TECHNICAL EVALUATION

AND

PRELIMINARY BACT DETERMINATION

Seminole Generating Station Unit 3

Palatka, Putnam County
Florida

Nominal 750 Net MW Supercritical Pulverized Coal Unit
PSD-FL-375
DEP File No. 1070025-005-AC

Division of Air Resources Management
Bureau of Air Regulation
North Permitting Section

August 21, 2006

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, Florida 33618
Authorized Representative: James R. Frauen, Project Director SGS Unit 3

1.2 Reviewing and Process Schedule

03-09-06: Date of receipt of Site Certification Application (SCA)
05-15-06: Application determined to be insufficient by Siting Coordination Office
07-03-06: Application Complete

2. FACILITY INFORMATION

2.1 Facility Location

The Seminole Generating Station (SGS) is located east of U.S. Highway 17, approximately seven miles north of Palatka, Putnam County. The SGS is located approximately 108 kilometers, 137 kilometers and 186 kilometers from the Okefenokee, Chassahowitzka and Wolf Island National Wilderness Areas, respectively. All of these areas are designated Class I PSD Areas. The UTM coordinates of this facility are Zone 17; 438.8 km E; 3,289.2 km N.

2.2 Standard Industrial Classification Codes (SIC)

Industry Group No.	49	Electric, Gas, and Sanitary Services
Industry No.	4911	Electric Services

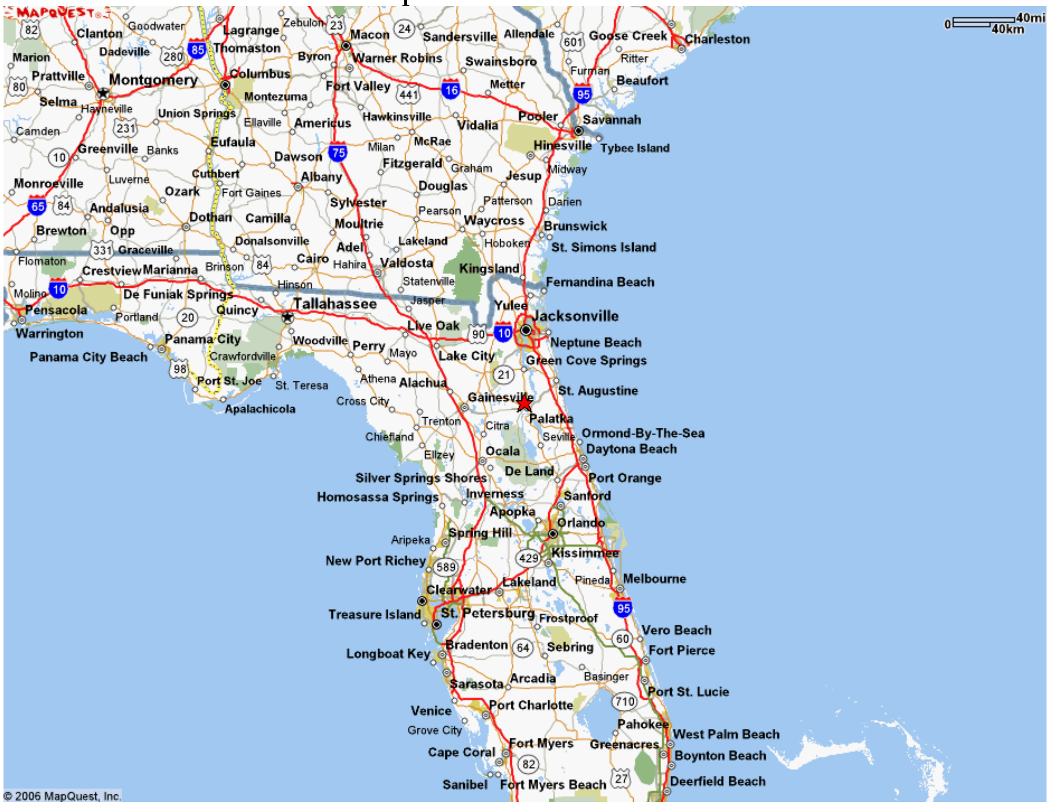
2.3 Facility Category

Steam Electric Generator Units 1 and 2 are coal-fired, utility dry bottom wall-fired boilers, each having a maximum generator rating of 714.6 megawatts, electric. The maximum heat input to each emissions unit is 7,172 million Btu per hour. The only fuels allowed to be fired are coal, coal with a maximum of 30 percent (by weight) petroleum (pet) coke, No. 2 fuel oil, and on-specification used oil. Steam Electric Generator Nos. 1 and 2 are each equipped with an electrostatic precipitator (ESP) to control particulate matter, a wet limestone flue gas desulfurization (FGD) unit to control sulfur dioxide, and low NO_X burners with low excess-air firing to control nitrogen oxides. Both of these generating units are currently undergoing upgrades for air pollution control equipment as per DEP Project 1070025-004-AC.

The emissions units are regulated under: Acid Rain, Phase I; NSPS - 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.; Rule 212.400(PSD), F.A.C., Prevention of Significant Deterioration (PSD); and Rule 62-210.200 (BACT), F.A.C., Best Available Control Technology (BACT) Determination, dated August 9, 1979. Steam Electric Generator No. 2 began commercial operation in 1984 and Steam Electric Generator No. 1 began commercial operation in 1985.

Seminole is identified within an industry included in the list of the 28 Major Facility Categories specified in Rule 62-210.200(164 - Major Stationary Source), F.A.C. The installation of proposed Seminole Unit 3 is considered a “major modification” with respect to Rule 62-212.400(PSD), Prevention of Significant Deterioration, based on at least one potential emission increase at a rate above the PSD Significant Emission Rates defined in Rule 62-210.200(243), F.A.C.

Figure 1
Map and Site Information



Emission reductions will occur in the way of federally enforceable, multi-unit emissions caps for Units 1 and 2 in order to off-set many of the air emission increases associated with the (new) coal-fired Unit 3. Such requested multi-unit emissions caps are typically identified within the specific conditions of the permit, as will be the case for this project. Specifically, the applicant asserts that a BACT Determination is only required for PM, PM_{10}, CO, VOC and HF, and that netting will be used to avoid a PSD/BACT Review for SO_2, NO_X, SAM and Hg.

3. PROJECT AS PROPOSED BY APPLICANT

This project addresses the following emissions units:

EMISSION UNIT NO.	EMISSION UNIT DESCRIPTION
014	SGS Unit 3, 750 MW Supercritical Pulverized Coal
015	Mechanical cooling tower, 26-cell
016	Diesel-Fired Zero Liquid Discharge (ZLD) Spray Dryers (bank of 3)

Seminole proposes to integrate SGS Unit 3 into the existing, certified SGS Site located north of Palatka in Putnam County. SGS Unit 3 (as proposed) will be located adjacent to the existing SGS Units 1 and 2. Seminole anticipates beginning commercial operation of Unit 3 in 2012. The addition of SGS Unit 3 will increase the total output capability of the SGS by almost 60 percent. The design of SGS Unit 3 will maximize the co-use of existing site facilities to the greatest extent possible, including fuel handling facilities (SGS Unit 3 proposes the same fuel slate as SGS Units 1 and 2).

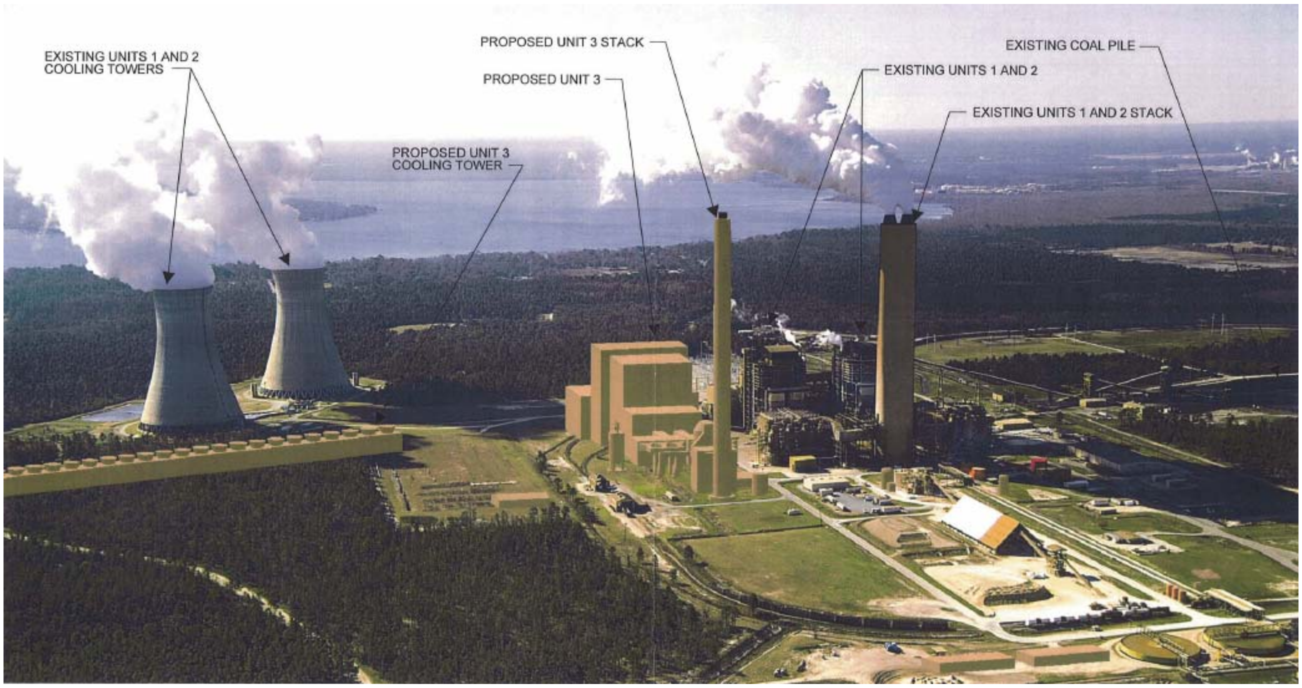
SGS Unit 3 will feature supercritical pulverized coal technology with modern emission controls. The Unit 3 air pollution control equipment will include wet Flue Gas Desulfurization (FGD) for SO_2 removal, selective catalytic reduction (SCR) for control of nitrogen oxides (NO_X), electrostatic precipitator (ESP) for collection and removal of fine particles, a Wet ESP (WESP) for control of sulfuric acid mist (SAM), with fluoride (HF) and mercury (Hg) removal to be accomplished through co-benefits of the above technologies. Fuel (coal and petroleum coke) for SGS Unit 3 will be delivered by an existing rail system.

Under the Unit 3 Site Certification Application (SCA) most process wastewater streams from Units 1 and 2, as well as Unit 3, will be treated and recycled as make-up water to the FGD scrubber system. Wastewater from the existing Units and Unit 3 will be treated as necessary in a proposed zero liquid discharge (ZLD) system that will remove dissolved solids from the wastewater and maximize reuse. Upon initial operation of Unit 3, the only SGS industrial wastewater proposed to be discharged to the St. Johns River from Units 1, 2 and 3 will be cooling tower blowdown.

Net environmental impacts associated with Unit 3, in combination with the Units 1 and 2 pollution controls upgrade (Project 1070025-004-AC), can be summarized as follows:

1) No increase in facility-wide SO_2, NO_X, SAM, and mercury when compared to historical (baseline) air emissions.
2) PSD-Significant increases in facility-wide PM/PM_{10}, CO, VOC and fluoride air emissions.
3) Reuse of FGD product, fly ash and bottom ash.

What follows is the applicant's description of the control technology being proposed. Additionally, the below rendition depicts the expected layout of the facility upon completion.



3.1. PSD Netting Information

Rule 62-210.200(34) defines Baseline Actual Emissions as follows:

(34) "Baseline Actual Emissions" and "Baseline Actual Emissions for PAL" – The rate of emissions, in tons per year, of a PSD pollutant, as follows:

(a) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding the date a complete permit application is received by the Department. The Department shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

The following baseline emission data was provided by the applicant for project No. 107025-004-AC:

Pollutant	Baseline Years	Annual Emissions (TPY)	Basis
SO_2	2004-2005	29,074	CEMS
NO_X	2001-2002	23,289	CEMS
CO	2003-2004	13,451	CEMS
VOC	2002-2003	108	Emission Factors
PM	2002-2003	822	Stack testing
PM_{10}	2002-2003	822	Stack testing
SAM	2002-2003	2,129	Stack testing
Mercury	2004-2005	0.065	Stack testing

The table below illustrates the applicant's estimate of the "post-change" emissions (identified as "Net Emissions Change", inclusive of the complete SGS Unit 3 project) as compared to the Baseline Actual Emissions. Based upon the applicant's submittals, only some PSD pollutants are expected to exceed the significant emission rate, and thus trigger a BACT review.

Pollutant	Baseline Actual Emissions (TPY)	SGS 3 Projected Emissions (TPY)	SGS 1/ 2 [A] Emission Reductions (TPY)	Projected Actual Emissions (TPY)	Net Emissions Change (TPY)	Significant Emission Rate (TPY)	PSD Review Required ?
SO_2	29074	5437	5437	29074	0	40	NO
NO_X	23289	2336	2336	23289	0	40	NO
CO	13451	4936	0	18387	4936	100	**YES**
VOC	108	132	0	240	132	40	**YES**
PM	822	519	0	1341	519	25	**YES**
PM_{10}	822	511	0	1333	511	15	**YES**
SAM	2129	164	164	2129	0	7	NO
Mercury	0.065	0.023	0.023	0.065	0	0.1	NO
Pb	No data	0.247	0	NA	0.247	1	NO
HF	No data	7.5	0	NA	7.5	3	**YES**

Note **A**: 1070025-004-AC establishes enforceable emission limits for SGS 1 and 2, which in combination with the requested limits in this project, keep SGS-3 from triggering a PSD/BACT Review for SO_2, NO_X, SAM and Hg. These emission limitations will also be identified in the SGS-3 permit since PSD avoidance is applied.

3.2. Control of PM/PM_{10}

The proposed BACT for SGS Unit 3 is an emission limit of 0.015 lb/MMBtu using an ESP as the primary PM control device with a Wet ESP (WESP) as a secondary level of control. This technology can achieve the maximum amount of emission reduction available, is technically feasible, demonstrated and is acceptable based on the economic, environmental, and energy impacts.

The applicant states that one reason an ESP is preferable to a fabric filter, is due to the difficulties that fabric filters incur in high-sulfur applications. Additionally, the applicant notes that there is only one fabric filter operating on high-sulfur coal, that unit has been in service under two years, and is unable to achieve the proposed BACT limit for SGS Unit 3. In addition, the ESP is preferable based on the overall cost-effectiveness of the two devices, which is due in part to the increased pressure drop and resulting greater energy penalty associated with a fabric filter.

While the primary purpose of the WESP is to limit emissions of SAM, this control device is equally efficient in removing filterable PM/PM_{10}. The combination of the ESP and WESP will achieve a high degree of PM/PM_{10} emission reduction. The annual PTE is proposed as 493 TPY of PM/PM_{10}.

For the cooling tower, the installation of drift eliminators is the preferred technology for controlling PM emissions. Drift eliminators use inertial separation caused by airflow direction changes to remove water droplets from the air stream exhausting from the cooling tower. These water droplets generally contain the same concentration of dissolved solids and chemical impurities as the water circulating through the tower. Drift eliminator configurations include cellular (or honeycomb), wave-form, and herringbone (blade-type) designs. Drift eliminators may also be constructed of various materials, such as ceramic, fiberglass, metal, plastic and wood installed or formed into slats, sheets, honeycomb assemblies, or tiles.

Particulate emissions from the proposed cooling tower will be controlled utilizing high-efficiency drift eliminators achieving a drift loss rate of 0.0005 percent of the cooling tower re-circulating water flow, consistent with recent BACT determinations. The annual PTE is 9.5/5.5 TPY (PM/PM_{10}).

Particulate emissions from the proposed diesel-fired ZLD Spray Dryers (3) will be controlled by a fabric filter with a removal efficiency of greater than 99.5%. The annual PTE (PM/PM_{10}) is 3.9 TPY.

Annual PM/PM_{10} emissions from the diesel-fired Caterpillar Emergency Generator are 0.04 TPY. Fugitive emissions account for the remainder of the PM/PM_{10} emissions.

3.3. Control of CO Emissions

CO emissions result from incomplete combustion of the fuel. CO emissions for coal-fired steam boilers are typically controlled by boiler design features and combustion controls, as is the case for the proposed SGS Unit 3.

Theoretically, CO emissions can be reduced by passing the flue gas over an oxidation catalyst at a suitable temperature (900 to l000°F). However, this technology has some unknowns such as those listed by the applicant below:

1. Utility pulverized coal-fired boilers have very limited experience with catalytic CO control systems.
2. By their nature, catalysts convert some SO_2 to SO_3 which can induce new problems.
3. Catalysts can be eroded and/or fouled by silica and trace metals in particulate-laden flue gas such as from a coal-fired boiler. Use of such a technology could reduce the availability and reliability of the plant (e.g., catalyst plugging).
4. The additional costs associated with operating a catalytic CO system (i.e., additional pressure drops, potential catalyst replacement and disposal, etc.) were not quantifiable by the applicant.

CO emission limits established as BACT over the last several years range from 0.10 to 0.16 lb/MMBtu, with a median of 0.15 lb/MMBtu. Accordingly, Seminole proposes combustion controls as the primary method used to control CO emissions at a level of 0.13 lb/MMBtu firing coal and 0.15 lb/MMBtu firing the coal/pet coke blend. The annual PTE proposed is 4928 TPY. There are no applicable NSPS for the control of carbon monoxide (CO) from utility boilers.

For the diesel-fired ZLD Spray Dryers, an AP-42 emission factor is used to estimate an annual PTE of 8.11 TPY. Annual CO emissions from the diesel-fired Caterpillar Emergency Generators are also proposed with the use of an AP-42 emission factor, representing an annual PTE of 0.15 TPY.

3.4. Control of VOC Emissions

Similar to CO, there are no applicable NSPS for VOC emissions (hydrocarbons) from utility boilers. VOC emissions result from incomplete combustion of the fuel. This incomplete combustion can result from poor air/fuel mixing or insufficient oxygen for combustion. Such emissions are typically reduced by modifying the design features of the boiler and controlling the combustion air feed rates. According to Seminole, the design of a boiler and combustion air system to efficiently burn the coal represents the control technology with the greatest degree of emissions reduction.

BACT emission limits established over the last several years range from 0.0024 to 0.01, with a median of about 0.004 lb/MMBtu. Accordingly, the proposed BACT emission rate for VOCs would be achieved through good combustion practices, at a proposed level of 0.004 lb/MMBtu representing an annual PTE of 131.4 TPY.

For the diesel-fired ZLD Spray Dryers, an AP-42 emission factor is used to estimate an annual PTE of 0.55 TPY. Annual VOC emissions from the diesel-fired Caterpillar Emergency Generators are also proposed with the use of an AP-42 emission factor, representing an annual PTE of 0.06 TPY.

3.5. Control of Fluoride Emissions

Fluorides are emitted in the combustion process in gaseous and particulate form as a trace element in fuel. The primary control device for fluorides proposed by Seminole is the wet FGD system, since fluorides are highly soluble. Furthermore, those fluorides in particulate form will be readily removed within the ESP. According to the applicant, there are no other control technologies with a greater amount of emissions reduction than the ESP when followed by a wet FGD system. In addition, the incorporation of a WESP assures extremely low emissions of fluorides.

The proposed emission rate of 0.00023 lb/MMBtu as BACT is at the low end of recent BACT determinations, and is based on 97 percent removal.

3.6. Emissions of HAPS

The emergency generator will be subject 40 CFR 63, Subpart ZZZZ, the Reciprocating Internal Combustion Engine (RICE) MACT Rule, since it will be located at a major source of HAP emissions and will have a site rating of greater that 500 horsepower. The emergency generator will only be subject to the notification requirements of the RICE MACT (i.e., no emissions limitations will apply) since it would qualify for the following rule exemption:

Emergency Generator - Any stationary RICE that operates in an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility is interrupted, or stationary RICE used to pump water in case of fire or flood, etc. Emergency stationary RICE may be operated for the purpose of maintenance checks and readiness testing provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of the emergency stationary RICE in emergency situations and for routine testing and maintenance. Emergency stationary RICE may also operate an additional 50 hours per year in non-emergency situations.

Florida's regulations for new stationary sources are covered in the F.A.C. The FDEP has adopted the EPA NSPS by reference in Rule 62-204.800(8) and the EPA NESHAP by reference in Rule 62-204.800(10) and (11).

Although there exist no State or Federal Standards for utility boiler control of Hazardous Air Pollutants (i.e., there is no applicable MACT nor does case-by-case MACT apply; see http://www.epa.gov/air/mercuryrule/rule.htm), the following tables represent the applicant's estimates of those unregulated metal emissions, as well as the regulated (PSD) pollutants of Lead and Mercury.

TRACE METAL HAP EMISSIONS ESTIMATES FOR SECI SGS UNIT 3

	Trace Metal in Coal											
	Antimony	Arsenic	Beryllium	Cadmium	Chromium	Cobalt	Lead	Manganese	Mercury	Nickel	Selenium	Vanadium
Emissions-EPA Factors (EF = a x (C/A x PM) [b]												
Multiplier - a	0.92	3.1	1.2	3.3	3.7	1.7	3.4	3.8		4.4		3.8
Exponent - b	0.63	0.85	1.1	0.5	0.58	0.69	0.8	0.6		0.48		0.6
Concentration (C) (ppm)	1.64	29.72	3.330	0.72	19.21	8.39	22.890	44.97		172.057	4.08	520.736
Actual PM Concentration (PM) (lb/mmBtu)	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150		0.0150		0.0150
Ash Concentration (A) (fraction)	0.1273	0.1273	0.1273	0.1273	0.1273	0.1273	0.1273	0.1273		0.1273		0.1273
Emission Factor (lb/10^12 Btu)	0.327	8.996	0.429	0.961	5.943	1.687	7.520	10.335	0.707	18.654	17.317	44.927
Heat Input (mmBtu/hr)	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500
Maximum Fuel Input (lb/hr)	636,672	636,672	636,672	636,672	636,672	636,672	636,672	636,672	636,672	636,672	636,672	636,672
Emissions (lb/hr)	0.002	0.067	0.003	0.007	0.045	0.013	0.056	0.078	0.005	0.140	0.130	0.337
Uncontrolled (lb/hr)	1.044	18.922	2.120	0.458	12.230	5.342	14.573	28.631		109.544	2.598	331.538
Removal	99.77%	99.64%	99.85%	98.43%	99.64%	99.76%	99.61%	99.73%		99.87%	95.00%	99.90%
Emissions (tons/yr)	0.011	0.296	0.014	0.032	0.195	0.055	0.247	0.339	0.023	0.613	0.569	1.476

Sources: EPA,1998, AP-42, Table 1.1-16 (all metals except mercury, selenium and vanadium), Trace Metal Concentration based on upper 95% Confidence Interval from USGS COALQUAL Database Trace Elements for the Central Appalachian Region
http://energy.er.usgs.gov/coalqual.htm
Controlled Mercury emissions based on 7.05E-06 lb/MW-hr
Controlled Selenium emissions based on 95% control from FGD system
EPA Emission Factor Rating: A-Excellent
Souce: EIR NAPP EIR EIR NAPP EIR EIR EIR
Legend for source: EIR = Eastern Interior Region (Illinois, Indiana, Western Kentucky), CAPP = Central Appalachian, NAPP = Northern Appalachian

As can be seen from this table, each of the listed HAPs emitted are removed at rates of 95% or above, with the removal of all but three of the listed trace metals over 99.6%.

4. RULE APPLICABILITY

The SGS Unit 3 project is subject to preconstruction review requirements and emission limiting standards under the provisions of Chapter 403, Florida Statutes, and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.).

SGS is located in Putnam County, an area designated as attainment for all criteria pollutants in accordance with Rule 62-204.360, F.A.C. As part of the PSD review, PSD Class II and Class I increment analyses are required, if the proposed facility's impacts are greater than the EPA Class I significant impact levels. The nearest PSD Class I area is the Okefenokee National Wilderness Area (NWA), located approximately 108 kilometers (km) north of the SGS; the Chassahowitzka NWA, located about 137 km to the southwest; and the Wolf Island NWA, located about 186 km to the north. Air impact modeling analyses for the Class I increment and for applicable AQRVs were performed for the PSD Class I areas of Okefenokee and Chassahowitzka NWA. Section 6 of this evaluation addresses this in more detail. A determination of Maximum Achievable Control Technology (MACT) for SGS Unit 3 steam generator was not required per 40 CFR 63.40 (c).

The emissions units affected by this PSD permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein) and, specifically, the following Chapters and Rules:

4.1 State Rules

Chapter/Rule	Description
Chapter 62-4	Permits
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.260	Prevention of Significant Deterioration Increments
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments

Chapter/Rule	Description
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements For Sources Subject To The Federal Acid Rain Program
Rule 62-296.320	General Pollutant Emission Limiting Standards
Rule 62-297.310	General Test Requirements
Rule 62-297.401	Compliance Test Methods
Rule 62-297.520	EPA Continuous Monitor Performance Specifications

4.2 Federal Regulations

Regulation	Description
40 CFR 60	NSPS Subparts A, Da, Y and OOO (applicable sections)
40 CFR 63	Subparts A and ZZZZ (for the Emergency Generator)
40 CFR 72	Acid Rain Permits (applicable sections)
40 CFR 73	Allowances (applicable sections)
40 CFR 75	Monitoring (applicable sections including applicable appendices)
40 CFR 77	Acid Rain Program-Excess Emissions (future applicable requirements)

4.3 NSPS Limits

The Unit 3 boiler will be subject to emission limitations covered under 40 CFR Subpart Da, which limits Hg, NO_X, SO_2 and PM emissions from electric utility generating units capable of combusting more than 73 MW (250 MMBtu/hr heat input) using fossil fuel. EPA promulgated revisions to this NSPS on February 27, 2006 (71 FR 9866). The revised NSPS, applicable to new affected facilities that commence construction after February 28, 2005 revises the emission limits for Hg, PM, SO_2 and NO_X. The following table summarizes the applicable emissions standards of NSPS Subpart Da and the applicant's proposed emissions standards for this project.

Pollutant	NSPS Limit	Proposed Project Limit
PM	0.015 lb/MMBtu or 0.03 lb/MMBtu & 99.9% removal	0.015 lb/MMBtu
SO_2	1.4 lb/MWh or 95% removal	0.165 lb/MMBtu (note: this equates to ~98% removal)
NO_X	1.0 lb/MWh	0.64 lb/MWh
Mercury	20×10^{-6} lb/MWh	7.05×10^{-6} lb/MWh

As shown above, EPA has promulgated a mercury emission limit within NSPS Subpart Da. According to EPA literature, mercury removal is enhanced when PM controls are used with NO_X and SO_2 controls as co-benefit of these control systems. As a result, the Unit 3 boiler will be designed to achieve a much lower mercury emission rate than the NSPS Standard, as indicated by the applicant's proposed mercury limit.

4.4 Future Applicable Rules

The federal Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) became effective in July 2005. The Florida Department of Environmental Protection (DEP) must implement CAIR and CAMR in Florida during calendar year 2006. CAIR provides two options to achieve the emissions reductions: 1) follow a federally-approved template (included in the CAIR rule) that would achieve compliance through a cap-and-trade program directed at electric generating units; or 2) develop an alternate means of meeting the required reductions that could focus on any industry or combination of industries including power generation. Each affected state decides on the strategy it will use. The state must modify its State Implementation Plan (SIP) to include its compliance strategy by September 2006. If it does not do so, it will be subject to a Federal Implementation Plan (FIP) which will incorporate the cap-and-trade program.

The CAIR cap-and-trade model includes a formula for allocating SO_2 and NO_X allowances, and DEP has directed electric utilities to use this formula for planning purposes. The actual allocation may change through the rulemaking process, and depends, in part, on the number of allowances put into the "new unit set aside." That is, some percentage of the allowances may be held back for new electric generating units or other new sources.

The below table provides a summary of estimated changes in annual air emissions limits for Florida electric generating units assuming a CAIR cap-and-trade compliance program is established.

Estimated Annual Florida Air Emission Limits due to a CAIR Cap-and-Trade Program						
			CAIR – Phase I		CAIR - Phase II	
	Pre-CAIR through 2008		2009-2014	2010-2014	2015 – forward	
Emissions	NO_X	SO_2	NO_X	SO_2	NO_X	SO_2
Annual Budget	151,054 Tons	506,900 Tons	99,445 Tons	253,450 Tons	82,871 Tons	177,415 Tons

CAMR requires a phased reduction of mercury emissions from electric generating units. Unlike CAIR, CAMR applies only to electric generating units. Compliance with the first phase of CAMR, 2010 through 2017, is expected to be achieved in large part by the pollution control equipment required to limit emissions of NOx and SO_2 under CAIR. The second phase of CAMR begins in 2018.

5. DEPARTMENT REVIEW

Although the proposed project does not trigger a BACT review for NO_X, SO_2, SAM or Hg, the Department notes that SCR and Wet FGD are considered top control technologies for removing those respective pollutants. Beyond that, this project incorporates an ESP plus a Wet ESP (WESP), primarily for the purpose of PM/PM_{10} removal. Baghouse control systems have been installed on 14% of U.S. coal-fired boilers and ESP control systems have been installed on 72% of U.S. coal-fired boilers. The Department accepts that an ESP, in conjunction with a WESP, can provide comparable removal efficiencies and offer increased benefits for the removal of certain types of particulate matter. According to EPA literature, mercury removal is enhanced when PM controls are used with NO_X and SO_2 controls. Likewise, the co-benefits of an ESP, Wet FGD and WESP are accepted as an appropriate BACT proposal for HF removal.

Regarding CO (and VOC) removal, a more detailed evaluation can be found below.

Lastly, a recent PSD applicability determination (dated December 13, 2005) was issued by Stephen D. Page, Director of EPA's Office of Air Quality Planning and Standards (OAQPS) which is relevant to this application. EPA's determination was that companies proposing new coal-fired electrical generating units are not required to consider IGCC technology in determining what constitutes Best Available Control Technology under the Clean Air Act. As noted in prior EPA decisions and guidance, EPA does not have to consider the BACT requirement as a means to redefine the basic design of the source or change the fundamental scope of the project when considering available control alternatives. EPA's conclusion is that the IGCC process would redefine the basic design of the source being proposed and, therefore, neither Seminole nor the Department is required to consider IGCC in a BACT analysis for a proposed new coal plant employing conventional pulverized coal-burning technology such as SGS Unit 3.

5.1 Review for PM/PM_{10}

A review of the BACT Clearinghouse for large pulverized coal-fired steam boilers from July 10, 2001 through July 10, 2006 reveals the following (filterable assumed unless otherwise noted):

Facility	Size/Name of Unit	Emission Rate for Coal	Permit Date
Louisiana Generating LLC	675MW Big Cajun II Unit 4	PM: 0.015 lb/MMBtu	Aug. 2005
PSC Colorado	750MW Comanche Unit 3	PM: 0.013 lb/MMBtu filt. PM: 0.022 lb/MMBtu w/cond. PM_{10}: 0.012 lb/MMBtu filt. PM_{10}: 0.02 lb/MMBtu w/cond.	July 2005
Montana Dakota Utilities	220MW Gascoyne Greenfield	PM: 0.0167 lb/MMBtu filt. PM_{10}: 0.013 lb/MMBtu filt. PM_{10}: 0.0275 lb/MMBtu w/cond.	June 2005
Newmont Nevada	200MW TS Plant Greenfield	PM_{10}: 012 lb/MMBtu filt.	May 2005
Omaha Public Power	660MW Nebraska City Unit 2	PM: 0.018 lb/MMBtu	March 2005
Wisconsin Public Service	500MW Weston Greenfield	PM: 0.02 lb/MMBtu w/cond. PM_{10}: 0.018 lb/MMBtu w/cond.	October 2004
Utah Intermountain PSC	950MW Intermountain Unit 3	PM: 0.013 lb/MMBtu filt. PM_{10}: 0.012 lb/MMBtu filt.	October 2004
West Virginia Longview	600MW Monongahela Greenfield	PM: 0.018 lb/MMBtu PM_{10}: 0.018 lb/MMBtu w/cond.	March 2004
S. Carolina Santee Cooper	570MW Cross Units 2 and 3	PM: 0.018 lb/MMBtu PM_{10}: 0.015 lb/MMBtu	Feb. 2004
Arkansas Plum Point	800MW Greenfield Unit 1	PM_{10}: 0.018 lb/MMBtu	August 2003
Iowa MidAmerican	765MW MidAmerican Greenfield	PM: 0.027 lb/MMBtu w/cond. PM: 0.018 lb/MMBtu filt. PM_{10}: 0.025 lb/MMBtu w/cond.	June 2003
Ky. Thoroughbred	750MW Greenfield Units 1 & 2	PM: 0.018 lb/MMBtu	October 2002
Kansas Sand Sage	660MW Holcomb Unit 2	PM_{10}: 0.018 lb/MMBtu	October 2002
Wyoming Black Hills	500MW Wygen Unit 2	PM: 0.012 lb/MMBtu	Sept. 2002
Pa. AES Beaver Valley	215MW Greenfield	PM_{10}: 0.02 lb/MMBtu	Nov. 2001

When considering filterable matter, the BACT emission range for PM is from 0.012 to 0.018 lb/MMBtu and for PM_{10} is from 0.012 to 0.02 lb/MMBtu. Therefore, the applicant's proposed filterable BACT limit of 0.015 lb/MMBtu for PM/PM_{10} does not appear to be very aggressive, but rather is in the middle of the pack for recent BACT Determinations. When considering the inclusion of condensable, the emission range for PM is from 0.02 to 0.027 lb/MMBtu and for PM_{10} is from 0.018 to 0.0275 lb/MMBtu.

The legislative history is clear that Congress intended BACT to perform a technology-forcing function. The Department asserts that a BACT limit for PM of 0.015 lb/MMBtu does not include a technology-forcing component, but rather is more of an average of past BACT limits. Accordingly, a more aggressive limit of 0.013 lb/MMBtu (Method 5) is established, which is at the low end of recent BACT Determinations. The Department also will require that condensables be captured and reported (from the impingers) in accordance with EPA Method 202.

5.2 Review for Carbon Monoxide

Carbon monoxide emissions are the result of incomplete combustion. For coal combustion, the quantity of CO remaining after combustion depends largely on the combustion temperature, available air, amount of turbulence (mixing), and exhaust gas residence time, all of which are determined by the design and operation of the system. Unfortunately, reducing CO emissions results in an increase of NO_X emissions. For example, the use of low NO_X burners reduces the flame temperature, which increases products of incomplete combustion (i.e. CO and VOCs).

The Department has identified the following control technologies, in order of effectiveness, for consideration in the top-down BACT analysis for control of CO from the PC Boiler:

1. Thermal Oxidation (~95% reduction)
2. Catalytic Oxidation (~85% reduction)
3. Proper Boiler Design and Operation (good combustion practices)

Thermal Oxidation
Thermal oxidation oxidizes CO to CO_2 through a separate combustion process. Using thermal oxidation, the exhaust stream of the PC Boiler passes over or around a burner into a residence chamber where oxidation of the products of incomplete combustion is converted into products of complete combustion. Thermal oxidizers are usually operated at 1500-1800 ºF to achieve 95% destruction efficiency for CO. One of the problems that can degrade performance of thermal oxidizers is fouling and plugging of its components. The exhaust stream of the PC Boiler can be laden with fly ash, LOI coal, and salts. These types of contaminants can cause significant problems with thermal oxidizers.

Catalytic Oxidation
Catalytic oxidation converts CO to CO_2 in the presence of a catalyst (typically a precious metal), usually deposited onto a solid honeycomb substrate. Some of the technical problems that could potentially occur with the catalyst bed of a catalytic oxidizer include: scouring, thermal burnout, thermal aging, soot or particulate masking, and poisoning. Phosphorus, bismuth, lead, antimony and mercury are fast acting inhibitors, which can cause an irreversible reduction of catalyst activity. Of these, lead, antimony and mercury are known to be in the exhaust stream of a PC Boiler. Additionally, sulfur can form a removable coating on the catalyst, which is present in the exhaust stream of a PC Boiler before and after an FGD system.

Proper Boiler Design and Operation
Good combustion practices means operation of the PC Boiler at high combustion efficiency, thereby, reducing products of incomplete combustion. The boiler must be designed in such a way to offset or minimize the effect of using overfire air and low NO_X burners, while achieving as close as possible to complete combustion of the fuel, minimizing the amount of CO generated.

5.2.1 CO Summary

Within the application, Seminole stated that thermal oxidation and catalytic oxidation are not feasible control technologies for CO on a PC Boiler. Seminole's logic for elimination of these technologies was based on the fact that no PC Boiler has been equipped and operated with these types of controls. The Department is aware that a Portland cement kiln in Midlothian, Texas, utilizes regenerative thermal oxidation (RTO) to control CO and VOC emissions. This control system was placed after a SO_2 scrubber to reduce the potential for plugging or fouling problems due to sulfur compounds.

As a result of the above plus the advancements in control technologies, the Department is unwilling to reject thermal oxidation on the basis of being infeasible. However, the Department recognizes that practical considerations exist when establishing BACT for a proven technology in an unproven configuration. Additionally, the Department acknowledges that upon review of the BACT/RACT/LAER Clearinghouse for Pulverized Coal boilers, no cases could be found where thermal oxidation was specified as BACT. In fact, every one of the determinations specified good combustion practices.

A review of the BACT Clearinghouse for large pulverized coal steam generating units (boilers) from July 10, 2001 through July 10, 2006 reveals the following emission limits based upon good combustion practices:

Facility	Size/Name of Unit	Emission Rate for Coal	Permit Date
Louisiana Generating LLC	675MW Big Cajun II Unit 4	0.135 lb/MMBtu annual avg.	Aug. 2005
PSC Colorado	750MW Comanche Unit 3	0.13 lb/MMBtu 8-hour avg.	July 2005
Montana Dakota Utilities	220MW Gascoyne Greenfield	0.154 lb/MMBtu 3-hour avg.	June 2005
Newmont Nevada	200MW TS Plant Greenfield	0.15 lb/MMBtu 24-hour rolling	May 2005
Omaha Public Power	660MW Nebraska City Unit 2	0.16 lb/MMBtu 3-hour rolling	March 2005
Wisconsin Public Service	500MW Weston Greenfield	0.15 lb/MMBtu 24-hour avg.	October 2004
Utah Intermountain PSC	950MW Intermountain Unit 3	0.15 lb/MMBtu 30-day rolling	October 2004
West Virginia Longview	600MW Monongahela Greenfield	0.11 lb/MMBtu 3-hour rolling	March 2004
S. Carolina Santee Cooper	570MW Cross Units 2 and 3	0.16 lb/MMBtu	February 2004
Arkansas Plum Point	800MW Greenfield Unit 1	0.16 lb/MMBtu	August 2003
Iowa MidAmerican	765MW MidAmerican Greenfield	0.154 lb/MMBtu 24-hour avg.	June 2003
Kentucky Thoroughbred	750MW Greenfield Units 1 and 2	0.10 lb/MMBtu 30-day rolling	October 2002
Kansas Sand Sage	660MW Holcomb Unit 2	0.15 lb/MMBtu	October 2002
Wyoming Black Hills	500MW Wygen Unit 2	0.15 lb/MMBtu	Sept. 2002
Pa. AES Beaver Valley	215MW Greenfield	0.20 lb/MMBtu	Nov. 2001

The BACT emission range for CO is from 0.10 to 0.20 lb/MMBtu. The Department will accept the applicant's proposed BACT limit at 0.13 lb/MMBtu while firing coal, as it is in the lower range of recent BACT Determinations. This limit shall be demonstrated via an initial stack test.

Additionally, the Department notes that the majority of the above Determinations are based upon CEMS. The Department is well aware of the variability of CO emissions and the rationale for establishing a continuous (CEMS) limit which is somewhat higher than that of a traditional steady-state test. In this regard, the applicant has also proposed a higher limit of 0.15 lb/MMBtu based upon a 30-day rolling average and firing any and all permitted combinations of fuels. The Department accepts this additional limit as BACT.

5.3 Review for VOC

The discussion within Section 5.2 (above) is applicable for this review, but not repeated here. A review of the BACT Clearinghouse for large pulverized coal steam generating units (boilers) from July 10, 2001 through July 10, 2006 reveals the following emission limits based upon good combustion practices:

Facility	Size/Name of Unit	Emission Rate for Coal	Permit Date
Louisiana Generating LLC	675MW Big Cajun II Unit 4	0.0150 lb/MMBtu	Aug. 2005
PSC Colorado	750MW Comanche Unit 3	0.0035 lb/MMBtu	July 2005
Montana Dakota Utilities	220MW Gascoyne Greenfield	0.005 lb/MMBtu	June 2005
Newmont Nevada	200MW TS Plant Greenfield	NA	May 2005
Omaha Public Power	660MW Nebraska City Unit 2	0.0034 lb/MMBtu	March 2005
Wisconsin Public Service	500MW Weston Greenfield	0.0036 lb/MMBtu	October 2004
Utah Intermountain PSC	950MW Intermountain Unit 3	0.0027 lb/MMBtu	October 2004
West Virginia Longview	600MW Monongahela Greenfield	0.0040 lb/MMBtu	March 2004
S. Carolina Santee Cooper	570MW Cross Units 2 and 3	0.0024 lb/MMBtu (LAER)	February 2004
Arkansas Plum Point	800MW Greenfield Unit 1	0.02 lb/MMBtu	August 2003
Iowa MidAmerican	765MW MidAmerican Greenfield	0.0036 lb/MMBtu	June 2003
Kentucky Thoroughbred	750MW Greenfield Units 1 and 2	0.0072 lb/MMBtu	October 2002
Kansas Sand Sage	660MW Holcomb Unit 2	0.0035 lb/MMBtu	October 2002
Wyoming Black Hills	500MW Wygen Unit 2	0.01 lb/MMBtu	Sept. 2002
Pa. AES Beaver Valley	215MW Greenfield	0.0068 lb/MMBtu	Nov. 2001

The BACT emission range for VOC is from 0.0024 to 0.02 lb/MMBtu. The applicant has proposed a BACT emission limit of 0.004 lb/MMBtu. However, from review of the above 14 determinations, more than 2/3 of them were established at lower (more aggressive) levels. Accordingly, the proposed limit does not appear to be adequately stringent. Furthermore, the Department understands that wet pollution control systems such as wet FGD's and WESP's are well suited for removing large percentages of HAPS and VOC's. In fact, efficiencies of over 95% have been reported by manufacturers of some gaseous emission condensation systems. Accordingly, the Department does not accept the proposed VOC emission rate and establishes a more aggressive BACT limit of 0.0034 lb/MMBtu, such that only one of above BACT Determinations is more aggressive. This limit shall be demonstrated via an initial stack test. Thereafter, compliance with the CEMS-based CO emissions standard will serve as a surrogate for VOC emissions.

5.4 Review for HF

A review of the BACT Clearinghouse for large pulverized coal steam generating units (boilers) from July 10, 2001 through July 10, 2006 reveals the following:

Facility	Size/Name of Unit	Emission Rate for Coal	Permit Date
Missouri KCP&L	930MW Weston Unit 2	34.43 lb/hr (~0.00043 lb/MMBtu)	January 2006
PSC Colorado	750MW Comanche Unit 3	0.00049 lb/MMBtu	July 2005
Montana Dakota Utilities	220MW Gascoyne Greenfield	0.00053 lb/MMBtu	June 2005
Missouri Springfield	275MW Southwest (2 units)	0.00037 lb/MMBtu	Dec. 2004
Wisconsin Public Service	500MW Weston Greenfield	0.000217 lb/MMBtu	October 2004
Utah Intermountain PSC	950MW Intermountain Unit 3	0.0005 lb/MMBtu	October 2004
S. Carolina Santee Cooper	570MW Cross Units 2 and 3	0.0003 lb/MMBtu	February 2004
Wisconsin Energy	615MW Elm Road (2 units)	0.00088 lb/MMBtu	January 2004
Iowa MidAmerican	765MW MidAmerican Greenfield	0.0009 lb/MMBtu	June 2003
Kentucky Thoroughbred	750MW Greenfield Units 1 and 2	0.00016 lb/MMBtu	October 2002

Fluorides are emitted in the combustion process in gaseous and particulate form as a trace element in fuel. The primary control device for fluorides would be the wet FGD system since fluorides are highly soluble. Fluorides in particulate form are readily removed in the ESP. The combination of emissions reductions from an ESP followed by a wet FGD system with the addition of a WESP assures extremely low emissions of fluorides. Indeed, the proposed emission rate of 0.00023 lb/MMBtu as BACT is based on 97 percent removal for the combination of coal and petroleum coke that will be fired in this unit.

The BACT emission range for HF is from 0.00016 to 0.0009 lb/MMBtu. The Department accepts the proposed BACT of 0.00023 lb/MMBtu which is in the lower quartile of recent BACT Determinations. This limit shall be demonstrated via an initial stack test and upon Title V renewals.

5.5 BACT Summary

The following table summarizes the Department's BACT Determination:

Pollutant	BACT Emission Limits	Compliance Method
PM/PM_{10}	SGS Unit 3: 0.013 lb/MMBtu filterable PM Cooling Towers: 0.0005% Drift Eliminators ZLD Spray Dryers: 0.3 lb/hr each via fabric filters Emergency Generator: 0.4 lb/hr via good combustion	Annual Stack Test Initial Certification Initial & T-5 Renewal Test Fuel specifications
Opacity	SGS Unit 3: 20% with up to 27% for 6-minutes per hour	COMS
CO CO	SGS Unit 3: 0.13 lb/MMBtu coal SGS Unit 3: 0.15 lb/MMBtu 30-day rolling any fuel ZLD Spray Dryers: 1.9 lb per hour Emergency Generator: 1.8 lb per hour	Initial Stack Test CEMS Initial Test Initial Test

Pollutant	BACT Emission Limits	Compliance Method
VOC	SGS Unit 3: 0.0034 lb/MMBtu	Initial Test
HF	SGS Unit 3: 0.00023 lb/MMBtu	Initial & T-5 Renewal Test
Pollutant	**Non-BACT Established Emission Limits**	**Compliance Method**
SO_2	SGS Unit 3: 0.165 lb/MMBtu 24-hour rolling via wet FGD ZLD Spray Dryers & Emergency Generator: 0.05% sulfur fuel	CEMS Fuel specifications
SAM	SGS Unit 3: 0.005 lb/MMBtu via wet FGD and WESP	Annual Test
NO_X	SGS Unit 3: 0.07 lb/MMBtu via SCR	CEMS
Hg	SGS Unit 3: 7.05 E-6 lb/MWh 12 month rolling	CEMS or Sorbent Traps (App K)

5.5.1 Startup and Shutdown Emissions

The startup and shutdown of Unit 3 will follow an established startup and shutdown procedure, which shall be submitted prior to the initial unit start-up, for the Department's review and acceptance. It is anticipated that such a protocol would be similar to the procedure that was submitted as part of the Units 1 and 2 Title V air permit application and is referenced in Specific Condition A.20 of the existing Title V permit. This procedure will be incorporated into Unit 3 operating procedures and shall be followed in order to minimize excess emissions.

Emissions during startup of the proposed unit will be minimized by the use of existing onsite steam and the use of No. 2 distillate oil igniters in the boiler to warm the boiler and steam turbine. The use of No. 2 fuel, along with the operation of the WESP and wet FGD systems will minimize emissions of those pollutants associated with contaminants in the fuel (PM and SO_2).

Because the igniters and the boiler will be operating at low load conditions and the SCR will not be operating, excess emissions (when compared to the lb/MMBtu emission limits) for combustion products such as CO, VOC, and NO_X are likely to occur. However the firing rate (BTU/hr) of the boiler is so low during these periods, that on a mass basis (lbs/hr), emissions are not likely to exceed the comparable hourly emission rates at full output. Additionally, the potential emissions (PTE) for Unit 3 are based on 100 percent capacity factor, and it stands to reason that for every hour that Unit 3 is off line (shut down), an hour of zero (or near zero) emissions exists.

The Department will authorize excess emissions in accordance with Rule 62-210.700, F.A.C.:

Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing:

(1) Best operational practices to minimize emissions are adhered to, and

(2) The duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

Due to of the large size of this boiler and steam turbine, and the design necessity to minimize thermal stresses, unit start-ups are expected to be long in duration. As a result, the Department will provide for the authorization of 2 hours per 24 hour period over a monthly time period rather than daily. Specifically, the Department authorizes up to 60 hours of excess emissions per calendar month due to startup, shutdown, and malfunction of SGS Unit 3.

5.5.2 Fugitive Emissions

Fugitive particulate emissions from fuel, ash and FGD by-product handling, conveying, and storage will be minimized by equipment design and operating procedures. Fuel will be unloaded in a partially enclosed rotary rail unloader using water sprays. Fuel is unloaded into an enclosed underground hopper that is protected from wind. Dust from fuel unloading operations will be controlled using wet suppression systems.

Conveyors used for transfer of the fuel to the active storage piles will be enclosed for minimizing wind-borne fugitive dust. Unloading onto the active and inactive storage piles will be accomplished using a stacker/reclaimer that is designed to minimize dust emissions. The fuel will be reclaimed and conveyed to an enclosed crusher tower. The transfer points for Unit 3 will have a fabric filter with a maximum design emission rate of 0.01 grain/cubic feet. After crushing, the fuel is then conveyed through an enclosed tripper house to the storage silos adjacent to the boiler. All fuel storage silos are connected to a dust collection system. Outdoor conveyors will be enclosed (i.e., covers and windskirts) to minimize dust emissions. All conveyor transfer points will have a dust collection system. The inactive storage pile will be compacted when built and sprayed with a crusting agent and/or chemical stabilizer to prevent wind erosion.

Fugitive particulate emissions from the limestone handling and storage systems will be minimized by equipment design and operating procedures. Limestone used in the wet FGD system will be transported to the SGS Site by truck. The limestone will be transferred from the existing truck unloading system to a storage facility utilizing the existing limestone handling system. Dust collection or suppression techniques will be utilized to minimize dust emissions.
Bottom ash will have sufficient moisture content to minimize fugitive dust during transport. A submerged chain conveyor system will be used to collect and transport the Unit 3 bottom ash to a truck loading area. Bottom ash will be sold to concrete and concrete block manufacturers. Fly ash will be pneumatically conveyed to a storage silo that will be equipped with a fabric filter to minimize PM emissions. Fly ash will be blended for use in the existing Carbon Burnout Unit if necessary or trucked or hauled by rail from the storage silo for offsite sales to the maximum extent feasible.

Fugitive emissions from the FGD byproduct storage area are minimized by the higher moisture content of the by-products. The FGD by-product is calcium sulfate (gypsum) with inherently high moisture content. Waste slurry from the plant's Unit 3 FGD system will be pumped to the existing Units 1 and 2 effluent processing systems, where it will be treated and dewatered to produce gypsum for use in the production of wallboard.

Watering, using a water-spray truck, will also be performed as necessary to minimize fugitive emissions from active areas (i.e., unpaved roads and working areas of the storage area).

6. AIR QUALITY IMPACT ANALYSIS

6.1 Introduction

The proposed project will increase PM_{10}, CO, HF and VOC emissions at levels in excess of PSD significant amounts. PM_{10} is a criteria pollutant and has national and state ambient air quality standards (AAQS), PSD increments, significant impact levels, and significant monitoring concentrations (de minimis concentrations) defined for it. CO is a criteria pollutant and has only AAQS, significant impact levels and a de minimis concentration defined for it. HF is a non-criteria pollutant and has only a de minimis concentration defined for it. Potential VOC emissions increases are above the ambient impact analysis threshold of 100 TPY for the pollutant ozone. VOC is a precursor to a criteria pollutant, ozone; and any net increase of 100 tons per year of VOC requires an ambient impact analysis including the gathering of preconstruction ambient air quality data. However, the applicant presented potential VOC emissions increases to the Department, and discussed available options to predict potential impacts associated with the emissions and formation of ozone, since no stationary point source models are available and approved for use in predicting ozone impacts. Based on the available information, the Department has determined that the use of a regional model that incorporates the complex chemical mechanisms for predicting ozone formation is not suitable for this project.

In addition, even though SO_2 and NO_X emissions were not proposed to be emitted at levels in excess of PSD significant amounts, the Department required air quality impacts for these pollutants to be evaluated. SO_2 and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels, and significant monitoring concentrations (de minimis concentrations) defined for them.

The air quality impact analyses required by the Department regulations for this project include:

- An analysis of existing air quality for PM_{10}, CO, HF and VOC;
- A significant impact analysis for PM_{10}, CO, NO_X and VOC;
- A PSD increment analysis for PM_{10} and SO_2;
- An Ambient Air Quality Standards (AAQS) analysis for PM_{10} and SO_2;
- An analysis of impacts on soils, vegetation, and visibility and growth-related impacts to air quality.

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The significant impact, PSD increment, and AAQS analyses depend on air quality dispersion modeling carried out in accordance with EPA and department guidelines. Based on the required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment.

6.2 Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. The use of previously existing representative monitoring data, if available may satisfy this monitoring requirement. An exemption to the monitoring requirement shall be granted by rule if either of the following conditions is met: the maximum predicted air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimis ambient concentration; or the existing ambient concentrations are less than a pollutant-specific de minimis ambient concentration. If preconstruction ambient monitoring is exempted, determination of background concentrations for PSD significant pollutants with established AAQS may still be necessary for use in any required AAQS analysis. These concentrations may be established from the required preconstruction ambient air quality monitoring analysis or from existing representative monitoring data. These background ambient air quality concentrations are added to pollutant impacts predicted by modeling and represent the air quality impacts of sources not included in the modeling. No de minimis ambient concentration is provided for ozone. Instead the net emissions increase of VOC is compared to a de minimis monitoring emission rate of 100 tons per year. The table below shows maximum predicted project air quality impacts for comparison to these de minimis levels.

MAXIMUM PREDICTED PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE DE MINIMIS CONCENTRATIONS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Impact Greater than De Minimis? (Yes/No)**	**De Minimis Concentration ($\mu g/m^3$)**
PM_{10}	24-hr	4	NO	10
CO	8-hr	21	NO	575
HF	24-hr	0.02	NO	0.25
NO_x	Annual	0.75	NO	1
VOC	Annual Emission Rate	132 TPY	YES	100 TPY

As shown in the table, all pollutant emissions, with the exception of VOC are predicted to be less than the de minimis levels; therefore, preconstruction monitoring is not required for these pollutants. However, since VOC impacts from the project are predicted to be greater than the de minimis level, the applicant is not exempt from preconstruction monitoring for this pollutant. The applicant may instead satisfy the preconstruction monitoring requirement using previously existing representative data. These data do exist from ozone monitors located in the urbanized Alachua county area to the west of the project. These data show no violation of any ozone standard.

Also since the Department is also requiring an SO_2 AAQS analysis as part of this application, appropriate background concentrations for use in this analysis were established from SO_2 data, which was collected in Palatka. These SO_2 concentrations are shown in the table below.

BACKGROUND CONCENTRATIONS FOR USE IN AAQS ANALYSES		
Pollutant	**Averaging Time**	**Background Concentration (μg/m^3)**
SO_2	Annual	6
	24-hour	28
	3-hour	134

6.3 Models and Meteorological Data Used in Significant Impact, PSD Increment and AAQS Analyses

6.3.1 PSD Class II Area Model

The EPA-approved American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model was used to evaluate the pollutant emissions from the proposed project and other existing major facilities. In November, 2005, the EPA promulgated AERMOD as the preferred regulatory model for predicting pollutant concentrations within 50 km from a source. AERMOD is a replacement for the Industrial Source Complex Short-Term Model (ISCST3). The AERMOD model calculates hourly concentrations based on hourly meteorological data. For evaluating plume behavior within the building wake of structures, the AERMOD model incorporates the Plume Rise Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). AERMOD can predict pollutant concentrations for annual, 24, 8, 3 and 1-hour. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options in each modeling scenario, and building downwash effects were evaluated for stacks below the good engineering practice (GEP) stack heights. The stack associated with this project satisfied the good engineering practice (GEP) stack height criteria.

Meteorological data used in the AERMOD model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the Jacksonville International Airport. The 5-year period of meteorological data was from 2001 through 2005. These stations were selected for use in the evaluation because they are the closest primary weather stations to the project area and are most representative of the project site.

Because five years of data are used in AERMOD, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate AAQS or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards. For determining the project's significant impact area in the vicinity of the facility, and for determining if there are significant impacts occur from the project on any PSD Class I area, both the highest short-term predicted concentrations and the highest predicted yearly averages were compared to their respective significant impact levels.

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

6.3.2 PSD Class I Area Model

Since the closest PSD Class I areas, the Okefenokee National Wilderness Area (NWA), the Chassahowitzka NWA and Wolf Island NWA are greater than 50 km from the proposed facility, long-range transport modeling was required for the Class I impact assessment. The California Puff (CALPUFF) dispersion model was used to evaluate the potential impact of the proposed pollutant emissions on the PSD Class I increments and on the Air Quality Related Values (AQRV): regional haze and nitrogen and sulfur deposition. CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources. It is also suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanisms.

The meteorological data used in the CALPUFF model was processed by the California Meteorological (CALMET) model. The CALMET model utilizes data from multiple meteorological stations and produces a three-dimensional modeling grid domain of hourly temperature and wind fields. The wind field is enhanced by the use of terrain data, which is also input into the model. Two-dimensional fields such as mixing heights, dispersion properties, and surface characteristics are produced by the CALMET model as well. 2001 through 2003, 4-km Florida domain, meteorological data were obtained and processed for use in the Class I analyses. The CALMET wind field and the CALPUFF model options used were consistent with the suggestions of the federal land managers.

6.4 Significant Impact Analysis

Preliminary modeling is conducted using only the proposed project's worst-case emission scenario for each pollutant and applicable averaging time. Over 2000 receptors were placed along the facility's restricted property line and out to 20 km from the facility, which is located in a PSD Class II area. Three PSD Class I areas are located within 200 km of the project: the Okefenokee NWA, 108 km to the north of the Mill, the Chassahowitzka NWA located 137 km southwest of the Mill and the Wolf Island NWA located 186 km to the north of the project. A total of 180, 58 and 30 receptors were placed in the Okefenokee NWA, Chassahowitzka NWA and Wolf Island NWA PSD Class I areas, respectively. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project were predicted in a PSD Class II area in the vicinity of the facility or in any PSD Class I area. In the event that the maximum predicted impact of a proposed project is less than the appropriate significant impact level, a full impact analysis for that pollutant is not required. Full impact modeling is modeling that considers not only the impact of the project but also other major sources, including background concentrations, located within the vicinity of the project to determine whether all applicable AAQS or PSD increments are predicted to be met for that pollutant. Consequently, a preliminary modeling analysis, which shows an insignificant impact, is accepted as the required air quality analysis (AAQS and PSD increments) for that pollutant and no further modeling for comparison to the AAQS and PSD increments is required for that pollutant. The tables below show the results of this modeling.

MAXIMUM PREDICTED PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO PSD CLASS II SIGNIFICANT IMPACT LEVELS IN THE VICINITY OF THE FACILITY

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact?
PM_{10}	Annual	0.6	1	NO
	24-hr	4.3	5	NO

CO	8-hr	21	500	NO
	1-hr	61	2,000	NO
NO_2	Annual	0.75	1	NO
VOC	AER	389 TPY	100 TPY	YES

MAXIMUM PREDICTED PROJECT IMPACTS IN THE PSD CLASS I AREAS FOR COMPARISON TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact (μg/m^3)**	**Significant Impact Level (μg/m^3)**	**Significant Impact? (ug/m^3)**
PM_{10}	Annual	0.006	0.2	NO
	24-hr	0.09	0.3	NO
NO_2	Annual	0.025	0.1	NO

As shown in the tables, less than significant impacts were predicted for all pollutants evaluated for significant impacts, with the exception of VOC; therefore, no further dispersion modeling was required to be performed for these pollutants. However, potential VOC emissions increases are above the ambient impact analysis threshold of 100 TPY for the pollutant ozone. As stated in the introduction to the air quality impact analysis section, the applicant presented potential VOC emissions increases to the Department, and discussed available options to predict potential impacts associated with the emissions and formation of ozone, since no stationary point source models are available and approved for use in predicting ozone impacts. Based on the available information, the Department has determined that the use of a regional model that incorporates the complex chemical mechanisms for predicting ozone formation is not suitable for this project.

No significant impact analysis impact was performed for SO_2 since there is a large decrease in short-term emissions and no increase in annual emissions. However, the Department required full impact modeling for this pollutant. The results of this modeling will be presented in the next section.

6.5 SO_2 Full Impact Analysis

6.5.1 Receptor Grids for Performing SO2 PSD Increments and AAQS Analyses

For the PSD Class II increment and AAQS analyses, the receptor grid was based on nearly 5000 receptors centered over SGS and out to 10 km from the facility. Included in this receptor network was a dense network of receptors near the southeastern boundary of the Georgia Pacific facility located 8 km to the southwest. The receptors in the vicinity of the GP facility were located where previous projects had shown the highest SO_2 concentrations. For the PSD Class I increment analysis, a total of 180, 58 and 30 receptors were placed in the Okefenokee NWA, Chassahowitzka NWA and Wolf Island NWA PSD Class I areas, respectively.

6.5.2 PSD Increment Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration which was established in 1977 for SO_2 (the baseline year was 1975 for existing major sources of SO_2). The emission values that are input into the model for predicting increment consumption are based on maximum emissions from increment-consuming facility sources and all other increment-consuming sources in the vicinity of the facility.

6.5.3 AAQS Analysis

For pollutants subject to an AAQS review, the total impact on ambient air quality is obtained by adding a “background” concentration to the maximum-modeled concentration. This “background” concentration takes into account all sources of a particular pollutant that are not explicitly modeled.

6.5.4 Discussion of SO_2 Impact Analyses

Previous air modeling analyses for other projects in the Jacksonville and Palatka vicinities have shown that SGS, when emitting at its allowable limit of 1.2 lb/MMBtu (17212 lb/hr) for sulfur dioxide (SO_2), caused predicted violations of the PSD Class II and Class I increments for the 3-hour and 24-hour averaging times. For the Unit 1and 2 project just recently permitted, SGS reduced the emission limits for Units 1 and 2 to 0.67 lb/MMBtu, 24-hour average, (9610 lb/hr, 24-hour average, for Units 1 and 2 combined). These limits were based on results of air modeling analyses performed to ensure that the maximum SO_2 concentrations from SGS alone would not exceed the allowable PSD Class I increments in the Okefenokee and Chassahowitzka National Wilderness (NWA) areas, the two PSD Class I areas closest to SGS. For this project the applicant is proposing to further reduce Units 1 and 2 SO_2 emission limits from 0.67 lb/MMBtu, 24-hour average to 0.38 lb/MMBtu, 24-hour average (5397 lb/hr, 24-hour average). In addition the applicant is proposing a 0.165 lb/MMBtu, 24-hour average, SO_2emission limit for Unit 3 (1238 lb/hr, 24-hour average). These limits would reduce 24-hour average emission limits from all three units to 6647 lbs/hr. These reductions, as proposed in this application, would ensure that the maximum concentrations from SGS sources, along with all other increment affecting sources, in the vicinity of the Okefenokee and Wolf Island NWA would not be exceeded as shown in the table below.

Okefenokee and Wolf Island NWA				
Pollutant	**Averaging Time**	**Maximum Predicted Impact (μg/m^3)**	**Allowable Increment (μg/m^3)**	**Impact Greater Than Allowable Increment?**
	Annual	0.00	1	No
SO_2	24-hour	4.14	5	No
	3-hour	24.4	25	No

The Chassahowitzka Class I area has shown potential PSD increment problems for several years. This project includes emission reductions which show a lessening of the ambient impacts in the Chassahowitzka. The predicted impacts from proposed Unit 3 SO_2 emissions in the Chassahowitzka Class I area are all less than Class I significant impact levels at receptors and time periods where the Class I SO_2increments are predicted to be exceeded. Therefore, this project will improve overall air quality in this area.

The results of SO_2 AAQS and Class II PSD increment modeling for the Unit 3 project are shown in the tables below. The results show that the SO_2 impacts for SGS, together with other sources, will comply with the AAQS and PSD Class II increments.

MAXIMUM PREDICTED AMBIENT AIR QUALITY IMPACTS (AAQS) IN THE VICINITY OF THE PROJECT						
Pollutant	**Averaging Time**	**Modeled Sources (μg/m^3)**	**Background Concentration (μg/m^3)**	**Total Impact (μg/m^3)**	**Total Impact Greater than AAQS**	**AAQS (μg/m^3)**
SO_2	Annual	23	6	29	No	60
	24-hour	165	34	199	No	260
	3-hour	563	128	691	No	1300

PSD CLASS II INCREMENT ANALYSIS IN THE VICINITY OF THE PROJECT				
Pollutant	**Averaging Time**	**Maximum Predicted Impact (μg/m^3)**	**Impact Greater than Allowable Increment?**	**Allowable Increment (μg/m^3)**
SO_2	Annual	8	No	20
	24-hour	60	No	91
	3-hour	152	No	512

6.6 Additional Impacts Analysis

6.6.1 Impacts on Soils, Vegetation, Wildlife, and Visibility

The maximum ground-level concentrations predicted to occur due to PM_{10}, NOx and CO emissions as a result of the proposed project are less than the significant impact levels. The maximum ground-level concentrations predicted to occur due to SO_2 emissions as a result of the proposed project, including all other nearby sources, will be below the associated AAQS. The AAQS are designed to protect both the public health and welfare. As such, this project is not expected to have a harmful impact on soils and vegetation in the PSD Class II area. An air quality related values (AQRV) analysis was done by the applicant for the Class I area. No significant impacts on this area are expected. A regional haze analysis using the long-range transport model CALPUFF was done for the PSD Class I areas. This analysis showed no significant impact on visibility in this area. Because the project's SO_2 and NOx emissions did not exceed PSD significant emission rates, acid deposition rates for sulfur and nitrogen compounds were not predicted.

6.6.2 Growth-Related Air Quality Impacts

The proposed modification will not significantly change employment, population, housing or commercial/industrial development in the area to the extent that a significant air quality impact will result.

7.0 CONCLUSION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the draft permit.

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