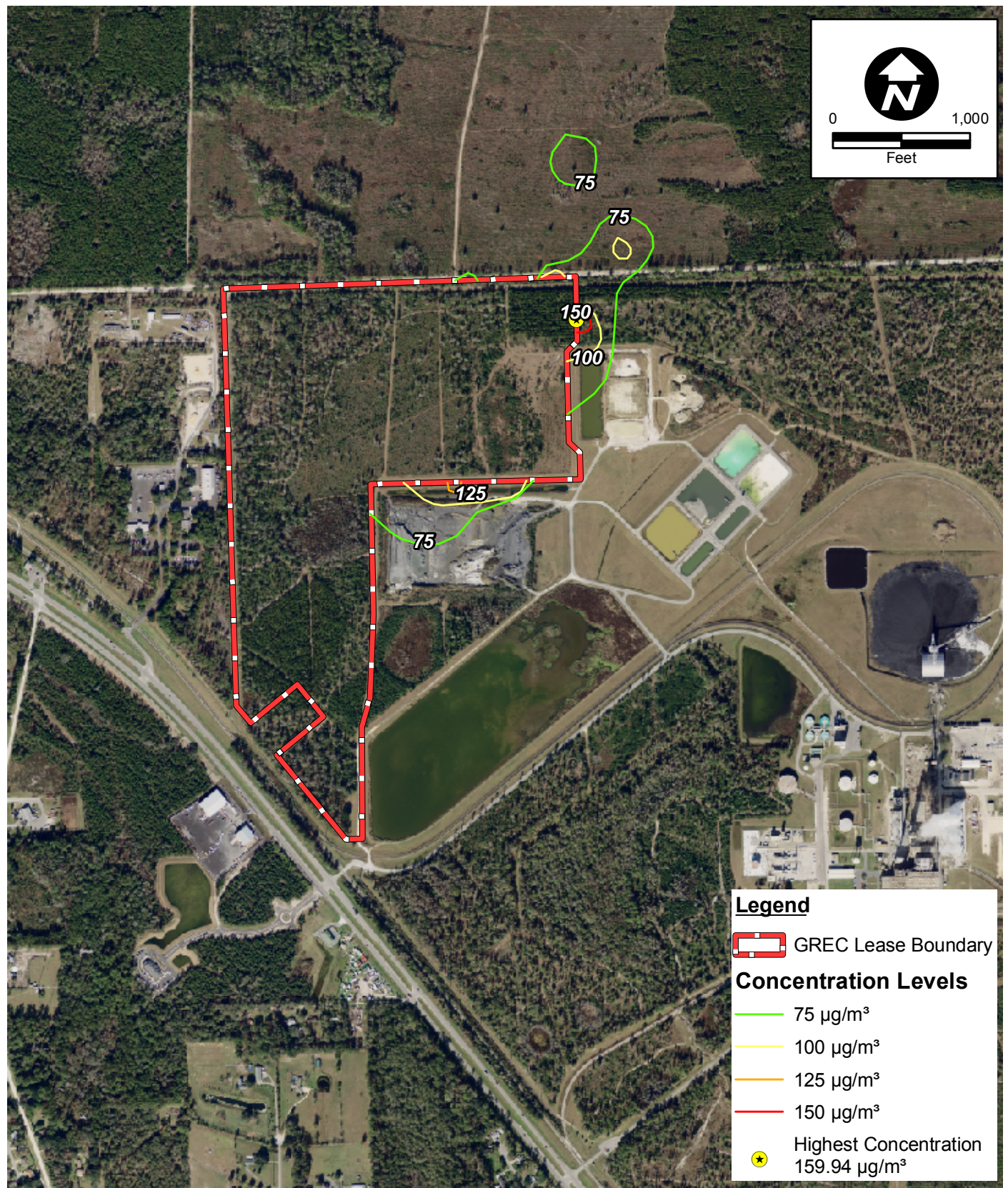


FIGURE 8-6.

GREC MAXIMUM 8-HOUR CO IMPACT
MODEL YEAR 2002

Sources: FDOT, 2008; ECT, 2009,

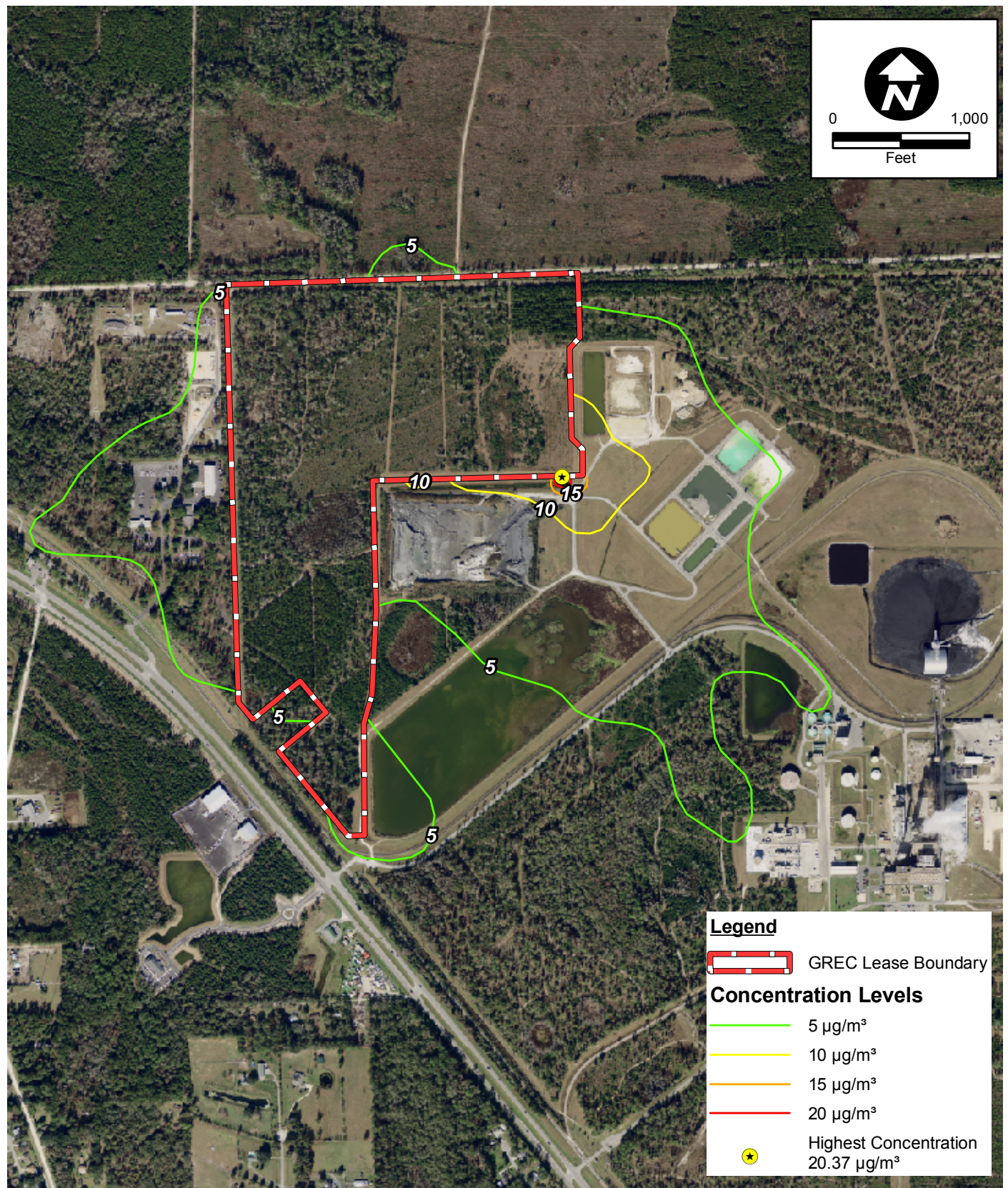


FIGURE 8-7.

GREC MAXIMUM 24- HOUR PM_{10} IMPACT
MODEL YEAR 2005

Sources: FDOT, 2008; ECT, 2009,

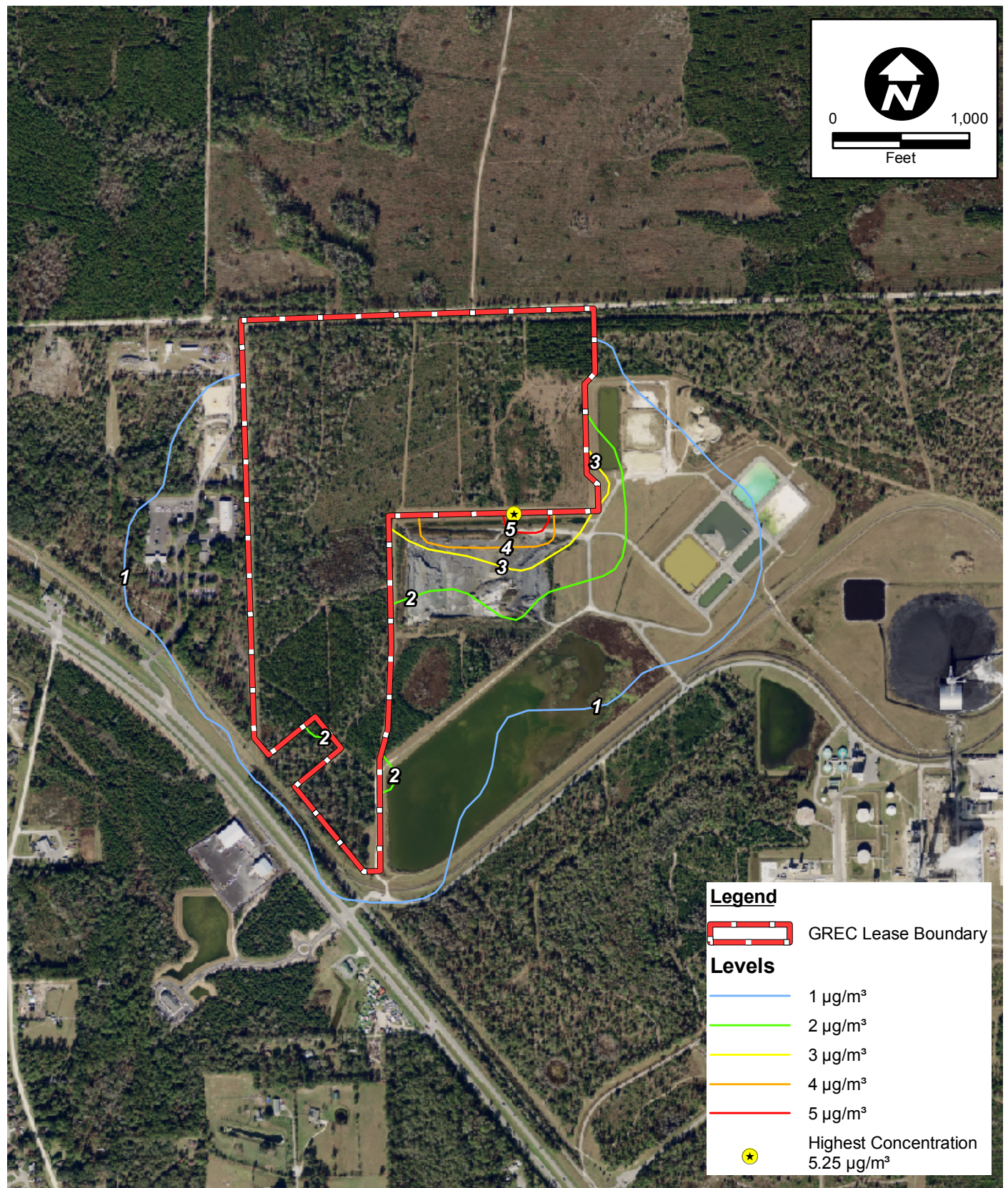


FIGURE 8-8.

GREC MAXIMUM ANNUAL PM_{10} IMPACT
MODEL YEAR 2002

Sources: FDOT, 2008; ECT, 2009,

50 km), an inventory of offsite PM₁₀ sources within 60 km of GREC was used. Table 7-5 lists the offsite sources that were selected from the inventory to be included in the NAAQS and PSD Class II increment analyses. For purposes of this analysis, a separate PSD source inventory was not developed; i.e., all PM₁₀ sources were conservatively assumed to consume PSD increment.

Table 8-15 summarizes the modeling results of the cumulative analysis. The PM₁₀ 24-hour concentrations are the highest, second-highest concentration, which is appropriate for evaluating the PM₁₀ PSD increment. The PM₁₀ 24-hour average NAAQS is in the form of an expected exceedance value, which cannot be exceeded more than once on average over a 3-year period. For a 5-year meteorological period, the highest, sixth-highest value (H6H) over the 5 years is used to assess compliance with the 24-hour average PM₁₀ NAAQS.

The nearest agency PM₁₀ ambient air monitoring site to GREC is located approximately 7 km (4.5 miles) south of the GREC site at the intersection of Northwest 53rd Avenue and Northwest 43rd Street. Ambient air quality data for the 2004 through 2008 period (excluding 2007) shows maximum 24-hour and annual average PM₁₀ concentrations of 63 and 19 µg/m³, respectively. Ambient data at this monitoring site for 2007 was influenced by a fire and therefore not included. These ambient PM₁₀ concentrations were added to the modeled concentrations for the NAAQS comparison. This approach is conservative (i.e., will overestimate actual total concentrations) since the air quality impacts for many of the modeled emission sources would be expected to be included in the ambient air monitoring data resulting in double-counting of these emission sources.

Tables 8-16 (24-hour PSD Class II increment), 8-17 (24-hour NAAQS), and 8-18 (annual average impacts) detail the model results for the cumulative PM₁₀ impacts. The cumulative PM₁₀ modeling demonstrates that air quality impacts from all modeled emission sources, including background, will be well below the 24-hour and annual PSD Class II increments and NAAQS. Therefore, GREC will not cause or contribute to an exceedance of the PM₁₀ PSD increments or NAAQS.

Table 8-15. Summary of PM₁₀ Cumulative Analysis

Pollutant	Averaging Period	Meteorological Site Surface Characteristics	Maximum Predicted Concentration (µg/m³)					Maximum Impact
			Year of Meteorology					
			2001	2002	2003	2004	2005	
PM ₁₀	24-hour (2 nd High)	GRA	16.4	16.0	16.1	15.2	16.1	16.4
		GREC Site	13.7	13.5	13.6	12.8	12.0	13.7
	24-hour (6 th High)*	GRA	N/A	N/A	N/A	N/A	16.0	16.0
		GREC Site	N/A	N/A	N/A	N/A	13.6	13.6
	Annual	GRA	5.9	6.1	5.5	5.4	5.8	6.1
		GREC Site	4.9	4.8	4.5	4.4	4.8	4.9

Note: Maximum impact for 100-percent or 70-percent BFB boiler load.
Maximum impact shown in bold.

*Highest, sixth highest value (H6H) over the 5-year (2001 through 2005) period.

Source: ECT, 2009.

Table 8-16. PM₁₀ Cumulative Analysis Details—24-Hour Average PM₁₀ Impacts: PSD Class II Increment

	Year of Meteorology				
	2001	2002	2003	2004	2005
Predicted highest, 2 nd highest (H2H) concentration (µg/m ³)	16.4	16.0	16.1	15.2	16.1
Receptor UTM easting (meter)	364,967	364,967	364,967	365,061	365,061
Receptor UTM northing (meter)	3,293,714	3,293,714	3,293,714	3,293,714	3,293,714
Distance from grid origin (meter)	119	119	119	122	122
Direction from grid origin (degrees)	201	201	201	155	155
Receptor elevation (meter, amsl)	56.15	56.15	56.15	56.15	56.15
Date of maximum impact (YYMMDDHH)	01120324	02012624	03122624	04110624	05013024
PSD increment level (µg/m ³)	30	30	30	30	30
Exceed PSD Class II increment level? (Yes/No)	No	No	No	No	No
Percent of PSD Class II increment level (%)	54.7	53.2	53.8	50.5	53.8

Note: Distance and direction measured from BFB stack at UTM 365,001 meters easting, and 3,293,825 meters northing.

Maximum impact shown in **bold**.

Maximum impact for GRA or GREC Site surface characteristics and for 100-percent or 70-percent loads.

Source: ECT, 2009.

Table 8-17. PM₁₀ Cumulative Analysis Details—24-Hour Average PM₁₀ Impacts: NAAQS

	Year of Meteorology				
	2001	2002	2003	2004	2005
Predicted highest, 2 nd highest (H2H) concentration (µg/m ³)	16.4	16.0	16.1	15.2	16.1
Background air quality (µg/m ³)	63.0	63.0	63.0	63.0	63.0
Total predicted 24-hour concentration (µg/m ³)	79.4	79.0	79.1	78.2	79.1
Receptor UTM easting (meter)	364,967	364,967	364,967	365,061	365,061
Receptor UTM northing (meter)	3,293,714	3,293,714	3,293,714	3,293,714	3,293,714
Distance from grid origin (meter)	119	119	119	122	122
Direction from grid origin (degrees)	201	201	201	155	155
Receptor elevation (meter, amsl)	56.15	56.15	56.15	56.15	56.15
Date of maximum impact (YYMMDDHH)	01120324	02012624	03122624	04110624	05013024
PM ₁₀ 24-hour NAAQS (µg/m ³)	150	150	150	150	150
Exceed PM ₁₀ 24-hour NAAQS? (Yes/No)	No	No	No	No	No
Percent of annual NAAQS (%)	52.9	52.6	52.8	52.1	52.8

Note: Distance and direction measured from BFB stack at UTM 365,001 meters easting, and 3,293,825 meters northing.

Maximum impact shown in **bold**.

Maximum impact for GRA or GREC Site surface characteristics and for 100-percent or 70-percent loads.

Source: ECT, 2009.

Table 8-18. PM₁₀ Cumulative Analysis Details—Annual Average PM₁₀ Impacts

	Year of Meteorology				
	2001	2002	2003	2004	2005
Predicted annual concentration (µg/m ³)	5.9	6.1	5.5	5.4	5.8
Background air quality (µg/m ³)	19.0	19.0	19.0	19.0	19.0
Total predicted annual concentration (µg/m ³)	24.9	25.1	24.5	24.4	24.8
Receptor UTM easting (meter)	364,967	364,920	364,967	364,967	364,967
Receptor UTM northing (meter)	3,293,714	3,293,715	3,293,714	3,293,714	3,293,714
Distance from grid origin (meter)	119	142	119	119	119
Direction from grid origin (degrees)	201	219	201	201	201
Receptor elevation (meter, amsl)	56.15	56.15	56.15	56.15	56.15
PSD increment level (µg/m ³)	17	17	17	17	17
Exceed PSD Class II increment level? (Yes/No)	No	No	No	No	No
Percent of PSD Class II increment level (%)	34.7	35.9	32.4	31.8	34.1
PM ₁₀ annual NAAQS (µg/m ³)	50	50	50	50	50
Exceed PM ₁₀ annual NAAQS? (Yes/No)	No	No	No	No	No
Percent of annual NAAQS (%)	49.8	50.2	49.0	48.8	49.6

Note: Distance and direction measured from BFB stack at UTM 365,001 meters easting, and 3,293,825 meters northing.

Maximum impact shown in **bold**.

Maximum impact for GRA or GREC Site surface characteristics and for 100-percent or 70-percent loads.

Source: ECT, 2009.

8.2 OZONE ANALYSIS

Ozone is formed in a complex series of chemical reactions involving primarily NO_x and VOCs during warm ambient temperatures in the presence of sunlight. Since ozone is formed from precursor pollutants, assessment of ambient ozone impacts is typically conducted on a regional basis using resource-intensive models such as the EPA Community Multiscale Air Quality (CMAQ) model. Currently, all areas of Florida are attaining the 8-hour ozone AAQS.

GREC estimated potential NO_x and VOC emissions are 418.1 and 78.1 tpy, respectively. These annual emission rates are relatively minor in comparison to regional emissions. For example, Duval County (Jacksonville area) NO_x and VOC emissions in 2002 were 76,620 and 57,871 tons, respectively, based on data obtained from the EPA AirData Web site. NO_x and VOC emissions for Orange County (Orlando area) in 2002 were 44,336 and 63,995 tons, respectively. In contrast, Alachua County (Gainesville area) NO_x and VOC emissions in 2002 were 14,763 and 19,351 tons, respectively. Duval and Orange Counties, all of which have higher population densities and greater NO_x and VOC emissions compared to Alachua County (including the emission increases associated with the GREC) currently have monitored ambient ozone levels below the ozone AAQS.

Ambient ozone levels in Alachua County are primarily due to ozone transport from upwind areas. Despite significant increases in population and motor vehicle activity, ambient ozone air quality in Florida has improved over the last 5 years due to improvements in motor vehicle emission rates. Continued reductions in average motor fleet emissions would be expected to further improve ozone air quality. In addition, CAIR will result in significant actual reductions in existing power plant NO_x emissions throughout Florida. During Phase 1 (2009 through 2014) of the CAIR program, EPA estimates that actual Florida power plant NO_x emissions during the 5-month ozone season (May through September) will be reduced from 119,000 tons (in 2003) to 33,000 tons—a reduction of 86,000 tons. In comparison, GREC estimated ozone season NO_x emissions will be only approximately 174 tons. The CAIR power plant emission reductions will occur through-

out Florida, including areas in Alachua County, and will occur prior to the commencement of operation of GREC. As an example, GRU is retrofitting emission control systems to its existing DGS Unit 2 that will result in an estimated annual reduction in actual NO_x emissions of 3,200 tons—approximately 7.6 times the estimated GREC NO_x emissions.

In summary, the relatively minor GREC NO_x and VOC emissions will not significantly impact ambient ozone levels in Alachua County or other areas in Florida. Alachua County is projected to remain in compliance with the ozone ambient air quality standard due to the continued significant reductions in regional motor vehicle and power plant emissions.

9.0 AMBIENT AIR QUALITY MONITORING AND ANALYSIS

9.1 EXISTING AMBIENT AIR QUALITY MONITORING DATA

The nearest ambient air quality monitoring station is located at the intersection of Northwest 53rd Avenue and Northwest 43rd Street, approximately 7 km (4.5 miles) south of GREC. This station monitors the ambient air for PM₁₀ and PM_{2.5}. The nearest ambient air quality monitoring station that monitors for 1- and 8-hour average ozone is located at 2821 Northwest 143rd Street, approximately 14 km (8 miles) southwest of GREC. The nearest NO₂ ambient air quality monitoring station is located on Bennett Street in Jacksonville, Duval County, approximately 98 km (61 miles) northeast of GREC. The nearest CO ambient air quality monitoring station is located on South McDuff Avenue in Jacksonville, approximately 89 km (55 miles) northeast of GREC. The nearest ambient air quality monitoring station for lead is situated in Valdosta, Lowndes County, Georgia, approximately 148 km (92 miles) north west of GREC. Tables 9-1 and 9-2 provide summaries of the 2004 through 2008 ambient air quality data for these monitoring stations.

9.2 PRECONSTRUCTION AMBIENT AIR QUALITY MONITORING EXEMPTION APPLICABILITY

As previously discussed in Section 3.4.2, PSD review may require continuous ambient air monitoring data to be collected in the area of the proposed source for pollutants emitted in significant amounts. Because several PSD pollutants will be emitted from GREC in excess of their respective significant emission rates, preconstruction monitoring is required. However, Rule 62-212.400(3)(e), F.A.C., provides for an exemption from the preconstruction monitoring requirement for sources with *de minimis* air quality impacts. The *de minimis* ambient impact levels were previously presented in Table 3-3. To assess the appropriateness of monitoring exemptions, dispersion modeling analyses were performed to determine the maximum pollutant concentrations caused by GREC emissions.

The results of these analyses were presented in detail in Section 8.0. The following paragraphs summarize the GREC dispersion modeling results as applied to the preconstruction ambient air quality monitoring exemptions.

Table 9-1. Alachua County Ambient Air Quality Data—2004 through 2008

(Page 1 of 2)

Pollutant	Site Location		Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration (ug/m ³)				Percent of Standard
	County	City								1 st High	2 nd High	Arithmetic Mean	Standard*	
PM ₁₀	Alachua	Gainesville	Northwest 53 rd Avenue and Northwest 43 rd Street	120010023	7	175	2004	24-Hour	343	63	48		150†	32.0
							2005	24-Hour	307	61	61		150†	40.7
							2006	24-Hour	353	54	39		150†	26.0
							2007	24-Hour	354	163‡	77‡		150†	51.3
							2008	24-Hour	273	53	51		150†	34.0
							2004	Annual	362			18	50§	36.0
							2005	Annual	355			19	50§	38.0
							2006	Annual	347			18	50§	36.0
							2007	Annual	355			20‡	50§	40.0
							2008	Annual	348			18	50§	36.0
PM _{2.5}	Alachua	Gainesville	Northwest 53 rd Avenue and Northwest 43 rd Street	120010023	7	175	2004	24-Hour	115	22.4	21.4		65†	32.9
							2005	24-Hour	120	39.5	25.3		65†	38.9
							2006	24-Hour	113	21.1	20.9		65†	32.2
							2007	24-Hour	118	60.9‡	50.9‡		65†	78.3
							2008	24-Hour	89	17.7	15.7		65†	24.2
							2004	Annual	115			9.18	15§	61.2
							2005	Annual	120			9.28	15§	61.9
							2006	Annual	113			9.09	15§	60.6
							2007	Annual	118			38.1‡	15§	254.0
							2008	Annual	89			15.7	15§	104.7
PM _{2.5}	Alachua	Gainesville	Southwest 8 th Avenue	120010024	14	188	2004	24-Hour	115	39.1	23.2		65†	0.0
							2005	24-Hour	110	34.5	24.6		65†	0.0
							2006	24-Hour	117	21.2	20.0		65†	0.0
							2007	24-Hour	117	50.0‡	44.8‡		65†	68.9
							2008	24-Hour	91	18.0	16.0		65†	0.0
							2004	Annual				9.45	15§	63.0
							2005	Annual				9.74	15§	64.9
							2006	Annual				9.34	15§	62.3
							2007	Annual				9.85	15§	65.7
							2008	Annual				8.08	15§	53.9
SO ₂	Putnam	Palatka	Comfort and Port Roads	121071008	72	98	2004	3-Hour	8,706	99	94		1,300†	7.2
							2005	3-Hour	8,686	133	128		1,300†	9.8
							2006	3-Hour	8,657	196	128		1,300†	9.8
							2007	3-Hour	8,533	65	63		1,300†	4.8
							2008	3-Hour	6,469	269	71		1,300†	5.4
							2004	24-Hour	8,706	34	26		260†	10.0
							2005	24-Hour	8,686	34	34		260†	13.1
							2006	24-Hour	8,657	37	37		260†	14.1
							2007	24-Hour	8,533	21	18		260†	7.0
							2008	24-Hour	6,469	39	18		260†	7.0

Table 9-1. Alachua County Ambient Air Quality Data—2004 through 2008

(Page 2 of 2)

Pollutant	Site Location		Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration (ug/m ³)				
	County	City								1 st High	2 nd High	Arithmetic Mean	Standard*	Percent of Standard
SO ₂ (Continued)	Putnam	Palatka	Comfort and Port Roads	121071008	72	98	2004	Annual	8,706			5.2	60§	8.7
							2005	Annual	8,686			5.2	60§	8.7
							2006	Annual	8,657			5.2	60§	8.7
							2007	Annual	8,533			5.2	60§	8.7
							2008	Annual	6,469			5.2	60§	8.7
NO ₂	Duval	Jacksonville	2900 Bennett Street	120310032	98	49	2004	Annual	7,451			26.3	100§	26.3
							2005	Annual	7,890			24.4	100§	24.4
							2006	Annual	8,086			22.5	100§	22.5
							2007	Annual	7,990			18.8	100§	18.8
							2008	Annual	6,032			16.9	100§	16.9
CO	Duval	Jacksonville	1184 South McDuff Avenue	120310083	89	49	2004	1-Hour	7,963	4,300	3,500		40,000†	8.8
							2005	1-Hour	7,862	3,800	3,300		40,000†	8.3
							2006	1-Hour	8,467	3,900	3,900		40,000†	9.8
							2007	1-Hour	8,576	3,000	2,900		40,000†	7.3
							2008	1-Hour	6,318	2,900	2,400		40,000†	6.0
							2004	8-Hour	7,963	3,000	2,600		10,000†	26.0
							2005	8-Hour	7,862	2,300	2,200		10,000†	22.0
							2006	8-Hour	8,467	2,600	1,800		10,000†	18.0
							2007	8-Hour	8,576	2,100	1,700		10,000†	17.0
							2008	8-Hour	6,318	1,600	1,400		10,000†	14.0
							2004	24-Hour	24	0.01	0.01		0.15⊗	6.7
							2005	24-Hour	27	0.01	0.00		0.15⊗	6.7
							2006	24-Hour	31	0.01	0.01		0.15⊗	6.7
Lead	Lowndes	Valdosta, GA	Valdosta_S.L. Mason	131850003	148	326	2007	24-Hour	27	0.00	0.00		0.15⊗	0.0
							2008	24-Hour	23	0.00	0.00		0.15⊗	0.0
							2004	Max quarterly	24	0.00			1.5§	0.0
							2005	Max quarterly	27	0.00			1.5§	0.0
							2006	Max quarterly	31	0.00			1.5§	0.0
							2007	Max quarterly	27	0.00			1.5§	0.0
							2008	Max quarterly	23	0.00			1.5§	0.0
							2004	Max quarterly	24	0.00			1.5§	0.0
							2005	Max quarterly	27	0.00			1.5§	0.0
							2006	Max quarterly	31	0.00			1.5§	0.0

*See Table 3.3.7-4 for the complete conditions associated with each standard.

†Not to be exceeded more than once per year.

‡FDEP suggests interference from a fire. EPA is currently reviewing the exclusion of this data.

§Arithmetic mean.

⊗Rolling 3-month average.

Sources: FDEP, 2007.
 EPA AirData, 2009.
 ECT, 2009.

Table 9-2. Alachua County Ozone Ambient Air Quality Data—2002 through 2008

Site Location		Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Days	Ambient Ozone Concentration ($\mu\text{g}/\text{m}^3$)					Percent of Standard*
County	City								1 st High	2 nd High	3 rd high	4 th high	Standard	
Alachua	Gainesville	200 Savannah Boulevard	120013011	27	159	2002	1-Hour	243	176	167	157	157	235†	N/C
						2003	1-Hour	238	174	170	159	157	235†	N/C
						2004	1-Hour	232	186	178	167	161	235†	74.2
						2005	1-Hour	146	168	165	165	163	235†	72.5
						2006	1-Hour	244	174	168	167	167	235†	71.7
						2007	1-Hour	245	188	182	182	178	235†	75.9
						2008	1-Hour	209	165	149	147	147	235†	62.5
						2002	8-Hour	240	149	141	139	139	157‡	N/C
						2003	8-Hour	236	159	147	143	139	157‡	N/C
						2004	8-Hour	231	161	155	153	147	157‡	90.3
						2005	8-Hour	146	153	147	143	143	157‡	91.1
						2006	8-Hour	244	153	151	147	147	157‡	92.8
						2007	8-Hour	245	161	159	155	153	157‡	94.0
						2008	8-Hour	207	149	139	137	135	157‡	92.3
Alachua	Gainesville	2821 Northwest 143 rd Street	120010025	13	223	2002	1-Hour	N/A	N/A	N/A	N/A	N/A	235†	N/A
						2003	1-Hour	234	174	168	161	155	235†	N/C
						2004	1-Hour	219	182	161	159	155	235†	N/C
						2005	1-Hour	243	165	165	165	165	235†	70.0
						2006	1-Hour	N/A	N/A	N/A	N/A	N/A	235†	N/A
						2007	1-Hour	N/A	N/A	N/A	N/A	N/A	235†	N/A
						2008	1-Hour	N/A	N/A	N/A	N/A	N/A	235†	N/A
						2002	8-Hour	N/A	N/A	N/A	N/A	N/A	157‡	N/A
						2003	8-Hour	234	165	153	151	143	157‡	N/C
						2004	8-Hour	216	165	147	143	143	157‡	N/C
						2005	8-Hour	242	151	151	143	141	157‡	90.7
						2006	8-Hour	N/A	N/A	N/A	N/A	N/A	157‡	N/A
						2007	8-Hour	N/A	N/A	N/A	N/A	N/A	157‡	N/A
						2008	8-Hour	N/A	N/A	N/A	N/A	N/A	157‡	N/A

Note: N/A = not available.
N/C = not calculated.

*Percent of standard for 1-hour values is based on 1-hour design values (4th highest daily 1-hour maximum over a 3-year period).

†Average number of expected exceedances above the standard per year, over a 3-year period, is less than or equal to one.

‡4th highest daily 8-hour concentration averaged over a 3-year period.

Sources: FDEP, 2007.
EPA AirData, 2009.
ECT, 2009.

9.2.1 PM₁₀

The GREC maximum 24-hour PM₁₀ impact of 20.4 µg/m³ is above the 10-µg/m³ *de minimis* level ambient impact level for PM₁₀, and therefore a preconstruction monitoring exemption in accordance with Rule 62-212.400(3)(e), F.A.C., is not applicable. However, in accordance with EPA guidance (EPA, 1992) representative current quality-assured ambient data collected at an FDEP ambient monitoring site in the general vicinity of GREC can be used to satisfy the PSD preconstruction ambient air monitoring requirements. Ambient air data collected by FDEP at Site 120010023, intersection of Northwest 53rd Avenue and Northwest 43rd Street (located approximately 4.5 miles south of GREC), is representative ambient air data for PM₁₀, and therefore onsite preconstruction ambient air monitoring is not required.

9.2.2 SO₂

The GREC maximum 24-hour SO₂ impact of 3.3 µg/m³ is below the 13-µg/m³ *de minimis* ambient impact level for the 24-hour averaging period. Therefore, a preconstruction monitoring exemption for SO₂ is appropriate in accordance with FDEP PSD regulations.

9.2.3 NO₂

The GREC maximum annual NO₂ impact of 0.52 µg/m³ is below the 14-µg/m³ *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption is appropriate for NO₂ in accordance with the FDEP PSD regulations.

9.2.4 CO

The GREC maximum 8-hour CO impact of 160 µg/m³ is below the 575-µg/m³ *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption is appropriate for CO in accordance with the FDEP PSD regulations.

9.2.5 OZONE

Preconstruction monitoring for ozone is required if potential VOC emissions from a project subject to PSD review exceed 100 tpy. Estimated GREC potential VOC emissions are 78.1 tpy. Therefore, a preconstruction monitoring exemption is appropriate for ozone in accordance with the FDEP PSD regulations.

10.0 ADDITIONAL IMPACT ANALYSIS

The additional impacts analysis, required for projects subject to PSD review, evaluates project impacts pertaining to associated growth; soils, vegetation, and wildlife; and visibility impairment. Each of these topics is discussed in the following subsections. Based on a thorough review of emissions expected as a result of this project, it is concluded that GREC will not cause any adverse impacts to the soils, vegetation, or wildlife of relevant Class I and II areas.

10.1 GROWTH IMPACTS ANALYSIS

10.1.1 PROJECT GROWTH IMPACTS

The purpose of the growth impact analysis is to quantify growth resulting from the construction and operation of the proposed project and assess air quality impacts that would result from that growth.

Impacts associated with construction of GREC will be minor. During the approximate 34-month construction period, GREC will employ an average of 168 workers. While not readily quantifiable, the temporary increase in vehicle miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.

GREC is being constructed to meet general area electric power demands; therefore, no significant secondary growth effects due to operation of the project are anticipated. When operational, GREC is projected to employ approximately 44 fulltime workers. This number of new personnel will not significantly affect growth in the area. The increase in natural gas and diesel fuel oil demand due to the operation of GREC will have no major impact on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected at this time.

10.1.2 AREA GROWTH SINCE 1977

United States census data shows that the populations of Alachua County and the City of Gainesville have increased by 64 and 51 percent between 1980 and 2007, respectively.

The 2007 estimated populations of Alachua County and Gainesville are 247,561 and 122,671, respectively. Alachua County was the 23rd most populous of the 67 counties in Florida based on the 2007 census data, and it ranked 23rd in density.

Alachua County has also experienced little industrial growth since 1977. The EPA Air-Data Web site shows only three significant (i.e., actual emissions greater than 5 tpy) NO_x and SO₂ emission sources for 2002—the latest year available for facility data. The largest industrial facility, DGS, has been operating in Alachua County for more than 30 years. The latest significant emission source to locate in Alachua County is the Florida Rock Industries cement plant situated in Newberry. This facility was subject to PSD review and therefore uses BACT to minimize emissions.

Based on the current low densities of population and industrial activity, it is concluded that air quality in Alachua County has not deteriorated since 1977. As discussed in Section 8.0, the emissions associated with GREC will result in air quality impacts that are well below the national and Florida AAQS.

10.2 IMPACTS ON SOILS, VEGETATION, AND WILDLIFE

Potential impacts to soils, vegetation, and wildlife resources of the GREC Site and environs resulting from the proposed plant operation include effects of air emissions. Table 10-1 summarizes the modeled emissions concentrations due to the GREC emission sources for all relevant Class I and II areas. As previously discussed, GREC will employ state-of-the-art equipment and emission controls. Maximum air quality impacts in the vicinity of GREC will be well below the applicable AAQS. Given the resulting low emission rates and insignificant potential air quality impacts, potential detrimental effects on soils, vegetation, and wildlife will be insignificant.

A general discussion of air emission impacts on soils, vegetation, and wildlife is provided in the following subsection. Following this general discussion, specific analyses of impacts in the vicinity of GREC as well as the two nearest Class I areas (i.e., the Okefenokee and Chassahowitzka NWAs) are provided.

Table 10-1. GREC Maximum Pollutant Concentration Impacts

Pollutant	Averaging Period	Class I Area Impact ($\mu\text{g}/\text{m}^3$)		Class II Area Impact ($\mu\text{g}/\text{m}^3$)
		Chassahowitzka NWA	Okefenokee NWA	
NO _x	Annual	0.0015	0.0025	0.4
SO ₂	Annual	0.0015	0.0023	0.3
	24-Hour	0.044	0.051	3.3
	3-Hour	0.15	0.23	5.6
PM ₁₀	Annual	0.0021	0.0029	5.3
	24-Hour	0.051	0.057	20.4
CO	1-Hour	N/A	N/A	159.9
	8-Hour	N/A	N/A	420.5

Source: ECT, 2009.

10.2.1 GENERAL AIR EMISSIONS IMPACTS ON SOILS

Sulfur and nitrogen can be added to soil as a result of atmospheric deposition. Sulfur and nitrogen deposition in soil can have beneficial effects to vegetation if they are currently lacking these elements. At levels above plant requirements, gaseous emission impacts on soils can cause acidic conditions to develop. Acidic conditions in the soil can cause the leaching of basic cations essential for plant life and in extreme circumstances can transform aluminum to a more soluble form where toxicity can occur (Goldstein *et al.*, 1985).

Nitrogen deficiency is common in nonagricultural areas, and, therefore, much of the atmospherically deposited NO_x is biologically assimilated. There is a limited soil adsorption mechanism for nitrate, so unutilized nitrate will be leached through the soil (Johnson and Reuss, 1984). Both of these factors indicate that nitrate does not play a significant role in soil acidification, and sulfate is more of a concern. Atmospheric deposition of nitrogen can facilitate eutrophication of the soil and vegetative community. Critical loads of nitrogen above which eutrophication caused a change in vegetative species present in calcareous forests was found to be 15 to 20 kilograms per hectare per year (kg/ha/yr) (Thimonier *et al.*, 1994).

Sulfur deposition can facilitate soil acidification. Sulfur exists in the soil predominantly in the form of sulfate. The maintenance of sulfate in soil solution facilitates the loss of cations. Therefore, the more sulfate that is adsorbed to soil particles, the more buffered the soils will be (Johnson and Reuss, 1984). The soil is a much larger sink for sulfate than vegetation (Johnson and Reuss, 1984). Sulfate can be adsorbed on the surface of reactive clays and iron/aluminum oxides within the soil, which often releases hydroxide, further buffering the soil (Johnson and Reuss, 1984). Soils found in Florida and Georgia that have high adsorption rates for sulfates include ultisols and certain suborders of inceptisols and entisols (Psammments) (Johnson and Reuss, 1984). The high iron and aluminum content of the subsurface spodic (B_h) horizon of spodosols likely adsorbs the sulfate anion to a large extent as is shown to occur with the anion of phosphate. The development of acid-

ic conditions in the Southeast are thought to be well buffered by the high amount of sulfate adsorption (USGS, 1999).

Dissolution of sulfate and nitrate can also facilitate the formation of nitric and sulfuric acid in rainwater, which increases acidic hydrogen ion (H^+) composition within the soil. Soils that are well buffered to the addition of acid causing H^+ ions, have a high cation exchange capacity (CEC), often imparted by surface or subsurface clays and a high base saturation. Barton *et al.* (2002) found soils with a base saturation of 12 to 19 percent and reactive clays, to be buffered to acidic inputs, whereas soils with a base saturation of 3 to 7 percent by depth show the effects of soil acidification. In addition, organic horizons of wetland histosols buffer acidic inputs protecting the depletion of cations from the mineral horizons (Koptsik *et al.*, 1998).

10.2.2 GENERAL AIR EMISSIONS IMPACTS ON VEGETATION

It is difficult to predict site-specific ecological impacts due to air emissions based on data and conclusions in available literature because of significant variations in experimental designs relating dose, duration, and vegetation species. Minor variations in experimental design and the conditions under which the various vegetation species have been fumigated can result in large differences in the tolerance limits of tested species.

Table 10-2 presents a summary of the thresholds for the most sensitive vegetation and the air-pollution induced effects, for important air pollution constituents. To demonstrate the range of tolerances for relevant vegetation, Table 10-3 lists literature results for injury threshold concentrations and characteristic injury symptoms of plants found in the southeastern United States. The species listed are likely to occur in all or many of the Class I areas addressed herein. As a result, all listed vegetation will be used as bioindicators for impacts to all the Class I and II areas relevant to GREC.

Vegetation damage is described as impacts resulting in foliar damage. Less apparent vegetation injury is described as a reduction in growth and/or productivity without visible damage, as well as changes in secondary metabolites such as tannins and phenolic

Table 10-2. Estimated Maximum Facility Impacts Compared to General Plant Injury Symptoms and Threshold Concentrations for Important Air Pollutants

Pollutant	Symptoms	Injury Threshold		Estimated Maximum Facility Impact (µg/m ³)
		µg/m ³	Sustainable Exposure	
SO ₂	Bleached spots, intercostal chlorosis	131*	8 hours	5.6†† (3-hour)
SO ₂	Absence of the most sensitive lichen	13-26†	Chronic	
NO ₂	Increase in Nitrate Reductase activity in sensitive bryophytes	65‡	24 hours	0.4†† (annual)
Mercury	Chlorosis and abscission; brown spotting; yellowing of veins	0.08**	5 weeks	1.1 E-04††

Note: Conservative (worst-case) impact estimated based on modeling results presented in Section 8.0.

Sources: *Jones *et al.*, 1974.
†Wetmore, 1983.
‡World Health Organization, 2000.
**Hindawi, 1970.
††ECT 2009.

Table 10-3. Air Pollutant Injury Threshold Concentrations for Plants Native to the Southeast

Common Name	Scientific Name	SO ₂	NO _x
Red maple	<i>Acer rubrum</i>	786 ^a (5 hours)	
Maple	<i>Acer</i> sp.	524 to 6,550 ^b (8 hours)	
Bald Cypress	<i>Taxodium distichum</i>	2,620 ^c (48 hours)	
Bracken fern	<i>Pteridium aquilinum</i>	131 to 1,310 ^b (8 hours)	
Blackberry	<i>Rubus</i> sp.	131 to 1,310 ^b (8 hours)	
Ragweeds	<i>Ambrosia</i> sp.	1,310 to 2,620 ^h (1 hour) 790 to 1,570 (3 hours)	
Southern red oak	<i>Quercus falcata</i>	1,310 to 2,620 ^h (1 hour) 790 to 1,570 (3 hours)	
Black oak	<i>Quercus velutina</i>	1,310 to 2,620 ^h (1 hour) 790 to 1,570 (3 hours)	
Legumes		1,310 to 2,620 ^h (1 hour) 790 to 1,570 (3 hours)	
Locust	<i>Gleditsia</i> sp.	2,620 to 5,240 ^h (1 hour) 1,570 to 2,100 (3 hours)	
Many crop and garden species		2,620 to 5,240 ^h (1 hour) 1,570 to 2,100 (3 hours)	
American elm	<i>Ulmus americana</i>	131 to 1,310 ^b (8 hours)	
White ash	<i>Fraxinus americana</i>	131 to 1,310 ^b (8 hours)	
Sumacs	<i>Rhus</i> spp.	131 to 1,310 ^b (8 hours)	
Tulip poplar	<i>Liriodendron tulipifera</i>	524 to 6,550 ^b (8 hours)	
Sweetgum	<i>Liquidambar styraciflua</i>	524 to 6,550 ^b (8 hours)	
Slash pine	<i>Pinus elliotii</i>	149 ^f (chronic)	
Basswood	<i>Tilia glabra</i> = <i>T. americana</i>	524 to 6,550 ^b (8 hours)	
Pin oak	<i>Quercus palustris</i>	524 to 6,550 ^b (8 hours)	
Red cedar	<i>Juniperus virginiana</i>	>5,240 ^b (8 hours)	
Potato		2,620 to 5,240 ^h (1 hour) 1,570 to 2,100 (3 hours)	

Table 10-3. Air Pollutant Injury Threshold Concentrations for Plants Native to the Southeast
(Continued, Page 2 of 2)

Common Name	Scientific Name	SO ₂	NO _x
Upland cotton	<i>Gossypium hirsutum</i>	>5,240 ^h (1 hour) >2,100 (3 hours)	
Corn	<i>Zea mays</i>	>5,240 ^h (1 hour) >2,100 (3 hours)	
Lichen	<i>Ramalina americana</i>	13 to 26 ^d (chronic)	
Lichens	Sensitive species of <i>Us- nea, Lobaria, Cladonia</i>	>30 ^e (chronic)	
White oak	<i>Quercus alba</i>	>5,240 ^b (8 hours)	
Dogwood	<i>Cornus florida</i>	>5,240 ^b (8 hours)	
Bryophyte	<i>Several Bryophyte species</i>		65 ^g (24 hours)
Birch	<i>Betula</i> sp.		120 ^g (chronic)
Common sunflow- er	<i>Helianthus annuus</i>		375 ^g (chronic)
Alfalfa	<i>Medicago sativa</i>		1,000 ^g (5 hours)
Peach	<i>Prunus persica</i>		>5,240 (1 hour) >2,100 (3 hours)
Garden pea	<i>Pisum sativum</i>		850 ^g (7 hours)
Cultivated tobacco	<i>Nicotiana tabacum</i>		2,000 to 3,000 ^g (3.5 hours)
Perennial ryegrass	<i>Lolium perenne</i>		125 ^g (chronic)
Southern pine	<i>Pinus</i> spp.	1572 ^b (3 hours)	

Note: Concentrations in µg/m³ (exposure times shown in parentheses).

Sources: ^aDavis and Shelly, 1992.

^bJones *et al.*, 1974.

^cShanklin and Kozlowski, 1985.

^dWetmore, 1983.

^eTreshow and Anderson, 1989.

^fHogsett *et al.*, 1985.

^gWorld Health Organization, 2000.

^hEPA, 1982.

compounds (Fitzgerald *et al.*, 1996). Vegetation damage often results from acute exposure to pollution (i.e., relatively high doses over relatively short time periods). Injury is also associated with prolonged exposures of vegetation to relatively low doses of pollutants (chronic exposure). Acute damages, which have both functional and visible consequences, are usually manifested by internal physical damage to foliar tissues. Chronic injuries are typically more associated with changes in physiological processes. The following discussion summarizes descriptions from the literature of the potential effects upon vegetation associated with the relevant pollutants.

10.2.2.1 Nitrogen Oxides

During combustion, atmospheric nitrogen is oxidized to NO and small amounts of NO₂ (Taylor *et al.*, 1975). Impacts to vegetation from NO₂ result from high concentrations occurring during short time periods (Taylor and MacLean, 1970). Acute exposures of this sort will cause necrotic lesions in leaf tissue and excessive defoliation (MacLean *et al.*, 1968). Nonvascular bryophytes are very sensitive to NO_x exhibiting reductions in nitrate reductase activity at concentrations of 65 µg/m³ with an exposure duration of 24 hours (WHO 2000). Bald cypress (*Taxodium distichum*), a common tree species in wetlands of this geographical area, shows no adverse impacts below 2,620 µg/m³ with an exposure time of 48 hours (Shanklin and Kozlowski, 1985).

10.2.2.2 Sulfur Dioxide

Natural (ambient) background concentrations of SO₂ range between 0.28 and 2.8 µg/m³ on a mean annual basis (Prinz and Brandt, 1985). The most common source of atmospheric SO₂ is the combustion of fossil fuels (Mudd and Kozlowski, 1975). Gaseous SO₂ primarily affects vegetation by diffusion through the stomata (Varshney and Garg, 1979). Small amounts of SO₂ may also be absorbed through the protective cuticle. At low concentrations SO₂ byproducts are effectively detoxified by the plant and can become a sulfur source to the plant, while elevated concentrations can be toxic (Zeiger, 2002). Adverse effects on plants from SO₂ are primarily due to impacts to photosynthetic processes. SO₂ can react with chlorophyll by bleaching or phaeophytinization. This latter process constitutes a photosynthetic deactivation of the chlorophyll molecule. Acute damage due

to SO₂ appears as marginal or intercostal areas of dead tissue that at first cause leaves to appear water-soaked (Barett and Benedict, 1970). Chronic injuries are less apparent; the leaves remain turgid and continue to function at a reduced level. In more severe cases of chronic SO₂ exposure, there is some bleaching of the chlorophyll that appears as a mild chlorosis or yellowing of the leaf and/or a silvery or bronzing of the undersurface. Species that are categorized as sensitive to SO₂ emissions are those which show damage to at least 5 percent of the leaf area upon being exposed to 131 to 1,310 µg/m³ SO₂ for a period of 8 hours (Jones *et al.*, 1974).

Researchers have conducted numerous studies to determine the effects of SO₂ exposure to a wide variety of selected plant species. A review of the literature demonstrates that the most sensitive vascular plants (e.g., white ash, sumacs, tulip poplar, goldenrods [*Solidago* spp.], legumes, blackberry [*Rubus* spp.], black oak [*Quercus velutina*], and ragweeds [*Ambrosia* spp.]) exhibit visible injury to short-term (3 hours) exposure to SO₂ concentrations ranging from 790 to 1,570 µg/m³. Tolerant plants native to the southeast region are dogwood (*Cornus florida*), red cedar (*Juniperus virginiana*), and white oak (*Quercus alba*) with injury thresholds greater than 5,240 µg/m³ for a 3-hour exposure period (Jones *et al.*, 1974). Plants with intermediate tolerance (131 to 1,310 µg/m³ for an 8-hour period) are maples (*Acer* spp.), tulip poplar (*Liriodendron tulipifera*), and sweetgum (*Liquidambar styraciflua*). Vascular plant species found in this region of the southeast, which are sensitive or moderately sensitive to SO₂, include bracken fern (*Pteridium aquilinum*), blackberry, sumacs (*Rhus* spp.), and tulip poplar. Complicating generalizations regarding SO₂ injury is the observation that the genetic variability of native annual plants can result in the selection of SO₂ resistant strains in as little as 25 years (Westman *et al.*, 1985).

Due to their rather diminutive and inconspicuous nature, lichens and bryophytes are often not considered as important biological components of the ecosystem. However, these nonvascular plants do play a valid role in the environment by functioning as habitat for invertebrates, containing blue-green bacteria that fix nitrogen, participating in mineral cycling, and providing a food source for various fauna, among others.

Nonvascular plants such as lichens and bryophytes are especially important as bioindicators due to well-documented air pollution sensitivity. Because of relatively low chlorophyll content and the absence of the protective covering of a cuticle (common in the leaves of higher plants), nonvascular plants are more sensitive to SO₂ injury. Hart *et al.* (1988) showed that *Ramalina* sp., a lichen genus, exhibited a reduction of CO₂ uptake and biomass gain at SO₂ exposures of 400 µg/m³ for 6 weeks. Tolerant lichens can resist SO₂ concentrations in the range of 79 to 157 µg/m³; higher concentrations are deleterious to most nonvascular flora (LeBlanc and Rao, 1975). A mean annual concentration of 30 µg/m³ of SO₂ may injure sensitive individuals of some lichen species such as *Usnea*, *Lobaria*, *Ramalina*, and *Cladonia* (Treshow and Anderson, 1989). One lichen species, *Ramalina americana*, is known to be absent where SO₂ concentration mean annual values range from 13 to 26 µg/m³ (LeBlanc and Rao, 1972; Wetmore, 1983).

10.2.2.3 Particulate Matter

In addition to gaseous emissions, small amounts of PM will be emitted by the proposed Project. Typically, the density of PM limits impacts such that only vegetation in proximity to the source may be affected.

Included among the PM may be low concentrations of metals, to the extent present at low levels in biomass fuels. Mercury may occur as both mercury vapors and particulates. The mechanism of mercury phytotoxicity is currently under investigation. Past investigations indicate that mercury vapors will cause chlorosis, abscission of older leaves, growth reduction, and poor development. Most investigations have been restricted to greenhouse crops where air quality monitoring was not conducted. One investigation indicates that vegetation exposed to 50 µg/m³ mercury for 7 days experienced leaf abscission (Siegel *et al.*, 1984). Plants found in the region showing injury at this concentration and period of exposure to mercury are willow (*Salix* spp.) and red maple (*Acer rubrum*).

The literature regarding effects on vegetation from beryllium, arsenic, and lead is scarce. One investigation indicates that vegetation growth was reduced by beryllium concentrations in excess of 735 µg/m³ (Gough *et al.*, 1979). Arsenic uptake by vegetation to a con-

centration of 5 micrograms per gram ($\mu\text{g/g}$) is considered harmful. Lead retards plant growth above a concentration of 30 $\mu\text{g/g}$ in the soil.

10.2.2.4 Carbon Monoxide

CO is not considered harmful to plants and is not known to be effectively taken up by plants (Bennett and Hill, 1975). Microorganisms within the soil appear to be a major sink for CO.

10.2.3 GENERAL AIR EMISSIONS IMPACTS ON WILDLIFE

Impacts to wildlife can occur due to direct uptake of pollutants through ingestion or via the skin and more indirectly as a result of air pollution induced changes to wildlife habitat and food source. Studies have shown direct air pollution induced injury and death in wildlife as a result of fluoride, cadmium, SO_2 , particulates, NO_x , arsenic, mercury, and oxidants like ozone (Newman 1980; Newman & Schreiber 1985). These impacts are mostly the result of extreme incidences due to acute toxicity. This acute toxicity occurs most severely in circumstances where air pollutants were likely elevated far above the AAQS, or where significantly elevated concentrations of pollutants occurred on vegetation that was subsequently consumed. The AAQS were previously shown in Section 3.0 on Table 3-1. No observed impacts upon wildlife are expected at concentrations below the values reported in Table 10-4.

Studies have shown damage to the tracheal epithelium of bird species at extreme concentrations of NO_x and SO_2 of 2,500 $\mu\text{g/m}^3$ and 1,221 $\mu\text{g/m}^3$, respectively (Llacuna *et al.*, 1993). These values are far elevated above concentrations that are expected.

Ambient air quality concentrations as a result of GREC will not exceed the NAAQS or values listed in Table 10-4. Pollutant deposition on vegetation at levels harmful to wildlife will likely be lower than plant injury thresholds (Table 10-2 and 10-3). Absent any site-specific studies on baseline levels of pollutants, it is assumed that wildlife impacts will be insignificant if pollutant effects on vegetation are also expected to be insignificant.

Table 10-4. Examples of Reported Stresses to Animals at Various Air Pollutant Concentrations

Pollutant	Reported Effect	Concentration ($\mu\text{g}/\text{m}^3$)	Animal Exposure
SO_2^*	Respiratory stress in guinea pigs	427 to 854	1 hour
	Respiratory stress in rats	267	7 hours/day; 5 days/week for 10 weeks continually for 5 months
	Decreased abundance in deer mice	13 to 157	
$\text{NO}_x^{\dagger\dagger}$	Respiratory stress in mice	1,917	3 hours
	Respiratory stress in guinea pigs	96 to 958	8 hours/day for 122 days continually for 2 months
Particulates*	Respiratory stress, reduced respiratory disease defenses	120 PbO_3	2 hours
	Decreased respiratory disease defenses in rats, same with hamsters	100 NiCl_2	

Sources: *Newman and Schreiber, 1988.

$\dagger$ Gardner and Graham, 1976.

$\ddagger$ Trzeciak *et al.*, 1977.

Persistent pollutants such as mercury have the potential to collect in the environment and bioaccumulate to elevated concentrations in upper-trophic level wildlife. Mercury is a persistent pollutant that accumulates in the sediments. Mercury methylation, whereby inorganic forms of mercury are biologically converted to a bioavailable organic form, occurs most predominantly in the anaerobic conditions found in ponds, lakes, and wetlands (St. Louis *et al.*, 1994; Krabbenhoft *et al.*, 1995; Driscoll *et al.*, 1998). As a result, species living and feeding within these aquatic systems are the most sensitive to mercury bioaccumulation.

Most impacts to wildlife due to emissions from power plants are indirect, predominantly as a result of effects on habitat quality. One such indirect effect is increased acidification. Amphibians are particularly sensitive to increased acidification in vernal pools and ponds as a result of the permeability of their skin. The highest potential for acidification to impact amphibian egg-laying habitat occurs in snow-melt water pools, which do not occur in the project area (Schreiber and Newman, 1988). Loss of fish, amphibians, algae, invertebrates, and vegetative habitat as a result of acidification can impact species further up the food chain such as fish-eating feral mink (Bevanger and Albu, 1986) and wetland waterfowl (Rattner *et al.*, 1987). These studies indicate that the greatest possible impact to wildlife as a whole is degradation of the composition, structure, and habitat value due to increased acidification of the soils and aquatic systems caused by elevated SO_x and NO_x. As discussed in subsequent sections, the atmospheric concentrations of SO_x and NO_x and deposition of sulfur and nitrogenous compounds as a result of the GREC Project are unlikely to cause soil and water acidification.

10.2.4 SPECIFIC AIR EMISSIONS IMPACTS IN THE VICINITY OF GREC

10.2.4.1 Vegetation Impact Evaluation

A description of the vegetative community in the vicinity of GREC is provided Section 3.3.5 of the SCA.

Nitrogen Oxides

Vegetation most sensitive to nitrogen oxides are bryophytes, which have NO₂ tolerances of 65 µg/m³ for 24 hour exposure (Table 9-3). The maximum annual average NO₂ air quality impact projected for GREC of 0.4 µg/m³ (Table 10-1) is well below the NAAQS of 100 µg/m³ (0.0523 ppm) (Table 3-1), and lower than the thresholds of sensitive bryophytes (Table 10-2). As such, no significant vegetative impacts are likely to occur as a result of NO_x emissions from GREC.

Sulfur Dioxide

Sensitive vegetative species show damage to at least 5 percent of their leaf area upon exposures of 131 to 1,310 µg/m³ SO₂ for a period of 8 hours (Table 10-3). One species of lichen (*Ramalina Americana*) has been shown to be absent at concentrations from 13 to 26 µg/m³ with chronic, long-term exposures (Table 10-3). The maximum GREC air quality impacts for averaging times of 3 hours, 24 hours, and annual durations of 5.6, 3.3, and 0.3 µg/m³ (Table 10-1), respectively, result in impacts that are well below the 24-hour and annual AAQS of 0.10 ppm (260 µg/m³) and 0.02 ppm (60 µg/m³), respectively (Table 3-1). The most sensitive vascular plants will not exhibit injury symptoms until concentrations increase to values of at least 131 µg/m³ for 8 hours (Table 10-2) much more than the modeled values of 5.6 µg/m³ for 3 hours (Table 10-1). Vascular plants are not expected to be affected by emissions from GREC.

PM₁₀

PM₁₀ concentrations are projected to increase in the vicinity of GREC by 5.3 and 20.4 µg/m³, for annual and 24-hour durations, respectively (Table 10-1). NAAQS standards for PM₁₀ are 150 µg/m³ for a 24-hour duration (Table 3-1). Florida's PM₁₀ AAQS standards are 150 and 50 µg/m³ for 24-hour and annual averaging periods, respectively. GREC emissions are well below these AAQS standards. Therefore, no adverse impacts to vegetation are expected in the project vicinity as a result of particulate matter emissions.

CO

CO is not considered harmful to plants and is not known to be effectively taken up by plants (Bennett and Hill, 1975). In addition, the GREC CO air quality impacts of 0.42 milligram per cubic meter (mg/m^3) ($420.5 \mu\text{g}/\text{m}^3$) and $0.16 \text{ mg}/\text{m}^3$ ($159.9 \mu\text{g}/\text{m}^3$) for durations of 1 hour and 8 hours (Table 10-1), respectively, are orders of magnitude smaller than the 1-hour and 8-hour primary NAAQS of 40 and $10 \text{ mg}/\text{m}^3$, respectively (Table 3-1). Therefore, no adverse impacts to vegetation are expected as a result of CO emitted by GREC.

10.2.4.2 Wildlife Impact Evaluation

A description of wildlife in the vicinity of GREC is discussed in Subsection 3.3.6 of the SCA.

Air pollutant concentrations in the project vicinity are projected to be significantly lower than NAAQS standards and minimum threshold concentrations (Table 10-4), below which no wildlife acute toxicity is expected to occur. Most effects on wildlife are indirect, predominantly as a result of decreased habitat quality. As discussed in Section 10.2.4.1, minimal impacts to vegetation are expected to occur as a result of GREC. Therefore, no adverse impacts to wildlife are expected.

Mercury deposition in the area surrounding GREC is projected to be 0.0102 microgram per square meter per year ($\mu\text{g}/\text{m}^2/\text{yr}$). This value is two orders of magnitude smaller than average conservative estimates for background deposition rates of 0.5 to $1 \mu\text{g}/\text{m}^2/\text{yr}$ as reported in the literature (Bindler, 2003). Therefore, direct impacts to wildlife should be less than normal background deposition.

10.2.4.3 Soil Characteristics

A description of wildlife in the vicinity of GREC is discussed in Subsection 3.3.1 of the SCA.

10.2.4.4 Soils Impact Evaluation

Dominant soil in the vicinity of GREC has a moderately high cation exchange capacity in the surface horizon as well as the subsurface organometallic spodic horizon. In addition, the surface horizon of the dominant soil has a cation exchange capacity in the range where sensitivity to changes in pH have been shown to be reduced (Barton *et al.*, 2002). As a result of these chemical properties, it is likely that the dominant soil will not be adversely impacted by GREC. It is also concluded that the hydric/wetland soils in the vicinity will not be adversely affected by GREC.

10.2.5 SPECIFIC AIR EMISSIONS IMPACTS—CLASS I AREAS

The following subsections describe environmental features and provide a discussion of potential impacts to vegetation, wildlife, and soils at the Okefenokee and Chassahowitzka NWA Class I areas.

10.2.5.1 Okefenokee NWA

Vegetation Types

The Okefenokee NWA consists predominantly of a large swamp with a diversity of wetland communities, intermixed with vegetated islands and a few uplands. The vegetative communities as listed in the Okefenokee NWA Comprehensive Conservation Plan are described in the following paragraphs (U.S. Fish and Wildlife Service [USFWS], 2006).

Broadleaved Hardwoods

This vegetative community covers a large portion of the northwest side of the swamp. The canopy of evergreen, deciduous, and broadleaved trees limits understory vegetation. The canopy consists predominantly of blackgum (*Nyssa sylvatica*) and cypress (*Taxodium* spp.). In addition the vegetation consists of loblolly bay (*Gordonia lasianthus*), red bay (*Persea borbonia*), sweet bay (*Magnolia virginiana*), largeleaf gallberry (*Ilex coriacea*), and dahoon holly (*Ilex cassine*) with a sphagnum moss groundcover.

Cypress/Hardwoods

This community consists of unlogged virgin pond cypress (*Taxodium ascendens*) wetlands and logged areas where cypress recruitment is high enough to be separated from broadleaved hardwoods. The understory vegetation is similar to broadleaved hardwoods.

Mixed Wetland Pine

The mixed wetland pine community is defined by a presence of at least 30-percent slash pine (*Pinus elliottii*) in the canopy mixed with other vegetation types. Associated vegetation includes blackgum, loblolly bay, sweet bay, and a variety of ferns.

Scrub/Shrub

The scrub/shrub ecosystem consists of many species of evergreen and deciduous shrubs intermixed with even-aged stands of young, small trees. Evergreen and deciduous shrubs found in this vegetation type include hurrah bush (*Lyonia leucothoe*), dahoon holly, largeleaf gallberry, gallberry (*Ilex glabra*), titi (*Cyrilla racemiflora*), buttonbush (*Cephalanthus occidentalis*), poor man's soap (*Clethra alnifolia*), Virginia sweetspire (*Itea virginica*), fetterbush (*Leucothoe racemosa*), and highbush blueberry (*Vaccinium fuscatum*). Scrub trees include cypress, blackgum, and bay.

Prairie

Prairies are consistent with communities that are usually described as freshwater marsh. There are two types of prairie communities: aquatic macrophyte prairie and herbaceous prairie. The aquatic macrophyte prairie contains water lily (*Nymphaea odorata*), spatterdock (*Nuphar lutea*), floating heart (*Nymphoides aquatica*), pickerel weed (*Pontederia cordata*), golden club (*Orontium aquaticum*), wampee (*Peltandra virginica*), pipewort (*Eriocaulon compressum*), yellow-eyed grass (*Xyris smalliana*), sphagnum moss species (*Utricularia* spp.), as well as algae.

The herbaceous prairie is dominated by sedges. In addition chain fern (*Woodwardia virginica*), pitcher plants (*Saracenia* spp.), swamp loosestrife (*Decodon verticillatus*), paint

root (*Lachnanthes tinctoria*), wampee, golden club, water lily, pipewort, and yellow-eyed grasses.

Upland Hardwoods

Upland hardwoods contain a variety of scrub oaks that are found in sandhills and sandy ridges.

Longleaf Pine

Longleaf pine comprises 70 percent of the basal area of this forest type. The vegetative composition of this community is predominantly defined by the recurrence of fire. Longleaf pine (*Pinus palustris*) and wiregrass (*Aristida stricta*) occur where fire is frequent. In regions surrounding ponds and wetlands where fire is less common, slash pine, loblolly pine, and pond pine (*Pinus serotina*) occur. In addition, several other hardwoods can be found in this community including several scrub oaks species, black gum, persimmon (*Diospyros virginiana*), and sweetgum (*Liquidambar styraciflua*).

Longleaf/Mixed Pine

A total of 35 to 70 percent of the basal area consists of pine trees in longleaf/mixed pine forests. This is a transitional forest where slash, loblolly, and pond pines intermix with longleaf pines.

Mixed Pine/Longleaf Pine

This vegetation type occurs primarily where longleaf pine was logged and/or where fire was suppressed to allow invasion by slash, loblolly, or pond pines from wetter regions. As a result longleaf pine makes up less than 35 percent of the basal area.

Mixed Pine

The longleaf pine component has been replaced by slash, loblolly, and pond pine in mixed pine forests. Other associated species includes sweetbay, swamp tupelo (*Nyssa sylvatica*), pond cypress, pond pine, loblolly bay, live oak (*Quercus virginiana*), red

maple (*Acer rubrum*), water oak (*Quercus nigra*), and laurel oak (*Quercus hemisphaerica*).

The hairy rattlesnake (*Baptisia arachnifera*) is the only endangered plant species within Okefenokee NWA, and the parrot pitcher plant (*Sarracenia psittacina*), a threatened species, is found there. There are four Georgia species of special concern found within Okefenokee NWA including silver buckthorn (*Sideroxylon alachuense*), greenfly orchid (*Epidendrum conopseum*), fly catcher/golden trumpet (*Sarracenia flava*), and the hooded pitcher plant (*Sarracenia minor*).

Vegetation Impact Evaluation

EPA monitors NO₂, PM₁₀ and SO₂ at monitoring stations across the nation. These data are publicly available at the EPA Web site (<http://www.epa.gov/air/oaqps/montring.html#attainment>). These data will be referred to throughout this discussion to determine baseline concentrations. These stations are monitored for a determination of nonattainment areas based on the NAAQS (Table 3-1). Monitoring stations are spread throughout the region, which makes it difficult to determine the relevance of monitored concentrations to impacts at the Okefenokee NWA. Nevertheless, monitoring stations in the closest proximity will be used to place emissions values in perspective. NO₂ concentrations in Jacksonville, Florida, remain approximately one-fifth of the national standard of 0.053 ppm (100 µg/m³) (Table 3-1) and below the vegetative injury threshold of 65 µg/m³ with a 24-hour duration (Table 10-2). GREC is projected to have a maximal annual increase in atmospheric NO₂ concentration within the Okefenokee NWA of 0.0025 µg/m³ (Table 10-1). This is well below concentrations where any potential vegetative impact to the refuge is likely to occur (Table 10-2). SO₂ monitored at the aforementioned sites consistently remains well below the national standard of 0.03 ppm (80 µg/m³) (Table 3-1). GREC is modeled to increase the maximum 3-hour, 24-hour, and annual atmospheric SO₂ concentrations by 0.23, 0.051, and 0.0023 µg/m³, respectively (Table 10-1). As shown in Table 10-3, the species most sensitive to SO₂ within an 8-hour duration are American elm and white ash, although injury does not occur until concentrations exceed 131 µg/m³ (Table 10-3), which is well above the projected 3-hour average increase

(0.23 $\mu\text{g}/\text{m}^3$) as a result of GREC. Lichens, which are more sensitive to chronic exposure, do not exhibit injury symptoms until concentrations exceed 13 $\mu\text{g}/\text{m}^3$ (Table 10-3). Therefore, it is unlikely that vegetation in Okefenokee NWA will be adversely impacted by GREC SO_2 impacts.

Average annual PM_{10} concentrations at Jacksonville have never exceeded the Florida/Georgia annual AAQS standard of 50 $\mu\text{g}/\text{m}^3$ (Table 3-1). Maximum PM_{10} emissions as a result of GREC (Table 10-1) are several orders of magnitude lower than national standards (Table 3-1).

Typical Wildlife

The Okefenokee NWA is home to 48 species of mammals, 200 species of birds, 33 species of fish, 101 species of reptiles and amphibians, and many species of invertebrates. The refuge was originally established for the conservation of birds, and there are a variety of migratory and resident birds. Birds found within the refuge include wood ducks, osprey, swallow-tailed kites, as well as a variety of wading birds including great egrets, great blue herons, white ibis, and little blue herons. The refuge is a temporary stopping point for many migrating waterfowl, although populations are not as great as other coastal wetlands within the east coast. Species of waterfowl found in the refuge include ring-necked ducks, mallards, blue-winged, and green-winged teal and wood ducks. Listed bird species known to occur in the Okefenokee NWA include the red-cockaded woodpecker, and one swallow-tailed kite nest was also found. In addition, the swamp has both resident and migratory sandhill cranes.

There are some notable large mammals present in the Okefenokee NWA. Florida black bear, white-tailed deer, the round-tailed muskrat, and the Rafinesque's big-eared bat have been observed on the property. The dominant fish species present on the property include the bowfin and the flier comprising 88 percent of the catch. Overall, 36 species of fish have been identified. The wetlands of the Okefenokee NWA facilitate a diverse amount of herptofauna and reptiles including the American alligator and many species of frogs and turtles. Ephemeral ponds support the flatwoods salamander, the striped newt, the go-

pher frog, and other species. Federally listed species include indigo snakes along with the American alligator. Other rare or sensitive species that can be found include the gopher tortoise, pine snake, eastern hognose, diamondback rattlesnake, and eastern glass lizard.

Wildlife Impact Evaluation

Air pollutant concentrations in the project vicinity are projected to be well below NAAQS and minimum threshold concentrations (Table 10-4), below which no wildlife acute toxicity is expected to occur. Most air pollution effects on wildlife are indirect, predominantly as a result of decreased habitat quality. As discussed previously, minimal impacts to vegetation are expected to occur as a result of the low emissions increases in the Okefenokee NWA. Therefore, no adverse impacts to wildlife are expected.

Natural conservative background mercury deposition levels determined from accumulated peat are 0.5 and 1 $\mu\text{g}/\text{m}^2/\text{yr}$ (Bindler, 2003). Mercury methylation, whereby mercury is transformed into an organic toxic form, is accelerated in wetlands like Okefenokee (St. Louis *et al.*, 1994; Krabbenhoft *et al.*, 1995; Driscoll *et al.*, 1998). Studies in the Okefenokee Swamp have found mean mercury concentration in fish tissues of 0.359 ± 0.21 mg/L weight) (Mason and Bowers, 1995). The presence of mercury in the Okefenokee NWA is thought to occur as a result of wet and dry atmospheric deposition.

As discussed previously, the mercury deposition rate as a result of GREC ($0.0102 \mu\text{g}/\text{m}^2/\text{yr}$) in the vicinity is an order of magnitude lower than natural background deposition (0.5 to $1 \mu\text{g}/\text{m}^2/\text{yr}$) (Bindler 2003). It is safe to assume that mercury deposition at the distant Okefenokee NWA will be much lower than the small amount emitted in the vicinity of GREC, where it was deemed that no wildlife impacts are projected to occur. Therefore, it is concluded that there will be no adverse impacts to wildlife from mercury within the Okefenokee NWA as a result of GREC.

Soil Characteristics

Soil types within the Okefenokee NWA change with their elevation along a gradient from wetlands to uplands, with corresponding changes in vegetation. Soil series present in the

Okefenokee NWA are Dasher, Pamlico, Croatan, Allanton, Lynn Haven, Surrency, Plummer, Pelham, Sapelo, Leon, Mascotte, Olustee, Mandarin, and Ridgeland (USFWS, 2006). National Resources Conservation Service (NRCS)/U.S. Department of Agriculture (USDA) soil surveys were used where available to compile a table of soil pHs (Table 10-7) and relevant soil chemical properties such as CEC and base saturation (Table 10-8). None of the counties in Georgia where the Okefenokee NWA is present have published soil surveys. As a result, all data was taken from Baker County, Florida. The soils listed are histosols in the permanently inundated areas with ultisols in the intermediate elevations and spodosols in the highest elevations.

Soils Impact Evaluation

Dominant soil types (Histosols, Ultisols, and Spodosols) have a high degree of sulfate adsorption capability, increasing their buffering capacity to changes in pH (Johnson and Reuss, 1984). The soils by their very nature have a low pH, base saturation, and CEC, and it is likely that the vegetation is adapted to these low pH, low fertility conditions.

As discussed previously, soils are impacted by air pollution predominantly as a result of wet and dry atmospheric deposition of sulfur and nitrogen containing compounds and other trace elements such as mercury. This can contribute to acidification, eutrophication, and other effects.

Due to the relatively low GREC NO_x and SO₂ emissions, sulfur and nitrogen atmospheric wet and dry deposition within the Okefenokee NWA will be insignificant and will not cause any measurable impact on soils or ecosystem health.

10.2.5.2 Chassahowitzka NWA

Vegetation Types

The predominant vegetative communities that are represented in the Chassahowitzka NWA include hardwood swamps, cypress ponds, flatwoods, saltmarsh, sandhill, scrub, and wet prairies (USFWS, 2001).

Table 10-7. Soil pHs for the Soils Found on Okefenokee NWA

Soil	Depth (inches)	Soil Reaction
Dasher	0 to 80	3.6 to 4.4
Allanton	0 to 80	3.6 to 5.5
Leon	0 to 80	3.6 to 6.5
Mandarin	0 to 80	3.6 to 6.0
Mascotte	0 to 80	3.6 to 5.5
Olustee	0 to 80	3.6 to 5.5
Pamlico	0 to 18	3.6 to 4.4
	18 to 80	3.6 to 5.5
Pelham	0 to 80	3.6 to 5.5
Plummer	0 to 80	3.6 to 5.5
Sapelo	0 to 80	3.6 to 5.5
Surrency	0 to 28	3.6 to 5
	28 to 80	3.6 to 5.5

Source: USDA, NRCS soil surveys of Baker County, Florida 1996.

Table 10-8. Chemical Properties of the Soils Within the Okefenokee NWA

Soil	Depth (cm)	Horizon	Ca	Mg	Na	K	CEC	Base Saturation
Leon	0 to 7	A1	0.25	0.11	0.02	0.01	4.83	8
	7 to 21	A2	0.04	0.01	0.01	0	1.05	6
	21 to 24	Bh1	0.04	0.01	0	0	23.83	—
	24 to 26	Bh2	0.03	0.01	0.01	0	12.35	—
	26 to 38	BC	0.02	0.01	0	0	2.96	1
	38 to 47	E	0.02	0.01	0	0	3.52	1
	47 to 55	B'h1	0.01	0.01	0	0	2.78	1
	55 to 80	B'h2	0.03	0.01	0	0	5.83	1
Mascotte	0 to 6	A	0.7	0.22	0.04	0.06	10.65	10
	6 to 18	E	0.06	0.02	0	0	1.24	6
	18 to 20	Bh1	0.12	0.04	0.02	0.02	13.61	1
	20 to 24	Bh2	0.06	0.02	0	0	24.24	0
	24 to 29	BE	0.03	0.02	0	0	3.86	1
	29 to 38	E'	0.03	0.03	0	0	0.35	17
	38 to 52	Btg1	0.09	0.14	0	0.02	6.42	4
	52 to 56	Btg2	0.03	0.04	0	0.01	15.83	1
	56 to 80	C	0.02	0.01	0	0.01	17.84	0
Olustee	0 to 8	Ap	0.19	0.08	0.03	0.04	5.76	6
	8 to 14	Bh	0.04	0.02	0.03	0.01	4.42	3
	14 to 27	E1	0.02	0.02	0.03	0	1.67	4
	27 to 37	E2	0.02	0.02	0.03	0	2.55	3
	37 to 57	Btg1	0.15	0.29	0.05	0.02	5.32	10
	57 to 80	Btg2	0.18	1.07	0.09	0.01	6.3	21
Sapelo	0 to 6	A	0.12	0.1	0	0.02	3.8	6
	6 to 18	E	0.05	0.03	0	0.01	1.39	6
	18 to 22	Bh1	0.08	0.06	0.02	0.02	3.49	5
	22 to 26	Bh2	0.07	0.02	0	0.01	20.27	0
	26 to 31	BE	0.03	0.01	0	0	5.24	1
	31 to 48	E'	0.04	0.01	0	0.01	0.6	10
	48 to 55	Btg1	0.04	0.02	0	0.01	3.89	2
	55 to 70	Btg2	0.09	0.09	0	0.02	5.95	3
	70 to 80	C	0.08	0.11	0	0.01	4.2	5

Source: USDA, NRCS soil surveys of Baker County, Florida 1996.

Hardwood Swamp

The hardwood swamp is the most prevalent vegetative community in the Chassahowitzka NWA. This community is a palustrine wetland community characterized by the diverse mixture of trees, shrubs, and vines that vary with the differences in elevation. Dominant tree species include bald cypress (*Taxodium distichum*), red maple (*Acer rubrum*), sweet gum (*Liquidambar styraciflua*), winged elm (*Ulmus alata*), southern magnolia (*Magnolia grandiflora*), ashes (*Fraxinus* spp.), and southern red cedar (*Juniperus silicicola*). The subcanopy includes redbud (*Cercis canadensis*) and basswood (*Tilia* spp.) in higher elevation sites and red bay (*Persea borbonia*), swamp dogwood (*Cornus foemina*), and dahoon holly (*Ilex cassine*) in lower elevations. The understory vegetation consists of dwarf palmetto (*Sabal minor*), American beautyberry (*Callicarpa americana*), and grape vines (*Vitis* spp.) in higher elevations, while wax myrtle (*Myrica cerifera*), dewberry (*Rubus* spp.), and various ferns are found in lower elevations. The vegetative community provides a good source of mast for numerous wildlife species and plentiful habitat.

Cypress Pond

Cypress ponds are found in depressions throughout the uplands. The vegetative community consists of pond cypress (*Taxodium ascendens*), bald cypress, red maple, sweet gum, Virginia willow (*Itea virginica*), and buttonbush (*Cephalanthus occidentalis*).

Flatwoods

Flatwoods are often located in regions with unproductive soils with low water available to the vegetation. The plant community consists largely of longleaf pine (*Pinus palustris*) or slash pine (*P. elliottii*) with an understory consisting of saw palmetto (*Serenoa repens*) wax myrtle, and gallberry (*Ilex glabra*). The quality of this community for wildlife utilization appears to be poor as a result of historic fire suppression.

Sandhills

Xeric conditions brought on by sandy soils define the sparse vegetative community of the sandhills. The tree canopy consists of longleaf pine, sand pine (*Pinus clausa*), blackjack

oak (*Q. incana*), and turkey oak (*Quercus laevis*) with wiregrass (*Aristida stricta*), palmettos, and various herbs in the understory.

Saltmarsh

The saltmarsh community occurs from the Gulf of Mexico in to the tidal creeks with the vegetative community transitioning from black needle rush (*Juncus roemerianus*) and smooth cordgrass (*Spartina alterniflora*) in the high salinity portions to sawgrass (*Cladium jamaicense*) in the fresher portions. Upland islands consist of red cedar, cabbage palm, and live oaks.

Scrub

The scrub community occurs on north-south strands occurring along prehistoric dunes. Scrub communities consist of sand pine, myrtle oak (*Q. myrtifolia*), and scrub live oak (*Q. geminata*).

Wet Prairie

Wet prairies occur scattered throughout the sandhills. They are dominated by marsh species including white-tops (*Dichromena colorata*), spikerushes (*Eleocharis* spp.), bog buttons (*Lachnocaulon anceps*), dahoon holly, American lotus (*Nelumbo lutea*), and spatterdock (*Nuphar lutea*).

Vegetation Impact Analysis

Monitoring stations are spread throughout the region at different distances from the Chassahowitzka NWA. Nonetheless, these measurements can be illustrative of baseline conditions at the Chassahowitzka NWA. The NO₂ concentration at St. Petersburg remains stable at approximately one-fifth of the national annual standard of 0.053 ppm (100 µg/m³). As a result of GREC, maximum NO₂ concentrations are projected to have a maximum annual increase of only 0.0015 µg/m³ (Table 10-1), a small fraction of levels known to cause harm to the most sensitive vegetation (65 µg/m³ for 24 hours) as shown in Table 10-2. Currently, SO₂ at the Tampa-St. Petersburg-Clearwater sites are well below the annual national standard 0.03 ppm (80 µg/m³) (Table 3-1). A maximum SO₂ increase in

3-hour, 24-hour, and annual concentrations of 0.15, 0.044, and 0.0015 $\mu\text{g}/\text{m}^3$, respectively (Table 10-1), as a result of GREC will not impact the most sensitive vegetation with tolerances of 131 $\mu\text{g}/\text{m}^3$ for 8 hours and 13 $\mu\text{g}/\text{m}^3$ for chronic exposures (Table 10-3). The SO_2 concentration increase as a result of GREC will produce a negligible increase in concentrations with respect to vegetative impacts.

PM_{10} concentrations in the St. Petersburg-Tampa-Clearwater area remain well below the annual average Florida AAQS standard of 50 $\mu\text{g}/\text{m}^3$. The impact from the small maximum annual and 24-hour PM_{10} increases of 0.0029 and 0.057 $\mu\text{g}/\text{m}^3$, respectively (Table 10-1), as a result of GREC, are negligible with regard to ecosystem impacts within the Chassahowitzka NWA.

Typical Wildlife

The diverse array of communities and the close association between wetlands and uplands allows for a wide array of wildlife species. Many species of wildlife that are endangered, threatened, or species of special concern are present in the Chassahowitzka NWA including the Florida black bear, Florida mouse, gopher tortoise, Eastern indigo snake, Florida gopher frog, American alligator, Florida pine snake, and potentially bald eagles. The heterogeneous composition of the aquatic communities and range of salinities allows for a large diversity of fish species typical of this region of Florida.

Whooping crane populations have recently been established to winter in the Chassahowitzka NWA. In addition, along their migratory pathway, they have been known to occur near the GREC Site. This is a sensitive species brought back from the brink of extinction. On their wintering grounds, the whooping crane prefers a habitat within estuarine marshes, shallow bays, and salt tidal flats and can be found within freshwater wetlands along their migration path. They prefer to feed on crabs, shrimps, clams, snails, frogs, snakes, grasshoppers, larval and nymph forms of flies, beetles, water bugs, birds, and small mammals. In addition, they have been known to eat more than 58 species of fish.

Wildlife Impact Evaluation

Air pollutant concentrations in the project vicinity are projected to be well below NAAQS (Table 3-1) and minimum threshold concentrations (Table 10-4), below which no wildlife acute toxicity is expected to occur. Most air pollution effects on wildlife are indirect, predominantly as a result of decreased habitat quality. As discussed previously, minimal impacts to vegetation are expected to occur as a result of the low emissions increases in the Chassahowitzka NWR. Therefore, no adverse impacts to wildlife are expected due to GREC.

Due to the fact that the cranes are a carnivorous species, predominantly feeding in wetlands, (where mercury methylation is accelerated) there is a potential for biomagnification of mercury. Mercury deposition is monitored at the Chassahowitzka NWR as part of the Mercury Deposition Program. Annual average wet deposition values of mercury at the monitoring station range from 0.3 to 0.5 kg/ha/yr. These values are within the lower end of the range of reported background mercury deposition rates of 0.5 to 1 $\mu\text{g}/\text{m}^2/\text{yr}$ (Bindler, 2003). No studies have been found that determine the impact of mercury deposition on the Chassahowitzka NWA ecosystem, but these deposition levels are roughly equivalent to deposition occurring in Okefenokee NWA.

The mercury deposition rate as a result of GREC (0.0102 $\mu\text{g}/\text{m}^2/\text{yr}$) in the vicinity of GREC is an order of magnitude lower than conservative natural background deposition estimates (0.5 to 1 $\mu\text{g}/\text{m}^2/\text{yr}$) (Bindler 2003). It is safe to assume that mercury deposition at the distant Chassahowitzka NWR will be much lower than the small amount emitted in the vicinity of GREC, where it was deemed that no wildlife impacts are projected to occur. Therefore, it is unlikely that whooping cranes will be significantly affected by mercury along their migratory pathway or in their wintering grounds in the Chassahowitzka NWA as a result of GREC.

Migratory birds spending time in freshwater wetlands can be affected by acidification (Longcore, Ross, and Fischer, 1987). Reproductive success of birds with a variety of feeding habits has declined as a result of acidification-induced reductions in food abun-

dance (Blancher and McAuley, 1987). Due to the low emissions discussed throughout these sections, which have been shown to be below levels causing significant acidity, it is unlikely that the whooping crane will be affected.

Soil Characteristics

Soil types within the Chassahowitzka NWA are listed in the conceptual management plan (USFWS, 2001). NRCS/USDA soil surveys were used to compile a table of soil pH (Table 10-9). Soils found in the Chassahowitzka NWA range from very poorly drained organic soils (Aripeka-Okeelanta-Lauderhill and Okeelanta-Terra Ceia) in the freshwater wetlands and saltwater marshes to excessively drained sandy soils in the sandhills (Candler fine sand). The dominant soils are histosols and the psamment subgroup of the series entisols.

Soils Impacts Evaluation

Dominant soil types (histosols, psamment entisols) have a high sulfate adsorption capacity, increasing buffering to changes in pH (Johnson and Reuss, 1984). Base saturation of the soils of the Chassahowitzka NWA tends to be high, even in surface horizons, further indicating a strong buffering capacity. The Astatula soil has a low base saturation, but it comprises only 0.15 percent of the refuge.

Due to the relatively low GREC NO_x and SO₂ emissions, sulfur and nitrogen atmospheric wet and dry deposition within the Chassahowitzka NWA will be insignificant and will not cause any measurable impact on soils or ecosystem health.

Table 10-9. Soil pHs for the Soils Found in the Chassahowitzka NWA

Soil	Depth (inches)	Soil Reaction (pH)
Adamsville-fine sand	0 to 80	4.5 to 7.8
Anclote fine sand	0 to 80	5.1 to 8.4
Aripeka fine sand	0 to 13	5.6 to 7.8
	13 to 21	6.6 to 8.4
Aripeka - Okeelanta - Lauderdale		
Okeelanta	0 to 27	5.1 to 6.5
	27 to 60	5.1 to 7.3
Lauderhill	0 to 80	6.1 to 8.4
Astatula fine sand	0 to 80	4.5 to 6.5
Basinger fine sand	0 to 8	3.6 to 8.4
	8 to 60	3.6 to 7.3
Basinger fine sand, depressional	0 to 80	3.6 to 7.3
Candler fine sand	0 to 80	4.5 to 6.0
EauGallie fine sand	0 to 25	4.5 to 6.0
	25 to 33	4.5 to 6.5
	33 to 57	5.1 to 7.8
	57 to 63	5.1 to 7.8
Homosassa mucky fine sandy loam	0 to 80	6.1 to 7.8
Lacoochee fine sandy loam	0 to 8	7.9 to 8.4
	8 to 13	6.6 to 8.4
Myakka fine sand	0 to 80	3.6 to 6.5
Okeelanta - Terra Ceia		
Okeelanta	0 to 27	4.5 to 7.8
	27 to 60	5.1 to 7.8
Terra Ceia	0 to 80	5.6 to 8.4
Paola fine sand	0 to 80	3.6 to 7.3
Pomello fine sand	0 to 80	4.5 to 6.0
Tavares fine sand	0 to 80	4.5 to 6.0
Weekiwachee muck	0 to 80	6.1 to 7.8
Weekiwachee - Homosassa	0 to 80	6.1 to 7.8

Source: USDA, NRCS soil surveys of Citrus County, 1988 and Hernando County, 1977.

11.0 CLASS I IMPACT RESULTS

11.1 OVERVIEW

Comprehensive refined modeling was conducted to assess GREC Class I area air quality impacts in accordance with EPA, Federal Land Managers (FLMs), and FDEP modeling guidance. This section provides the results of the GREC air quality assessment with respect to long-range transport impacts at two PSD Class I areas: the Okefenokee and Chassahowitzka NWAs. Section 9.0 previously addressed GREC air quality impacts in the vicinity of the project Site.

PSD Class I areas located within 300 km of GREC include the Okefenokee, Chassahowitzka, Bradwell Bay, Wolf Island, and St. Marks NWAs. The Everglades National Park is located more than 400 km south of GREC. The nearest PSD Class I areas are the Okefenokee NWA situated approximately 93 km (58 miles) to the north of GREC and the Chassahowitzka NWA situated approximately 110 km (68 miles) southwest of GREC.

11.2 INITIAL SCREENING ANALYSIS

For new sources that will be located at a distance of 50 km or greater from a Class I area, the FLAG 2008 draft guidance on initial screening criteria recommends using the ratio of potential project emission rates divided by the project's distance from a Class I area (i.e., Q/D or 10D Rule) to determine whether an assessment of Class I area AQRVs is necessary. This screening approach is similar to that implemented by EPA as part of its Regional Haze Regulation. Potential project emissions (i.e., Q) include SO₂, NO₂, PM₁₀, and H₂SO₄ mist annual emissions in tpy, based on 24-hour maximum allowable emissions. The distance (i.e., D) is the distance in km from the Class I area. For cases in which the calculated Q/D ratio is 10 or less, a Class I AQRV impact analyses is not required.

The Q/D ratio was calculated for GREC using the BFB boiler stack annual potential emission rates and the nearest distance to each of the five Class I areas located within 300 km of GREC. Table 11-1 summarizes the BFB boiler stack's NO₂, SO₂, H₂SO₄ mist, and PM₁₀ potential annual emissions in tpy, the distance to each Class I area (km), and

Table 11-1. GREC PSD Class I Initial Screening Analysis

	NO _x	SO ₂	H ₂ SO ₄ Mist	PM ₁₀ (total)*	Totals
GREC potential emissions (Q)	416.4	243.9	tpy 5.9	249.8	916.0
	Okefenokee NWA	St. Marks NWA	Chassaho- witzka NWA	Bradwell Bay NWA	Wolf Island NWA
Distance from GREC (D)	93.4	159.3	km 110.1	210.9	202.2
FLAG screening ratio (Q/D)	9.8	5.8	ton/yr-km 8.3	4.3	4.5

*Filterable and condensable PM.

Source: ECT, 2009.

the calculated Q/D ratio for each Class I area. The calculated Q/D ratios are all below the FLM threshold of 10; therefore, Class I AQRV analyses are not required in accordance with the FLAG guidance.

Based on the initial screening results, the GREC analysis with respect to the PSD Class I increments addressed the two nearest PSD Class I areas; i.e., the Okefenokee and Chassahowitzka NWAs. GREC air quality impacts at the more distant PSD Class I areas will be lower than those predicted for the Okefenokee and Chassahowitzka NWAs. Figure 11-1 provides the locations of the Okefenokee and Chassahowitzka NWAs in relation to GREC.

11.3 CONCLUSIONS

Comprehensive dispersion modeling using the CALMET/CALPUFF/CALPOST modeling suite demonstrates that the GREC will have insignificant air quality impacts for all modeled PSD pollutants and all averaging periods in the PSD Class I areas. Accordingly, a multisource cumulative assessment of air quality impacts with respect to the PSD Class I increments for NO₂, SO₂, and PM₁₀ was not required.

11.4 GENERAL APPROACH

The required Class I area impact assessments were conducted using the CALPUFF dispersion model in accordance with the recommendations contained in the Interagency Workgroup on Air Quality Modeling (IWAQM) *Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts*, the FLAG Phase I Report, and EPA's GAQM. In addition, an Air Quality Impact Analysis Modeling Protocol was submitted to FDEP, the U.S. Fish and Wildlife Service (USFWS), and EPA Region 4 in July 2009 for review and comments. The air quality impact analyses conducted for GREC incorporates the comments and suggestions received from these regulatory agencies on the modeling protocol.

The CALPUFF model was employed in a refined mode using 3 years (2001 through 2003) of 4-km resolution CALMET data and Class I area receptor grids as recommended

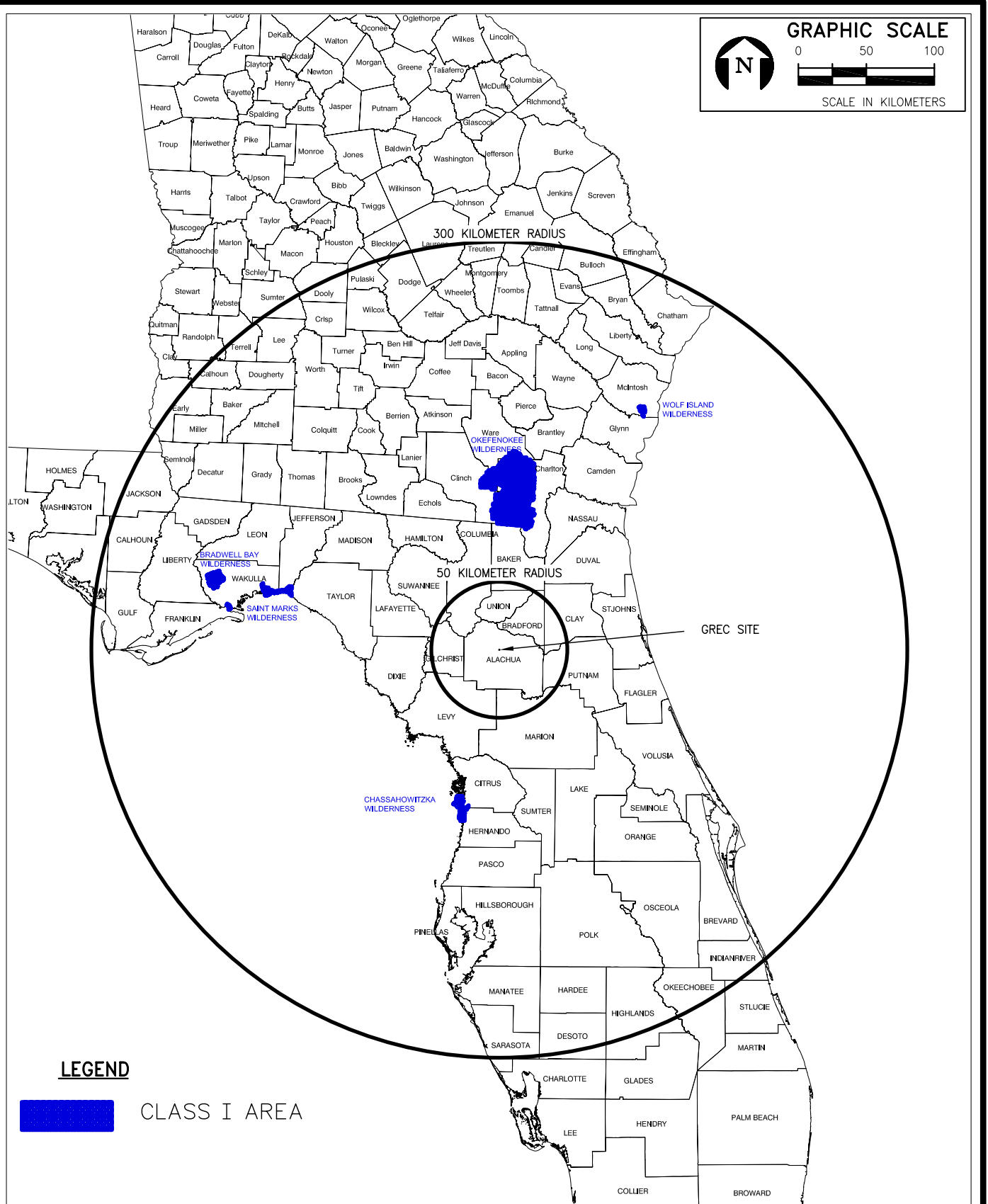


FIGURE 11-1.
CLASS I AREAS WITHIN 300 KM OF THE GREC SITE

Sources: FWS, 2007; USFS, 2007; NPS, 2007; ECT, 2009.

by the National Park Service (NPS). The CALPUFF suite of programs, including the CALPOST postprocessing program, was employed to develop estimates of GREC impacts at the Okefenokee and Chassahowitzka NWAs with respect to the PSD Class I increments.

11.5 MODEL SELECTION AND USE

Steady-state dispersion models do not consider temporal or spatial variations in plume transport direction, nor do they limit the downwind transport of a pollutant as a function of windspeed and travel time. Due to these limitations, conventional steady-state dispersion models, such as AERMOD, are not considered suitable for predicting air quality impacts at receptors located more than 50 km from an emission source.

Because of the need to assess air quality impacts at PSD Class I areas, which are typically located at distances greater than 50 km from the emission sources of interest, EPA and the FLMs initiated efforts to develop dispersion models appropriate for the assessment of long-range transport of air pollutants. The IWAQM was formed to coordinate the model development efforts of EPA and the FLMs.

The IWAQM work plan indicates that a phased approach would be taken with respect to the implementation of recommendations for long-range transport modeling. In Phase 1, the IWAQM would review current EPA modeling guidance and issue an interim modeling approach applicable to projects undergoing permit review. For Phase 2, a review would be made of other available long-range transport models and recommendations developed for the most appropriate modeling techniques.

The Phase 1 recommendation, issued in April 1993, is to use the Lagrangian puff model, MESOPUFF II, for long-range transport air quality assessments. The Phase 2 recommendations, issued in December 1998, are contained in the IWAQM *Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts*. Additional FLM guidance with respect to the assessment of visibility and deposition impacts is provided in the FLAG Phase I report dated December 2000. The Phase 2 IWAQM recom-

mendation is to apply the CALPUFF Modeling System to assess air quality impacts at distances greater than 50 km from an emission source. In April 2003, EPA designated the CALPUFF model as a preferred model (i.e., a model listed in Appendix A to W of 40 CFR 51, Summaries of Preferred Air Quality Models) for use in assessing the long-range transport of air pollutants.

The EPA GAQM indicates that the CALPUFF modeling system is appropriate for long-range transport (source-receptor distances of 50 to several hundred kilometers) of emissions from point, volume, area, and line sources. All the receptors at the Class I areas evaluated are situated at distances greater than 50 km from GREC.

The EPA-approved version of the CALPUFF modeling suite was used for the GREC Class I area impact assessments. The EPA-approved CALPUFF modeling suite is comprised of the following programs:

- | | | |
|-----------|-----------------|---------------|
| • CALMET | Version 5.8 | Level: 070623 |
| • CALPUFF | Version: 5.8 | Level: 070623 |
| • CALPOST | Version: 5.6394 | Level: 070622 |

These programs were used to assess PSD Class I increments impacts.

The CALPUFF modeling system consists of three main components: CALMET, CALPUFF, and CALPOST. Each of these components is described in the following subsections.

11.5.1 CALMET

CALMET is a meteorological model that develops hourly wind and temperature fields on a three-dimensional gridded modeling domain. The meteorological file produced by CALMET for use by CALPUFF also includes two-dimensional parameters such as mixing height, surface characteristics, and dispersion properties.

CALMET requires a number of input data files to develop the gridded three- and two-dimensional meteorological file used by CALPUFF. The specific meteorological data used by the CALMET program include:

- Penn State/National Center for Atmospheric Research mesoscale model gridded, prognostic wind field data (terrain elevation, land use code, sea level pressure, rainfall amount, snow cover indicator, pressure, temperature/dew point, wind direction, and windspeed).
- Surface station weather data (windspeed, wind direction, ceiling height, opaque sky cover, air temperature, relative humidity, station pressure, and precipitation type code).
- Upper air sounding (mixing height) data (pressure, height above sea level, temperature, wind direction, and windspeed at each sounding).
- Surface station precipitation data (precipitation rates).
- Overwater data (air-sea surface temperature difference, air temperature, relative humidity, overwater mixing height, windspeed, and wind direction).
- Geophysical data (land use type, terrain elevation, surface parameters including surface roughness, length, albedo, Bowen ratio, soil heat flux, and vegetation leaf area index, and anthropogenic heat flux).

Further technical discussion of the CALMET model can be found in Section 2 of the User's Guide for the CALMET meteorological model dated January 2000.

VISTAS has developed a 3-year (2001 through 2003) CALMET dataset for a fine, 4-km, subregional domain that covers all of Florida and the adjacent Class I areas of interest to Florida. The VISTAS 2001-2003 meteorological data was recently reprocessed by USFWS using the current EPA regulatory version of CALMET; i.e., Version 5.8, Level: 070623. This reprocessed fine-grid CALMET dataset (containing more than 250 gigabytes of data) was obtained from FDEP and was used in the GREC Class I impact assessments.

11.5.2 CALPUFF

CALPUFF is a transport and puff model that advects puffs of material from an emission source. These puffs undergo various dispersion and transformation simulation processes as they are advected from an emission source to a receptor of interest. The simulation processes include wet and dry deposition and chemical transformation. CALPUFF typically uses the gridded meteorological data created by the CALMET program. CALPUFF, when used in a screening mode, can also use nongridded meteorological data similar to that used by a steady-state dispersion model such as AERMOD. The distribution of puffs by CALPUFF explicitly incorporates the temporal and spatial variations in the meteorological fields thereby overcoming one of the main shortcomings of steady-state dispersion models. Further technical discussion of the CALPUFF model can be found in Section 2 of the User's Guide for the CALPUFF Model dated January 2000.

There are a number of optional CALPUFF input files that were not used for the GREC Class I area impact assessments. These include time-varying emission rates, user-specified deposition velocities and chemical transformation conversion rates, complex terrain receptor and hill geometry data, and coastal boundary data.

CALPUFF generates output files consisting of hourly concentrations, deposition fluxes, and data required for visibility assessments for each receptor. These CALPUFF output files are subsequently processed by the POSTUTIL and CALPOST programs to provide impact summaries for the pollutants and averaging periods of interest.

The various CALPUFF program options are implemented by means of a control file. CALPUFF options selected for the GREC Class I area impact assessments conform to the recommendations contained in the IWQAM Phase 2 report and EPA's GAQM. Key CALPUFF model options selected for the GREC Class I impact assessments are listed:

- CALPUFF domain configured to include the GREC emission sources and all Class I receptors with a minimum 50-km buffer in all directions.
- 4-km spacing meteorological and computational grid.
- Class I receptors as defined by NPS.

- Modeling of six species (SO₂, SO₄, NO_x, nitric acid, nitrate, and PM₁₀).
- Use of the MESOPUFF II chemical mechanism module.
- IWAQM default guidance, including Pasquill-Gifford dispersion coefficients.
- 2001 through 2003 ozone data from CASTNet and AIRS stations.
- Integrated puff sampling methodology.
- No consideration of building downwash.

11.5.3 CALPOST

CALPOST is a postprocessing program used to process the concentration, deposition, and visibility files generated by CALPUFF. The CALPOST program was formulated to average and report pollutant concentrations or wet/dry deposition fluxes using the hourly data contained in the CALPUFF output files. CALPOST can produce summary tables of pollutant concentrations and depositions for each receptor for various averaging times and can develop ranked lists of these impacts. For visibility-related modeling (e.g., regional haze), CALPOST uses the CALPUFF generated pollutant concentrations to calculate extinction coefficients and other related indicators of visibility.

Similar to the CALPUFF program, the various CALPOST program options are implemented by means of a control file. CALPOST options selected for the GREC Class I impact assessments conform to the recommendations contained in the FLAG Phase I report.

11.6 RECEPTOR GRIDS

The GREC Class I area receptor grids included the Okefenokee NWA (500 discrete receptors), and the Chassahowitzka NWA (113 discrete receptors) receptors identified by NPS for these two Class I areas. The Class I receptor locations, which are provided by NPS in geographic (latitude and longitude) coordinates, were converted to Lambert Conformal Conic coordinates consistent with the VISTAS fine 4-km CALMET grid parameters (i.e., two matching parallels, latitude/longitude of the projection origin, and coordinate datum) using the NPS Class I areas conversion program.

All receptors were included in each CALPUFF model run. In CALPOST, only the receptor ranges for the specific Class I areas were processed.

11.7 MODELED EMISSION SOURCES

GREC modeled emission sources included only the main BFB boiler stack. The other GREC point sources, fugitive material handling, and cooling tower emission sources will have minor PM₁₀ emission rates and low release heights. Accordingly, these emission sources will have negligible impacts at the distant Class I areas.

Maximum potential emission rates were used for the GREC BFB boiler. Table 11-2 summarizes the GREC BFB boiler stack parameters and emission rates used in the CALPUFF modeling assessments.

11.8 MODEL RESULTS

GREC CALPUFF modeling results for the PSD Class I increments at the two Class I areas evaluated are discussed in the following subsections.

Table 11-3 summarizes the GREC NO₂, SO₂, and PM₁₀ impacts with respect to the PSD Class I SILs. This table provides the highest annual average impacts (for NO₂, SO₂, and PM₁₀), highest 3-hour average impacts (for SO₂), and highest 24-hour average impacts (for SO₂ and PM₁₀) for the two Class I areas evaluated.

All impacts are below the PSD Class I SILs for all pollutants and all averaging periods. Accordingly, a multisource cumulative assessment of air quality impacts with respect to the PSD Class I increments for NO₂, SO₂, and PM₁₀ was not required.

Table 11-2. CALPUFF Modeling Input Data—GREC BFB Boiler

Parameter	Units	Value
<u>Boiler Stack Units</u>		
Stack height	ft	230
Stack diameter	ft	12
Stack velocity	ft/sec	76.7
Stack temperature	°F	310
SO ₂ emissions	lb/hr	55.7
NO _x emissions	lb/hr	95.1
PM ₁₀ emissions (total)	lb/hr	57.0

Source: ECT, 2009.

Table 11-3. Summary of GREC PSD Class I Air Quality Impacts—NO_x, SO₂, and PM₁₀

Pollutant	Year of Meteorology	Averaging Period	Class I Area Impact (µg/m³)	
			Okefenokee NWA	Chassahowitzka NWA
<u>NO_x</u>	2001	Annual	0.0017	0.0015
	2002		0.0025	0.0013
	2003		0.0023	0.0014
	Maximum		0.0025	0.0015
	PSD SIL	0.1	0.1	
	% of PSD SIL	2.5	1.5	
	Exceed PSD SIL (Yes/No)	No	No	
<u>SO₂</u>	2001	Annual	0.0017	0.0015
	2002		0.0023	0.0015
	2003		0.0021	0.0014
	Maximum		0.0023	0.0015
	PSD SIL	0.1	0.1	
	% of PSD SIL	2.3	1.5	
	Exceed PSD SIL (Yes/No)	No	No	
	2001	24-Hour	0.041	0.033
	2002		0.051	0.026
	2003		0.040	0.044
	Maximum		0.051	0.044
	PSD SIL	0.2	0.2	
	% of PSD SIL	25.4	21.9	
	Exceed PSD SIL (Yes/No)	No	No	
2001	3-Hour	0.157	0.108	
2002		0.231	0.110	
2003		0.173	0.146	
Maximum		0.23	0.15	
PSD SIL	1.0	1.0		
% of PSD SIL	23.1	14.6		
Exceed PSD SIL (Yes/No)	No	No		
<u>PM₁₀</u>	2001	Annual	0.002	0.002
	2002		0.003	0.002
	2003		0.002	0.002
	Maximum		0.0029	0.0021
	PSD SIL	0.2	0.2	
	% of PSD SIL	1.5	1.0	
	Exceed PSD SIL (Yes/No)	No	No	
	2001	24-Hour	0.053	0.049
	2002		0.057	0.031
	2003		0.047	0.051
	Maximum		0.057	0.051
	PSD SIL	0.3	0.3	
	% of PSD SIL	18.9	17.0	
	Exceed PSD SIL (Yes/No)	No	No	

Source: ECT, 2009.

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APPENDIX A

EMISSION RATE CALCULATIONS

Appendix A - Gainesville Renewable Energy Center Emission Rate Calculations

List of Tables

Table No.	Description
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**Table A-1. Gainesville Renewable Energy Center
Annual Potential Emission Rate Summary**

A. Criteria Pollutants and PM

Pollutant	Potential Emission Rates						
	BFB Boiler (tpy)	Material Handling Point Sources (tpy)	Material Handling Fugitive Sources (tpy)	Cooling Tower (tpy)	Emergency Generator Diesel Engine (tpy)	Emergency Firewater Pump Diesel Engine (tpy)	GREC Project Totals (tpy)
SO ₂	243.9	0.0	0.0	0.0	0.00078	0.0020	243.9
NO _x	416.4	0.0	0.0	0.0	1.40	0.32	418.1
CO	713.8	0.0	0.0	0.0	1.46	0.39	715.6
VOC	77.3	0.0	0.0	0.0	0.60	0.14	78.1
PM (filterable)	89.2	28.0	11.6	1.5	0.063	0.023	130.4
PM ₁₀ (total)	249.8	28.0	2.3	1.0	0.063	0.023	281.2
PM _{2.5} (total)	249.8	28.0	0.34	0.0032	0.063	0.023	278.3
Pb	0.12	Neg.	Neg.	Neg.	Neg.	Neg.	0.12

B. Hazardous Air Pollutants

Pollutant	Potential Emission Rates						
	BFB Boiler (tpy)	Material Handling Point Sources (tpy)	Material Handling Fugitive Sources (tpy)	Cooling Tower (tpy)	Emergency Generator Diesel Engine (tpy)	Emergency Firewater Pump Diesel Engine (tpy)	GREC Project Totals (tpy)
<u>Organics</u>							
Acetaldehyde	0.086	0.0	0.0	0.0	0.000032	0.00039	0.086
Acrolein	0.051	0.0	0.0	0.0	0.000010	0.000047	0.051
Benzene	0.73	0.0	0.0	0.0	0.000099	0.00047	0.73
1,3-Butadiene	-	0.0	0.0	0.0	0.000050	0.000020	0.000069
Dibenzofurans	0.000010	0.0	0.0	0.0	-	-	0.000010
Dioxins	0.000014	0.0	0.0	0.0	-	-	0.000014
Ethylbenzene	0.057	0.0	0.0	0.0	-	-	0.057
Formaldehyde	1.6	0.0	0.0	0.0	0.00010	0.00060	1.6
Methyl Chloroform	0.077	0.0	0.0	0.0	-	-	0.077
Methylene Chloride	0.29	0.0	0.0	0.0	-	-	0.29
PAH/POM	0.13	0.0	0.0	0.0	0.00043	0.00013	0.13
Toluene	0.12	0.0	0.0	0.0	0.00036	0.00021	0.13
o-Xylenes	0.093	0.0	0.0	0.0	-	-	0.093
Xylenes	0.033	0.0	0.0	0.0	0.00014	0.00025	0.034
<u>Inorganics</u>							
Hydrochloric Acid (HCl)	35.7	0.0	0.0	0.0	Neg	Neg	35.7
Hydrofluoric Acid (HF)	71.4	0.0	0.0	0.0	Neg	Neg	71.4
<u>Metals</u>							
Arsenic	0.030	Neg	Neg	Neg	Neg	Neg	0.030
Beryllium	0.0093	Neg	Neg	Neg	Neg	Neg	0.0093
Cadmium	0.021	Neg	Neg	Neg	Neg	Neg	0.021
Chromium	0.76	Neg	Neg	Neg	Neg	Neg	0.76
Lead	0.12	Neg	Neg	Neg	Neg	Neg	0.12
Manganese	0.35	Neg	Neg	Neg	Neg	Neg	0.35
Mercury	0.0084	Neg	Neg	Neg	Neg	Neg	0.0084
Nickel	0.091	Neg	Neg	Neg	Neg	Neg	0.091
Phosphorus	2.2	Neg	Neg	Neg	Neg	Neg	2.2
Maximum Individual HAP							71.4
Total HAPs							113.9

C. Sulfuric Acid Mist (H₂SO₄ Mist), Ammonia (NH₃), and Carbon Dioxide (CO₂)

Pollutant	Potential Emission Rates						
	BFB Boiler (tpy)	Material Handling Point Sources (tpy)	Material Handling Fugitive Sources (tpy)	Cooling Tower (tpy)	Emergency Generator Diesel Engine (tpy)	Emergency Firewater Pump Diesel Engine (tpy)	GREC Project Totals (tpy)
H ₂ SO ₄ Mist	5.9	0.0	0.0	0.0	Neg.	Neg.	5.9
NH ₃	37.3	0.0	0.0	0.0	0.0	0.0	37.3
CO ₂	1,159,868	0.0	0.0	0.0	219.5	79.7	1,160,167

Neg. - negligible

**Table A-2. Gainesville Renewable Energy Center
BFB Boiler Criteria Pollutant Emission Estimates**

A. Emission Estimate Methodology

References - BFB Boiler Vendor Data and Boiler MACT Average Emission Factor (Pb).

$$E_1 = EF \times HI$$

$$E_2 = EF \times HI \times OP \times (1 \text{ ton} / 2,000 \text{ lb})$$

where:

E_1 = hourly emission rate; pounds per hour (lb/hr)

E_2 = annual emission rate; tons per year (ton/yr)

EF = emission factor; pounds per million British thermal units (lb/10⁶ Btu)

HI = hourly BFB boiler higher heating value (HHV) heat input (10⁶ Btu/hr);

OP = annual operating hours; hours per year (hr/yr)

B. Input Data

BFB Boiler Data	Units	BFB Boiler 100% Load (EU P-7)	BFB Boiler 70% Load (EU P-7)
Heat Input	10 ⁶ Btu/hr, HHV	1,358	951
Power Output	MW (gross)	116	81
Annual Operating Hours	hr/yr	8,760	8,760

C. Calculations

Criteria Pollutants	BFB Boiler 100% Load (EU P-7)	BFB Boiler 70% Load (EU P-7)
NO_x		
lb/10 ⁶ Btu, HHV	0.070	0.070
lb/hr	95.1	66.6
ton/yr	416.4	291.6
lb/MWh	0.82	0.82
CO		
lb/10 ⁶ Btu, HHV	0.12	0.12
lb/hr	163.0	114.1
ton/yr	713.8	499.8
lb/MWh	1.4	1.4
VOC		
lb/10 ⁶ Btu, HHV	0.013	0.013
lb/hr	17.7	12.4
ton/yr	77.3	54.1
lb/MWh	0.15	0.15
PM/PM₁₀/PM_{2.5} (filterable)		
lb/10 ⁶ Btu, HHV	0.015	0.015
lb/hr	20.4	14.3
ton/yr	89.2	62.5
lb/MWh	0.18	0.18
PM/PM₁₀/PM_{2.5} (condensable)		
lb/10 ⁶ Btu, HHV	0.027	0.027
lb/hr	36.7	25.7
ton/yr	160.6	112.5
lb/MWh	0.32	0.32
PM/PM₁₀/PM_{2.5} (total)		
lb/10 ⁶ Btu, HHV	0.042	0.042
lb/hr	57.0	39.9
ton/yr	249.8	174.9
lb/MWh	0.49	0.49
SO₂		
lb/10 ⁶ Btu, HHV	0.041	0.041
lb/hr	55.7	39.0
ton/yr	243.9	170.8
lb/MWh	0.48	0.5
Pb		
lb/10 ⁶ Btu, HHV	0.000021	0.000021
lb/hr	0.029	0.020
ton/yr	0.12	0.09
lb/MWh	0.00025	0.00025

Table A-3. Gainesville Renewable Energy Center
BFB Boiler Criteria Pollutant Emission Estimates - H₂SO₄ Mist, NH₃, and CO₂

A. Emission Estimate Methodology

References - BFB Boiler Vendor Data and AP-42 Table 1.6-3. (CO₂).

$$E_1 = EF \times HI$$

$$E_2 = EF \times HI \times OP \times (1 \text{ ton} / 2,000 \text{ lb})$$

where:

E₁ = hourly emission rate; pounds per hour (lb/hr)

E₂ = annual emission rate; tons per year (ton/yr)

EF = emission factor; pounds per million British thermal units (lb/10⁶ Btu)

HI = hourly BFB boiler higher heating value (HHV) heat input (10⁶ Btu/hr);

OP = annual operating hours; hours per year (hr/yr)

B. Input Data

BFB Boiler Data	Units	BFB Boiler 100% Load (EU P-7)	BFB Boiler 70% Load (EU P-7)
Heat Input	10 ⁶ Btu/hr, HHV	1,358	951
Power Output	MW (gross)	116	81
Annual Operating Hours	hr/yr	8,760	8,760

C. Calculations

Criteria Pollutants	BFB Boiler 100% Load (EU P-7)	BFB Boiler 70% Load (EU P-7)
H₂SO₄ Mist		
lb/10 ⁶ Btu, HHV	0.0010	0.0010
lb/hr	1.4	1.0
ton/yr	5.9	4.2
lb/MWh	0.012	0.012
NH₃		
lb/10 ⁶ Btu, HHV	0.0063	0.0063
lb/hr	8.5	5.9
ton/yr	37.3	25.9
lb/MWh	0.073	0.073
CO₂		
lb/10 ⁶ Btu, HHV	195	195
lb/hr	264,810	185,445
ton/yr	1,159,868	812,249
lb/MWh	2,283	2,284

**Table A-4. Gainesville Renewable Energy Center
BFB Boiler Pollutant Concentrations**

A. BFB Boiler Exhaust Flow Rates - 100% Load

Item	BFB Boiler (100% Load)
Exhaust Temperature	310.0 °F
Exhaust Oxygen	3.62 volume %, dry
Exhaust Moisture	27.6 volume %
Volume of 1 lb-mole at 68°F	385.1 dscf
Exhaust Flow Rates	520,638 acf/min @ 3.62% O ₂
	376,942 dacf/min @ 3.62% O ₂
	258,475 dscf/min @ 3.62% O ₂
	19,279,608 dscf/hr @ 7.0% O ₂
	321,327 dscf/min @ 7.0% O ₂
	9,099 dscm/min @ 7% O ₂

B. BFB Boiler Pollutant Concentrations - 100% Load

Pollutant	MW (lb/lb-mole)	Emission Rates - 100% Load			
		(lb/hr)	(mg/dscm) ¹	(ug/dscm) ¹	(ppmvd) ²
SO ₂	64.0	55.7	N/A	N/A	17.4
NO _x	46.0	95.1	N/A	N/A	41.3
CO	28.0	163.0	N/A	N/A	116.3
VOC	16.0	17.7	N/A	N/A	22.1
PM/PM ₁₀ /PM _{2.5} (filterable)	N/A	20.4	16.9	N/A	N/A
PM/PM ₁₀ /PM _{2.5} (total)	N/A	57.0	47.4	N/A	N/A
H ₂ SO ₄ Mist	98.0	1.4	1.1	N/A	N/A
Mercury	200.6	0.0019	N/A	1.6	N/A
Ammonia	17.0	8.5	N/A	N/A	10.0
Lead	N/A	0.029	N/A	23.7	N/A

¹ At 68 °F

² At 7% oxygen

**Table A-5. Gainesville Renewable Energy Center
BFB Boiler Hazardous Air Pollutant Emission Estimates**

A. Emission Estimate Methodology

References - BFB Boiler Vendor Data, Fuel Analyses, and Boiler MACT Average Emission Factors.

$$E_1 = EF \times HI$$

$$E_2 = EF \times HI \times OP \times (1 \text{ ton} / 2,000 \text{ lb})$$

where:

E_1 = hourly emission rate; pounds per hour (lb/hr)
 E_2 = annual emission rate; tons per year (ton/yr)
 EF = emission factor; pounds per million British thermal units (lb/10⁶ Btu)
 HI = hourly BFB boiler higher heating value (HHV) heat input (10⁶ Btu/hr);
 OP = annual operating hours; hours per year (hr/yr)

B. Input Data

BFB Boiler Data	Units	BFB Boiler 100% Load (EU P-7)
Biomass Fuel Consumed	lb/hr	318,500
Heat Input	10 ⁶ Btu/hr, HHV	1,358
Power Output	MW (gross)	116
Annual Operating Hours	hr/yr	8,760
Biomass Fuel Hg Concentration	ppmw	0.0060

C. Calculations

Hazardous Air Pollutant	FDEP ID Code	CAS Number	Emission Factor (lb/10 ⁶ Btu)	Emission Factor Source ¹	BFB Boiler (100% Load)	
					(lb/hr)	(ton/yr)
Organics						
Acetaldehyde	H001	75-07-0	1.44E-05	1	0.0196	0.0857
Acrolein	H006	107-02-8	8.52E-06	1	0.0116	0.0507
Benzene	H017	71-43-2	1.23E-04	1	0.1670	0.7316
Dibenzofurans	H058	132-64-9	1.62E-09	1	0.0000022	0.0000096
Dioxins (equiv.)	H165	1746-01-6	2.38E-09	1	0.0000032	0.0000142
Ethylbenzene	H085	100-41-4	9.52E-06	1	0.0129	0.0566
Formaldehyde	H095	50-00-0	2.70E-04	1	0.3667	1.6060
Methyl Chloroform	H119	71-55-6	1.30E-05	1	0.0177	0.0773
Methylene Chloride	H128	75-09-2	4.90E-05	1	0.0665	0.2915
o-Xylenes	H187	95-47-6	1.57E-05	1	0.0213	0.0934
16-PAH (POM)	H151	-	2.16E-05	1	0.0293	0.1285
Toluene	H169	108-88-3	2.10E-05	1	0.0285	0.1249
Xylenes	H186	1330-20-7	5.59E-06	1	0.0076	0.0332
Total Organics					0.75	3.3
Inorganics						
Hydrogen Chloride	H106	7647-01-0	6.00E-03	2	8.1480	35.6882
Hydrogen Fluoride	H107	7664-39-3	1.20E-02	2	16.2960	71.3765
Total Inorganics					24.4	107.1
Metals						
Arsenic	H015	-	5.01E-06	1	0.0068	0.0298
Beryllium	H021	-	1.57E-06	1	0.0021	0.0093
Cadmium	H027	-	3.54E-06	1	0.0048	0.0211
Chromium	H046	-	1.28E-04	1	0.1738	0.7613
Lead	PB	-	2.10E-05	1	0.0285	0.1249
Manganese	H113	-	5.89E-05	1	0.0800	0.3503
Mercury	H114	-	1.41E-06	3	0.0019	0.0084
Nickel	H133	-	1.53E-05	1	0.0208	0.0910
Phosphorus	H148	7723-14-0	3.68E-04	1	0.4997	2.1889
Total Metals					0.52	2.28
			Maximum Individual HAP			71.4
			Total HAPs			112.6

¹ Emission Factors:

- Boiler MACT Docket; Development of Average Emission Factors and Baseline Emission Estimates for the Industrial, Commercial, and Institutional Boilers and Process Heaters National Emission Standard for Hazardous Air Pollutants, Eastern Research Group, October 2002.
- BFB boiler vendor data.
- Fuel analysis and mass balance.

² 16-PAH: Acenaphthene, acenaphthylene, anthracene, benz(a)anthracene, benzo(b)fluoranthene, benzo(e)pyrene, benzo(g,h,i)perylene, benzo(k)fluoranthene, chrysene, dibenz(ah)anthracene, fluoranthene, fluorene, ideno(1,2,3-cd)pyrene, naphthalene, phenanthrene, and pyrene.

**Table A-6. Gainesville Renewable Energy Center
BFB Boiler Startup Emission Estimates**

References - BFB Boiler Vendor Data (duration of cold startup events and emission rates), GREC (annual frequency of cold startup events).

A. Input Data

Parameter	Units	Value
Duration of Each Cold Startup Event	hours	14
Number of Cold Startup Events Per Year	-	20

B. Hourly Startup Event Emission Estimates

Pollutant	Emission Rates (lb/hr)							
	Hour 1	Hour 2	Hour 3	Hour 4	Hour 5	Hour 6	Hour 7	
NO _x	23.94	39.48	39.16	71.02	67.47	93.35	156.34	
SO ₂	0.00	0.00	0.00	0.00	0.00	0.00	1.34	
PM/PM ₁₀	1.67	2.78	2.78	5.11	5.11	5.11	6.50	
CO	4.28	7.05	6.99	12.68	12.68	38.05	104.23	
VOC	0.38	0.63	0.63	1.14	1.14	3.42	9.38	
H ₂ SO ₄ Mist	0.000	0.000	0.000	0.000	0.000	0.000	0.017	
NH ₃	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Pollutant	Emission Rates (lb/hr)							Totals (lb/event)
	Hour 8	Hour 9	Hour 10	Hour 11	Hour 12	Hour 13	Hour 14	
NO _x	177.77	269.87	214.90	147.90	117.37	86.98	82.30	1,587.9
SO ₂	2.14	8.02	9.09	9.09	9.09	9.09	11.23	59.1
PM/PM ₁₀	7.33	9.72	9.72	9.44	9.44	9.44	11.67	95.8
CO	121.21	159.73	132.04	97.52	78.51	72.49	89.90	937.3
VOC	10.91	14.38	11.88	8.78	7.07	6.52	8.09	84.4
H ₂ SO ₄ Mist	0.027	0.102	0.116	0.116	0.116	0.116	0.143	0.75
NH ₃	0.51	0.78	0.80	0.79	16.07	16.32	15.25	50.5

C. Annual Startup Event Emission Estimates

Pollutant	Emissions (ton/yr)
NO _x	15.9
SO ₂	0.59
PM/PM ₁₀	0.96
CO	9.4
VOC	0.84
H ₂ SO ₄ Mist	0.0075
NH ₃	0.51

**Table A-7. Gainesville Renewable Energy Center
BFB Boiler Shutdown Emission Estimates**

References - BFB Boiler Vendor Data (duration of shutdown events and emission rates), GREC (annual frequency of shutdown events).

A. Input Data

Parameter	Units	Value
Duration of Each Shutdown Event	hours	3
Number of Shutdown Events Per Year	-	20

B. Hourly Shutdown Event Emission Estimates

Pollutant	Emission Rates (lb/hr)			Totals (lb/event)
	Hour 1	Hour 2	Hour 3	
NO _x	82.30	86.98	117.37	286.7
SO ₂	11.23	9.09	9.09	29.4
PM/PM ₁₀	11.67	9.44	9.44	30.6
CO	89.90	72.49	78.51	240.9
VOC	8.09	6.52	7.07	21.7
H ₂ SO ₄ Mist	0.14	0.12	0.12	0.37
NH ₃	15.25	16.32	16.07	47.6

C. Annual Shutdown Event Emission Estimates

Pollutant	Emissions (ton/yr)
NO _x	2.9
SO ₂	0.29
PM/PM ₁₀	0.31
CO	2.4
VOC	0.22
H ₂ SO ₄ Mist	0.0037
NH ₃	0.48

**Table A-8. Gainesville Renewable Energy Center
Emergency Diesel Engine Criteria Pollutant and CO₂ Emission Estimates**

A. Emission Estimate Methodology

References - NSPS Subpart IIII (NO_x, CO, VOC, and PM), Mass Balance (SO₂), and AP-42 Table 3.4-1 (CO₂).

$$E_1 = EF \times P$$

$$E_2 = EF \times P \times OP \times (1 \text{ ton} / 2,000 \text{ lb})$$

$$EFSO_2 = FOFLOW \times FODENSITY \times (FOSULFUR / 100) \times (1 / P) \times (2 \text{ lb SO}_2 / \text{lb S}) \times (453.59 \text{ g} / \text{lb})$$

where:

E_1 = hourly emission rate; pounds per hour (lb/hr)
 E_2 = annual emission rate; tons per year (ton/yr)
 EF = emission factor; grams per brake horsepower-hour (g/bhp-hr)
 P = engine output; brake horsepower-hour (bhp-hr)
 OP = annual operating hours; hours per year (hr/yr)
 EFSO₂ = SO₂ emission factor; grams per brake horsepower hour (g/bhp-hr)
 FOFLOW = ULSD fuel oil flow rate; gallons per hour (gal/hr)
 FODENSITY = ULSD fuel oil density; pounds per gallon (lb/gal)
 FOSULFUR = ULSD fuel oil sulfur content; weight percent (weight %)

B. Input Data

Diesel Engine Data	Units	Emergency Fire Water Pump Diesel (EU P-9)	Emergency Generator Diesel (EU P-10)
Engine Output	bhp	275	757
	kW	205	564
Engine ULSD Fuel Oil Flow Rate	gal/hr	14.7	36.8
Engine Operating Hours	hr/yr	500	500
Applicable EPA Nonroad Tier	-	3	2
ULSD Fuel Oil Sulfur Content	weight %	0.0015	0.0015
ULSD Fuel Oil Density	lb/gal	7.08	7.08

C. Calculations

Criteria Pollutants and CO ₂	Emergency Fire Water Pump Diesel (EU P-9)	Emergency Generator Diesel (EU P-10)
NO_x		
g/bhp-hr ¹	2.1	3.4
lb/hr	1.3	5.6
ton/yr	0.32	1.4
CO		
g/bhp-hr	2.6	3.5
lb/hr	1.6	5.8
ton/yr	0.39	1.5
VOC		
g/bhp-hr ²	0.90	1.4
lb/hr	0.55	2.4
ton/yr	0.14	0.60
PM/PM₁₀/PM_{2.5}		
g/bhp-hr	0.15	0.15
lb/hr	0.091	0.25
ton/yr	0.023	0.063
SO₂		
g/bhp-hr ³	0.0051	0.0047
lb/hr	0.0031	0.0078
ton/yr	0.00078	0.0020
CO₂		
g/bhp-hr	526.2	526.2
lb/hr	319.0	878.1
ton/yr	79.7	219.5

¹ NO_x emission rate assumed equal to 70% of Subpart IIII NMHC + NO_x emission standard.

² VOC emission rate assumed equal to 30% of Subpart IIII NMHC + NO_x emission standard.

³ Based on use of ULSD fuel oil.

**Table A-9. Gainesville Renewable Energy Center
Emergency Diesel Engine Hazardous Air Pollutant Emission Estimates**

A. Emission Estimate Methodology

References - AP-42 Tables 3.3-2. (EU P-9) and 3.4-4.(EU P-10), and engine vendor data..

$$E_1 = EF \times HI$$

$$E_2 = EF \times HI \times OP \times (1 \text{ ton} / 2,000 \text{ lb})$$

where:

E_1 = hourly emission rate; pounds per hour (lb/hr)

E_2 = annual emission rate; tons per year (ton/yr)

EF = emission factor; pounds per million British thermal units (lb/10⁶ Btu)

HI = engine heat input; million British thermal units per hour (10⁶ Btu/hr)

OP = annual operating hours; hours per year (hr/yr)

B. Input Data

Diesel Engine Data	Units	Emergency Fire Water Pump Diesel (EU P-9)	Emergency Generator Diesel (EU P-10)
Engine Output	bhp	275	757
Engine ULSD Fuel Oil Flow Rate	gal/hr	14.7	36.8
ULSD Fuel Oil Heat Content, HHV	10 ⁶ Btu/gal	138,000	138,000
Engine Heat Input, HHV	10 ⁶ Btu/hr	2.0	5.1
Engine Operating Hours	hr/yr	500	500

C. Calculations

Hazardous Air Pollutant	Emergency Fire Water Pump Diesel (EU P-9)	Emergency Generator Diesel (EU P-10)
1,3-Butadiene		
lb/10 ⁶ Btu	3.91E-05	3.91E-05
lb/hr	7.93E-05	1.99E-04
ton/yr	1.98E-05	4.96E-05
Acrolein		
lb/10 ⁶ Btu	9.25E-05	7.88E-06
lb/hr	1.88E-04	4.00E-05
ton/yr	4.69E-05	1.00E-05
Acetaldehyde		
lb/10 ⁶ Btu	7.76E-04	2.52E-05
lb/hr	1.57E-03	1.28E-04
ton/yr	3.94E-04	3.20E-05
Benzene		
lb/10 ⁶ Btu	9.33E-04	7.76E-04
lb/hr	1.89E-03	3.94E-03
ton/yr	4.73E-04	9.85E-04
Formaldehyde		
lb/10 ⁶ Btu	1.18E-03	7.89E-05
lb/hr	2.39E-03	4.01E-04
ton/yr	5.98E-04	1.00E-04
Naphthalene		
lb/10 ⁶ Btu	8.48E-05	1.30E-04
lb/hr	1.72E-04	6.60E-04
ton/yr	4.30E-05	1.65E-04
Polycyclic Aromatic Hydrocarbons (PAH)		
lb/10 ⁶ Btu	1.68E-04	2.12E-04
lb/hr	3.41E-04	1.08E-03
ton/yr	8.52E-05	2.69E-04
Toluene		
lb/10 ⁶ Btu	4.09E-04	2.81E-04
lb/hr	8.30E-04	1.43E-03
ton/yr	2.07E-04	3.57E-04
Xylenes		
lb/10 ⁶ Btu	2.85E-04	1.93E-04
lb/hr	5.78E-04	9.80E-04
ton/yr	1.45E-04	2.45E-04

POTENTIAL EMISSION INVENTORY WORKSHEET				Table A-10	
Gainesville Renewable Energy Center - Cooling Tower				Cooling Tower	
EMISSION SOURCE TYPE					
COOLING TOWERS - PM/PM ₁₀					
FACILITY AND SOURCE DESCRIPTION					
Emission Source Description:		Mechanical Draft Cooling Tower			
Emission Control Method(s)/ID No.(s):		Mist Eliminators			
Emission Point Description:					
EMISSION ESTIMATION EQUATIONS					
$\text{PM Emission Rate (lb/hr)} = \text{Recirculating Water Flow Rate (gpm)} \times \text{Drift Loss Rate (\%)} / 100 \times 8.345 \text{ lb/gal} \times (\text{TDS (ppmw)} / 10) \times 60 \text{ min/hr}$					
$\text{PM Emission Rate (ton/yr)} = \text{PM Emission (lb/hr)} \times \text{Operating Period (hrs/yr)} \times (1 \text{ ton} / 2,000 \text{ lb})$					
$\text{PM}_{10} \text{ Emission Rate (lb/hr)} = \text{PM Emissions (lb/hr)} \times \text{PM}_{10}/\text{PM Fraction}$					
$\text{PM}_{10} \text{ Emission Rate (ton/yr)} = \text{PM}_{10} \text{ Emission (lb/hr)} \times \text{Operating Period (hrs/yr)} \times (1 \text{ ton} / 2,000 \text{ lb})$					
Source: ECT, 2009.					
INPUT DATA AND EMISSIONS CALCULATIONS					
Cooling Tower Data					
Operating Hours:	8,760	hrs/yr			
Number of Cells:	4				
Recirculating Water Flow Rate:	78,000	gal/min			
Drift Loss Rate:	0.0005	%			
Total Dissolved Solids (TDS):	1,700	ppmw			
PM ₁₀ /PM Fraction:	0.694				
PM _{2.5} /PM Fraction:	0.00218				
Number of Towers:	1				
Pollutant	Potential Emission Rates (Per Cell)		Potential Emission Rates (Total)		
	(lb/hr)	(tpy)	(lb/hr)	(tpy)	
PM	0.083	0.36	0.33	1.5	
PM ₁₀	0.058	0.25	0.23	1.0	
PM _{2.5}	0.00018	0.00079	0.00072	0.0032	
SOURCES OF INPUT DATA					
Parameter		Data Source			
Operating Hours (annual)		GREC, 2009.			
Recirculating Water Flow Rate (gpm)		Zachry, 2009.			
Drift Loss Rate (%)		Zachry, 2009.			
Total Dissolved Solids (ppmw)		Zachry, 2009.			
PM ₁₀ /PM Fraction:		ECT, 2009.			
NOTES AND OBSERVATIONS					
DATA CONTROL					
Prepared by:	T. Davis, ECT			September 2009	
Reviewed by:	L. Fagen, GREC			September 2009	

**Table A-11. Gainesville Renewable Energy Center
Cooling Tower PM/PM₁₀ Fractions**

Procedure Citation:

AWMA Abstract No. 216, Session No. AM-1b, Orlando, 2001.
Calculating Realistic PM₁₀ Emissions from Cooling Towers

Cooling Tower Design Data:

Cooling Tower Recirculating Water Total Dissolved Solids:	1,700	ppmw
Cooling Tower PM ₁₀ Density (assumed NaCl):	2.2	g/cm ³

Particle Size Distribution:

Droplet Diameter (μm)	Droplet Volume (m ³)	Droplet Mass (g)	Particle Mass (g)	Particle Volume (m ³)	Particle Diameter (μm)	Mass Fraction (%)
10	5.24E-16	5.24E-10	8.90E-13	4.05E-19	0.918	0.000
20	4.19E-15	4.19E-09	7.12E-12	3.24E-18	1.835	0.196
30	1.41E-14	1.41E-08	2.40E-11	1.09E-17	2.753	0.226
40	3.35E-14	3.35E-08	5.70E-11	2.59E-17	3.671	0.514
50	6.54E-14	6.54E-08	1.11E-10	5.06E-17	4.588	1.816
60	1.13E-13	1.13E-07	1.92E-10	8.74E-17	5.506	5.702
70	1.80E-13	1.80E-07	3.05E-10	1.39E-16	6.424	21.348
90	3.82E-13	3.82E-07	6.49E-10	2.95E-16	8.259	49.812
110	6.97E-13	6.97E-07	1.18E-09	5.39E-16	10.094	70.509
130	1.15E-12	1.15E-06	1.96E-09	8.89E-16	11.929	82.023
150	1.77E-12	1.77E-06	3.00E-09	1.37E-15	13.765	88.012
180	3.05E-12	3.05E-06	5.19E-09	2.36E-15	16.518	91.032
210	4.85E-12	4.85E-06	8.24E-09	3.75E-15	19.271	92.468
240	7.24E-12	7.24E-06	1.23E-08	5.59E-15	22.024	94.091
270	1.03E-11	1.03E-05	1.75E-08	7.96E-15	24.776	94.689
300	1.41E-11	1.41E-05	2.40E-08	1.09E-14	27.529	96.288
350	2.24E-11	2.24E-05	3.82E-08	1.73E-14	32.118	97.011
400	3.35E-11	3.35E-05	5.70E-08	2.59E-14	36.706	98.340
450	4.77E-11	4.77E-05	8.11E-08	3.69E-14	41.294	99.071
500	6.54E-11	6.54E-05	1.11E-07	5.06E-14	45.882	99.071
600	1.13E-10	1.13E-04	1.92E-07	8.74E-14	55.059	100.000

Linear Interpolation:

Droplet Diameter (μm)	Droplet Volume (m ³)	Droplet Mass (g)	Particle Mass (g)	Particle Volume (m ³)	Particle Diameter (μm)	Mass Fraction (%)
90	3.82E-13	3.82E-07	6.49E-10	2.95E-16	8.259	49.812
110	6.97E-13	6.97E-07	1.18E-09	5.39E-16	10.094	70.509
					10.000	69.448

Mass Fraction of Cooling Tower PM ≤ PM ₁₀ :	0.694
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Sources: ECT, 2009
Zachry, 2009

**Table A-12. Gainesville Renewable Energy Center
Cooling Tower PM/PM_{2.5} Fractions**

Procedure Citation:

AWMA Abstract No. 216, Session No. AM-1b, Orlando, 2001.
Calculating Realistic PM₁₀ Emissions from Cooling Towers

Cooling Tower Design Data:

Cooling Tower Recirculating Water Total Dissolved Solids:	1,700	ppmw
Cooling Tower PM ₁₀ Density (assumed NaCl):	2.2	g/cm ³

Particle Size Distribution:

Droplet Diameter (μm)	Droplet Volume (m ³)	Droplet Mass (g)	Particle Mass (g)	Particle Volume (m ³)	Particle Diameter (μm)	Mass Fraction (%)
10	5.24E-16	5.24E-10	8.90E-13	4.05E-19	0.918	0.000
20	4.19E-15	4.19E-09	7.12E-12	3.24E-18	1.835	0.196
30	1.41E-14	1.41E-08	2.40E-11	1.09E-17	2.753	0.226
40	3.35E-14	3.35E-08	5.70E-11	2.59E-17	3.671	0.514
50	6.54E-14	6.54E-08	1.11E-10	5.06E-17	4.588	1.816
60	1.13E-13	1.13E-07	1.92E-10	8.74E-17	5.506	5.702
70	1.80E-13	1.80E-07	3.05E-10	1.39E-16	6.424	21.348
90	3.82E-13	3.82E-07	6.49E-10	2.95E-16	8.259	49.812
110	6.97E-13	6.97E-07	1.18E-09	5.39E-16	10.094	70.509
130	1.15E-12	1.15E-06	1.96E-09	8.89E-16	11.929	82.023
150	1.77E-12	1.77E-06	3.00E-09	1.37E-15	13.765	88.012
180	3.05E-12	3.05E-06	5.19E-09	2.36E-15	16.518	91.032
210	4.85E-12	4.85E-06	8.24E-09	3.75E-15	19.271	92.468
240	7.24E-12	7.24E-06	1.23E-08	5.59E-15	22.024	94.091
270	1.03E-11	1.03E-05	1.75E-08	7.96E-15	24.776	94.689
300	1.41E-11	1.41E-05	2.40E-08	1.09E-14	27.529	96.288
350	2.24E-11	2.24E-05	3.82E-08	1.73E-14	32.118	97.011
400	3.35E-11	3.35E-05	5.70E-08	2.59E-14	36.706	98.340
450	4.77E-11	4.77E-05	8.11E-08	3.69E-14	41.294	99.071
500	6.54E-11	6.54E-05	1.11E-07	5.06E-14	45.882	99.071
600	1.13E-10	1.13E-04	1.92E-07	8.74E-14	55.059	100.000

Linear Interpolation:

Droplet Diameter (μm)	Droplet Volume (m ³)	Droplet Mass (g)	Particle Mass (g)	Particle Volume (m ³)	Particle Diameter (μm)	Mass Fraction (%)
20	4.19E-15	4.19E-09	7.12E-12	3.24E-18	1.835	0.196
30	1.41E-14	1.41E-08	2.40E-11	1.09E-17	2.753	0.226
					2.500	0.218

Mass Fraction of Cooling Tower PM ≤ PM ₁₀ :	0.00218
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Table A-13. Gainesville Renewable Energy Center
Point Emission Source PM/PM₁₀/PM_{2.5} Emission Estimates
Material Transfer Operations with Baghouse or Bin Vent Filter

A. Emission Estimate Methodology

Reference - Mass Balance, ECT, 2009.

$$E_1 = c \times Q \times (60 \text{ min / hr}) \times (1 \text{ lb / 7,000 grains})$$

$$E_2 = c \times Q \times (60 \text{ min / hr}) \times (1 \text{ lb / 7,000 grains}) \times OP \times (1 \text{ ton / 2,000 lb})$$

where:

E_1 = hourly emission rate (lb/hr)
 E_2 = annual emission rate (ton/yr)
 c = outlet PM/PM₁₀/PM_{2.5} concentration; grains per standard cubic foot (gr/scf)
 Q = exhaust flow rate; standard cubic feet per minute (scfm)
 OP = annual operating hours (hrs/yr)

Note: Standard temperature = 68 °F.

B. Input Data

Parameter	Units	Value
Outlet PM/PM ₁₀ /PM _{2.5} concentration (c), baghouse/bin vent outlet	gr/scf	0.015

C. Calculations

Emission Point	EU ID	Exhaust Flow Rate (scfm)	Operating Hours (hrs/yr)	PM/PM ₁₀ /PM _{2.5} Emission Estimates	
				(lb/hr)	(tpy)
Screen/Hog Building Baghouse	P-1	35,397	8,760	4.55	19.9
BFB Boiler Fuel Day Bin Vent Filter No. 1	P-2	3,933	8,760	0.51	2.2
BFB Boiler Fuel Day Bin Vent Filter No. 2	P-3	1,967	8,760	0.25	1.1
Fly Ash Silo Vacuum Blower No. 1	P-4	3,300	8,760	0.42	1.9
Fly Ash Silo Vacuum Blower No. 2	P-5	3,300	8,760	0.42	1.9
Fly Ash Silo Bin Vent Filter	P-6	1,886	8,760	0.24	1.1
Sorbent Silo Bin Vent Filter ¹	P-11	1,886	36	0.24	0.0044
Totals		51,669		6.6	28.0

¹ Operates up to 1 hour per day, 3 times per month.

Table A-14. Gainesville Renewable Energy Center
Fugitive Emission Source PM/PM₁₀/PM_{2.5} Emission Estimates - Biomass Fuel Transfer Operations

A. Emission Estimate Methodology

Reference - AP-42, Section 13.2.4, Aggregate Handling and Storage Piles - Equation (1), EPA November 2006.

$$E_1 = k \times (0.0032) \times [(U / 5)^{1.3} / (M / 2)^{1.4}] \times [1 - (CE / 100)] \times T_1$$
$$E_2 = k \times (0.0032) \times [(U / 5)^{1.3} / (M / 2)^{1.4}] \times [1 - (CE / 100)] \times T_2 \times (1 \text{ ton} / 2,000 \text{ lb})$$

where:
E₁ = hourly emission rate (lb/hr)
E₂ = annual emission rate (ton/yr)
k = particle size multiplier
U = mean wind speed, miles per hour (mph)
M = material moisture content, weight percent (%)
CE = control efficiency (%)
T₁ = material transfer rate (ton/hr)
T₂ = material transfer rate (ton/yr)

B. Input Data

Parameter	Units	Value
Particle size multiplier (k), particle size <30 µm	-	0.74
Particle size multiplier (k), particle size <10 µm	-	0.35
Particle size multiplier (k), particle size <2.5 µm	-	0.053
Mean Wind Speed (U)	mph	6.5
Minimum Daily Moisture Content (M), Biomass Fuel	weight %	20
Annual Average Moisture Content (M), Biomass Fuel	weight %	45
Control Efficiency (CE) - Partial Enclosure	%	70

C. Calculations

Emission Point	EU ID	Material Transfer Rates		PM Emission Estimates					
				PM		PM ₁₀		PM _{2.5}	
		(ton/hr)	(ton/yr)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Biomass Fuel Truck Unloading Shed - Truck Unloading	FUG-1	600	1,395,030	0.0239	0.0089	0.0113	0.0042	0.00171	0.00064
Transfer from Conveyor No. 3 to Conveyor No. 5	FUG-2	300	1,395,030	0.0119	0.0089	0.0056	0.0042	0.00085	0.00064
Transfer from Conveyor No. 4 to Conveyor No. 5	FUG-3	300	1,395,030	0.0119	0.0089	0.0056	0.0042	0.00085	0.00064
Transfer from Conveyor No. 5 to Conveyor No. 6	FUG-4	600	1,395,030	0.0239	0.0089	0.0113	0.0042	0.00171	0.00064
(will not operate concurrently with FUG-5 and FUG-16)									
Transfer from Conveyor No. 5 to Conveyor No. 7	FUG-5	600	1,395,030	0.0239	0.0089	0.0113	0.0042	0.00171	0.00064
(will not operate concurrently with FUG-4, FUG-6, and FUG-7)									
Transfer from Conveyor No. 6 to Stack No. 1	FUG-6	600	1,395,030	0.0239	0.0089	0.0113	0.0042	0.00171	0.00064
(Will not operate concurrently with FUG-5 and FUG-16)									
Transfer from Stack No. 1 to Storage Pile No. 1	FUG-7	600	1,395,030	0.0239	0.0089	0.0113	0.0042	0.00171	0.00064
(Will not operate concurrently with FUG-5 and FUG-16)									
Automated Reclaim from Storage Pile No. 1 - Transfer from Reclaimer to Conveyor No. 8	FUG-10	250	1,395,030	0.0099	0.0089	0.0047	0.0042	0.00071	0.00064
(Will not operate concurrently with FUG-11 and FG-12)									
(Will not operate concurrently with Storage Pile No. 2 or Sawdust Pile Reclaim)									
Manual Reclaim from Storage Pile No. 1 - Transfer from Dozer to Drag Chain Hopper	FUG-11	250	1,395,030	0.0099	0.0089	0.0047	0.0042	0.00071	0.00064
(Will not operate concurrently with FUG-10)									
(Will not operate concurrently with Storage Pile No. 2 or Sawdust Pile Reclaim)									
Manual Reclaim from Storage Pile No. 1 - Transfer from Drag Chain to Conveyor No. 8	FUG-12	250	1,395,030	0.0099	0.0089	0.0047	0.0042	0.00071	0.00064
(Will not operate concurrently with FUG-10)									
(Will not operate concurrently with Storage Pile No. 2 or Sawdust Pile Reclaim)									
Transfer from Conveyor No. 8 to Conveyor No. 9	FUG-13	250	1,395,030	0.0099	0.0089	0.0047	0.0042	0.00071	0.00064
(Will not operate concurrently with Storage Pile No. 2 or Sawdust Pile Reclaim)									
Transfer from Conveyor No. 9 to Conveyor No. 10	FUG-14	250	1,395,030	0.0099	0.0089	0.0047	0.0042	0.00071	0.00064
(Will not operate concurrently with FUG-15)									
(Will not operate concurrently with Storage Pile No. 2 or Sawdust Pile Reclaim)									
Transfer from Conveyor No. 9 to Conveyor No. 11	FUG-15	250	1,395,030	0.0099	0.0089	0.0047	0.0042	0.00071	0.00064
(Will not operate concurrently with FUG-14)									
(Will not operate concurrently with Storage Pile No. 2 or Sawdust Pile Reclaim)									
Transfer from Conveyor No. 7 to Stock Pile No. 1	FUG-16	600	1,395,030	0.0239	0.0089	0.0113	0.0042	0.00171	0.00064
(Will not operate concurrently with FUG-4, FUG-6 and FUG-7)									
Transfer from Trucks to Sawdust Pile	FUG-21	50	182,500	0.0020	0.0012	0.0009	0.0006	0.00014	0.00008
Manual Reclaim from Storage Pile No. 2 or Sawdust Pile - Transfer from Dozer to Drag Chain Hopper	FUG-24	250	1,395,030	0.0099	0.0089	0.0047	0.0042	0.00071	0.00064
(Will not operate concurrently with Storage Pile No. 1 Reclaim)									
Manual Reclaim from Storage Pile No. 2 or Sawdust Pile - Transfer from Drag Chain to Conveyor No. 14	FUG-25	250	182,500	0.0099	0.0012	0.0047	0.0006	0.00071	0.00008
(Will not operate concurrently with Storage Pile No. 1 Reclaim)									
Transfer from Conveyor No. 14 to Conveyor No. 10	FUG-26	250	1,395,030	0.0099	0.0089	0.0047	0.0042	0.00071	0.00064
(Will not operate concurrently with FUG-27)									
(Will not operate concurrently with Storage Pile No. 1 Reclaim)									
Transfer from Conveyor No. 14 to Conveyor No. 11	FUG-27	250	1,395,030	0.0099	0.0089	0.0047	0.0042	0.00071	0.00064
(Will not operate concurrently with FUG-26)									
(Will not operate concurrently with Storage Pile No. 1 Reclaim)									
Transfer from Conveyor No. 10 to Conveyor No. 12	FUG-28	250	1,395,030	0.0099	0.0089	0.0047	0.0042	0.00071	0.00064
(Will not operate concurrently with FUG-29)									
Transfer from Conveyor No. 11 to Conveyor No. 13	FUG-29	250	1,395,030	0.0099	0.0089	0.0047	0.0042	0.00071	0.00064
(Will not operate concurrently with FUG-28)									
Totals				0.2884	0.1717	0.1364	0.0812	0.0207	0.0123

**Table A-15. Gainesville Renewable Energy Center
Fugitive Emission Source PM/PM₁₀/PM_{2.5} Emission Estimates - Biomass Storage Piles
Storage Pile Wind Erosion**

A. Emission Estimation Methodology

Reference - EPA AP-42, Section 13.2.5, Industrial Wind Erosion, November 2006 - Equation (2).

$$EF = k \times \text{Sum}(P_i), \text{ sum is from } i \text{ to } N \text{ (Equation 2)}$$

where:

EF = emission factor (g/m²/yr)

k = particle size multiplier (unitless)

N = number of disturbances per year

P_i = erosion potential function based on fastest mile between disturbances (g/m²)

$$P = 58 (u^* - u_t^*)^2 + 25 (u^* - u_t^*) \quad (\text{equation 3})$$

P = 0 for u* < u_t*

u* is the friction velocity (= 0.053 times the fastest mile (m/s))

u_t* = threshold friction velocity (m/s) = 1.02 m/s for overburden from AP-42 Table 13.2.5-2

The fastest mile is defined as the fastest observed one mile of wind from Jacksonville, FL for the years 1951 - 1980.

B. Input Data

Parameter	Units	Value
Threshold friction velocity (u _t *)	m/s	1.02
Frequency of disturbance	dy/yr	365
Frequency of wind events resulting in wind erosion	dy/mo	1
Particle size multiplier (k), particle size <30 µm	-	1
Particle size multiplier (k), particle size <10 µm	-	0.5
Particle size multiplier (k), particle size <2.5 µm	-	0.075

C. Calculations

Erosion Potential Emission Factors

Month	Fastest Mile (mph)	Fastest Mile (m/s)	u* (m/s)	(u*-u _t *)	(u*-u _t *) ²	P _{PM} (g/m ²)	P _{PM10} (g/m ²)	P _{PM2.5} (g/m ²)
Jan	41	18.33	0.97	-0.05	0.002	0.00	0.00	0.00
Feb	52	23.25	1.23	0.21	0.045	7.91	3.95	0.59
Mar	44	19.67	1.04	0.02	0.001	0.59	0.30	0.04
Apr	48	21.46	1.14	0.12	0.014	3.73	1.86	0.28
May	62	27.72	1.47	0.45	0.202	22.92	11.46	1.72
Jun	76	33.98	1.80	0.78	0.609	54.87	27.43	4.11
Jul	49	21.90	1.16	0.14	0.020	4.68	2.34	0.35
Aug	52	23.25	1.23	0.21	0.045	7.91	3.95	0.59
Sep	82	36.66	1.94	0.92	0.852	72.47	36.23	5.43
Oct	72	32.19	1.71	0.69	0.470	44.43	22.22	3.33
Nov	60	26.82	1.42	0.40	0.161	19.39	9.70	1.45
Dec	62	27.72	1.47	0.45	0.2016	22.92	11.46	1.72
Maximum Erosion Potential						72.47	36.23	5.43
Annualized Emission Factor (gm/m²-yr)						8.61	4.30	0.65

Wind Erosion Emissions

Emission Source	EU ID	Total Area (m ²)	Disturbed Area (%)	Total (m ²)	Control Efficiency (%)	PM	PM ₁₀	PM _{2.5}
						(tpy)	(tpy)	(tpy)
Storage No. 1	FUG-8	21,000	10	2,100	50	0.0100	0.0050	0.00075
Stockpile No. 1	FUG-17	3,200	50	1,600	50	0.0076	0.0038	0.00057
Storage Pile No. 2	FUG-19	14,000	25	3,500	50	0.0166	0.0083	0.00125
Sawdust Pile	FUG-22	2,000	50	1,000	50	0.0047	0.0024	0.00036
Totals		40,200		8,200		0.0389	0.0195	0.00292

Assumptions:

Control efficiency for water spray assumed to be 50%.

Annual emissions based on annualized emission factor which assumes one wind erosion event per month.

**Table A-16. Gainesville Renewable Energy Center
Fugitive Emission Source PM/PM₁₀/PM_{2.5} Emission Estimates - Biomass Storage Piles
Dozer Operations on Storage Piles**

A. Emission Estimate Methodology

Reference - AP-42, Section 11.9, Western Surface Coal Mining - Table 11.9-1, EPA October 1998.

$$E_1 = ([5.7 \times (s)^{1.2}] / (M)^{1.3}) \times [1 - (CE / 100)] \times DZ$$

$$E_2 = ([5.7 \times (s)^{1.2}] / (M)^{1.3}) \times [1 - (CE / 100)] \times DZ \times (1 \text{ ton} / 2,000 \text{ lb})$$

$$E_3 = ([k \times 1.0 \times (s)^{1.5}] / (M)^{1.4}) \times [1 - (CE / 100)] \times DZ$$

$$E_4 = ([k \times 1.0 \times (s)^{1.5}] / (M)^{1.4}) \times [1 - (CE / 100)] \times DZ \times (1 \text{ ton} / 2,000 \text{ lb})$$

where:

E_1 = PM hourly emission rate (lb/hr)

E_2 = PM annual emission rate (ton/yr)

s = material silt content (%)

M = material moisture content (%)

CE = control efficiency (%)

DZ = number of dozers

E_3 = PM₁₀/PM_{2.5} hourly emission rate (lb/hr)

E_4 = PM₁₀/PM_{2.5} annual emission rate (ton/yr)

k = particle size scaling factor

B. Input Data

Parameter	Units	Value
Material silt content (s)	%	0.20
Material moisture content (M)	%	20
Control Efficiency (CE) - watering, as necessary	%	50
Number of dozers		3
Particle size scaling factor, particle size <10 µm	-	0.75
Particle size scaling factor, particle size <2.5 µm	-	0.105

C. Calculations

Emission Point	EU ID	Operating Hours		PM Emission Estimates					
				PM		PM ₁₀		PM _{2.5}	
		(hrs/day)	(hrs/yr)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Dozer Operations on Storage Pile No. 1	FUG-9	24	8,760	0.025	0.11	0.0015	0.0066	0.00021	0.00093
Dozer Operations on Stock Pile No. 1	FUG-18	24	8,760	0.025	0.11	0.0015	0.0066	0.00021	0.00093
Dozer Operations on Storage Pile No. 2	FUG-20	24	8,760	0.025	0.11	0.0015	0.0066	0.00021	0.00093
Dozer Operations on Sawdust Pile	FUG-23	24	8,760	0.025	0.11	0.0015	0.0066	0.00021	0.00093
Totals				0.10	0.44	0.0061	0.027	0.00085	0.0037

Table A-17. Gainesville Renewable Energy Center
Fugitive Emission Source PM/PM₁₀/PM_{2.5} Emission Estimates - Biomass Fuel Transfer Operations
Biomass Fuel Truck Travel on Paved Facility Roadways

A. Emission Estimate Methodology

Reference - AP-42, Section 13.2.1, Paved Roads - Equation (1), EPA November 2006.

$$E_1 = (k \times [(sL / 2)^{0.65}] \times [(W / 3)^{1.5}] - C) \times [(1 - (P / 4N)) \times [1 - (CE / 100)]) \times VMT_1$$

$$E_2 = (k \times [(sL / 2)^{0.65}] \times [(W / 3)^{1.5}] - C) \times [(1 - (P / 4N)) \times [1 - (CE / 100)]) \times VMT_2 \times (1 \text{ ton} / 2,000 \text{ lb})$$

where:

E_1 = hourly emission rate (lb/hr)

E_2 = annual emission rate (ton/yr)

k = particle size multiplier (lb/VMT)

sL = road surface silt loading (g/m²)

W = average weight of vehicles (tons)

C = vehicle fleet exhaust, brake and tire wear (lb/VMT)

P = number of "wet" days/yr with 0.01 inches of precipitation

N = number of days in averaging period

CE = control efficiency (%)

VMT₁ = vehicle miles traveled (veh-mi/hr) = round-trip distance x number of trucks/hr

VMT₂ = vehicle miles traveled (veh-mi/yr) = round-trip distance x number of trucks/yr

B. Input Data

Parameter	Units	Value
Particle size multiplier (k), particle size <30 µm	lb/VMT	0.082
Particle size multiplier (k), particle size <10 µm	lb/VMT	0.016
Particle size multiplier (k), particle size <2.5 µm	lb/VMT	0.0024
Road Surface Silt Loading (sL), Table 13.2.1-3	g/m ²	0.6
Average Truck Weight (Average of empty and full truck weights)	tons	25
Fleet exhaust, brake and tire wear (C), particle size <30 µm	lb/VMT	0.00047
Fleet exhaust, brake and tire wear (c), particle size <10 µm	lb/VMT	0.00047
Fleet exhaust, brake and tire wear (c), particle size <2.5 µm	lb/VMT	0.00036
Number of "Wet" Days Per Year (P), Figure 13.2.1-2	-	115
Number of Days in Averaging Period (N)	-	365
Control Efficiency (CE) - Watering & Sweeping, as necessary	%	75
Round-Trip Distance - Biomass Fuel Trucks	mi	1.8
Round-Trip Distance - By-Product & Miscellaneous Trucks	mi	2.0

C. Calculations

Emission Point	EU ID	Number of Trucks		PM Emission Estimates					
				PM		PM ₁₀		PM _{2.5}	
		(trucks/hr)	(trucks/yr)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Biomass Fuel Truck Travel on Facility Paved Roadways	FUG-30	24	55,801	9.1	10.6	1.8	2.1	0.26	0.31
By-Product & Miscellaneous Truck Travel on Facility Paved Roadways	FUG-31	1	2,080	0.30	0.4	0.06	0.08	0.009	0.011
Totals				9.4	11.0	1.8	2.1	0.27	0.32

**Table A-18. Gainesville Renewable Energy Center
Fugitive Emission Source PM/PM₁₀/PM_{2.5} Emission Estimates
Construction Excavation and Fill Activity**

A. Emission Estimate Methodology

Reference - AP-42, Section 13.2.4, Aggregate Handling and Storage Piles - Equation (1), EPA November 2006.

$$E = k \times (0.0032) \times [(U / 5)^{1.3}] / (M / 2)^{1.4} \times [1 - (CE / 100)] \times T \times (1 \text{ ton} / 2,000 \text{ lb})$$

$$T = MD \times MT$$

where:

E = emission rate (tons)

k = particle size multiplier

U = mean wind speed, miles per hour (mph)

M = material moisture content, weight percent (%)

CE = control efficiency (%)

T = material transfer rate (tons)

MD = material delivered to site (tons)

MT = number of material transfers

B. Input Data

Parameter	Units	Value
Fill Material Density, Typical	lb/ft ³	100
Fill Material Delivered to Site (MD)	yd ³	40,000
	ft ³	1,080,000
	tons	54,000
Number of Material Transfers (MT)	-	2
Particle Size Multiplier (k), particle size <30 µm	-	0.74
Particle Size Multiplier (k), particle size <10 µm	-	0.35
Particle Size Multiplier (k), particle size <2.5 µm	-	0.053
Mean Wind Speed (U)	mph	6.5
Average Moisture Content (M), Fill Material	weight %	8
Control Efficiency, Watering (CE)	%	50

C. Calculations

Emission Point	Material Transfer (tons)	PM Emission Estimates		
		PM (tons)	PM ₁₀ (tons)	PM _{2.5} (tons)
Construction Excavation and Fill Activity	108,000	0.013	0.0061	0.00092

Table A-19. Gainesville Renewable Energy Center
Fugitive Emission Source PM/PM₁₀/PM_{2.5} Emission Estimates
Grading and Earth Moving Activity

A. Emission Estimate Methodology

Reference - AP-42, Section 11.9, Western Surface Coal Mining - Table 11.9-1, EPA July 1998.

$$E_1 = 0.040 \times (S^{2.5}) \times \text{VMT} \times (1 \text{ ton} / 2,000 \text{ lb})$$

$$E_2 = 0.051 \times (S^{2.0}) \times 0.60 \times \text{VMT} \times (1 \text{ ton} / 2,000 \text{ lb})$$

$$E_3 = 0.051 \times (S^{2.0}) \times 0.031 \times \text{VMT} \times (1 \text{ ton} / 2,000 \text{ lb})$$

$$\text{VMT} = S \times T \times N$$

where:

E_1 = PM emission rate; tons

S = mean vehicle speed, mph

VMT = vehicle miles traveled

E_2 = PM₁₀ emission rate; tons

E_3 = PM_{2.5} emission rate; tons

T = total operating hours; hrs/grading equipment

N = number of grading equipment

B. Input Data

Parameter	Units	Value
Construction Activity Duration	days	120
Mean Construction Vehicle Speed, Typical	mph	2.0
Number of Construction Equipment	-	15
Construction Equipment Operating Hours	hrs/dy	10
	hrs - total	1,200

C. Calculations

Emission Point	Vehicle Miles Traveled (VMT)	PM Emission Estimates		
		PM (tons)	PM ₁₀ (tons)	PM _{2.5} (tons)
Construction Grading and Earth Moving Activity	36,000	4.1	1.7	0.89

**Table A-20. Gainesville Renewable Energy Center
Fugitive Emission Source PM/PM₁₀/PM_{2.5} Emission Estimates
Construction Truck Travel on Unpaved Facility Roadways**

A. Emission Estimate Methodology

Reference - AP-42, Section 13.2.2, Unpaved Roads - Equation (1a), EPA November 2006.

$$E = (k \times [(s / 12)^a] \times [(W / 3)^b] \times [1 - (CE / 100)] \times VMT \times (1 \text{ ton} / 2,000 \text{ lb})$$

$$TM = SOIL + MISC$$

$$VMT = (TM / LOAD) \times L$$

where:

E = emission rate (tons)
 k = particle size multiplier (lb/VMT)
 s = surface material silt content (%)
 a = particle size constant
 W = average weight of construction trucks (tons)
 b = particle size constant
 CE = control efficiency (%)
 SOIL = soil (fill) material handled (tons)
 MISC = miscellaneous material handled (tons)
 TM = total material handled (tons)
 VMT = vehicle miles traveled (veh-mi)
 LOAD = average truck load (tons)
 L = average travel distance (miles)

B. Input Data

Parameter	Units	Value
Particle Size Multiplier (k), particle size <30 µm	lb/VMT	4.9
Particle Size Multiplier (k), particle size <10 µm	lb/VMT	1.5
Particle Size Multiplier (k), particle size <2.5 µm	lb/VMT	0.15
Surface Material Silt Content (s), Table 13.2.2-1	%	8.5
Particle Size Multiplier (a), particle size <30 µm	-	0.7
Particle Size Multiplier (a), particle size <10 µm	-	0.9
Particle Size Multiplier (a), particle size <2.5 µm	-	0.9
Average Weight of Construction Trucks (W)	tons	30
Particle Size Multiplier (b), particle size <30 µm	-	0.45
Particle Size Multiplier (b), particle size <10 µm	-	0.45
Particle Size Multiplier (b), particle size <2.5 µm	-	0.45
Control Efficiency (CE) - Watering, as necessary	%	50
Soil (Fill) Material Handled (SOIL)	tons	108,000
Miscellaneous Material Handled (MISC)	tons	5,400
Average Truck Load (LOAD)	tons	20
Average Truck Travel Distance (L)	mi	2.0

C. Calculations

Emission Point	Vehicle Miles Traveled (VMT)	PM Emission Estimates		
		PM (tons)	PM ₁₀ (tons)	PM _{2.5} (tons)
Construction Truck Travel on Facility Unpaved Roads	11,340	30.8	8.8	0.88

**Table A-21. Gainesville Renewable Energy Center
Fugitive Emission Source PM/PM₁₀/PM_{2.5} Emission Estimates
Construction Wind Erosion**

A. Emission Estimation Methodology

Reference - EPA AP-42, Section 13.2.5, Industrial Wind Erosion, November 2006 - Equation (2).

$$EF = k \times \text{Sum}(P_i), \text{ sum is from } i \text{ to } N \text{ (Equation 2)}$$

where:

EF = emission factor (g/m²/yr)

k = particle size multiplier (unitless)

N = number of disturbances per year

P_i = erosion potential function based on fastest mile between disturbances (g/m²)

$$P = 58 (u^* - u_t^*)^2 + 25 (u^* - u_t^*) \quad (\text{equation 3})$$

$$P = 0 \text{ for } u^* < u_t^*$$

u* is the friction velocity (= 0.053 times the fastest mile (m/s))

u_t* = threshold friction velocity (m/s) = 1.02 m/s for overburden from AP-42 Table 13.2.5-2

The fastest mile is defined as the fastest observed one mile of wind from Jacksonville, FL for the years 1951 - 1980.

B. Input Data

Parameter	Units	Value
Threshold friction velocity (u _t *)	m/s	1.02
Frequency of disturbance	dy/yr	365
Frequency of wind events resulting in wind erosion	dy/mo	1
Particle size multiplier (k), particle size <30 µm	-	1
Particle size multiplier (k), particle size <10 µm	-	0.5
Particle size multiplier (k), particle size <2.5 µm	-	0.075

C. Calculations

Erosion Potential Emission Factors

Month	Fastest Mile (mph)	Fastest Mile (m/s)	u* (m/s)	(u*-u _t *)	(u*-u _t *) ²	P _{PM} (g/m ²)	P _{PM10} (g/m ²)	P _{PM2.5} (g/m ²)
Jan	41	18.33	0.97	-0.05	0.002	0.00	0.00	0.00
Feb	52	23.25	1.23	0.21	0.045	7.91	3.95	0.59
Mar	44	19.67	1.04	0.02	0.001	0.59	0.30	0.04
Apr	48	21.46	1.14	0.12	0.014	3.73	1.86	0.28
May	62	27.72	1.47	0.45	0.202	22.92	11.46	1.72
Jun	76	33.98	1.80	0.78	0.609	54.87	27.43	4.11
Jul	49	21.90	1.16	0.14	0.020	4.68	2.34	0.35
Aug	52	23.25	1.23	0.21	0.045	7.91	3.95	0.59
Sep	82	36.66	1.94	0.92	0.852	72.47	36.23	5.43
Oct	72	32.19	1.71	0.69	0.470	44.43	22.22	3.33
Nov	60	26.82	1.42	0.40	0.161	19.39	9.70	1.45
Dec	62	27.72	1.47	0.45	0.2016	22.92	11.46	1.72
Maximum Erosion Potential						72.47	36.23	5.43
Annualized Emission Factor (gm/m²-yr)						8.61	4.30	0.65

Wind Erosion Emissions

Emission Source	Total Area (m ²)	Disturbed Area (%)	Total (m ²)	Control Efficiency (%)	PM	PM ₁₀	PM _{2.5}
					tons	(tons)	(tons)
Construction	263,044	5	13,152	50	0.062	0.031	0.0047

Assumptions:

Control efficiency for water spray assumed to be 50%.

Annual emissions based on annualized emission factor which assumes one wind erosion event per month.

Total area that will be disturbed during construction is approximately 65 acres.

**Table A-22. Gainesville Renewable Energy Center
Construction Diesel Engine Criteria Pollutant Emission Estimates**

A. Emission Estimate Methodology

References - NSPS Subpart IIII (NO_x, CO, VOC, and PM) and Mass Balance (SO₂).

$$E = EF \times P \times N \times OP \times (1 \text{ ton} / 2,000 \text{ lb})$$

$$EFSO_2 = FOFLOW \times FODENSITY \times (FOSULFUR / 100) \times (1 / P) \times (2 \text{ lb SO}_2 / \text{lb S}) \times (453.59 \text{ g} / \text{lb})$$

where:

E = annual emission rate; tons per year (ton/yr)
 EF = emission factor; grams per brake horsepower-hour (g/bhp-hr)
 P = engine output; brake horsepower-hour (bhp-hr)
 N = number of construction equipment diesel engines
 OP = annual operating hours; hours per year (hr/yr)
 EFSO₂ = SO₂ emission factor; grams per brake horsepower hour (g/bhp-hr)
 FOFLOW = ULSD fuel oil flow rate; gallons per hour (gal/hr)
 FODENSITY = ULSD fuel oil density; pounds per gallon (lb/gal)
 FOSULFUR = ULSD fuel oil sulfur content; weight percent (weight %)

B. Input Data

Diesel Engine Data	Units	Construction Equipment Diesel Engines
Diesel Engine Output, Typical (P)	bhp	500
	kW	373
Construction Activity Duration	days	550
Construction Equipment Operating Hours, Per Engine, (OP)	hrs/dy	5
	hrs - total	2,750
Number of Construction Equipment Diesel Engines ¹ (N)	-	23
Engine ULSD Fuel Oil Flow Rate (FOFLOW)	gal/hr	198
	gal/dy	990
	gal - total	544,500
EPA Nonroad Tier, Assumed (EF)	-	2
ULSD Fuel Oil Sulfur Content (FOSULFUR)	weight %	0.0015
ULSD Fuel Oil Density (FODENSITY)	lb/gal	7.08

C. Calculations

Criteria Pollutants	Construction Equipment Diesel Engines
NO_x g/bhp-hr ² tons	3.4
	117.1
CO g/bhp-hr ton/yr	2.6
	90.6
VOC g/bhp-hr ³ ton/yr	1.4
	50.2
PM/PM₁₀/PM_{2.5} g/bhp-hr ton/yr	0.15
	5.2
SO₂ g/bhp-hr ⁴ ton/yr	0.038
	1.3

¹ Total estimated number of diesel engines; conservatively assumed that all equipment will be in use at the same time.

² NO_x emission rate assumed equal to 70% of Subpart IIII NMHC + NO_x emission standard.

³ VOC emission rate assumed equal to 30% of Subpart IIII NMHC + NO_x emission standard.

⁴ Based on use of ULSD fuel oil.

Table A-23A. Gainesville Renewable Energy Center
As-Received Biomass Fuel Composition - Summary

Parameter ¹	Wood Type	Hardwoods			Slash Pine			Sand Pine		
	Units	Minimum	Maximum	Average	Minimum	Maximum	Average	Minimum	Maximum	Average
Moisture	weight %	41.27	62.52	52.89	43.64	60.86	51.77	47.49	59.67	53.58
Ash	weight %	0.59	0.76	0.67	0.14	0.25	0.19	0.32	0.38	0.35
Carbon	weight %	18.56	29.47	22.86	18.69	29.45	24.21	19.58	25.58	22.58
Sulfur	weight %	0.006	0.014	0.011	0.006	0.012	0.008	0.005	0.009	0.007
Nitrogen	weight %	0.04	0.13	0.08	0.05	0.11	0.08	0.11	0.12	0.12
Heat Content, HHV	Btu/lb	3,123	4,861	3,898	3,387	4,765	4,155	3,621	4,721	4,171
Chlorine	ppmw	16	30	23	11	33	17	9	16	13
Fluorine	ppmw	42	110	69	29	82	57	180	191	186
Antimony	ppmw	0.20	0.47	0.33	0.25	0.53	0.37	0.55	0.60	0.58
Arsenic	ppmw	0.10	0.47	0.24	0.13	0.53	0.31	0.55	0.60	0.58
Beryllium	ppmw	0.014	0.047	0.028	0.018	0.053	0.034	0.055	0.060	0.058
Cadmium	ppmw	0.014	0.056	0.035	0.017	0.029	0.023	0.046	0.067	0.057
Chromium	ppmw	0.68	1.20	0.94	0.16	3.70	1.77	2.00	3.60	2.80
Cobalt	ppmw	0.020	0.110	0.080	0.025	0.140	0.057	0.730	2.300	1.515
Lead	ppmw	0.036	0.120	0.071	0.045	0.130	0.083	0.110	0.140	0.125
Manganese	ppmw	36	37	37	0	33	13	15	22	19
Mercury	ppmw	0.004	0.006	0.005	0.004	0.006	0.005	0.006	0.006	0.006
Nickel	ppmw	0.31	0.61	0.46	0.37	1.50	0.88	1.10	1.90	1.50
Selenium	ppmw	0.29	0.83	0.48	0.38	0.80	0.60	0.32	0.57	0.45

Parameter ¹	Wood Type	Loblolly Pine			Data Summary - All Wood Types			BFB Boiler Design Wood Mix	
	Units	Minimum	Maximum	Average	Minimum	Maximum	Average	Dry	As-Received
Moisture	weight %	57.32	59.66	58.49	41.27	62.52	53.63	0.00	50.00
Ash	weight %	0.24	0.39	0.32	0.14	0.76	0.45	0.98	0.49
Carbon	weight %	19.09	20.15	19.62	18.56	29.47	22.71	48.95	24.48
Sulfur	weight %	0.006	0.008	0.007	0.0050	0.014	0.0085	0.018	0.0090
Nitrogen	weight %	0.09	0.11	0.10	0.040	0.13	0.089	0.18	0.090
Heat Content, HHV	Btu/lb	3,548	3,787	3,668	3,123	4,861	3,999	8,529	4,265
Chlorine	ppmw	15	18	17	9	33	18	40	20
Fluorine	ppmw	117	117	117	29	191	205		
Antimony	ppmw	0.45	0.54	0.50	0.20	0.60	0.42		
Arsenic	ppmw	0.45	0.54	0.50	0.10	0.60	0.37		
Beryllium	ppmw	0.045	0.054	0.050	0.014	0.060	0.039		
Cadmium	ppmw	0.025	0.051	0.038	0.014	0.067	0.043		
Chromium	ppmw	1.00	1.20	1.10	0.16	3.70	2.61		
Cobalt	ppmw	0.250	2.300	1.275	0.020	2.300	0.550		
Lead	ppmw	0.059	0.110	0.085	0.036	0.140	0.087	0.200	0.100
Manganese	ppmw	5	47	26	0	47	37		
Mercury	ppmw	0.005	0.005	0.005	0.004	0.006	0.005	0.011	0.006
Nickel	ppmw	0.59	0.63	0.61	0.31	1.90	1.32		
Selenium	ppmw	0.44	0.47	0.46	0.29	0.83	0.51		

¹ As-received

**Table A-23B. Gainesville Renewable Energy Center
As-Received Biomass Fuel Composition - Hardwoods**

Parameter ^{1,2}	Sample ID	AR-007	AR-009	AR-011	Data Summary			
	Units				Minimum	Maximum	Average	Median
Moisture	weight %	54.89	62.52	41.27	41.27	62.52	52.89	54.89
Ash	weight %	0.67	0.59	0.76	0.59	0.76	0.67	0.67
Carbon	weight %	20.56	18.56	29.47	18.56	29.47	22.86	20.560
Sulfur	weight %	0.014	0.006	0.014	0.006	0.014	0.011	0.01
Nitrogen	weight %	0.13	0.04	0.08	0.04	0.13	0.08	0.08
Heat Content, HHV	Btu/lb	3,711	3,123	4,861	3,123	4,861	3,898	3,711
Chlorine	ppmw	16	30	23	16	30	23	23
Fluorine	ppmw	110	42	55	42	110	69	55
Antimony	ppmw	0.47	0.20	0.31	0.20	0.47	0.33	0.31
Arsenic	ppmw	0.47	0.10	0.16	0.10	0.47	0.24	0.16
Beryllium	ppmw	0.047	0.014	0.023	0.014	0.047	0.028	0.023
Cadmium	ppmw	0.120	0.014	0.056	0.014	0.056	0.035	0.035
Chromium	ppmw	1.20	0.68	12.0	0.68	1.20	0.94	0.94
Cobalt	ppmw	0.110	0.020	0.110	0.020	0.110	0.080	0.110
Lead	ppmw	0.120	0.036	0.057	0.036	0.120	0.071	0.057
Manganese	ppmw	37	36	190	36	37	37	37
Mercury	ppmw	0.0050	0.0040	0.0060	0.0040	0.0060	0.0050	0.0050
Nickel	ppmw	0.61	0.31	5.90	0.31	0.61	0.46	0.46
Selenium	ppmw	0.29	0.31	0.83	0.29	0.83	0.48	0.31

¹ As-received

² Values shown with strikethrough font are outliers and were not used in data summary statistics

**Table A-23C. Gainesville Renewable Energy Center
Biomass Fuel Composition - Slash Pine**

Parameter ^{1,2}	Sample ID	AR-001	AR-004	AR-010	AR-012	Data Summary			
	Units					Minimum	Maximum	Average	Median
Moisture	weight %	60.86	49.38	43.64	53.20	43.64	60.86	51.77	60.86
Ash	weight %	0.14	0.19	1.06	0.25	0.14	0.25	0.19	0.19
Carbon	weight %	18.69	24.37	29.45	24.34	18.69	29.45	24.21	18.69
Sulfur	weight %	0.007	0.006	0.012	0.007	0.006	0.012	0.008	0.007
Nitrogen	weight %	0.08	0.11	0.06	0.05	0.05	0.11	0.08	0.08
Heat Content, HHV	Btu/lb	3,387	4,376	4,765	4,093	3,387	4,765	4,155	3,387
Chlorine	ppmw	12	11	12	33	11	33	17	12
Fluorine	ppmw	74	82	43	29	29	82	57	74
Antimony	ppmw	0.41	0.53	0.30	0.25	0.25	0.53	0.37	0.41
Arsenic	ppmw	0.41	0.53	0.15	0.13	0.13	0.53	0.31	0.41
Beryllium	ppmw	0.041	0.053	0.022	0.018	0.018	0.053	0.034	0.041
Cadmium	ppmw	0.029	0.026	0.021	0.017	0.017	0.029	0.023	0.029
Chromium	ppmw	2.10	0.16	3.70	1	0.16	3.70	1.77	2.10
Cobalt	ppmw	0.034	0.140	0.030	0.025	0.025	0.140	0.057	0.034
Lead	ppmw	0.100	0.130	0.055	0.045	0.045	0.130	0.083	0.100
Manganese	ppmw	12	0.27	7.4	33	0	33	13	12
Mercury	ppmw	0.004	0.005	0.006	0.005	0.004	0.006	0.005	0.004
Nickel	ppmw	1.10	0.53	1.50	0.37	0.37	1.50	0.88	1.10
Selenium	ppmw	0.38	0.59	0.80	0.61	0.38	0.80	0.60	0.38

¹ As-received

² Values shown with strikethrough font are outliers and were not used in data summary statistics

**Table A-23D. Gainesville Renewable Energy Center
Biomass Fuel Composition - Sand Pine**

Parameter ¹	Sample ID	AR-003	AR-006	Data Summary			
	Units			Minimum	Maximum	Average	Median
Moisture	weight %	59.67	47.49	47.49	59.67	53.58	59.67
Ash	weight %	0.32	0.38	0.32	0.38	0.35	0.32
Carbon	weight %	19.58	25.58	19.58	25.58	22.58	19.58
Sulfur	weight %	0.009	0.005	0.005	0.009	0.007	0.009
Nitrogen	weight %	0.11	0.12	0.11	0.12	0.12	0.11
Heat Content, HHV	Btu/lb	3,621	4,721	3,621	4,721	4,171	3,621
Chlorine	ppmw	16	9	9	16	13	16
Fluorine	ppmw	191	180	180	191	186	191
Antimony	ppmw	0.55	0.60	0.55	0.60	0.58	0.55
Arsenic	ppmw	0.55	0.60	0.55	0.60	0.58	0.55
Beryllium	ppmw	0.055	0.060	0.055	0.060	0.058	0.055
Cadmium	ppmw	0.046	0.067	0.046	0.067	0.057	0.046
Chromium	ppmw	2.00	3.60	2.00	3.60	2.80	2.00
Cobalt	ppmw	2.300	0.730	0.730	2.300	1.515	2.300
Lead	ppmw	0.140	0.110	0.110	0.140	0.125	0.140
Manganese	ppmw	22	15.00	15	22	19	22
Mercury	ppmw	0.006	0.006	0.006	0.006	0.006	0.006
Nickel	ppmw	1.10	1.90	1.10	1.90	1.50	1.10
Selenium	ppmw	0.32	0.57	0.32	0.57	0.45	0.32

¹ As-received

**Table A-23E. Gainesville Renewable Energy Center
Biomass Fuel Composition - Loblolly Pine**

Parameter ^{1,2}	Sample ID	AR-002	AR-005	Data Summary			
	Units			Minimum	Maximum	Average	Median
Moisture	weight %	57.32	59.66	57.32	59.66	58.49	57.32
Ash	weight %	0.24	0.39	0.24	0.39	0.32	0.24
Carbon	weight %	20.15	19.09	19.09	20.15	19.62	20.15
Sulfur	weight %	0.006	0.008	0.006	0.008	0.007	0.006
Nitrogen	weight %	0.11	0.09	0.09	0.11	0.10	0.11
Heat Content, HHV	Btu/lb	3,787	3,548	3,548	3,787	3,668	3,787
Chlorine	ppmw	18	15	15	18	17	18
Fluorine	ppmw	117	1,331	117	117	117	117
Antimony	ppmw	0.54	0.45	0.45	0.54	0.50	0.54
Arsenic	ppmw	0.54	0.45	0.45	0.54	0.50	0.54
Beryllium	ppmw	0.054	0.045	0.045	0.054	0.050	0.054
Cadmium	ppmw	0.051	0.025	0.025	0.051	0.038	0.051
Chromium	ppmw	1.00	1.20	1.00	1.20	1.10	1.00
Cobalt	ppmw	2.300	0.250	0.250	2.300	1.275	2.300
Lead	ppmw	0.059	0.110	0.059	0.110	0.085	0.059
Manganese	ppmw	47	5.40	5	47	26	47
Mercury	ppmw	0.005	0.005	0.005	0.005	0.005	0.005
Nickel	ppmw	0.59	0.63	0.59	0.63	0.61	0.59
Selenium	ppmw	0.47	0.44	0.44	0.47	0.46	0.47

¹ As-received

² Values shown with strikeout font are outliers and were not used in data summary statistics

**Table A-23D. Gainesville Renewable Energy Center
Biomass Fuel Composition - Sand Pine**

Parameter ¹	Sample ID	AR-003	AR-006	Data Summary			
	Units			Minimum	Maximum	Average	Median
Moisture	weight %	59.67	47.49	47.49	59.67	53.58	59.67
Ash	weight %	0.32	0.38	0.32	0.38	0.35	0.32
Carbon	weight %	19.58	25.58	19.58	25.58	22.58	19.58
Sulfur	weight %	0.009	0.005	0.005	0.009	0.007	0.009
Nitrogen	weight %	0.11	0.12	0.11	0.12	0.12	0.11
Heat Content, HHV	Btu/lb	3,621	4,721	3,621	4,721	4,171	3,621
Chlorine	ppmw	16	9	9	16	13	16
Fluorine	ppmw	191	180	180	191	186	191
Antimony	ppmw	0.55	0.60	0.55	0.60	0.58	0.55
Arsenic	ppmw	0.55	0.60	0.55	0.60	0.58	0.55
Beryllium	ppmw	0.055	0.060	0.055	0.060	0.058	0.055
Cadmium	ppmw	0.046	0.067	0.046	0.067	0.057	0.046
Chromium	ppmw	2.00	3.60	2.00	3.60	2.80	2.00
Cobalt	ppmw	2.300	0.730	0.730	2.300	1.515	2.300
Lead	ppmw	0.140	0.110	0.110	0.140	0.125	0.140
Manganese	ppmw	22	15.00	15	22	19	22
Mercury	ppmw	0.006	0.006	0.006	0.006	0.006	0.006
Nickel	ppmw	1.10	1.90	1.10	1.90	1.50	1.10
Selenium	ppmw	0.32	0.57	0.32	0.57	0.45	0.32

¹ As-received

**Table A-24. Gainesville Renewable Energy Center
Fuel Use**

A. BFB Boiler

Fuel	Annual Operating Hours (hrs/yr)	Heat Content, HHV		Maximum Heat Input (10 ⁶ Btu/hr, HHV)	Maximum Heat Input (10 ⁶ Btu/yr, HHV)	Biomass		Natural Gas ¹	
		Units	Value			Hourly (ton/hr)	Annual (ton/yr)	Hourly (10 ⁶ ft ³ /hr)	Annual (10 ⁶ ft ³ /yr)
Biomass (as received)	8,760	Btu/lb	4,264	1,358	11,896,080	159.3	1,395,030		
Natural Gas ¹	280	Btu/ft ³	1,050	341	46,000			0.324	43.81

B. Emergency Generator Diesel Engine (750 kW)

Fuel	Annual Operating Hours (hrs/yr)	Heat Content, HHV		Maximum Heat Input (10 ⁶ Btu/hr, HHV)	Maximum Heat Input (10 ⁶ Btu/yr, HHV)	ULSD	
		Units	Value			Hourly (10 ³ gal/hr)	Annual (10 ³ gal/yr)
Ultra Low Sulfur Diesel (ULSD)	500	Btu/gal	138,000	2.0	1,014	0.015	7.350

C. Emergency Firewater Pump Diesel Engine (300 HP)

Fuel	Annual Operating Hours (hrs/yr)	Heat Content, HHV		Maximum Heat Input (10 ⁶ Btu/hr, HHV)	Maximum Heat Input (10 ⁶ Btu/yr, HHV)	ULSD	
		Units	Value			Hourly (10 ³ gal/hr)	Annual (10 ³ gal/yr)
Ultra Low Sulfur Diesel (ULSD)	500	Btu/gal	138,000	5.1	2,539	0.037	18.400

¹ Only used during startups. Basis: 20 cold startups per year, 14 hours per cold startup, and 2,300 x 10⁶ Btu/cold startup event

**Table A-25. Gainesville Renewable Energy Center
Point Source Stack Parameters**

Point Emission Source	Emission ID	Height		Diameter		Temperature		Area		Standard Flow Rate ¹		Actual Flow Rate		Velocity	
		(ft)	(m)	(ft)	(m)	(°F)	(K)	(ft ²)	(m ²)	(ft ³ /min)	(m ³ /min)	(ft ³ /min)	(m ³ /min)	(ft/sec)	(m/s)
Screen/Hog Building Baghouse	P-1	50.0	15.24	3.25	0.99	77	298.2	8.30	0.77	35,397	1,002.3	36,000	1,019.4	72.33	22.04
BFB Boiler Fuel Bin Vent Filter No. 1	P-2	100.0	30.48	1.5	0.46	77	298.2	1.77	0.16	3,933	111.4	4,000	113.3	37.73	11.50
BFB Boiler Fuel Bin Vent Filter No. 2	P-3	100.0	30.48	1.0	0.30	77	298.2	0.79	0.07	1,967	55.7	2,000	56.6	42.44	12.94
Fly Ash Silo Vacuum Blowers (each)	P-4, P-5	70.0	21.34	1.5	0.46	100	310.9	1.77	0.16	3,300	93.5	3,500	99.1	33.01	10.06
Fly Ash Silo Bin Vent Filter	P-6	77.0	23.47	1.0	0.30	100	310.9	0.79	0.07	1,886	53.4	2,000	56.6	42.44	12.94
BFB Boiler - 100%	P-7A	230.0	70.10	12.00	3.66	310	427.6	113.10	10.51	357,125	10,112.7	520,600	14,741.8	76.72	23.38
BFB Boiler - 70%	P-7B	230.0	70.10	12.00	3.66	302	423.2	113.10	10.51	249,477	7,064.4	359,900	10,191.2	53.04	16.17
Cooling Tower Cells (Per Cell)	P-8A thru P-8D	53.1	16.20	36.75	11.20	93	307.0	1,060.73	98.54	2,315,503	65,567.8	2,425,000	68,668.4	38.10	11.61
Emergency Generator Diesel Engine (Kohler Model 500REOZVB or equiv.)	P-9	15.0	4.57	0.67	0.20	893	751.5	0.35	0.03	1,523	43.1	3,899	110.4	186.16	56.74
Emergency Fire Water Pump Diesel Engine (Caterpillar C9 ACERT 275 BHP or equiv.)	P-10	10.0	3.05	0.50	0.15	855	730.4	0.20	0.02	904	25.6	2,250	63.7	190.99	58.21
Sorbent Silo Bin Vent Filter	P-11	51.0	15.54	1.0	0.30	100	310.9	0.79	0.07	1,886	53.4	2,000	56.6	42.44	12.94

¹ At 68°F.

**Table A-26. Gainesville Renewable Energy Center
Fugitive Volume Source Release Parameters**

Fugitive Emission Source	EU ID	Release Height		Volume Source Parameters								
				Length of Side		Vertical Dimension		Initial Lateral Dimension, S _y		Initial Vertical Dimension, S _z		PM ₁₀
		(ft)	(m)	(ft)	(m)	(ft)	(m)	(ft)	(m)	(ft)	(m)	(g/s)
Biomass Fuel Truck Unloading Shed - Truck Unloading	FUG-1	10.0	3.0	20.00	6.10	20.0	6.10	4.65	1.42	4.65	1.418	0.00142
Transfer from Conveyor No. 3 to Conveyor No. 5	FUG-2	3.5	1.1	2.00	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00071
Transfer from Conveyor No. 4 to Conveyor No. 5	FUG-3	3.5	1.1	2.00	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00071
Transfer from Conveyor No. 5 to Conveyor No. 6 (will not operate concurrently with FUG-5 and FUG-16)	FUG-4	45.5	13.9	2.00	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00142
Transfer from Conveyor No. 5 to Conveyor No. 7 (will not operate concurrently with FUG-4, FUG-6, and FUG-7)	FUG-5	57.5	17.5	2.00	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00142
Transfer from Conveyor No. 6 to Stack No. 1 (Will not operate concurrently with FUG-5 and FUG-16)	FUG-6	67.1	20.5	2.00	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00142
Transfer from Stack No. 1 to Storage Pile No. 1 (Will not operate concurrently with FUG-5 and FUG-16)	FUG-7	42.3	12.9	2.00	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00142
Automated Reclaim from Storage Pile No. 1 - Transfer from Reclaimer to Conveyor No. 8 (Will not operate concurrently with FUG-11 and FG-12) (Will not operate concurrently with Storage Pile No. 2 or Sawdust Pile Reclaim)	FUG-10	3.5	1.1	2.00	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00059
Manual Reclaim from Storage Pile No. 1 - Transfer from Dozer to Drag Chain Hopper (Will not operate concurrently with FUG-10) (Will not operate concurrently with Storage Pile No. 2 or Sawdust Pile Reclaim)	FUG-11	2.5	0.8	2.00	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00059
Manual Reclaim from Storage Pile No. 1 - Transfer from Drag Chain to Conveyor No. 8 (Will not operate concurrently with FUG-10) (Will not operate concurrently with Storage Pile No. 2 or Sawdust Pile Reclaim)	FUG-12	5.0	1.5	2.00	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00059
Transfer from Conveyor No. 8 to Conveyor No. 9 (Will not operate concurrently with Storage Pile No. 2 or Sawdust Pile Reclaim)	FUG-13	3.5	1.1	2.00	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00059
Transfer from Conveyor No. 9 to Conveyor No. 10 (Will not operate concurrently with FUG-15) (Will not operate concurrently with Storage Pile No. 2 or Sawdust Pile Reclaim)	FUG-14	3.5	1.1	2.00	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00059
Transfer from Conveyor No. 9 to Conveyor No. 11 (Will not operate concurrently with FUG-14) (Will not operate concurrently with Storage Pile No. 2 or Sawdust Pile Reclaim)	FUG-15	3.5	1.1	2.00	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00059
Transfer from Conveyor No. 7 to Stock Pile No. 1 (Will not operate concurrently with FUG-4, FUG-6 and FUG-7)	FUG-16	30.0	9.1	2.0	0.61	2.0	0.61	0.47	0.14	0.47	0.142	0.00142
Transfer from Trucks to Sawdust Pile	FUG-21	5.0	1.5	2.0	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00012
Manual Reclaim from Storage Pile No. 2 or Sawdust Pile - Transfer from Dozer to Drag Chain Hopper (Will not operate concurrently with Storage Pile No. 1 Reclaim)	FUG-24	2.5	0.8	2.0	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00059
Manual Reclaim from Storage Pile No. 2 or Sawdust Pile - Transfer from Drag Chain to Conveyor No. 14 (Will not operate concurrently with Storage Pile No. 1 Reclaim)	FUG-25	5.0	1.5	2.0	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00059
Transfer from Conveyor No. 14 to Conveyor No. 10 (Will not operate concurrently with FUG-27) (Will not operate concurrently with Storage Pile No. 1 Reclaim)	FUG-26	3.5	1.1	2.0	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00059
Transfer from Conveyor No. 14 to Conveyor No. 11 (Will not operate concurrently with FUG-26) (Will not operate concurrently with Storage Pile No. 1 Reclaim)	FUG-27	3.5	1.1	2.0	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00059
Transfer from Conveyor No. 10 to Conveyor No. 12 (Will not operate concurrently with FUG-29)	FUG-28	110.9	33.8	2.0	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00059
Transfer from Conveyor No. 11 to Conveyor No. 13 (Will not operate concurrently with FUG-28)	FUG-29	110.9	33.8	2.0	0.61	1.0	0.30	0.47	0.14	0.23	0.071	0.00059
Biomass Truck Traffic on Paved Facility Roadways ¹	FUG-30	13.1	4.0	180.3	54.95	24.4	7.44	41.93	12.78	5.68	1.73	0.06941
Miscellaneous Truck Traffic on Paved Facility Roadways ¹	FUG-31	13.1	4.0	180.3	54.95	24.4	7.44	41.93	12.78	5.68	1.73	0.00339

¹ 24-hour average PM₁₀ emission rate.

APPENDIX B

FDEP AIR PERMIT APPLICATION FORM



Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit:

- For any required purpose at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air operation permit;
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment new source review, or maximum achievable control technology (MACT);
- To assume a restriction on the potential emissions of one or more pollutants to escape a requirement such as PSD review, nonattainment new source review, MACT, or Title V; or
- To establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

- An initial federally enforceable state air operation permit (FESOP); or
- An initial, revised, or renewal Title V air operation permit.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: Gainesville Renewable Energy Center, LLC (GREC LLC)	
2. Site Name: Gainesville Renewable Energy Center (GREC)	
3. Facility Identification Number: N/A	
4. Facility Location: Street Address or Other Locator: US 441 - Deerhaven Generating Station City: Gainesville County: Alachua Zip Code: 33653	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☐ Yes ☒ No

Application Contact

1. Application Contact Name: Joshua H. Levine Director of Project Development	
2. Application Contact Mailing Address Organization/Firm: American Renewables, LLC Street Address: 75 Arlington Street, 5th Floor City: Boston State: Massachusetts Zip Code: 02116	
3. Application Contact Telephone Numbers... Telephone: (617) 482-6150 ext. Fax: (617) 482-6159	
4. Application Contact Email Address: jlevine@amrenewables.com	

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	3. PSD Number (if applicable):
2. Project Number(s):	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

This application for air permit is being submitted to obtain: (Check one)

Air Construction Permit

- ☒ Air construction permit.
- ☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).
- ☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

- ☐ Initial Title V air operation permit.
- ☐ Title V air operation permit revision.
- ☐ Title V air operation permit renewal.
- ☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.
- ☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

- ☐ Air construction permit and Title V permit revision, incorporating the proposed project.
- ☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

- ☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Application is for an air construction permit to construct a nominal 100-megawatt (MW) net biomass-fired electric generating unit and associated facilities. The Gainesville Renewable Energy Center (GREC) will be located on approximately 131 acres of property in northwest Gainesville that GREC LLC will lease from the City of Gainesville (d/b/a/ Gainesville Regional Utilities [GRU]). A detailed description of the GREC project is provided in Section 2.0. Construction is scheduled to begin in December 2010 with initial commercial operation scheduled for December 2013.

GREC is being licensed under the Florida Electrical Power Plant Siting Act (FEPPSA).

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
001	Biomass Fuel Delivery, Preparation, Storage, and Handling	AC1A	
002	Bubbling Fluidized Bed (BFB) Boiler	AC1A	
003	Ash Handling, Storage, and Shipment	AC1A	
004	Alkaline Sorbent Storage Silo	AC1A	
005	Mechanical Draft Cooling Tower	AC1A	
006	757 HP Emergency Generator Diesel Engine	AC1A	
007	275 HP Emergency Firewater Pump Diesel Engine	AC1A	
	Total Air Permit Processing Fee		7,500

Application Processing Fee

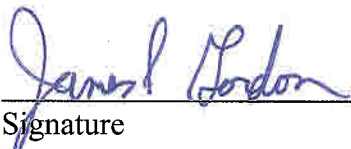
Check one: ☒ Attached - Amount: \$ 7,500 ☐ Not Applicable

Application processing fee of \$7,500 is required pursuant to Rule 62-4.050(4)(a)1., F.A.C.

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. Owner/Authorized Representative Name: James S. Gordon Chief Executive Officer
2. Owner/Authorized Representative Mailing Address Organization/Firm: Gainesville Renewable Energy Center, LLC Street Address: 75 Arlington Street, 7th Floor City: Boston State: Massachusetts Zip Code: 02116
3. Owner/Authorized Representative Telephone Numbers Telephone: (617) 904-3100 ext. Fax: (617) 904-3109
4. Owner/Authorized Representative Email Address: <u>igordon@amrenewables.com</u>
5. Owner/Authorized Representative Statement: <i>I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.</i>  _____ Signature  _____ Date

APPLICATION INFORMATION

Application Responsible Official Certification **NOT APPLICABLE**

Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:
2. Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source, CAIR source, or Hg Budget source.
3. Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4. Application Responsible Official Telephone Numbers... Telephone: () ext. Fax: ()
5. Application Responsible Official E-mail Address:
6. Application Responsible Official Certification: I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application. _____ Signature _____ Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: Thomas W. Davis Registration Number: 36777
2. Professional Engineer Mailing Address... Organization/Firm: Environmental Consulting & Technology, Inc. Street Address: 3701 Northwest 98th Street City: Gainesville State: Florida Zip Code: 32606-5004
3. Professional Engineer Telephone Numbers... Telephone: (352) 248 - 3351 ext. Fax: (352) 332 - 6722
4. Professional Engineer Email Address: tdavis@ectinc.com
5. Professional Engineer Statement: <i>I, the undersigned, hereby certify, except as particularly noted herein*, that:</i> (1) <i>To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and</i> (2) <i>To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.</i> (3) <i>If the purpose of this application is to obtain a Title V air operation permit (check here ☐ , if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.</i> (4) <i>If the purpose of this application is to obtain an air construction permit (check here ☒ , if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐ , if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.</i> (5) <i>If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here , if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.</i>  Signature _____ Date <u>11/23/09</u> (seal)

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates...		2. Facility Latitude/Longitude...	
Zone 17	East (km) 365.0	Latitude (DD/MM/SS)	
(NAD 83)	North (km) 3,293.8	Longitude (DD/MM/SS)	
3. Governmental Facility Code:	4. Facility Status Code:	5. Facility Major Group SIC Code:	6. Facility SIC(s):
0	C	49	4911
7. Facility Comment :			

Facility Contact

1. Facility Contact Name:	Joshua H. Levine, Director of Project Development		
2. Facility Contact Mailing Address...	Organization/Firm: American Renewables, LLC		
	Street Address: 75 Arlington Street, 5th Floor		
	City: Boston	State: Massachusetts	Zip Code: 02116
3. Facility Contact Telephone Numbers:	Telephone: (617) 482-6150 ext. Fax: (617) 482-6159		
4. Facility Contact Email Address:	jlevine@amrenewables.com		

Facility Primary Responsible Official **NOT APPLICABLE**

Complete if an “application responsible official” is identified in Section I that is not the facility “primary responsible official.”

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address...
Organization/Firm:
Street Address:
City:
State:
Zip Code:
3. Facility Primary Responsible Official Telephone Numbers...
Telephone: () - ext. Fax: () -
4. Facility Primary Responsible Official E-mail Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a “major source” and a “synthetic minor source.”

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR 60)	
10. ☒ One or More Emissions Units Subject to NESHAP (40 CFR 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: NSPS Subpart Da is applicable to the BFB boiler (EU ID 002). NSPS Subpart OOO is applicable to the alkaline sorbent silo (EU ID 003). NSPS Subpart IIII is applicable to the emergency diesel engines (EU IDs 006 and 007). NESHAP Subpart ZZZZ is applicable to the emergency diesel engines (EU IDs 006 and 007).	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NO_x	A	N
SO₂	A	N
CO	A	N
PM₁₀	A	N
VOC	B	N
H106 (Hydrogen Chloride)	A	N
H107 (Hydrogen Fluoride)	A	N
H114 (Mercury)	B	N
HAPS (Total)	A	N

FACILITY INFORMATION

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps **NOT APPLICABLE**

1. Pollutant Subject to Emissions Cap	2. Facility- Wide Cap [Y or N]? (all units)	3. Emissions Unit ID's Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

FACILITY INFORMATION

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: <u>Section 2.0</u> ☐ Previously Submitted, Date: _____
2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: <u>Section 2.0</u> ☐ Previously Submitted, Date: _____
3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: <u>Section 5.0</u> ☐ Previously Submitted, Date: _____

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☒ Attached, Document ID: <u>Section 2.0</u> ☐ Not Applicable (existing permitted facility)
2. Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☒ Attached, Document ID: <u>Section 2.0</u>
3. Rule Applicability Analysis: ☒ Attached, Document ID: <u>Section 4.0</u>
4. List of Exempt Emissions Units: ☐ Attached, Document ID: ☒ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification: ☒ Attached, Document ID: <u>Section 2.0</u> ☐ Not Applicable
6. Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☒ Attached, Document ID: <u>Section 9.0</u> ☐ Not Applicable
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☒ Attached, Document ID: <u>Sections 7.0, 8.0, and 11.0</u> ☐ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☒ Attached, Document ID: <u>Section 10.0</u> ☐ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☒ Attached, Document ID: <u>Section 10.0</u> ☐ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID: _____ ☒ Not Applicable

FACILITY INFORMATION

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications **NOT APPLICABLE**

- | |
|---|
| 1. List of Exempt Emissions Units:
☐ Attached, Document ID: _____ ☐ Not Applicable (no exempt units at facility) |
|---|

Additional Requirements for Title V Air Operation Permit Applications

NOT APPLICABLE

1. List of Insignificant Activities: (Required for initial/renewal applications only) ☐ Attached, Document ID: _____ ☐ Not Applicable
2. Identification of Applicable Requirements: (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Not Applicable (revision application with no change in applicable requirements)
3. Compliance Report and Plan: (Required for all initial/revision/renewal applications) ☐ Attached, Document ID: _____ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4. List of Equipment/Activities Regulated under Title VI: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID: _____ ☐ Equipment/Activities Onsite but Not Required to be Individually Listed ☐ Not Applicable
5. Verification of Risk Management Plan Submission to EPA: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID: _____ ☐ Not Applicable
6. Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID: _____ ☐ Not Applicable

FACILITY INFORMATION

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Facilities Subject to Acid Rain, CAIR, or Hg Budget Program

1. Acid Rain Program Forms:

Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)):

☒ Attached, Document ID: **Attach. A** ☐ Previously Submitted, Date: _____

☐ Not Applicable (not an Acid Rain source)

Phase II NO_x Averaging Plan (DEP Form No. 62-210.900(1)(a)1.):

☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____

☒ Not Applicable

New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.):

☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____

☒ Not Applicable

2. CAIR Part (DEP Form No. 62-210.900(1)(b)):

☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____

☒ Not Applicable (**Will be submitted prior to commencing operation per Rule 62-213.420(1)(a)4.b., F.A.C.**)

3. Hg Budget Part (DEP Form No. 62-210.900(1)(c)):

☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____

☒ Not Applicable (not a Hg Budget unit)

Additional Requirements Comment

EMISSIONS UNIT INFORMATION

Section [1] of [7]

A. GENERAL EMISSIONS UNIT INFORMATION**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)
- ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
- ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)
- ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).
- ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.
- ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.
2. Description of Emissions Unit Addressed in this Section:
Biomass fuel delivery, processing, handling, and storage.
3. Emissions Unit Identification Number: **001**
- | | | | |
|--|---|--|---|
| 4. Emissions Unit Status Code:
C | 5. Commence Construction Date: N/A | 6. Initial Startup Date:
N/A | 7. Emissions Unit Major Group SIC Code: 49 |
|--|---|--|---|
8. Federal Program Applicability: (Check all that apply)
- ☐ Acid Rain Unit
- ☐ CAIR Unit
- ☐ Hg Budget Unit
9. Package Unit:
Manufacturer: _____ Model Number: _____
10. Generator Nameplate Rating: **MW**
11. Emissions Unit Comment:
Emission unit includes truck unloading, processing (screening and sizing), handling, and storage of biomass fuels. See Section 2.3.1 for a detailed description.

EMISSIONS UNIT INFORMATION

Section [1] of [7]

Emissions Unit Control Equipment/Method: Control 1 of 3

1. Control Equipment/Method Description:
Dust Suppression by Water Sprays

2. Control Device or Method Code: **061**

Emissions Unit Control Equipment/Method: Control 2 of 3

1. Control Equipment/Method Description:
**Fabric Filter – Low Temperature (T < 180 °F
(Screen/Hog Building, BFB Boiler Fuel Day Bins)**

2. Control Device or Method Code: **018**

Emissions Unit Control Equipment/Method: Control 3 of 3

1. Control Equipment/Method Description:
**Dust Suppression – Traffic Control
(Watering and/or Sweeping of Paved Facility Roadways, as necessary)**

2. Control Device or Method Code: **108**

Emissions Unit Control Equipment/Method: Control of

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:

2. Control Device or Method Code:

EMISSIONS UNIT INFORMATION

Section [1] of [7]

B. EMISSIONS UNIT CAPACITY INFORMATION**(Optional for unregulated emissions units.)****Emissions Unit Operating Capacity and Schedule**

1. Maximum Process or Throughput Rate:	1,395,030 tons/year of biomass fuels	
2. Maximum Production Rate:		
3. Maximum Heat Input Rate:	million Btu/hr	
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:		
	24 hours/day	7 days/week
	52 weeks/year	8,760 hours/year
6. Operating Capacity/Schedule Comment:		

EMISSIONS UNIT INFORMATION

Section [1] of [7]

C. EMISSION POINT (STACK/VENT) INFORMATION**(Optional for unregulated emissions units.)****Emission Point Description and Type**

1. Identification of Point on Plot Plan or Flow Diagram: N/A		2. Emission Point Type Code: 3 and 4	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Biomass fuel unloading, processing (screening and sizing), handling, and storage.			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: N/A	6. Stack Height: N/A feet	7. Exit Diameter: N/A feet	
8. Exit Temperature: N/A °F	9. Actual Volumetric Flow Rate: N/A acfm	10. Water Vapor: N/A %	
11. Maximum Dry Standard Flow Rate: N/A dscfm		12. Nonstack Emission Point Height: N/A feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) : Longitude (DD/MM/SS) :	
15. Emission Point Comment: Information regarding the biomass fuel point and fugitive emission sources is provided in Section 2.0.			

EMISSIONS UNIT INFORMATION

Section [1] of [7]

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 1

1. Segment Description (Process/Fuel Type): Miscellaneous Manufacturing Industries, Miscellaneous Industrial Processes Biomass fuel delivery, processing, handling, and storage.		
2. Source Classification Code (SCC): 3-99-999-99		3. SCC Units: Tons
4. Maximum Hourly Rate: 600	5. Maximum Annual Rate: 1,395,030	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment:		

Segment Description and Rate: Segment of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):		3. SCC Units:
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

EMISSIONS UNIT INFORMATION

Section [1] of [7]

E. EMISSIONS UNIT POLLUTANTS**List of Pollutants Emitted by Emissions Unit**

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			NS
PM₁₀			NS

EMISSIONS UNIT INFORMATION

Section [1] of [7]

POLLUTANT DETAIL INFORMATION

Page [1] of [4]

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM		2. Total Percent Efficiency of Control: N/A	
3. Potential Emissions: 16.5 lb/hour 39.6 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A To tons/year			
6. Emission Factor: Various Reference: AP-42, Engineering Estimate		7. Emissions Method Code: 3 and 5	
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: Potential PM emissions include biomass fuel point and fugitive emission sources. See Appendix A (Tables A-13 through A-17) for detailed emission rate calculations.			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

Section [1] of [7]

POLLUTANT DETAIL INFORMATION

Page [2] of [4]

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 5% Opacity (Surrogate for PM)	4. Equivalent Allowable Emissions: 16.5 lb/hour 39.6 tons/year
5. Method of Compliance: EPA Reference Method 9	
6. Allowable Emissions Comment (Description of Operating Method): Proposed BACT - Rule 62-212.400(10)(b), F.A.C.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

Section [1] of [7]

POLLUTANT DETAIL INFORMATION

Page [3] of [4]

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM₁₀		2. Total Percent Efficiency of Control: N/A	
3. Potential Emissions: 8.6 lb/hour 30.3 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A To tons/year			
6. Emission Factor: Reference:		7. Emissions Method Code: 3	
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: Potential PM₁₀ emissions include biomass fuel point and fugitive emission sources. See Appendix A (Tables A-13 through A-17) for detailed emission rate calculations.			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

Section [1] of [7]

POLLUTANT DETAIL INFORMATION

Page [4] of [4]

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 5% Opacity (Surrogate for PM₁₀)	4. Equivalent Allowable Emissions: 8.6 lb/hour 30.3 tons/year
5. Method of Compliance: EPA Reference Method 9	
6. Allowable Emissions Comment (Description of Operating Method): Proposed BACT - Rule 62-212.400(10)(b), F.A.C.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

Section [1] of [7]

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: VE 05	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 5 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: Proposed BACT - Rule 62-212.400(10)(b), F.A.C.	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: VE 20	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: Rule 62-296.320(4)(b), F.A.C.	

EMISSIONS UNIT INFORMATION

Section [1] of [7]

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor of **NOT APPLICABLE**

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

EMISSIONS UNIT INFORMATION

Section [1] of [7]

I. EMISSIONS UNIT ADDITIONAL INFORMATION**Additional Requirements for All Applications, Except as Otherwise Stated**

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Section 2.0 ☐ Previously Submitted, Date: _____
2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Section 5.0 ☐ Previously Submitted, Date: _____
4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☒ Not Applicable
5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records: ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute: ☐ Attached, Document ID: _____ ☒ Not Applicable

Section [1] of [7]

Additional Requirements for Air Construction Permit Applications

Additional Requirements for Title V Air Operation Permit Applications

Additional Requirements Comment

[illegible]

EMISSIONS UNIT INFORMATION

Section [2] of [7]

A. GENERAL EMISSIONS UNIT INFORMATION**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)
- ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
- ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)			
☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).			
☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.			
☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.			
2. Description of Emissions Unit Addressed in this Section: Bubbling Fluidized Bed (BFB) Boiler			
3. Emissions Unit Identification Number: 002			
4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 49
8. Federal Program Applicability: (Check all that apply)			
☒ Acid Rain Unit ☒ CAIR Unit ☐ Hg Budget Unit			
9. Package Unit: N/A			
Manufacturer:		Model Number:	
10. Generator Nameplate Rating: 100 MW (nominal net)			
11. Emissions Unit Comment:			

EMISSIONS UNIT INFORMATION

Section [2] of [7]

Emissions Unit Control Equipment/Method: Control 1 of 6

1. Control Equipment/Method Description:
Staged Combustion

2. Control Device or Method Code: **025**

Emissions Unit Control Equipment/Method: Control 2 of 6

1. Control Equipment/Method Description:
Overfire Air

2. Control Device or Method Code: **204**

Emissions Unit Control Equipment/Method: Control 3 of 6

1. Control Equipment/Method Description:
Flue Gas Recirculation (FGR)
(FGR will be used when lower moisture content biomass fuels are combusted and during partial load boiler operations.)

2. Control Device or Method Code: **026**

Emissions Unit Control Equipment/Method: Control 4 of 6

1. Control Equipment/Method Description:
Dry Sorbent Injection (DSI)

2. Control Device or Method Code: **206**

Emissions Unit Control Equipment/Method: Control 5 of 6

1. Control Equipment/Method Description:
Fabric Filter – High Temperature (T > 250 °F)

2. Control Device or Method Code: **016**

Emissions Unit Control Equipment/Method: Control 6 of 6

1. Control Equipment/Method Description:
Selective Catalytic Reduction (SCR)

2. Control Device or Method Code: **139**

Section [2] of [7]

(Optional for unregulated emissions units.)

1.	Maximum Process or Throughput Rate:		
2.	Maximum Production Rate:		
3.	Maximum Heat Input Rate:	1,358 million Btu/hr (biomass fuels)	
		341 million Btu/hr (natural gas during startups)	
4.	Maximum Incineration Rate: pounds/hr tons/day		
5.	Requested Maximum Operating Schedule:		
	24 hours/day		7 days/week
	52 weeks/year		8,760 hours/year
6.	Operating Capacity/Schedule Comment:		

Section [2] of [7]

(Optional for unregulated emissions units.)

1. Identification of Point on Plot Plan or Flow Diagram: P-7		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: V		6. Stack Height: 230 feet	
7. Exit Diameter: 12.0 feet		8. Exit Temperature: 310°F	
9. Actual Volumetric Flow Rate: 520,600 acfm		10. Water Vapor: N/A %	
11. Maximum Dry Standard Flow Rate: N/A dscfm		12. Nonstack Emission Point Height: N/A feet	
13. Emission Point UTM Coordinates... Zone: 17 East (km): 365.01 North (km): 3,293.83		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) : Longitude (DD/MM/SS) :	
15. Emission Point Comment:			

EMISSIONS UNIT INFORMATION

Section [2] of [7]

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 2

1. Segment Description (Process/Fuel Type): External Combustion Boilers, Electric Generation, Wood Waste/Bark, Fluidized Bed Combustion		
2. Source Classification Code (SCC): 1-01-009-12		3. SCC Units: Tons Combusted
4. Maximum Hourly Rate: 159.3	5. Maximum Annual Rate: 1,395,030	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: 0.01 (as received)	8. Maximum % Ash: 0.49 (as received)	9. Million Btu per SCC Unit: 8.5 (as received)
10. Segment Comment:		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): External Combustion Boilers, Electric Generation, Natural Gas, Boilers > 100 x 10⁶ Btu/hr except Tangentially Fired Units		
2. Source Classification Code (SCC): 1-01-006-01		3. SCC Units: Million cubic feet burned
4. Maximum Hourly Rate: 0.324	5. Maximum Annual Rate: 35.1	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: 1,050
10. Segment Comment:		

EMISSIONS UNIT INFORMATION

Section [2] of [7]

E. EMISSIONS UNIT POLLUTANTS**List of Pollutants Emitted by Emissions Unit**

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO	025, 204, 026		EL
NOX	025, 204, 026	139	EL
PM	016		EL
PM10	016		EL
SO2	206	016	EL
VOC	025, 204, 026		EL
H106 (HCl)	206	016	EL
H107 (HF)	206	016	EL
H114 (Mercury)			EL
HAPS	206	016	NS

EMISSIONS UNIT INFORMATION

Section [2] of [7]

POLLUTANT DETAIL INFORMATION

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: CO		2. Total Percent Efficiency of Control: N/A	
3. Potential Emissions: 163.0 lb/hour 713.8 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A To tons/year			
6. Emission Factor: 0.12 lb/10⁶ Btu Reference: Boiler vendor guarantee		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: See Appendix B, Table A-2 for detailed emission rate calculations.			
11. Potential, Fugitive, and Actual Emissions Comment:			

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.****Allowable Emissions** Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.12 lb/10⁶ Btu, 30 day rolling average	4. Equivalent Allowable Emissions: 163.0 lb/hour 713.8 tons/year
5. Method of Compliance: CO CEMS	
6. Allowable Emissions Comment (Description of Operating Method): Proposed BACT - Rule 62-212.400(10)(b), F.A.C.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: NO_x		2. Total Percent Efficiency of Control: > 80	
3. Potential Emissions: 95.1 lb/hour 416.4 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A To tons/year			
6. Emission Factor: 0.070 lb/10⁶ Btu Reference: Boiler vendor guarantee		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: See Appendix B, Table A-2 for detailed emission rate calculations.			
11. Potential, Fugitive, and Actual Emissions Comment:			

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.****Allowable Emissions** Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.070 lb/10⁶ Btu, 30 day rolling average	4. Equivalent Allowable Emissions: 95.1 lb/hour 416.4 tons/year
5. Method of Compliance: NO_x CEMS	
6. Allowable Emissions Comment (Description of Operating Method): Proposed BACT - Rule 62-212.400(10)(b), F.A.C.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM/PM₁₀ (filterable)		2. Total Percent Efficiency of Control: 99	
3. Potential Emissions: 20.4 lb/hour 89.2 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A To tons/year			
6. Emission Factor: 0.015 lb/10⁶ Btu Reference: Boiler vendor guarantee		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: See Appendix B, Table A-2 for detailed emission rate calculations.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.015 lb/10⁶ Btu (filterable)	4. Equivalent Allowable Emissions: 20.4 lb/hour 89.2 tons/year
5. Method of Compliance: EPA Reference Methods 5, 5B, 17, and 201	
6. Allowable Emissions Comment (Description of Operating Method): Proposed BACT - Rule 62-212.400(10)(b), F.A.C.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: SO₂		2. Total Percent Efficiency of Control: Approx. 35	
3. Potential Emissions: 55.7 lb/hour 243.9 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A To tons/year			
6. Emission Factor: 0.041 lb/10⁶ Btu Reference: Boiler vendor guarantee		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: See Appendix B, Table A-2 for detailed emission rate calculations.			
11. Potential, Fugitive, and Actual Emissions Comment:			

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.****Allowable Emissions** Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.041 lb/10⁶ Btu, 30 day rolling average	4. Equivalent Allowable Emissions: 55.7 lb/hour 243.9 tons/year
5. Method of Compliance: SO₂ CEMS	
6. Allowable Emissions Comment (Description of Operating Method): Proposed BACT - Rule 62-212.400(10)(b), F.A.C.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: VOC		2. Total Percent Efficiency of Control: N/A	
3. Potential Emissions: 17.7 lb/hour 77.3 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A To tons/year			
6. Emission Factor: 0.013 lb/10⁶ Btu Reference: Boiler vendor guarantee		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: See Appendix B, Table A-2 for detailed emission rate calculations.			
11. Potential, Fugitive, and Actual Emissions Comment:			

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.013 lb/10⁶ Btu, 30 day rolling average	4. Equivalent Allowable Emissions: 17.7 lb/hour 77.3 tons/year
5. Method of Compliance: EPA Reference Methods 18, 25, and 25A	
6. Allowable Emissions Comment (Description of Operating Method): Proposed BACT - Rule 62-212.400(10)(b), F.A.C.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: H106 (Hydrogen Chloride)		2. Total Percent Efficiency of Control: Approx. 50	
3. Potential Emissions: 8.1 lb/hour 35.7 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A To tons/year			
6. Emission Factor: 0.006 lb/10⁶ Btu Reference: Boiler vendor guarantee		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: See Appendix B, Table A-5 for detailed emission rate calculations.			
11. Potential, Fugitive, and Actual Emissions Comment:			

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.****Allowable Emissions** Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.006 lb/10⁶ Btu	4. Equivalent Allowable Emissions: 8.1 lb/hour 35.7 tons/year
5. Method of Compliance: EPA Reference Methods 26 and 26A	
6. Allowable Emissions Comment (Description of Operating Method): Proposed MACT - Rule 62-204.800(11)(d)2., F.A.C.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: H107 (Hydrogen Fluoride)		2. Total Percent Efficiency of Control: Approx. 50	
3. Potential Emissions: 16.3 lb/hour 71.4 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A To tons/year			
6. Emission Factor: 0.012 lb/10⁶ Btu Reference: Boiler vendor guarantee		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: See Appendix B, Table A-5 for detailed emission rate calculations.			
11. Potential, Fugitive, and Actual Emissions Comment:			

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.****Allowable Emissions** Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.006 lb/10⁶ Btu (HCl)	4. Equivalent Allowable Emissions: 16.3 lb/hour 71.4 tons/year
5. Method of Compliance: EPA Reference Methods 26 and 26A	
6. Allowable Emissions Comment (Description of Operating Method): Proposed HCl emission limit as a surrogate for HF. Proposed MACT - Rule 62-204.800(11)(d)2., F.A.C.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: H114 (Mercury)		2. Total Percent Efficiency of Control: N/A	
3. Potential Emissions: 0.0019 lb/hour 0.0084 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A To tons/year			
6. Emission Factor: 0.00000141 lb/10⁶ Btu Reference: EPA Boiler MACT average emission factor		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: See Appendix B, Table A-5 for detailed emission rate calculations.			
11. Potential, Fugitive, and Actual Emissions Comment:			

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**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.****Allowable Emissions** Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.00000141 lb/10⁶ Btu	4. Equivalent Allowable Emissions: 0.0019 lb/hour 0.0084 tons/year
5. Method of Compliance: EPA Reference Methods 29 (Part 60) and 101A (Part 61), ASTM Method D6784-02	
6. Allowable Emissions Comment (Description of Operating Method): Proposed MACT - Rule 62-204.800(11)(d)2., F.A.C.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

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**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: HAPS		2. Total Percent Efficiency of Control: N/A	
3. Potential Emissions: 25.7 lb/hour 113.9 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A To tons/year			
6. Emission Factor: 0.019 lb/10⁶ Btu Reference: Boiler vendor guarantees and EPA Boiler MACT average emission factors		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: See Appendix B, Table A-5 for detailed emission rate calculations.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions of **NOT APPLICABLE**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

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G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: VE 20	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: 27 % Maximum Period of Excess Opacity Allowed: 6 min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: NSPS Subpart Da.	

Visible Emissions Limitation: Visible Emissions Limitation of

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

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H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 4

1. Parameter Code: EM	2. Pollutant(s): NO_x
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: Required by 40 CFR Part 75 (Acid Rain Program) and NSPS Subpart Da. Specific CEMS information will be provided to FDEP when available.	

Continuous Monitoring System: Continuous Monitor 2 of 4

1. Parameter Code: EM	2. Pollutant(s): SO₂
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: Required by 40 CFR Part 75 (Acid Rain Program). Specific CEMS information will be provided to FDEP when available.	

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H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 3 of 4

1. Parameter Code: EM	2. Pollutant(s): CO
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: Required by BACT. Specific CEMS information will be provided to FDEP when available.	

Continuous Monitoring System: Continuous Monitor 4 of 4

1. Parameter Code: VE	2. Pollutant(s): N/A
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: Required by NSPS Subpart Da. Specific CEMS information will be provided to FDEP when available.	

EMISSIONS UNIT INFORMATION

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I. EMISSIONS UNIT ADDITIONAL INFORMATION**Additional Requirements for All Applications, Except as Otherwise Stated**

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Section 2.0 ☐ Previously Submitted, Date: _____
2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Section 2.0 ☐ Previously Submitted, Date: _____
3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Section 5.0 ☐ Previously Submitted, Date: _____
4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records: ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute: ☐ Attached, Document ID: _____ ☒ Not Applicable

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Additional Requirements for Air Construction Permit Applications

Additional Requirements for Title V Air Operation Permit Applications

Additional Requirements Comment

EMISSIONS UNIT INFORMATION

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A. GENERAL EMISSIONS UNIT INFORMATION**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)
- ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
- ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)
- ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).
- ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.
- ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.
2. Description of Emissions Unit Addressed in this Section:
Ash handling, storage, and shipment.
3. Emissions Unit Identification Number: **003**
- | | | | |
|--|---|--|---|
| 4. Emissions Unit Status Code:
C | 5. Commence Construction Date: N/A | 6. Initial Startup Date:
N/A | 7. Emissions Unit Major Group SIC Code: 49 |
|--|---|--|---|
8. Federal Program Applicability: (Check all that apply)
- ☐ Acid Rain Unit
- ☐ CAIR Unit
- ☐ Hg Budget Unit
9. Package Unit:
Manufacturer: _____ Model Number: _____
10. Generator Nameplate Rating: **MW**
11. Emissions Unit Comment:
Emission unit includes bottom and fly ash handling, storage, and shipment. See Section 2.3.3 for a detailed description.

EMISSIONS UNIT INFORMATION

Section [3] of [7]

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description:
**Fabric Filter – Low Temperature (T < 180 °F
(Fly ash silo vacuum blowers and bin vent)**

2. Control Device or Method Code: **018**

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ____ of ____

1. Control Equipment/Method Description:

2. Control Device or Method Code:

EMISSIONS UNIT INFORMATION

Section [3] of [7]

B. EMISSIONS UNIT CAPACITY INFORMATION**(Optional for unregulated emissions units.)****Emissions Unit Operating Capacity and Schedule**

1. Maximum Process or Throughput Rate:	27,594 tons/year (fly ash)
	13,140 tons/year (bottom ash)
2. Maximum Production Rate:	
3. Maximum Heat Input Rate:	million Btu/hr
4. Maximum Incineration Rate:	pounds/hr tons/day
5. Requested Maximum Operating Schedule:	
	24 hours/day 7 days/week
	52 weeks/year 8,760 hours/year
6. Operating Capacity/Schedule Comment:	
	Bottom ash will consist of noncombustible materials (i.e., rocks, glass, sand, metal) from the BFB combustor. The bottom ash will be collected in ash containers and subsequently transported and emptied at an offsite, properly permitted landfill.

EMISSIONS UNIT INFORMATION

Section [3] of [7]

C. EMISSION POINT (STACK/VENT) INFORMATION**(Optional for unregulated emissions units.)****Emission Point Description and Type**

1. Identification of Point on Plot Plan or Flow Diagram: N/A		2. Emission Point Type Code: 3 and 4	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Ash handling, storage, and shipment.			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: N/A	6. Stack Height: N/A feet	7. Exit Diameter: N/A feet	
8. Exit Temperature: N/A °F	9. Actual Volumetric Flow Rate: N/A acfm	10. Water Vapor: N/A %	
11. Maximum Dry Standard Flow Rate: N/A dscfm		12. Nonstack Emission Point Height: N/A feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) : Longitude (DD/MM/SS) :	
15. Emission Point Comment: Information regarding the ash point and fugitive emission sources is provided in Section 2.0.			

EMISSIONS UNIT INFORMATION

Section [3] of [7]

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 2

1. Segment Description (Process/Fuel Type): Industrial Processes; Mineral Products; Bulk Material Storage Bins; Fly Ash		
2. Source Classification Code (SCC): 3-05-102-98		3. SCC Units: Tons
4. Maximum Hourly Rate: 3.2	5. Maximum Annual Rate: 27,594	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment:		

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): Industrial Processes; Mineral Products; Bulk Material Storage Bins; Bottom Ash		
2. Source Classification Code (SCC): 3-05-102-98		3. SCC Units: Tons
4. Maximum Hourly Rate: 1.5	5. Maximum Annual Rate: 13,140	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment: Bottom ash will consist of noncombustible materials (i.e., rocks, glass, sand, metal) from the BFB combustor		

EMISSIONS UNIT INFORMATION

Section [3] of [7]

E. EMISSIONS UNIT POLLUTANTS**List of Pollutants Emitted by Emissions Unit**

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	018		NS
PM₁₀	018		NS

EMISSIONS UNIT INFORMATION

Section [3] of [7]

POLLUTANT DETAIL INFORMATION

Page [1] of [2]

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM/PM₁₀		2. Total Percent Efficiency of Control: N/A	
3. Potential Emissions: 1.1 lb/hour 4.7 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A To tons/year			
6. Emission Factor: 0.015 gr/scf Reference: Engineering estimate		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: See Appendix A (Table A-13) for detailed emission rate calculations.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 5% Opacity (Surrogate for PM/PM₁₀)	4. Equivalent Allowable Emissions: 1.1 lb/hour 4.7 tons/year
5. Method of Compliance: EPA Reference Method 9	
6. Allowable Emissions Comment (Description of Operating Method): Proposed BACT - Rule 62-212.400(10)(b), F.A.C.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

Section [3] of [7]

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: VE 05	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 5 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: Proposed BACT - Rule 62-212.400(10)(b), F.A.C.	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: VE 20	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: Rule 62-296.320(4)(b), F.A.C.	

EMISSIONS UNIT INFORMATION

Section [3] of [7]

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor of **NOT APPLICABLE**

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

EMISSIONS UNIT INFORMATION

Section [3] of [7]

I. EMISSIONS UNIT ADDITIONAL INFORMATION**Additional Requirements for All Applications, Except as Otherwise Stated**

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Section 2.0 ☐ Previously Submitted, Date: _____
2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Section 5.0 ☐ Previously Submitted, Date: _____
4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☒ Not Applicable
5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records: ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute: ☐ Attached, Document ID: _____ ☒ Not Applicable

Section [3] of [7]

Additional Requirements for Air Construction Permit Applications

Additional Requirements for Title V Air Operation Permit Applications

Additional Requirements Comment

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EMISSIONS UNIT INFORMATION

Section [4] of [7]

A. GENERAL EMISSIONS UNIT INFORMATION**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)
- ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
- ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one) ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent). ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions. ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.			
2. Description of Emissions Unit Addressed in this Section: Sorbent Storage Silo			
3. Emissions Unit Identification Number: 004			
4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 49
8. Federal Program Applicability: (Check all that apply) ☐ Acid Rain Unit ☐ CAIR Unit ☐ Hg Budget Unit			
9. Package Unit: Manufacturer:		Model Number:	
10. Generator Nameplate Rating: MW			
11. Emissions Unit Comment: Storage silo for hydrated lime DSI sorbent.			

EMISSIONS UNIT INFORMATION

Section [4] of [7]

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description:
Fabric Filter – Low Temperature (T < 180 °F)

2. Control Device or Method Code: **018**

Emissions Unit Control Equipment/Method: Control of

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:

2. Control Device or Method Code:

EMISSIONS UNIT INFORMATION

Section [4] of [7]

B. EMISSIONS UNIT CAPACITY INFORMATION**(Optional for unregulated emissions units.)****Emissions Unit Operating Capacity and Schedule**

1. Maximum Process or Throughput Rate: 876 tons/year
2. Maximum Production Rate:
3. Maximum Heat Input Rate: million Btu/hr
4. Maximum Incineration Rate: pounds/hr tons/day
5. Requested Maximum Operating Schedule: 24 hours/day 7 days/week 52 weeks/year 8,760 hours/year
6. Operating Capacity/Schedule Comment:

EMISSIONS UNIT INFORMATION

Section [4] of [7]

C. EMISSION POINT (STACK/VENT) INFORMATION**(Optional for unregulated emissions units.)****Emission Point Description and Type**

1. Identification of Point on Plot Plan or Flow Diagram: N/A		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: N/A		6. Stack Height: 51 feet	
		7. Exit Diameter: 0.3 feet	
8. Exit Temperature: 100°F		9. Actual Volumetric Flow Rate: 2,000 acfm	
		10. Water Vapor: N/A %	
11. Maximum Dry Standard Flow Rate: N/A dscfm		12. Nonstack Emission Point Height: N/A feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) : Longitude (DD/MM/SS) :	
15. Emission Point Comment:			

EMISSIONS UNIT INFORMATION

Section [4] of [7]

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 1

1. Segment Description (Process/Fuel Type): Industrial Processes; Mineral Products; Bulk Material Storage Bins; Lime		
2. Source Classification Code (SCC): 3-05-102-98		3. SCC Units: Tons
4. Maximum Hourly Rate: 0.10	5. Maximum Annual Rate: 876	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment:		

Segment Description and Rate: Segment of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):		3. SCC Units:
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

EMISSIONS UNIT INFORMATION

Section [4] of [7]

E. EMISSIONS UNIT POLLUTANTS**List of Pollutants Emitted by Emissions Unit**

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	018		NS
PM₁₀	018		NS

EMISSIONS UNIT INFORMATION

Section [4] of [7]

POLLUTANT DETAIL INFORMATION

Page [1] of [2]

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM/PM₁₀		2. Total Percent Efficiency of Control: N/A	
3. Potential Emissions: 0.24 lb/hour 0.0044 tons/year		4. Synthetically Limited? ☐ Yes ☒ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A To tons/year			
6. Emission Factor: 0.015 gr/scf Reference: Engineering estimate		7. Emissions Method Code: 5	
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: See Appendix A (Table A-13) for detailed emission rate calculations. Annual emission rate based on estimated 36 hours/year operation of lime truck unloading to storage silo.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 5% Opacity (Surrogate for PM/PM₁₀)	4. Equivalent Allowable Emissions: 0.24 lb/hour 0.0044 tons/year
5. Method of Compliance: EPA Reference Method 9	
6. Allowable Emissions Comment (Description of Operating Method): Proposed BACT - Rule 62-212.400(10)(b), F.A.C.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

Section [4] of [7]

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: VE 05	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 5 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: Proposed BACT - Rule 62-212.400(10)(b), F.A.C.	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: VE 20	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: Rule 62-296.320(4)(b), F.A.C.	

EMISSIONS UNIT INFORMATION

Section [4] of [7]

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor of **NOT APPLICABLE**

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

EMISSIONS UNIT INFORMATION

Section [4] of [7]

I. EMISSIONS UNIT ADDITIONAL INFORMATION**Additional Requirements for All Applications, Except as Otherwise Stated**

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Section 2.0 ☐ Previously Submitted, Date: _____
2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Section 5.0 ☐ Previously Submitted, Date: _____
4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☒ Not Applicable
5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records: ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute: ☐ Attached, Document ID: _____ ☒ Not Applicable

Section [4] of [7]

Additional Requirements for Air Construction Permit Applications

Additional Requirements for Title V Air Operation Permit Applications

Additional Requirements Comment

[illegible]

EMISSIONS UNIT INFORMATION

Section [5] of [7]

A. GENERAL EMISSIONS UNIT INFORMATION**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)
- ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
- ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)			
☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).			
☒ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.			
☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.			
2. Description of Emissions Unit Addressed in this Section: One, 4-cell mechanical draft cooling tower.			
3. Emissions Unit Identification Number: 005			
4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 49
8. Federal Program Applicability: (Check all that apply)			
☐ Acid Rain Unit			
☐ CAIR Unit			
☐ Hg Budget Unit			
9. Package Unit: N/A			
Manufacturer:		Model Number:	
10. Generator Nameplate Rating: N/A MW			
11. Emissions Unit Comment:			

EMISSIONS UNIT INFORMATION

Section [5] of [7]

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description:

Mist (Drift) Eliminators – High Velocity (V>250 ft/min)

2. Control Device or Method Code: **015**

Emissions Unit Control Equipment/Method: Control of

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Section [5] of [7]

(Optional for unregulated emissions units.)

1. Maximum Process or Throughput Rate:	78,000 gal/min	
2. Maximum Production Rate:		
3. Maximum Heat Input Rate:	million Btu/hr	
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:		
	24 hours/day	7 days/week
	52 weeks/year	8,760 hours/year
6. Operating Capacity/Schedule Comment:		
Field 1 maximum process rate is the cooling tower water recirculation rate.		

EMISSIONS UNIT INFORMATION

Section [5] of [7]

C. EMISSION POINT (STACK/VENT) INFORMATION**(Optional for unregulated emissions units.)****Emission Point Description and Type**

1. Identification of Point on Plot Plan or Flow Diagram: P-8A thru P-8D		2. Emission Point Type Code: 3	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: Cooling tower consists of 4 cells.			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: V	6. Stack Height: 53 feet	7. Exit Diameter: 11.2 feet	
8. Exit Temperature: 93 °F	9. Actual Volumetric Flow Rate: 2,425,000 acfm	10. Water Vapor: N/A %	
11. Maximum Dry Standard Flow Rate: N/A dscfm		12. Nonstack Emission Point Height: N/A feet	
13. Emission Point UTM Coordinates Zone: East (km): N/A North (km): N/A		14. Emission Point Latitude/Longitude N/A Latitude (DD/MM/SS) N/A Longitude (DD/MM/SS)	
15. Emission Point Comment: Cooling tower consists of 4 cells with 4 individual exhaust fans. Stack height and diameter data provided in Fields 6 and 7 are for each cell. Exhaust volume and temperature will vary with ambient temperatures.			

EMISSIONS UNIT INFORMATION

Section [5] of [7]

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 1

1. Segment Description (Process/Fuel Type): Cooling Tower, Process Cooling, Mechanical Draft. Cooling tower water recirculation rate.		
2. Source Classification Code (SCC): 3-85-001-01		3. SCC Units: Million gallons
4. Maximum Hourly Rate: 4.68	5. Maximum Annual Rate: 40,997	6. Estimated Annual Activity Factor: N/A
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
10. Segment Comment:		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):		3. SCC Units:
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

EMISSIONS UNIT INFORMATION

Section [5] of [7]

E. EMISSIONS UNIT POLLUTANTS**List of Pollutants Emitted by Emissions Unit**

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	014	N/A	EL
PM₁₀	014	N/A	EL

EMISSIONS UNIT INFORMATION

Section [5] of [7]

POLLUTANT DETAIL INFORMATION

Page [1] of [4]

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM		2. Total Percent Efficiency of Control: N/A	
3. Potential Emissions: 0.33 lb/hour 1.5 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.0005 % drift loss rate Reference: Proposed BACT		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: See Appendix B, Table A-10 for detailed emission rate calculations.			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

Section [5] of [7]

POLLUTANT DETAIL INFORMATION

Page [2] of [4]

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0005 % drift loss rate	4. Equivalent Allowable Emissions: 0.33 lb/hour 1.5 tons/year
5. Method of Compliance: Cooling tower vendor certification	
6. Allowable Emissions Comment (Description of Operating Method): Proposed BACT - Rule 62-212.400(10)(b), F.A.C.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

Section [5] of [7]

POLLUTANT DETAIL INFORMATION

Page [3] of [4]

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS****(Optional for unregulated emissions units.)**

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM₁₀		2. Total Percent Efficiency of Control: N/A	
3. Potential Emissions: 0.23 lb/hour 1.0 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.0005 % drift loss rate Reference: Proposed BACT		7. Emissions Method Code: 2	
8.a. Baseline Actual Emissions (if required): tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: See Appendix B, Table A-10 for detailed emission rate calculations.			
11. Potential, Fugitive, and Actual Emissions Comment:			

EMISSIONS UNIT INFORMATION

Section [5] of [7]

POLLUTANT DETAIL INFORMATION

Page [4] of [4]

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS****Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.**

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0005 % drift loss rate	4. Equivalent Allowable Emissions: 0.23 lb/hour 1.0 tons/year
5. Method of Compliance: Cooling tower vendor certification	
6. Allowable Emissions Comment (Description of Operating Method): Proposed BACT - Rule 62-212.400(10)(b), F.A.C.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

Section [5] of [7]

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: VE 20	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: Rule 62-296.320(4)(b), F.A.C.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

Section [5] of [7]

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor of **NOT APPLICABLE**

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

EMISSIONS UNIT INFORMATION

Section [5] of [7]

I. EMISSIONS UNIT ADDITIONAL INFORMATION**Additional Requirements for All Applications, Except as Otherwise Stated**

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Section 2.0 ☐ Previously Submitted, Date: _____
2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Section 5.0 ☐ Previously Submitted, Date: _____
4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☒ Not Applicable
5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records: ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute: ☐ Attached, Document ID: _____ ☒ Not Applicable

Section [5] of [7]

Additional Requirements for Air Construction Permit Applications

Additional Requirements for Title V Air Operation Permit Applications

Additional Requirements Comment

[illegible]

EMISSIONS UNIT INFORMATION

Section [6] of [7]

A. GENERAL EMISSIONS UNIT INFORMATION**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)
- ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
- ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)			
☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).			
☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.			
☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.			
2. Description of Emissions Unit Addressed in this Section: Emergency Generator Diesel Engine			
3. Emissions Unit Identification Number: 006			
4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 49
8. Federal Program Applicability: (Check all that apply)			
☐ Acid Rain Unit ☐ CAIR Unit ☐ Hg Budget Unit			
9. Package Unit: Manufacturer: Kohler (or equivalent) Model Number: 500REOZVB			
10. Generator Nameplate Rating: 0.50 MW (nominal)			
11. Emissions Unit Comment: Diesel Engine Rating: 757 hp (564 kW)			

EMISSIONS UNIT INFORMATION

Section [6] of [7]

Emissions Unit Control Equipment/Method: Control of **NOT APPLICABLE**

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control of

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control of

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control of

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:

2. Control Device or Method Code:

EMISSIONS UNIT INFORMATION

Section [6] of [7]

B. EMISSIONS UNIT CAPACITY INFORMATION**(Optional for unregulated emissions units.)****Emissions Unit Operating Capacity and Schedule**

1. Maximum Heat Input Rate: million Btu/hr
2. Maximum Incineration Rate: pounds/hr tons/day
3. Requested Maximum Operating Schedule: hours/day days/week weeks/year 96 hours/year
4. Operating Capacity/Schedule Comment: Excluding operation during emergencies.

EMISSIONS UNIT INFORMATION

Section [6] of [7]

C. EMISSION POINT (STACK/VENT) INFORMATION**(Optional for unregulated emissions units.)****Emission Point Description and Type**

1. Identification of Point on Plot Plan or Flow Diagram: P-9		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: V	6. Stack Height: 15 feet	7. Exit Diameter: 0.7 feet	
8. Exit Temperature: 890 °F	9. Actual Volumetric Flow Rate: 3,900 acfm	10. Water Vapor: N/A %	
11. Maximum Dry Standard Flow Rate: N/A dscfm		12. Nonstack Emission Point Height: N/A feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) : Longitude (DD/MM/SS) :	
15. Emission Point Comment:			

EMISSIONS UNIT INFORMATION

Section [6] of [7]

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 1

1. Segment Description (Process/Fuel Type): Emergency generator diesel engine fired with distillate fuel oil.		
2. Source Classification Code (SCC): 2-01-001-02		3. SCC Units: Thousand Gallons Burned
4. Maximum Hourly Rate: 0.037	5. Maximum Annual Rate: 18.5	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash: 0.01	9. Million Btu per SCC Unit: 140
10. Segment Comment:		

Segment Description and Rate: Segment of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):		3. SCC Units:
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

EMISSIONS UNIT INFORMATION

Section [6] of [7]

E. EMISSIONS UNIT POLLUTANTS**List of Pollutants Emitted by Emissions Unit**

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NO_x			EL
SO₂			EL
PM/PM₁₀			EL
CO			EL
VOC			EL

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: NO_x		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 5.6 lb/hour 1.4 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 3.36 gm/hp-hr Reference: NSPS Subpart IIII			7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: Potential NO_x emission rates based on 70% of NSPS Subpart IIII NO_x + HC standard of 4.8 g/hp-hr (EPA Nonroad Diesel Engine Tier 2) and 757 hp. Potential annual emission rate based on 500 hrs/yr operation.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 4.8 gm/hp-hr (NO_x + HC)	4. Equivalent Allowable Emissions: 5.6 lb/hour 1.4 tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart III.	
6. Allowable Emissions Comment (Description of Operating Method): NSPS Subpart III (EPA Nonroad Diesel Engine Tier 2) Equivalent allowable emissions based on 70% of NO_x + HC standard.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: SO₂		2. Total Percent Efficiency of Control: N/A	
3. Potential Emissions: 0.0078 lb/hour 0.0020 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.0015 weight % S fuel oil Reference: NSPS Subpart IIII		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: Potential annual emission rate based on 500 hrs/yr operation.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0015 weight % S fuel oil (on and after 10/1/2010)	4. Equivalent Allowable Emissions: 0.0078 hour 0.0020 tons/year
5. Method of Compliance: Diesel fuel oil vender certification	
6. Allowable Emissions Comment (Description of Operating Method): Diesel fuel requirements of 40 CFR Part 80.510(b) – on and after 10/1/2010.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 0.25 lb/hour 0.063 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.15 gm/hp-hr Reference: NSPS Subpart IIII			7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: Potential PM emission rates based on NSPS Subpart IIII PM standard of 0.15 g/hp-hr (EPA Nonroad Diesel Engine Tier 2) and 757 hp. Potential annual emission rate based on 500 hrs/yr operation.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.15 gm/hp-hr	4. Equivalent Allowable Emissions: 0.25 lb/hour 0.063 tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart III.	
6. Allowable Emissions Comment (Description of Operating Method): NSPS Subpart III (EPA Nonroad Diesel Engine Tier 2)	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: CO		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 5.8 lb/hour 1.5 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 3.5 gm/hp-hr Reference: NSPS Subpart IIII		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): Tons/year N/A	8.b. Baseline 24-month Period: N/A From: To:		
9.a. Projected Actual Emissions (if required): Tons/year N/A	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A		
10. Calculation of Emissions: Potential CO emission rates based on NSPS Subpart IIII CO standard of 3.5 g/hp-hr (EPA Nonroad Diesel Engine Tier 2) and 757 hp. Potential annual emission rate based on 500 hrs/yr operation.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 3.5 gm/hp-hr	4. Equivalent Allowable Emissions: 5.8 lb/hour 1.5 tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart III.	
6. Allowable Emissions Comment (Description of Operating Method): NSPS Subpart III (EPA Nonroad Diesel Engine Tier 2)	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: VOC (HC)		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 2.4 lb/hour 0.60 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 1.44 gm/hp-hr Reference: NSPS Subpart IIII			7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: Potential VOC (HC) emission rates based on 30% of NSPS Subpart IIII NO_x + HC standard of 4.8 g/hp-hr (EPA Nonroad Diesel Engine Tier 2) and 757 hp. Potential annual emission rate based on 500 hrs/yr operation.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 4.8 gm/hp-hr (NO_x + HC)	4. Equivalent Allowable Emissions: 2.4 lb/hour 0.60 tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart III.	
6. Allowable Emissions Comment (Description of Operating Method): NSPS Subpart III (EPA Nonroad Diesel Engine Tier 2) Equivalent allowable emissions based on 30% of NO_x + HC standard.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

Section [6] of [7]

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: VE 20	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: Rule 62-296.320(4)(b), F.A.C.	

Visible Emissions Limitation: Visible Emissions Limitation of

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

EMISSIONS UNIT INFORMATION

Section [6] of [7]

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor of **NOT APPLICABLE**

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

EMISSIONS UNIT INFORMATION

Section [6] of [7]

I. EMISSIONS UNIT ADDITIONAL INFORMATION**Additional Requirements for All Applications, Except as Otherwise Stated**

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Section 2.0 ☐ Previously Submitted, Date: _____
2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Section 2.0 ☐ Previously Submitted, Date: _____
3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Section 5.0 ☐ Not Applicable
4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable
5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records: ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute: ☐ Attached, Document ID: _____ ☒ Not Applicable

Section [6] of [7]

Additional Requirements for Air Construction Permit Applications

Additional Requirements for Title V Air Operation Permit Applications

Additional Requirements Comment

--

EMISSIONS UNIT INFORMATION

Section [7] of [7]

A. GENERAL EMISSIONS UNIT INFORMATION**Title V Air Operation Permit Emissions Unit Classification**

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)
- ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.
- ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)			
☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).			
☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.			
☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.			
2. Description of Emissions Unit Addressed in this Section: Emergency Fire Water Pump Diesel Engine			
3. Emissions Unit Identification Number: 007			
4. Emissions Unit Status Code: C	5. Commence Construction Date: N/A	6. Initial Startup Date: N/A	7. Emissions Unit Major Group SIC Code: 49
8. Federal Program Applicability: (Check all that apply)			
☐ Acid Rain Unit			
☐ CAIR Unit			
☐ Hg Budget Unit			
9. Package Unit:			
Manufacturer: Caterpillar (or equivalent)		Model Number: C9 ACERT	
10. Generator Nameplate Rating: MW			
11. Emissions Unit Comment:			
Diesel Engine Rating: 275 hp (205 kW)			

EMISSIONS UNIT INFORMATION

Section [7] of [7]

Emissions Unit Control Equipment/Method: Control of **NOT APPLICABLE**

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control of

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control of

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control of

1. Control Equipment/Method Description:

2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control ___ of ___

1. Control Equipment/Method Description:

2. Control Device or Method Code:

EMISSIONS UNIT INFORMATION

Section [7] of [7]

B. EMISSIONS UNIT CAPACITY INFORMATION**(Optional for unregulated emissions units.)****Emissions Unit Operating Capacity and Schedule**

1. Maximum Heat Input Rate: million Btu/hr
2. Maximum Incineration Rate: pounds/hr tons/day
3. Requested Maximum Operating Schedule: hours/day days/week weeks/year 96 hours/year
4. Operating Capacity/Schedule Comment: Excluding operation during emergencies.

EMISSIONS UNIT INFORMATION

Section [7] of [7]

C. EMISSION POINT (STACK/VENT) INFORMATION**(Optional for unregulated emissions units.)****Emission Point Description and Type**

1. Identification of Point on Plot Plan or Flow Diagram: P-10		2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: N/A			
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A			
5. Discharge Type Code: V		6. Stack Height: 10 feet	
		7. Exit Diameter: 0.5 feet	
8. Exit Temperature: 860 °F		9. Actual Volumetric Flow Rate: 2,300 acfm	
		10. Water Vapor: N/A %	
11. Maximum Dry Standard Flow Rate: N/A dscfm		12. Nonstack Emission Point Height: N/A feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) : Longitude (DD/MM/SS) :	
15. Emission Point Comment:			

EMISSIONS UNIT INFORMATION

Section [7] of [7]

D. SEGMENT (PROCESS/FUEL) INFORMATION**Segment Description and Rate:** Segment 1 of 1

1. Segment Description (Process/Fuel Type): Emergency fire water pump diesel engine fired with distillate fuel oil.		
2. Source Classification Code (SCC): 2-01-001-02		3. SCC Units: Thousand Gallons Burned
4. Maximum Hourly Rate: 0.015	5. Maximum Annual Rate: 7.4	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.0015	8. Maximum % Ash: 0.01	9. Million Btu per SCC Unit: 140
10. Segment Comment:		

Segment Description and Rate: Segment of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):		3. SCC Units:
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

EMISSIONS UNIT INFORMATION

Section [7] of [7]

E. EMISSIONS UNIT POLLUTANTS**List of Pollutants Emitted by Emissions Unit**

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NO_x			EL
SO₂			EL
PM/PM₁₀			EL
CO			EL
VOC			EL

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: NO_x		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 1.3 lb/hour 0.32 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 2.10 gm/hp-hr Reference: NSPS Subpart IIII			7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: Potential NO_x emission rates based on 70% of NSPS Subpart IIII NO_x + HC standard of 3.0 g/hp-hr (EPA Nonroad Diesel Engine Tier 3) and 275 hp. Potential annual emission rate based on 500 hrs/yr operation.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 3.0 gm/hp-hr (NO_x + HC)	4. Equivalent Allowable Emissions: 1.3 lb/hour 0.32 tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart III.	
6. Allowable Emissions Comment (Description of Operating Method): NSPS Subpart III (EPA Nonroad Diesel Engine Tier 3) Equivalent allowable emissions based on 70% of NO_x + HC standard.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: SO₂		2. Total Percent Efficiency of Control: N/A	
3. Potential Emissions: 0.0031 lb/hour 0.00078 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.0015 weight % S fuel oil Reference: NSPS Subpart IIII		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: Potential annual emission rate based on 500 hrs/yr operation.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.0015 weight % S fuel oil (on and after 10/1/2010)	4. Equivalent Allowable Emissions: 0.0031 hour 0.00078 tons/year
5. Method of Compliance: Diesel fuel oil vender certification	
6. Allowable Emissions Comment (Description of Operating Method): Diesel fuel requirements of 40 CFR Part 80.510(b) – on and after 10/1/2010.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: PM		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 0.091 lb/hour 0.023 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.15 gm/hp-hr Reference: NSPS Subpart IIII			7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: Potential PM emission rates based on NSPS Subpart IIII PM standard of 0.15 g/hp-hr (EPA Nonroad Diesel Engine Tier 3) and 275 hp. Potential annual emission rate based on 500 hrs/yr operation.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 0.15 gm/hp-hr	4. Equivalent Allowable Emissions: 0.091 lb/hour 0.023 tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart III.	
6. Allowable Emissions Comment (Description of Operating Method): NSPS Subpart III (EPA Nonroad Diesel Engine Tier 3)	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: CO		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 1.6 lb/hour 0.39 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 2.6 gm/hp-hr Reference: NSPS Subpart IIII		7. Emissions Method Code: 0	
8.a. Baseline Actual Emissions (if required): Tons/year N/A	8.b. Baseline 24-month Period: N/A From: To:		
9.a. Projected Actual Emissions (if required): Tons/year N/A	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A		
10. Calculation of Emissions: Potential CO emission rates based on NSPS Subpart IIII CO standard of 2.6 g/hp-hr (EPA Nonroad Diesel Engine Tier 3) and 275 hp. Potential annual emission rate based on 500 hrs/yr operation.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 2.6 gm/hp-hr	4. Equivalent Allowable Emissions: 1.6 lb/hour 0.39 tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart III.	
6. Allowable Emissions Comment (Description of Operating Method): NSPS Subpart III (EPA Nonroad Diesel Engine Tier 3)	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

**F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION –
POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS**

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: VOC (HC)		2. Total Percent Efficiency of Control:	
3. Potential Emissions: 0.55 lb/hour 0.14 tons/year		4. Synthetically Limited? ☒ Yes ☐ No	
5. Range of Estimated Fugitive Emissions (as applicable): N/A to tons/year			
6. Emission Factor: 0.90 gm/hp-hr Reference: NSPS Subpart IIII			7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): Tons/year N/A		8.b. Baseline 24-month Period: N/A From: To:	
9.a. Projected Actual Emissions (if required): Tons/year N/A		9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years N/A	
10. Calculation of Emissions: Potential VOC (HC) emission rates based on 30% of NSPS Subpart IIII NO_x + HC standard of 3.0 g/hp-hr (EPA Nonroad Diesel Engine Tier 3) and 275 hp. Potential annual emission rate based on 500 hrs/yr operation.			
11. Potential, Fugitive, and Actual Emissions Comment:			

**F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION -
ALLOWABLE EMISSIONS**

Complete Subsection F2 if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Allowable Emissions and Units: 3.0 gm/hp-hr (NO_x + HC)	4. Equivalent Allowable Emissions: 0.55 lb/hour 0.14 tons/year
5. Method of Compliance: Engine manufacturer certification per NSPS Subpart III.	
6. Allowable Emissions Comment (Description of Operating Method): NSPS Subpart III (EPA Nonroad Diesel Engine Tier 3) Equivalent allowable emissions based on 30% of NO_x + HC standard.	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

EMISSIONS UNIT INFORMATION

Section [7] of [7]

G. VISIBLE EMISSIONS INFORMATION

Complete Subsection G if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: VE 20	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment: Rule 62-296.320(4)(b), F.A.C.	

Visible Emissions Limitation: Visible Emissions Limitation of

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

EMISSIONS UNIT INFORMATION

Section [7] of [7]

H. CONTINUOUS MONITOR INFORMATION

Complete Subsection H if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor of **NOT APPLICABLE**

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

EMISSIONS UNIT INFORMATION

Section [7] of [7]

I. EMISSIONS UNIT ADDITIONAL INFORMATION**Additional Requirements for All Applications, Except as Otherwise Stated**

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Section 2.0 ☐ Previously Submitted, Date: _____
2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Section 2.0 ☐ Previously Submitted, Date: _____
3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: Section 5.0 ☐ Not Applicable
4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable
5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____ ☒ Not Applicable
6. Compliance Demonstration Reports/Records: ☐ Attached, Document ID: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ Previously Submitted, Date: _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute: ☐ Attached, Document ID: _____ ☒ Not Applicable

Section [7] of [7]

Additional Requirements for Air Construction Permit Applications

Additional Requirements for Title V Air Operation Permit Applications

Additional Requirements Comment

[illegible]

ATTACHMENT A

ACID RAIN PART

Acid Rain Part Application

For more information, see instructions and refer to 40 CFR 72.30, 72.31, and 74; and Chapter 62-214, F.A.C.

This submission is: ☒ New ☐ Revised ☐ Renewal

STEP 1

Identify the source by plant name, state, and ORIS or plant code.

Gainesville Renewable Energy Center	Florida	Pending
Plant name	State	ORIS/Plant Code

STEP 2

Enter the unit ID# for every Acid Rain unit at the Acid Rain source in column "a."

If unit a SO₂ Opt-in unit, enter "yes" in column "b".

For new units or SO₂ Opt-in units, enter the requested information in columns "d" and "e."

a	b	c	d	e
Unit ID#	SO ₂ Opt-in Unit? (Yes or No)	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	New or SO ₂ Opt-in Units Commence Operation Date	New or SO ₂ Opt-in Units Monitor Certification Deadline
BFB	No	Yes	December 2013	March 2014
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		

Gainesville Renewable Energy Center

Plant Name (from STEP 1)

STEP 3

Read the standard requirements.

Acid Rain Part Requirements.

- (1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
 - (i) Submit a complete Acid Rain Part application (including a compliance plan) under 40 CFR Part 72 and Rules 62-214.320 and 330, F.A.C., in accordance with the deadlines specified in Rule 62-214.320, F.A.C.; and
 - (ii) Submit in a timely manner any supplemental information that the DEP determines is necessary in order to review an Acid Rain Part application and issue or deny an Acid Rain Part;
- (2) The owners and operators of each Acid Rain source and each Acid Rain unit at the source shall:
 - (i) Operate the unit in compliance with a complete Acid Rain Part application or a superseding Acid Rain Part issued by the DEP; and
 - (ii) Have an Acid Rain Part.

Monitoring Requirements.

- (1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75, and Rule 62-214.420, F.A.C.
- (2) The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
- (3) The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.
- (4) For applications including a SO₂ Opt-in unit, a monitoring plan for each SO₂ Opt-in unit must be submitted with this application pursuant to 40 CFR 74.14(a). For renewal applications for SO₂ Opt-in units include an updated monitoring plan if applicable under 40 CFR 75.53(b).

Sulfur Dioxide Requirements.

- (1) The owners and operators of each source and each Acid Rain unit at the source shall:
 - (i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)), or in the compliance subaccount of another Acid Rain unit at the same source to the extent provided in 40 CFR 73.35(b)(3), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
 - (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
- (2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
- (3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
 - (i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
 - (ii) Starting on the later of January 1, 2000, or the deadline for monitor certification under 40 CFR Part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
- (4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
- (5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
- (6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain Part application, the Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
- (7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements. The owners and operators of the source and each Acid Rain unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements.

- (1) The designated representative of an Acid Rain unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR Part 77.
- (2) The owners and operators of an Acid Rain unit that has excess emissions in any calendar year shall:
 - (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR Part 77; and
 - (ii) Comply with the terms of an approved offset plan, as required by 40 CFR Part 77.

Recordkeeping and Reporting Requirements.

- (1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the EPA or the DEP:
 - (i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
 - (ii) All emissions monitoring information, in accordance with 40 CFR Part 75, provided that to the extent that 40 CFR Part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply;
 - (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

Gainesville Renewable Energy Center

Plant Name (from STEP 1)

**STEP 3,
Continued.****Recordkeeping and Reporting Requirements (cont)**

(iv) Copies of all documents used to complete an Acid Rain Part application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an Acid Rain source and each Acid Rain unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR Part 72, Subpart I, and 40 CFR Part 75.

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.

(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.

(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.

(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.

(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_x averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR Part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.

(7) Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities.

No provision of the Acid Rain Program, an Acid Rain Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a unit can hold; *provided*, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any state law regulating electric utility rates and charges, affecting any state law regarding such state regulation, or limiting such state regulation, including any prudence review requirements under such state law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or

(5) Interfering with or impairing any program for competitive bidding for power supply in a state in which such program is established.

STEP 4**For SO₂ Opt-in
units only.****In column "f" enter
the unit ID# for
every SO₂ Opt-in
unit identified in
column "a" of
STEP 2.****For column "g"
describe the
combustion unit
and attach
information and
diagrams on the
combustion unit's
configuration.****In column "h"
enter the hours.**

f	g	h (not required for renewal application)
Unit ID#	Description of the combustion unit	Number of hours unit operated in the six months preceding initial application

Gainesville Renewable Energy Center

STEP 5

For SO₂ Opt-in units only.
(Not required for SO₂ Opt-in renewal applications.)

In column "i" enter the unit ID# for every SO₂ Opt-in unit identified in column "a" (and in column "f").

For columns "j" through "n," enter the information required under 40 CFR 74.20-74.25 and attach all supporting documentation required by 40 CFR 74.20-74.25.

i	j	k	l	m	n
Unit ID#	Baseline or Alternative Baseline under 40 CFR 74.20 (mmBtu)	Actual SO ₂ Emissions Rate under 40 CFR 74.22 (lbs/mmBtu)	Allowable 1985 SO ₂ Emissions Rate under 40 CFR 74.23 (lbs/mmBtu)	Current Allowable SO ₂ Emissions Rate under 40 CFR 74.24 (lbs/mmBtu)	Current Promulgated SO ₂ Emissions Rate under 40 CFR 74.25 (lbs/mmBtu)

STEP 6

For SO₂ Opt-in units only.

Attach additional requirements, certify and sign.

- If the combustion source seeks to qualify for a transfer of allowances from the replacement of thermal energy, a thermal energy plan as provided in 40 CFR 74.47 for combustion sources must be attached.
- A statement whether the combustion unit was previously an affected unit under 40 CFR 74.
- A statement that the combustion unit is not an affected unit under 40 CFR 72.6 and does not have an exemption under 40 CFR 72.7, 72.8, or 72.14.
- Attach a complete compliance plan for SO₂ under 40 CFR 72.40.
- The designated representative of the combustion unit shall submit a monitoring plan in accordance with 40 CFR 74.61. For renewal application, submit an updated monitoring plan if applicable under 40 CFR 75.53(b).
- The following statement must be signed by the designated representative or alternate designated representative of the combustion source: "I certify that the data submitted under 40 CFR Part 74, Subpart C, reflects actual operations of the combustion source and has not been adjusted in any way."

Signature		Date	
Certification (for designated representative or alternate designated representative only)			
I am authorized to make this submission on behalf of the owners and operators of the Acid Rain source or Acid Rain units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.			
Robert E. Donahoe Name		Vice President of Environmental Services Title	
Gainesville Renewable Energy Center, LLC Owner Company Name			
(617) 482-6150 Phone		bdonahoe@amrenewables.com E-mail address	
Signature <i>Robert E. Donahoe</i>		Date <i>11/24/09</i>	

STEP 7

Read the certification statement; provide name, title, owner company name, phone, and e-mail address; sign, and date.

APPENDIX C

MODELING PROTOCOL AND AGENCY COMMENTS



Environmental Consulting & Technology, Inc.

July 10, 2009
ECT No. 090408-0100

Mr. Cleve Holladay
Florida Department of Environmental Protection
Division of Air Resource Management
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Re: Gainesville Renewable Energy Center (GREC)—Air Quality Impact Analysis Modeling Protocol

Dear Mr. Holladay:

Gainesville Renewable Energy Center, LLC, intends to construct, own, and operate a nominal net 100-megawatt, biomass-fired electric generating facility at a site in Gainesville, Alachua County, Florida. The proposed electrical power plant will be called the Gainesville Renewable Energy Center (GREC). The GREC project will be built on property that is leased from Gainesville Regional Utilities and contained within the site of the existing Deerhaven Generating Station.

An air quality impact analysis modeling protocol for the proposed GREC biomass power project is enclosed for your review and comments.

Please contact me at 352/248-3351 or email at tdavis@ectinc.com if there are any questions regarding this modeling protocol.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Thomas W. Davis, P.E.
Vice President

TWD/dlm

cc: Meredith Bond, USFWS (w/enc)
Stan Krivo, EPA Region 4 (w/enc)
Josh Levine, GREC LLC (w/enc)

Enclosure

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332-6444

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Y:\GDP-09\AR\GREC\TWD0710.DOC.1

AIR QUALITY IMPACT ANALYSIS MODELING PROTOCOL

Prepared for:



Prepared by:



ECT No. 090408-0100

July 2009

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1.0 INTRODUCTION

Gainesville Renewable Energy Center, LLC, intends to construct, own, and operate a nominal net 100-megawatt (MW) biomass-fired electric generating facility at a site in Gainesville, Alachua County, Florida. The proposed electrical power plant will be called the Gainesville Renewable Energy Center (GREC). The GREC project will be built on property that is leased from Gainesville Regional Utilities (GRU) and contained within the site of the existing Deerhaven Generating Station (DGS).

The GREC project will include: (a) areas and equipment used for receiving, processing, handling, and storing woody biomass (biomass) fuel; (b) one biomass-fired bubbling fluidized bed (BFB) steam boiler; (c) one steam turbine generator (STG); and (d) materials handling and storage systems for sand, fly ash, and bottom ash. Ancillary equipment will include a process water treatment system, a four-cell mechanical draft cooling tower, a zero liquid discharge (ZLD) treatment system, and emergency firewater pump and generator diesel engines.

The BFB boiler will be fired with chipped/ground forest residue (primarily residual tops and limbs of trees, unutilized cull trees, precommercial thinning, and slash), mill residue (including sawdust), and urban wood waste (primarily clean wood waste from land clearing and right-of-way maintenance operations as well as waste pallets and storm debris). The BFB boiler will be equipped with natural gas-fired burners for startup purposes only. The two diesel engines will be fired with ultra-low sulfur diesel (ULSD) fuel oil.

The BFB boiler will be equipped with an enhanced selective noncatalytic reduction (SNCR) control system to reduce nitrogen oxides (NO_x) emissions and a fabric filter (i.e., baghouse) to control particulate matter (PM)/particulate matter less than or equal to 10 micrometers (PM_{10}) emissions. Material (i.e., biomass fuel, sand, bottom ash, and fly ash) handling and storage PM/ PM_{10} emissions will be controlled by means of covers, enclosures, watering as necessary, baghouses, and bin vent filters.

GREC will be subject to review and licensing under the Florida Electrical Power Plant Siting Act (FEPPSA) and will also require a Prevention of Significant Deterioration (PSD) air construction permit. For projects subject to PSD review, the Florida Department of Environmental Protection (FDEP) recommends that an air quality impact analysis modeling protocol be submitted for agency review and approval prior to the start of regulatory modeling. Accordingly, this modeling protocol for the GREC project PSD air quality impact analysis was prepared by Environmental Consulting & Technology, Inc. (ECT), for agency review and comments.

This modeling protocol addresses the following major topics:

- General project information, including project description, location, and emissions.
- Pollutants to be evaluated.
- Dispersion models and model options.
- Building wake effects (downwash).
- Receptor grids including terrain considerations.
- Meteorological data.
- Format of model results.
- Additional impacts analysis.

Following this introduction, the GREC project modeling protocol is organized as follows:

- Section 2.0—Project Overview.
- Section 3.0—Modeled Emissions Inventory.
- Section 4.0—Models Proposed and Modeling Techniques.
- Section 5.0—Terrain Consideration.
- Section 6.0—Building Wake Effects.
- Section 7.0—Receptor Grids.
- Section 8.0—Meteorological Data.
- Section 9.0—Class I Area Analyses.
- Section 10.0—Format of Model Results.

2.0 PROJECT OVERVIEW

2.1 PROJECT LOCATION

The GREC project will be built on leased property at the existing GRU DGS, which is located approximately 8 miles northwest of downtown Gainesville and approximately 7 miles southeast of the city of Alachua. Figure 2-1 illustrates the location of the GREC project within the state of Florida and within Alachua County. Figure 2-2 provides an aerial showing the location of the GRU DGS, the GREC site, and the preliminary location and layout of the GREC facility.

2.2 PROJECT DESCRIPTION

The GREC project will include biomass fuel receiving, processing, handling and storage areas; one biomass-fired BFB steam boiler; one STG; and systems used for the handling and storage of sand, fly ash, and bottom ash. Ancillary equipment will include a process water treatment system, a four-cell mechanical draft cooling tower, a ZLD treatment system, and two diesel engines that will be used for the emergency firewater pump and the generator.

The biomass fuel receiving, processing, handling, and storage system will consist of three truck tippers, two sets of screens and hogs (i.e., machines used to grind wood chips), and automatic and manual stacker/reclaimers to maintain an approximate 25-day supply of biomass fuel for the BFB boiler based on full-load operation and average biomass fuel moisture content.

Biomass fuel, consisting of chipped/ground forest residue (primarily residual tops and limbs of trees, unutilized cull trees, precommercial thinning, and slash), mill residue (including sawdust), and urban wood waste (primarily clean wood waste from land clearing and right-of-way maintenance operations as well as waste pallets and storm debris) will be transported to the GREC site by truck. The biomass material will be chipped, ground, or otherwise reduced in size before it is delivered to the GREC site. Between 130 and 150 fuel truck deliveries per day are expected based on the maximum BFB boiler biomass fuel consumption rate/average moisture content and a 6-day-per-week delivery

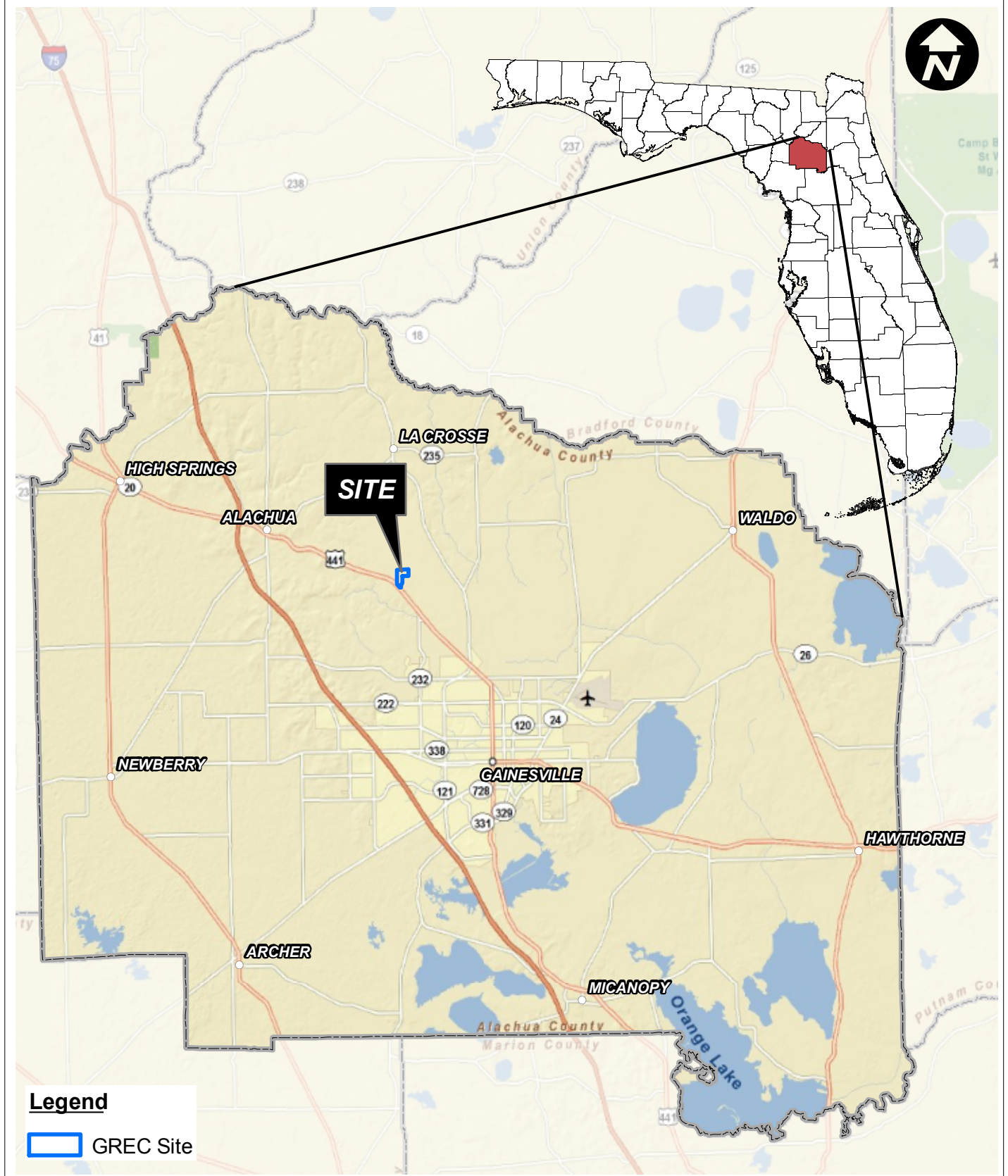


FIGURE 2-1.

GREC SITE LOCATION

Sources: ERSI, 2009; US Census, 2000; ECT, 2009.



FIGURE 2-2.
GAINESVILLE RENEWABLE ENERGY CENTER
PRELIMINARY SITE LOCATION AND LAYOUT

Sources: FDOT, 2008; ECT, 2009.

schedule. The biomass fuel trucks will enter the GREC site from U.S. Highway 441 on the southern side of the site and travel north on a paved roadway to the truck weigh scale and biomass fuel receiving areas. In addition, there will be approximately 40 trucks per week delivering boiler bed sand, aqueous ammonia, and miscellaneous chemicals, as well as removing fly ash and other waste material.

Three truck tippers will be located within a single three-sided (two walls and a roof) shed, which the trucks will enter from one end and exit from the other. Within the biomass fuel unloading shed, a hydraulic dumper will tilt each truck to cause its contents to drop into below-grade receiving hoppers, which will be covered by hydraulic lids when not in use. From these hoppers, the biomass fuel will then be transferred by covered conveyor belts to the biomass fuel processing building. Prior to entering the processing building, the biomass fuel will first pass under a metal detector and magnet to remove ferrous metals.

Incoming biomass fuel will be screened and resized, if necessary, in the fully enclosed fuel processing building. Scalping screens will be used to separate oversize biomass chips from the fuel flow and redirect them to a hogging system. The hogging system will consist of two electric motor-driven hogs that will reduce oversize biomass fuel chips to the size suitable for firing in the BFB boiler. The properly sized biomass fuel and the biomass fuel resized in the hogging system will be transferred from the fuel processing building by covered conveyor belts to the biomass fuel storage piles. The fully enclosed biomass fuel processing building will be vented to a baghouse for abatement of PM/PM₁₀ emissions.

From the biomass fuel processing building, the chipped biomass fuel will be stored in two open piles, which will be managed by a stacker/reclaimer (Storage Pile 1), a fixed stacker (Storage Pile 2), and rolling stock equipment. The biomass fuel reclaim system will provide for automatic reclaim from Storage Pile 1 using the stacker/reclaimer from Storage Pile 1 and manual reclaim from Storage Pile 2 using a front-end loader. The reclaimed biomass fuel from both storage piles will be transferred via a series of covered conveyors and hoppers to the main conveyor belt, which will transfer the biomass fuel to the BFB boiler fuel bins. Telescoping chutes will be employed on both stackers to reduce

fugitive PM/PM₁₀ emissions during the transfer of biomass fuel to the storage piles. The two storage piles will be watered, as necessary, to control wind-blown fugitive PM/PM₁₀ emissions. The biomass fuel conveyor belts will be covered and transfer points enclosed, as practicable, to reduce fugitive PM/PM₁₀ emissions.

In addition to the chipped/ground biomass fuel, moist sawdust (typically obtained from sawmill operations) will be received at the site for use as a supplementary fuel in the BFB boiler. Sawdust will be delivered with self-unloading trucks and deposited in an open area adjacent to Storage Pile 2. The front-end loaders used to manually reclaim fuel from Storage Pile 2 will also be used to reclaim sawdust. The reclaimed sawdust will be blended with the chipped biomass fuel and transferred to the BFB boiler fuel bins. The sawdust storage pile will be watered, as necessary, to control wind-blown fugitive PM/PM₁₀ emissions.

The two BFB boiler biomass fuel bins will each provide storage of biomass fuel sufficient to fuel the boiler for approximately 45 minutes. The BFB boiler biomass fuel bins will be equipped with bin vent filters for control of PM/PM₁₀ emissions.

The biomass fuel will then be transferred from the fuel bins and combusted in the BFB boiler to generate steam. In the BFB boiler, combustion of biomass fuel takes place in the dense fluidized sand bed located at the bottom of the furnace and above the bed. Small fuel particles will burn rapidly above the fluidized bed, while larger particles filter into the bed where they will be dried and gasified. In addition to the biomass fuel, the fluidized bed consists of sieved natural sand, which is maintained in suspension by the fluidizing air system. Sand will be delivered to the site by truck and pneumatically conveyed to a sand silo. The sand silo will be vented to the boiler to control PM/PM₁₀ emissions. The BFB boiler will be equipped with an enhanced SNCR control system to reduce NO_x emissions, and a baghouse to control PM/PM₁₀ emissions.

Steam generated by the BFB boiler will be sent to an 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.

The majority of ash created by the combustion of biomass fuel will exit the BFB boiler as fly ash with only a small amount leaving as bottom ash. Fly ash will be pneumatically conveyed to a single fly ash silo that will be equipped with a baghouse for control of PM/PM₁₀ emissions. 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 open trucks and hauled offsite for reuse or disposal. During the dry transfer of fly ash, an enclosed process will be used 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.

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.

Ancillary GREC emission sources include a four-cell mechanical draft cooling tower and two emergency diesel engines. GREC will operate as a baseload electrical generating facility with continuous operations up to 8,760 hours per year (hr/yr). The boiler will normally operate between 70- and 100-percent load, with commensurate STG load.

2.3 TYPE OF PERMIT REVIEW

GREC will have potential emissions of one or more PSD-regulated pollutants in excess of the PSD significant emission rates (SERs). Therefore, the project will qualify as a *major* source and will be subject to the PSD preconstruction requirements of Section 62-212.400, Florida Administrative Code (F.A.C.), for those pollutants that are emitted at or above the specified PSD SER levels. Among the PSD preconstruction review

requirements is the need to conduct an ambient impact analysis, including a dispersion modeling study.

2.4 POLLUTANTS TO BE EVALUATED

Operation of GREC will result in emissions of PM/PM₁₀, sulfur dioxide (SO₂), NO_x, carbon monoxide (CO), volatile organic compounds (VOCs), and minor amounts of metallic, inorganic, and organic compounds. The BFB boiler will be the primary source of GREC emissions. The biomass fuel, sand, and fly/bottom ash material receiving, processing, handling, and storage systems will result in fugitive and point-source emissions of PM/PM₁₀.

Detailed emission estimates and supporting calculations will be included with the PSD permit application for the GREC project. Based on a preliminary evaluation of potential emission rates, NO_x, CO, VOC, SO₂, PM, PM₁₀, and sulfuric acid (H₂SO₄) mist emissions are each anticipated to exceed the applicable PSD SER.

Ozone is formed in a complex series of chemical reactions involving primarily NO_x and VOCs during warm ambient temperatures in the presence of sunlight. Since ozone is formed from precursor pollutants, assessment of ambient ozone impacts is conducted on a regional basis using resource-intensive models such as the U.S. Environmental Protection Agency (EPA) Community Multiscale Air Quality (CMAQ) model. GREC impacts on ambient ozone concentrations will be evaluated by reviewing current and projected future regional emissions of ozone precursors.

There are no air quality standards or PSD increments for H₂SO₄ mist and PM. On July 18, 1997, EPA revised the National Ambient Air Quality Standards (NAAQS) for PM to add new standards for fine particulate matter less than or equal to 2.5 micrometers (PM_{2.5}) particles. The PM NAAQS were again revised by EPA on October 17, 2006. This revision reduced the existing 24-hour average PM_{2.5} NAAQS from 65 to 35 micrograms per cubic meter (µg/m³), retained the existing 15-µg/m³ annual PM_{2.5} NAAQS, retained the existing 150-µg/m³ 24-hour average PM₁₀ NAAQS, and revoked the existing 50-µg/m³ annual PM₁₀ NAAQS. On May 16, 2008, EPA issued a final rule implementing

the New Source Review (NSR) program with respect to the 1997 PM_{2.5} NAAQS. This rule, which became effective July 15, 2008, requires states with approved state implementation plan (SIP) PSD programs to submit revised PSD programs implementing the PM_{2.5} NSR requirements within 3 years of the effective date of EPA's final rule. Accordingly, Florida (which has a SIP-approved PSD program), is required to submit its PM_{2.5} NSR SIP revision no later than July 15, 2011. On October 23, 1997, EPA issued guidance regarding interim implementation of NSR for PM_{2.5}. The 1997 guidance stated that sources should continue to implement an approved PM₁₀ NSR program as a surrogate for meeting PM_{2.5} NSR requirements until certain issues were resolved. As discussed in the preamble to the May 16, 2008, EPA final rule, during the 3-year PM_{2.5} NSR SIP development period, states may continue to implement a PM₁₀ program as a surrogate to meet the PSD program for PM_{2.5} pursuant to the 1997 guidance.

Accordingly, the GREC air quality analysis will evaluate impacts for NO_x, CO, SO₂, and PM₁₀.

3.0 MODELING EMISSIONS INVENTORY

3.1 ON-PROPERTY SOURCES

GREC will include the following emission sources:

- Material (i.e., biomass fuel, BFB boiler sand, aqueous ammonia, fly ash, bottom ash, and miscellaneous chemicals) truck traffic on paved facility roads (fugitive source of PM₁₀).
- Biomass fuel receiving, processing, handling, and storage areas and systems (fugitive and point sources of PM₁₀).
- BFB boiler (point source of NO_x, CO, VOC, SO₂, and PM₁₀).
- Fly ash handling, storage, and truck loading systems (fugitive and point sources of PM₁₀).
- Mechanical draft cooling tower (point source of PM₁₀).
- Emergency diesel engines (NO_x, CO, VOC, SO₂, and PM₁₀ point sources).

The primary GREC emission source will be the BFB boiler. Excluding startups, shutdowns, and malfunctions, the BFB boiler will operate between 70 and 100 percent of its design capacity. The GREC dispersion modeling analysis will evaluate air quality impacts for the BFB boiler at both 70- and 100-percent load conditions.

With the exception of the emergency diesel engines, all of the GREC emission sources listed previously will be addressed in the air quality impact analysis. Excluding emergencies, the firewater pump and generator diesel engines will each be operated for up to 100 hr/yr for periodic reliability and maintenance testing. Since these emergency diesel engines will operate infrequently, their impacts on short-term standards will be insignificant; i.e., the joint probability of occurrence of worst-case meteorology and diesel engine operation will be low.

The ambient impact analysis submitted to FDEP will include summary tables of maximum short-term emission rates and stack parameters for each modeled GREC emission

source. Emission rates used for annual average impacts will be annualized based on the projected worst-case annual operating mode.

3.2 OFF-PROPERTY SOURCES

Maximum GREC air quality impacts are expected to be below the PSD significant impact levels (SILs) for all PSD pollutants. Accordingly, a cumulative multisource assessment of NAAQS attainment and PSD Class I and II increment consumption should not be required for the GREC project. This preliminary conclusion of project impacts will be discussed and fully documented in the GREC air quality impact analysis. If necessary, cumulative modeling will be conducted by obtaining appropriate emission inventories from the FDEP for emission sources located within 50 kilometers of any GREC significant impact area (SIA).

3.3 EMISSION RATE SCALING FACTORS

No scaling factors or variable emission rates will be used in the ambient impact analysis.

4.0 MODELS PROPOSED AND MODELING TECHNIQUES

4.1 MODELS PROPOSED

Air quality models are applied at two levels: screening and refined. At the screening level, models provide conservative estimates of impacts to determine whether more detailed modeling is required. Screening modeling can also be used to identify worst-case operating scenarios for subsequent refined modeling analysis.

The refined level consists of techniques that provide more advanced technical treatment of atmospheric processes. Refined modeling requires more detailed and precise input data, but also provides improved estimates of source impacts. For the GREC air quality impact analysis, the current version of the EPA-approved American Meteorological Society (AMS)/EPA Regulatory Model (AERMOD) modeling system, together with two sets of 5 years of hour-by-hour National Weather Service (NWS) meteorology will be used to obtain refined impact predictions for short-term periods (i.e., periods equal to or less than 24 hours) as well as annual average concentrations.

Recommended procedures for conducting air quality impact assessments are contained in EPA's *Guideline for Air Quality Models* (GAQM) (EPA, 2006d). The GAQM is codified in Appendix W of Chapter 40, Part 51, Code of Federal Regulations (CFR). In the November 9, 2005, Federal Register, EPA approved use of AERMOD as a GAQM Appendix A *preferred* model effective December 9, 2005. AERMOD is recommended for use in a wide range of regulatory applications, including both simple and complex terrain. The AERMOD modeling system consists of meteorological and terrain preprocessing programs (AERMET and AERMAP, respectively) and the AERMOD dispersion model. Accordingly, the current EPA-approved version of AERMOD (Version 07026 – January 26, 2007) will be used to assess GREC project air quality impacts at receptors located within 50 kilometers (km) of the project site.

Procedures applicable to the AERMOD modeling system specified in the latest version of the *User's Guide for the AMS/EPA Regulatory Model – AERMOD* (September) (EPA, 2004a), addenda to the User's Guide (EPA, 2006a), the *AERMOD Implementation Guide*

(last revised March 19, 2009), and EPA's GAQM will be followed. In particular, the AERMOD control pathway MODELOPT keyword parameters DFAULT and CONC will be selected. Selection of the parameter DFAULT, which specifies use of the regulatory default options, is recommended by the GAQM. The CONC option specifies the calculation of concentrations. GREC will be located in rural Alachua County. Therefore, AERMOD options regarding urban area increased surface heating (URBANOPT keyword), pollutant exponential decay (HALFLIFE and DCAYCOEF keywords), and flagpole receptors (FLAGPOLE keyword) will not be employed.

As previously mentioned, the AERMOD modeling system will be used to determine annual average impacts, in addition to short-term averages, by using the PERIOD parameter for the AVERTIME keyword.

4.2 NO₂ AMBIENT IMPACT ANALYSIS

For annual NO₂ impacts, the tiered screening approach described in GAQM, Section 6.2.3, will be used. Tier 1 of this screening procedure assumes complete conversion of NO_x to NO₂. Tier 2 applies an empirically derived NO₂/NO_x ratio of 0.75 to the Tier 1 results.

5.0 TERRAIN CONSIDERATION

The GAQM defines *flat terrain* as terrain equal to the elevation of the stack base, *simple terrain* as terrain lower than the height of the stack top, and *complex terrain* as terrain exceeding the height of the stack being modeled. As previously discussed in Section 4.1, AERMOD is capable of developing estimates of air quality impacts for all three types of terrain.

In accordance with the GAQM recommendations for AERMOD, each modeled receptor will be assigned a terrain elevation based on U.S. Geological Survey (USGS) 7.5-minute digital elevation model (DEM) data and use of the AERMAP (Version 09040 – April 17, 2009) preprocessing program. AERMAP will be used in accordance with the latest version (October) (EPA, 2004b) of the *User's Guide for the AERMOD Terrain Preprocessor (AERMAP)*, addenda to the User's Guide (EPA, 2006b), and EPA's GAQM.

6.0 BUILDING WAKE EFFECTS

The Clean Air Act Amendments of 1990 require the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds good engineering practice (GEP) or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (40 CFR 51). The stack heights for the GREC emission sources will comply with the EPA stack height regulations (40 CFR 51).

While the GEP stack height rules address the maximum stack height that can be employed in a dispersion model analysis, stacks having heights lower than GEP stack height can potentially result in higher downwind concentrations due to building downwash effects. AERMOD evaluates the effects of building downwash based on the plume rise model enhancements (PRIME) building downwash algorithms. For the GREC ambient impact analysis, the complex downwash analysis implemented by AERMOD will be performed using the current version of EPA's Building Profile Input Program (BPIP) for PRIME (BPIP-PRM—Version 04274 [September 30, 2004]). The EPA BPIP-PRM program will be used to determine the area of influence for each building, whether a particular stack is subject to building downwash, the area of influence for directionally dependent building downwash, and to generate the specific building dimension data required by the model. BPIP-PRM output consists of an array of 36 direction-specific (10 to 360-degree [°]) building heights (BUILDHGT keyword), lengths (BUILDLN keyword), widths (BUILDWID keyword), and along-flow (XBADJ keyword) and across-flow (YBADJ keyword) distances for each stack suitable for use as input to AERMOD.

7.0 RECEPTOR GRIDS

Receptors will be placed at locations considered to be *ambient air*, which is defined as “that portion of the atmosphere, external to buildings, to which the general public has access.” GREC will be located on property leased from GRU. The entire perimeter of the GRU DGS site, including the property to be leased to GREC, is fenced. Therefore, the nearest locations of general public access will be at the GRU DGS fence line.

Consistent with GAQM and FDEP guidance, the GREC ambient impact analysis will use the following receptor grids:

- Fence Line Receptors—Receptors placed on the GREC leased property boundary spaced 50 meters apart.
- Near-Field Cartesian Receptors—Receptors at 100-meter spacings starting 100 meters from the GREC leased property boundary receptors and extending to 3,000 meters from the center of the GREC site.
- Mid-Field Cartesian Receptors—Receptors at 250-meter spacings starting at 3,250 meters and extending to 6,000 meters from the center of the GREC site.
- Far-Field Cartesian Receptors—Receptors at 500-meter spacings starting at 6,500 meters and extending to 15,000 meters from the center of the GREC site.

The receptor grids used for the ambient impact analysis will be refined following preliminary modeling, as necessary, to ensure that the highest ambient impacts for each pollutant and averaging period have been identified using a receptor spacing of no more than 100 meters.

8.0 METEOROLOGICAL DATA

The EPA AERMET and AERSURFACE meteorological data preprocessing programs will be used to generate the meteorological data required by AERMOD.

The AERMET meteorological preprocessing program creates two files that are used by AERMOD (i.e., surface and profile files). The surface file contains boundary layer parameters including friction velocity, Monin-Obukhov length, convective velocity scale, temperature scale, convectively generated boundary layer (CBL) height, stable boundary layer (SBL) height, and surface heat flux. The profile file contains multilevel data of windspeed, wind direction, and temperature.

AERMET passes all observed meteorological parameters to AERMOD, including wind direction and speed (at multiple heights, if available), temperature, and, if available, measured turbulence. AERMOD uses this information to calculate concentrations in a manner that accounts for a dispersion rate that is a continuous function of meteorology. The current EPA-approved version of AERMET (Version 06341 – December 7, 2006) will be used in accordance with the latest version (November) (EPA, 2004c) of the *User's Guide for the AERMOD Meteorological Preprocessor (AERMET)*, addenda to the User's Guide (EPA, 2006c), and EPA's GAQM.

The AERMET meteorological processor requires the determination of three surface characteristics: surface roughness length (z_0), albedo (r), and Bowen ratio (B_0). Surface roughness length is related to the height of obstacles to the wind flow and is the height at which the mean horizontal wind speed is zero based on a logarithmic profile. Surface roughness length influences the surface shear stress and is an important factor in determining the magnitude of mechanical turbulence and the stability of the boundary layer. Albedo is the fraction of total incident solar radiation reflected by the surface back to space without absorption. The daytime Bowen ratio, an indicator of surface moisture, is the ratio of sensible heat flux to latent heat flux and, together with albedo and other meteorological observations, is used for determining planetary boundary layer parameters for convective conditions driven by the surface sensible heat flux. The EPA AERSUR-

FACE program was developed to aid users in obtaining realistic and reproducible surface characteristic values, including albedo, Bowen ratio, and surface roughness length, for input to AERMET. The program uses publicly available national land cover datasets and look-up tables of surface characteristics that vary by land cover type and season. The current EPA-approved version of AERSURFACE (Version 08009 – January 9, 2008) will be used in accordance with the latest version (January 2008) of the *AERSURFACE User's Guide*, updates to the User's Guide, and EPA's GAQM.

The nearest source of surface meteorological data is the NWS site (Weather-Bureau-Army-Navy [WBAN] Station No. 12816) located at the Gainesville Regional Airport (GRA) approximately 10 miles southeast of the GREC site. The nearest source of upper air meteorological data is the NWS site (WBAN Station No. 13889) located at the Jacksonville International Airport (JIA) approximately 66 miles northeast of the GREC site. Due to the proximity of the GRA and JIA meteorological stations, and in accordance with FDEP guidance, the most recent 5 years (i.e., (2001 through 2005) of readily available surface and upper air meteorological data from the GRA and JIA airports will be used for the GREC air quality impact analysis.

Since surface characteristics influencing dispersion within 1 km of the GRA meteorological station differ from the GREC site, two sets of meteorological data will be used to determine maximum GREC PSD Class II air quality impacts. Each dataset will contain 5 consecutive years (i.e., 2001 through 2005) of GRA surface and JIA upper air meteorological data. The first set will use the surface characteristics of the GRA site, while the second set will employ the GREC site surface characteristics. Figures 8-1 and 8-2 provide aerial views of the GREC and GRA sites, respectively. Both 5-year sets of GRA/JIA meteorological data, in conjunction with the AERMOD dispersion model, will be used to determine maximum GREC air quality impacts.

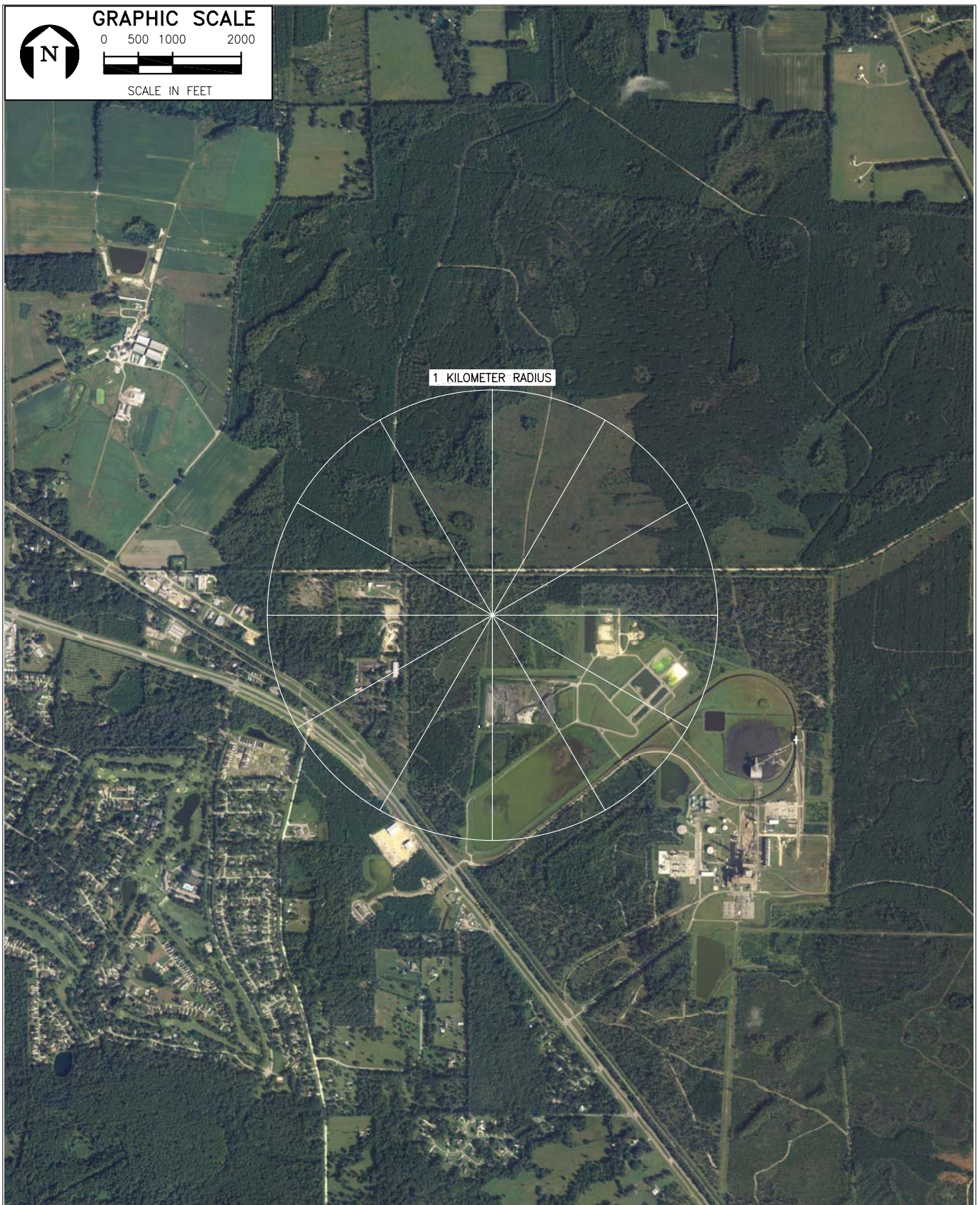


FIGURE 8-1.
GREC SITE AERIAL

Sources: SJRWMD, 2007; ECT, 2009.



FIGURE 8-2.
GAINESVILLE REGIONAL AIRPORT AERIAL

Sources: SJRWMD, 2007; ECT, 2009.

9.0 CLASS I AREA ANALYSES

GREC will be located within 300 km of five PSD Class I areas. The nearest PSD Class I area is the Okefenokee National Wildlife Refuge (NWR) located approximately 93 km (58 miles) north of the project site. The remaining Class I areas located within 300 km of the GREC site include:

- Chassahowitzka NWR, located 110 km (68 miles) south-southeast of the project site.
- St. Marks NWR, located 159 km (99 miles) west-northwest of the project site.
- Bradwell Bay NWR, located 211 km (131 miles) west-northwest of the project site.
- Wolf Island NWR, located 202 km (126 miles) northeast of the project site.

Figure 9-1 depicts the locations of these PSD Class I areas and the GREC site.

In accordance with current Federal Land Manager (FLM) and FDEP guidance, assessment of Class I area impacts will be required. ECT will provide this modeling protocol to the U.S. Fish and Wildlife Service (USFWS) and seek guidance regarding the need to conduct Class I area air quality impact analyses for the more distant PSD Class I areas using FLM-recommended screening procedures.

The following sections discuss the dispersion models and programs, meteorological data, receptor grids, and modeled emission sources proposed for the GREC PSD Class I air quality impact analyses.

9.1 MODEL SELECTION AND USE

For those PSD Class I areas that require air quality impact assessments, the required analyses will be conducted using the GAQM approved California Puff (CALPUFF) suite of modeling programs, including CALMET, CALPUFF, POSTUTIL, and CALPOST. These programs will be used in accordance with the recommendations contained in the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report*

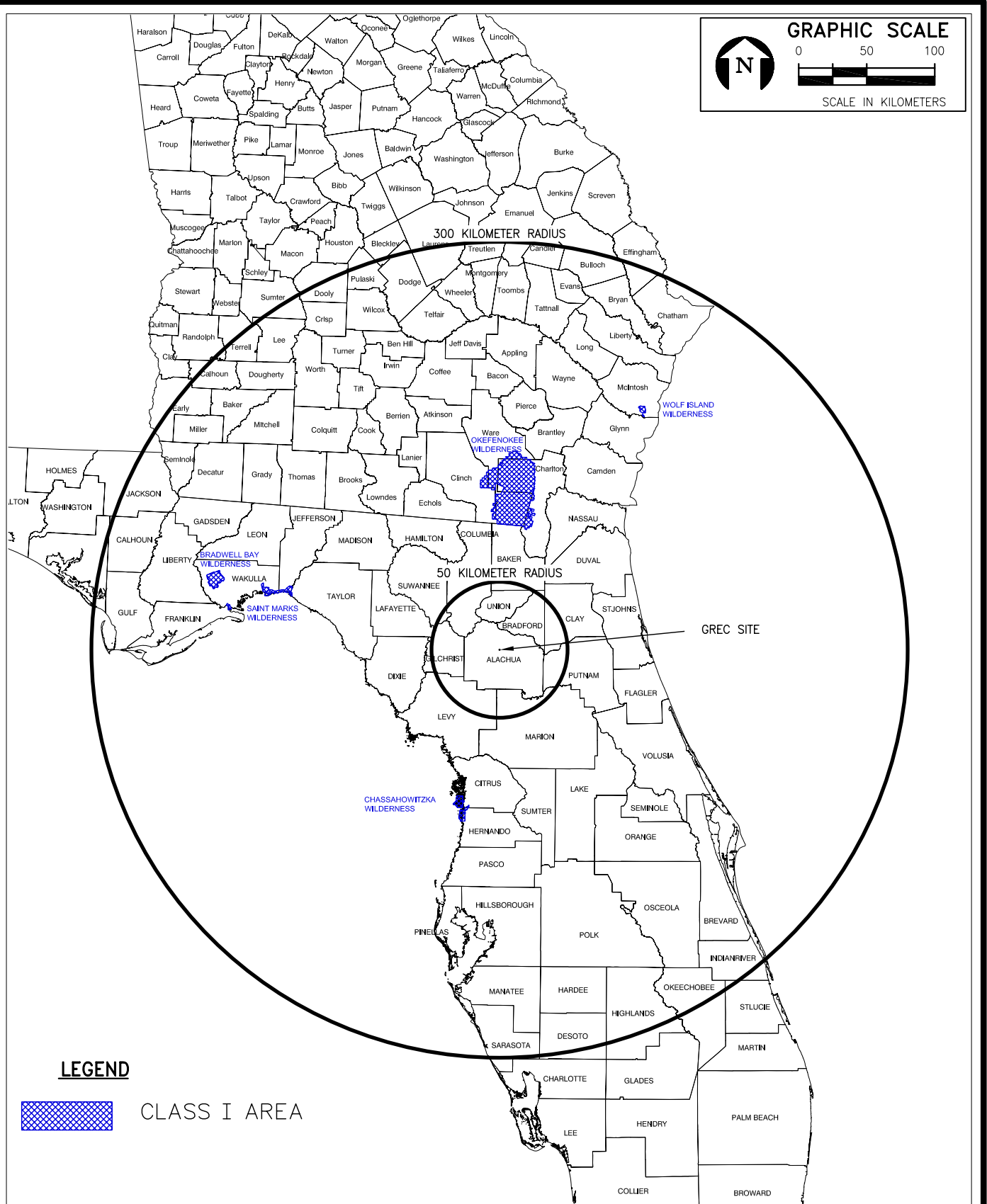


FIGURE 9-1.
CLASS I AREAS WITHIN 300 KM OF THE GREC SITE

Sources: FWS, 2007; USFS, 2007; NPS, 2007; ECT, 2009.

and Recommendations for Modeling Long Range Transport Impacts dated December 1998 (with respect to PSD Class I increment analyses), and the *Federal Land Managers' Air Quality-Related Values Workgroup (FLAG) Phase I Report* dated December 2000 (with respect to regional haze and deposition analyses). The EPA-approved CALPUFF modeling suite is comprised of the following programs:

- | | | |
|------------|-----------------|---------------|
| • CALMET | Version: 5.8 | Level: 070623 |
| • CALPUFF | Version: 5.8 | Level: 070623 |
| • POSTUTIL | Version: 1.56 | Level: 070627 |
| • CALPOST | Version: 5.6394 | Level: 070622 |

These programs will be used to assess PSD Class I increments, regional haze, and nitrogen and sulfur deposition impacts.

CALMET is a meteorological model that develops hourly wind and temperature fields on a three-dimensional gridded modeling domain. The meteorological file produced by CALMET for use by CALPUFF also includes two-dimensional parameters such as mixing height, surface characteristics, and dispersion properties.

CALPUFF is a transport and puff model that advects puffs of material from an emission source. These puffs undergo various dispersion and transformation simulation processes as they are advected from an emission source to a receptor of interest. The simulation processes include wet and dry deposition and chemical transformation. CALPUFF typically uses the gridded meteorological data created by the CALMET program. CALPUFF generates output files consisting of hourly concentrations, deposition fluxes, and data required for visibility assessments for each receptor. These CALPUFF output files are subsequently processed by the POSTUTIL and CALPOST programs to provide impact summaries for the pollutants and averaging periods of interest. Key CALPUFF model options that will be used for the GREC PSD Class I impact assessments are as follows:

- CALPUFF domain configured to include the GREC project and all Class I receptors with a minimum 50-km buffer in all directions.
- 4-km spacing meteorological and computational grid.

- Class I receptors as defined by the National Park Service (NPS).
- Modeling of SO₂, sulfite, NO_x, nitric acid (HNO₃), nitrate, and appropriate PM size fractions for biomass-fired BFB boilers.
- Use of the MESOPUFF II chemical mechanism module.
- IWAQM default guidance, including Pasquill-Gifford dispersion coefficients.
- 2001 through 2003 ozone data from the Clean Air Status and Trends Network (CASTNet) and Atmospheric Infrared Sounder (AIRS) stations.
- Background ammonia concentration of 0.5 part per billion (ppb).
- Integrated puff-sampling methodology.
- No consideration of building downwash.

The current EPA-approved version of the CALPUFF dispersion model (Version 5.8, Level 070623) will be employed to develop estimates of GREC impacts for PSD Class I increments, regional haze, and deposition.

POSTUTIL is a postprocessing program used to process the concentrations generated by CALPUFF. POSTUTIL will be used to recompute the HNO₃/nitrate concentration partition, develop visibility PM component emission rates (i.e., elemental and organic carbon PM fractions), consolidate the PM₁₀ impacts (i.e., impacts due to PM₁₀ fractions and primary sulfate), consolidate the wet and dry nitrogen and sulfur fluxes, and convert sulfate and nitrate fluxes to total sulfur and total nitrogen fluxes. The current EPA-approved version of the POSTUTIL program (Version 1.56, Level 070627) will be used for the GREC PSD Class I impacts analyses.

CALPOST is a post-processing program used to process the concentration, deposition, and visibility files generated by CALPUFF. The CALPOST program was formulated to average and report pollutant concentrations or wet/dry deposition fluxes using the hourly data contained in the CALPUFF output files. CALPOST can produce summary tables of pollutant concentrations and depositions for each receptor for various averaging times and can develop ranked lists of these impacts. For visibility-related modeling (e.g., re-

gional haze), CALPOST uses the CALPUFF-generated pollutant concentrations to calculate extinction coefficients and other related indicators of visibility. The various CALPOST program options are implemented by means of a control file. CALPOST options selected for the GREC PSD Class I area impact assessments will conform to the recommendations contained in the IWQAM Phase 2 and FLAG Phase 1 reports and NPS guidance. The current EPA-approved version of the CALPOST program (Version 5.8, Level 070623) will be used for the GREC PSD Class I impacts analyses.

Because GREC will be located at a distance greater than 50 km from the nearest PSD Class I area, nearfield coherent plume visibility impacts are not required. For distant regional haze assessments, the CALPUFF, POSTUTIL, and CALPOST models will be used in accordance with the FLAG Phase 1 report recommendations.

9.2 METEOROLOGICAL DATA

The Visibility Improvement State and Tribal Association of the Southeast (VISTAS) has developed a 3-year (2001 through 2003) CALMET dataset for a fine, 4-km, subregional domain that covers all of Florida and the adjacent Class I areas of interest to Florida. The VISTAS 2001 to 2003 meteorological data was reprocessed by the U.S. Fish and Wildlife Service (USFWS) using the current EPA regulatory version of CALMET (i.e., Version 5.8, Level 070623). This reprocessed fine-grid CALMET dataset (containing more than 250 gigabytes [GB] of data) was obtained from FDEP and will be used for the GREC PSD Class I impact assessments.

9.3 RECEPTOR GRIDS

For those PSD Class I areas requiring air quality impact assessments, the discrete receptors identified by NPS for each Class I area will be evaluated. The Class I receptor locations, which are provided by NPS in geographic (latitude and longitude) coordinates, will be converted to Lambert Conformal Conic (LCC) coordinates consistent with the VISTAS fine 4-km CALMET grid parameters (i.e., two matching parallels, latitude/longitude of the projection origin, and coordinate datum) using the NPS Class I areas conversion program.

9.4 MODELED EMISSION SOURCES

The GREC project modeled emission source will include only the biomass-fired BFB boiler operating at 100 percent of its design capacity. The BFB boiler is the primary GREC emission source. The remaining GREC emission sources (i.e., the biomass fuel, sand, bottom ash, and fly ash material receiving, handling, and storage systems; the mechanical draft cooling tower; and the emergency diesel engines) will operate intermittently and will have minor emission rates and low release heights.

10.0 MODEL RESULTS

10.1 PRESENTATION OF MODEL RESULTS

The primary objective of the GREC ambient impact analysis is to demonstrate that emissions from the proposed project will not cause or significantly contribute to a violation of any NAAQS or PSD increment. As previously discussed in Section 4.0, refined modeling will be performed to determine maximum GREC air quality impacts. It is anticipated that maximum GREC project impacts will be below the PSD Class I and II SILs for all PSD pollutants.

Refined modeling results obtained from the AERMOD modeling system will be summarized in tabular format. For the PSD *de minimis* and Class II SIL analyses, the model result tables will indicate, for each pollutant, the year of meteorology, applicable averaging period, and magnitude and location of the maximum modeled impact. If an NAAQS analysis is necessary, the model results tables will indicate, for each pollutant, the year of meteorology, applicable averaging period, magnitude and location of the maximum modeled impact, background concentration, and total impact. For the PSD Class II increment analysis (if necessary), the same data will be presented with the exception of background concentrations. The summary tables will include the PSD *de minimis* and Class II SILs, NAAQS, and PSD Class II increments, as appropriate, for comparison purposes.

PSD Class I area modeling results obtained from the CALPUFF modeling suite will also be summarized in tabular format. For the PSD Class I significant impact analyses, model result tables will indicate, for each pollutant, the year of meteorology, applicable averaging period, and magnitude and location of the maximum modeled impact. For the PSD Class I increment analysis (if necessary), the same data will be presented. The summary tables will include the PSD Class I SILs and PSD Class I increments, as appropriate, for comparison purposes. The Class I area impact analyses will also include tabular results of the visibility and deposition assessment results.

The ambient impact analysis will include all methods and data used in conducting the dispersion modeling study. All building downwash, dispersion model input and output, and meteorological data files will be provided (on magnetic media) with the analysis.

10.2 ADDITIONAL IMPACT ANALYSES

The additional impact analysis will discuss GREC project impacts pertaining to associated growth, soils and vegetation, and visibility impairment.

Project impacts due to associated growth will evaluate, in qualitative terms, potential air quality impacts resulting from project construction, affects on local fuel markets, increase in vehicle miles traveled resulting from GREC construction and operation, and any secondary growth. An evaluation of the change in regional air quality since 1977 due to growth will also be provided.

The soils and vegetation analysis will be conducted by comparing projected ambient concentrations for the pollutants of concern with applicable susceptibility data from the air pollution literature. For most types of soils and vegetation, ambient air concentrations of criteria pollutants below the NAAQS will not result in harmful effects. If sensitive vegetation is determined to be present, a more extensive assessment of potential adverse effects will be conducted.

No visibility impairment at the local level is expected due to the types and quantities of emissions projected for the GREC project. Visibility impairment will be evaluated based on an assessment of GREC project emissions and applicable FDEP requirements pertaining to visible emissions.

REFERENCES

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- U.S. Environmental Protection Agency (EPA). 1985. Guidelines for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations [Revised]). EPA-450/4-80-023R. Research Triangle Park, North Carolina.
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- . 2006c. Addendum User's Guide for the AERMOD Meteorological Preprocessor (AERMET). EPA-454/B-03-002. Research Triangle Park, North Carolina.
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- U.S. Forest Service, National Park Service, U.S. Fish and Wildlife Service. 2000. Federal Land Managers' Air Quality-Related Values Workgroup (FLAG) Phase I Report.

Tom Davis

From: Holladay, Cleve [Cleve.Holladay@dep.state.fl.us]
Sent: Wednesday, August 05, 2009 4:12 PM
To: Tom Davis
Subject: EPA Comments on GRU Modeling Protocol
Attachments: Alternate Procedure for Determining Class I Impacts When FLM Doesn't Request ARQV Analysis.doc.docx

The following are Stan Krivo's review comments on the above referenced air quality modeling protocol for the proposed construction and operation of a 100-megawatt biomass-fired electric generating facility. GREC will be located on leased land from Gainesville Regional Utilities. These comments are provided for your use in reviewing this protocol.

Proposed Project - The following comments are associated with the proposed project description.

- It appears that the existing Deerhaven Generating Station (DGS) and the proposed GREC are owned and operated by different entities. The relationships (e.g., ownership, contractual, etc.) between DGS and GREC should be provided. If other facilities are located within the Gainesville Regional Utilities property they should be identified along with any relationships (e.g., owners, shared resources, business contracts, etc.).
- Although the emission estimates for the proposed GREC were not provided, the PSD applicable pollutants were indicated to be SO₂, CO, VOC, NO_x, PM, PM₁₀ and sulfuric acid (H₂SO₄). The basis for the project emission estimates should be provided in the application.
- PM_{2.5} emissions were not considered in the protocol. Estimates of PM_{2.5} emissions from the project should be provided.
- The non-ambient air for GREC depends on the amount of land leased and the existence of barrier(s) to public access. The relationship between other facilities within Gainesville Regional Utilities may also affect this GREC non-ambient air determination. [22 June 2007 Steve Page Memorandum "Interpretation of "Ambient Air" in Situations Involving Leased Land Under the Regulations for Prevention of Significant Deterioration (PSD)" at <http://www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/leaseair.pdf>]
- The biomass fuel brought to the site in trucks will have been chipped, ground, and reduced in size. It is assumed that this biomass pre-treatment will occur at other offsite locations by facilities not owned or under the control of GREC.
- The protocol indicates the emergency generators and firewater pump diesel engines will operate 100 hours/year but they will not be included in the modeling. It is suggested that their emissions be included at least in the short-term modeling.

Assessment of PM_{2.5} Impacts - The USEPA PM₁₀ surrogate policy will be used to assess PM_{2.5} impacts. Because this surrogate policy is currently under review it is suggested that the appropriateness of this policy for this project be addressed (e.g., the characteristics of the project PM_{2.5} emissions are such that meeting the PM₁₀ PSD and NSR program requirements will be protective of the PM_{2.5} ambient air quality). Otherwise the impacts of PM_{2.5} project emissions should be addressed.

Receptor Grids - Receptors are proposed along the property fence line of Gainesville Regional Utilities. As indicated in comment 1 above, the non-ambient air for GREC appears to be the land leased and controlled by GREC with the existence of barrier(s) to public access. The guidance provided in the 22 June

2007 Steve Page Memorandum "Interpretation of "Ambient Air" in Situations Involving Leased Land Under the Regulations for Prevention of Significant Deterioration (PSD)" should be used to define GREC non-ambient air.

[<http://www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/leaseair.pdf>]

Meteorological Data - The Gainesville Regional Airport surface and Jacksonville International Airport upper air meteorological data for the period 2001 through 2005 were selected for this analysis. These data will be processed through AERMET twice - once with the Gainesville Regional Airport surface characteristics and once using the project location surface characteristics. The specific procedures (e.g., number of sectors, radii used for roughness, albedo, and Bowen ratio, etc.) were not provided. This information should be contained in the PSD permit application.

Land Use Analysis - The protocol indicates an analysis of the land use characteristics about the project location resulted in rural dispersion coefficients for the impact analyses. The resultant distribution of land use characteristics within the 3 km radius should be provided in the application to support this conclusion.

Inventory of Additional Emission Sources - The procedures propose for the development of NAAQS and PSD inventories of other sources have not been included in the protocol because no significant impacts are expected. If cumulative NAAQS and PSD increment compliance modeling are needed, the development of inventories of other emission sources should be done in coordination with FDEP. The application should describe the procedure used to develop the initial inventories and screen out sources from the modeling.

PSD Class I Area Analysis - The FLM's procedure to assess the need to perform AQRV modeling analyses may not be appropriate for PSD increment assessment. The application should address the project's expected impact on the PSD Class I increments. The emissions and exit stack parameters associated with the worst-case impact scenario should be modeled for this assessment. The procedures used to assess the project's impact on the PSD Class I area increment should be developed in consultation with FDEP and EPA. I am attaching an alternate procedure for Class I increment modeling suggested by Stan Krivo if an AQRV analysis is not requested by the federal land manager.

Additional Impact Analyses - The following comments are associated with the proposed additional analyses.

- A qualitative assessment is proposed for the impacts associated with project related growth. Depending on the expected type of grow and the expected emissions, the growth related impacts can be included in a quantitative impact assessment.
- The soils and vegetation analysis should be performed by comparing the anticipated ambient concentrations after project operation with the applicable susceptibility data. The use of project only impacts are not appropriate for this comparison.
- The need for visibility assessment within the PSD Class II area depends on the size of the significant impact area (SIA) and the location of visibility sensitive receptors. If there are no project SIA or visibility sensitive receptors within the SIA, then no additional visibility impact assessment is needed.

Please let me know if you have any questions.

Cleve

850-921-8986

The Department of Environmental Protection values your feedback as a customer. DEP Secretary Michael W. Sole is committed to continuously assessing and improving the level and quality of services provided to you. Please take a few minutes to comment on the quality of service you received. Simply click on [this link to the DEP Customer Survey](#). Thank you in advance for completing the survey.

APPENDIX D

DISPERSION MODELING FILES

**(Electronic copies of the dispersion modeling files
have been provided to the Florida Department of Environmen-
tal Protection, Bureau of Air Regulation)**

Gainesville Renewable Energy Center Class I Area Dispersion Modeling Files

Directory Name	No. of Files	File Name	File Description
A. Gainesville Renewable Energy Center (GREC) Runs			
CLASS I/PUFF-INP	3	GRECY.Y.INP YY = 01 - 03	CALPUFF input files Year of meteorology
CLASS I/PUFF-OUT	3	GRECY.Y.CON	CALPUFF output concentration files
	3	GRECY.Y.LST	CALPUFF output concentration list files
		YY = 01 - 03	Year of meteorology
Subtotal Files	6		
CLASS I/POST-INP	3	GRECY.NCHA.POI	CALPOST input NO ₂ files - Chassahowitzka NWA
	3	GRECY.PCHA.POI	CALPOST input PM ₁₀ files - - Chassahowitzka NWA
	3	GRECY.SCHA.POI	CALPOST input SO ₂ files - - Chassahowitzka NWA
	3	GRECY.NOKE.POI	CALPOST input NO ₂ files - Okefenokee NWA
	3	GRECY.POKE.POI	CALPOST input PM ₁₀ files - - Okefenokee NWA
	3	GRECY.SOKE.POI	CALPOST input SO ₂ files - - Okefenokee NWA
		YY = 01 - 03	Year of meteorology
Subtotal Files	18		
CLASS I/POST-OUT	3	GRECY.NO2CHA.POL	CALPOST output NO ₂ files - Chassahowitzka NWA
	3	GRECY.PM10CHA.POL	CALPOST output PM ₁₀ files - - Chassahowitzka NWA
	3	GRECY.SO2CHA.POL	CALPOST output SO ₂ files - - Chassahowitzka NWA
	3	GRECY.NO2OKE.POL	CALPOST output NO ₂ files - Okefenokee NWA
	3	GRECY.PM10OKE.POL	CALPOST output PM ₁₀ files - - Okefenokee NWA
	3	GRECY.SO2OKE.POL	CALPOST output SO ₂ files - - Okefenokee NWA
		YY = 01 - 03	Year of meteorology
Subtotal Files	18		
Total Files	45		

Source: ECT, 2009.

Gainesville Renewable Energy Center
Class II Area Dispersion Modeling Files - Significant Impact Level (SIL) Analysis

Directory Name	No. of Files	File Name	File Description
MET/GNV	1	GNV2_AERSURFACE.INP	AERSURFACE input file; Gainesville Airport
	1	GNV2_AERSURFACE.OUT	AERSURFACE output file; Gainesville Airport
	1	GNV2.RP1	AERMOD report file; Stage 1
	1	GNV2.RP2	AERMOD report file; Stage 2
	1	GNV2.RP3	AERMOD report file; Stage 3
	5	2GNVYY.PFL	Meteorological Data - Gainesville/Jacksonville profile files; Gainesville Airport characteristics
	5	2GNVYY.SFC	Meteorological Data - Gainesville/Jacksonville surface files; Gainesville Airport characteristics
MET/GREC SITE	1	SITE2_AERSURFACE.INP	AERSURFACE input file; GREC Site
	1	SITE2_AERSURFACE.OUT	AERSURFACE output file; GREC Site
	1	SITE2.RP1	AERMOD report file; Stage 1
	1	SITE2.RP2	AERMOD report file; Stage 2
	1	SITE2.RP3	AERMOD report file; Stage 3
	5	2SITEYY.PFL	Meteorological Data - Gainesville/Jacksonville profile files; GREC Site characteristics
	5	2SITEYY.SFC	Meteorological Data - Gainesville/Jacksonville surface files; GREC Site characteristics
		YY = 01 - 05	Year of meteorology
Subtotal Files	30		
GEP	1	GREC2.BPI	Building Profile Input Program (BPIP) input file
	1	GREC2.PRO	Building Profile Input Program (BPIP) output file
Subtotal Files	2		
RECEPTOR	1	GREC2FULL.ROU	15 km receptor grid
	1	5KMGREC2.ROU	5 km receptor grid
	1	2KMGREC2.ROU	2 km receptor grid
Subtotal Files	3		
BFBSIL	10	BFBSILYYMZ.INP	BFB Boiler SIL input files
	10	BFBSILYYMZ.OUT	BFB Boiler SIL output files
		YY = 01 - 05 Z = 1 or 2	Year of meteorology 1 = Gainesville Airport characteristics, 2 = GREC Site characteristics
Subtotal Files	20		
COSIL	10	COSILYYMZ.INP	GREC CO SIL input files
	10	COSILYYMZ.OUT	GREC CO SIL output files
		YY = 01 - 05 Z = 1 or 2	Year of meteorology 1 = Gainesville Airport characteristics, 2 = GREC Site characteristics
Subtotal Files	20		
PMSIL	10	PMSILYYMZ.INP	GREC PM ₁₀ SIL input files
	10	PMSILYYMZ.OUT	GREC PM ₁₀ SIL output files
		YY = 01 - 05 Z = 1 or 2	Year of meteorology 1 = Gainesville Airport characteristics, 2 = GREC Site characteristics
Subtotal Files	20		
Total Files	95		

Source: ECT, 2009.

Gainesville Renewable Energy Center
Class II Area Dispersion Modeling Files - Cumulative PM₁₀ Impact Analysis

Directory Name	No. of Files	File Name	File Description
RECEPTOR	1	PM10SIL.ROU	PM ₁₀ SIL receptor grid
Subtotal Files	1		
NAAQS	10	PMNAQYYMZ.INP	PM ₁₀ Cumulative Impacts input files - NAAQS
	10	PMNAQYYMZ.OUT	PM ₁₀ Cumulative Impacts output files - NAAQS
		YY = 01 - 05	Year of meteorology
		Z = 1 or 2	1 = Gainesville Airport characteristics, 2 = GREC Site characteristics
Subtotal Files	20		
PSD	10	PMPSDYYMZ.INP	PM ₁₀ Cumulative Impacts input files - PSD Class II Increment
	10	PMPSDYYMZ.OUT	PM ₁₀ Cumulative Impacts output files - PSD Class II Increment
		YY = 01 - 05	Year of meteorology
		Z = 1 or 2	1 = Gainesville Airport characteristics, 2 = GREC Site characteristics
Subtotal Files	20		
Total Files	41		

Source: ECT, 2009.