Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

August 24, 2006

James R. Frauen, Director SGS-3
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry
Tampa, FL 33618

Re: Draft Air Permit No. PSD-FL-375
Project No. 1070025-005-AC
Seminole Generating Station (SGS) Unit 3

Dear Mr. Frauen:

On March 9, 2006, Seminole Electric Cooperative, Inc. submitted an application to construct a new supercritical coal-fired steam generating unit at the existing Seminole Generating Station, which is located at 890 North U.S. Highway 17, north of Palatka, in Putnam County, Florida. Enclosed are the following documents: "Technical Evaluation and Preliminary BACT Determination", "Draft Permit", "Written Notice of Intent to Issue Air Permit", and "Public Notice of Intent to Issue Air Permit".

The "Technical Evaluation and Preliminary BACT Determination" summarizes the Bureau of Air Regulation's technical review of the application and provides the rationale for making the preliminary determination to issue a draft permit as well as the draft BACT evaluation. The proposed "Draft Permit" includes the specific conditions that regulate the emissions units covered by the proposed project. The "Written Notice of Intent to Issue Air Permit" provides important information regarding: the Permitting Authority's intent to issue an air permit for the proposed project; the requirements for publishing a Public Notice of the Permitting Authority's intent to issue an air permit; the procedures for submitting comments on the Draft Permit; the process for filing a petition for an administrative hearing; and the availability of mediation. The "Public Notice of Intent to Issue Air Permit" is the actual notice that you must have published in the legal advertisement section of a newspaper of general circulation in the area affected by this project.

If you have any questions, please contact the Project Engineer, Michael Halpin, P.E., at 850/245-8993.

Sincerely,

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

WRITTEN NOTICE OF INTENT TO ISSUE AIR PERMIT

In the Matter of an
Application for Air Permit by:

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

Draft Air Permit No. PSD-FL-375
Project No. 1070025-005-AC
Seminole Generating Station
Seminole Unit 3
Putnam County, Florida

Facility Location: Seminole Electric Company, Inc. operates an existing power plant north of Palatka at 890 North U.S. Highway 17, north of Palatka, in Putnam County, Florida.

Project: The applicant proposes to construct a new supercritical coal-fired steam generating unit. Details of the project are provided in the application and the enclosed "Technical Evaluation and Preliminary BACT Determination".

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

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at the address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary BACT Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. A copy of the complete project file is also available at the Department's Northeast District Office, located at 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256-7590. The District's telephone number is 904-807-3300.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all applicable provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Sections 403.087 and 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed "Public Notice of Intent to Issue Air Permit" (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet the requirements of Sections 50.011 and 50.031, F.S. in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Permitting Authority at the address or phone number listed above. Pursuant to Rule 62-110.106(5), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within seven (7) days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be received by the Permitting Authority at the above address before the close of business (5:00 p.m.) on or before the end of this 30-day period. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when each petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact; If there are none, the petitioner shall so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Written Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. For the purposes of judicial review, the Department may, when possible, consolidate a request for administrative hearing on this draft permit within a Power Plant Certification Hearing.

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this "Written Notice of Intent to Issue Air Permit" package (including the Public Notice, the Technical Evaluation and Preliminary BACT Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 8/25/06 to the persons listed below.

Mr. James R. Frauen, SECI *
Mr. Michael P. Opalinski, SECI
Mr. Mike Roddy, SECI
Mr. Scott Osbourn, Golder
Mr. Ken Kosky, Golder
Mr. Chris Kirts, NED
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS
Ms. Phyllis Fox, Ph.D.*

Clerk Stamp

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

Mary L. Harvey (Clerk) 8/25/06 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Florida Department of Environmental Protection
Project No. 1070025-005-AC / Draft Air Permit No. PSD-FL-375
Seminole Electric Cooperative, Inc. – Seminole Generating Station
Putnam County, Florida

Applicant: The applicant for this project is the Seminole Electric Cooperative, Inc. The applicant's authorized representative and mailing address is: James R. Frauen, Director SGS-3; Seminole Electric Cooperative, 16313 North Dale Mabry, Tampa, Florida 33618.

Facility Location: Seminole Electric Company, Inc. operates the existing Seminole Generating Station (SGS), north of Palatka at 890 North U.S. Highway 17, north of Palatka, in Putnam County, Florida.

Project: The applicant proposes to construct a new supercritical coal-fired steam generating unit referred to as SGS Unit 3. Seminole proposes to integrate SGS Unit 3 into the existing, certified SGS Site located north of Palatka in Putnam County and will locate Unit 3 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. Continuous Emission Monitoring Systems (CEMS) will be installed for SO_2, NO_X, CO and Hg.

Net environmental impacts associated with Unit 3, in combination with the Units 1 and 2 pollution controls upgrade Project No. 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. The applicant has accepted facility-wide caps for each above pollutant eliminating the requirement for a PSD review.
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.

The maximum potential annual emissions increases in tons per year based on the draft permit are summarized below:

Pollutants	Maximum Potential Emissions (TPY)	PSD Significant Emission Rate (TPY)
PM/PM_{10}	429.3	25/15
HF	7.6	3
VOC	73.2	40
CO	4927.5	100

Based on the emissions increases shown above, the project is subject to preconstruction review for the Prevention of Significant Deterioration (PSD) for these pollutants (Rule 62-212.400, F.A.C.). The Draft Permit includes preliminary determinations of the Best Available Control Technology (BACT) for each PSD-significant pollutant. In addition, an air quality impact analysis was conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class I and Class II significant impact levels applicable to all PSD Class I and II areas and including the nearest PSD Class I area which is the Okeefenokee National Wildlife Area. Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or contribute to a violation of any state or federal ambient air quality standard.

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

Project File: A complete project file is available for public inspection during the normal business hours of 8:00 a.m. to 5:00 p.m., Monday through Friday (except legal holidays), at the address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary BACT Determination, the application, and the information submitted by the applicant, exclusive of confidential records under Section 403.111, F.S.

(Public Notice to be Published in the Newspaper)

PUBLIC NOTICE OF INTENT TO ISSUE AIR PERMIT

Interested persons may contact the Permitting Authority's project review engineer for additional information at the address and phone number listed above. A copy of the complete project file is also available at the Department's Northeast District Office, located at 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256-7590. The District's telephone number is 904-807-3300.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of proposed equipment will not adversely impact air quality and that the project will comply with all applicable provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the Draft Permit for a period of thirty (30) days from the date of publication of the Public Notice. Written comments must be received by the Permitting Authority at the above address before the close of business (5:00 p.m.) on or before the end of this 30-day period. As part of his or her comments, any person may also request that the Permitting Authority hold a public meeting on this permitting action. If the Permitting Authority determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly and in a newspaper of general circulation in the area affected by the permitting action. For additional information, contact the Permitting Authority at the above address or phone number. If written comments or comments received at a public meeting result in a significant change to the Draft Permit, the Permitting Authority will issue a Revised Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when each petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact; If there are none, the petitioner shall so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Permitting Authority's final action may be different from the position taken by it in this Written Notice of Intent to Issue Air Permit. Persons whose substantial interests will be affected by any such final decision of the Permitting Authority on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. For the purposes of judicial review, the Department may, when possible, consolidate a request for administrative hearing on this draft permit within a Power Plant Certification Hearing.

Mediation: Mediation is not available in this proceeding.

(Public Notice to be Published in the Newspaper)

PERMITTEE:

Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, Florida 33618

Authorized Representative:
James R. Frauen, Project Director SGS Unit 3

Seminole Generating Station
SGS Unit 3
Draft Permit No. PSD-FL-375
Project No. 1070025-005-AC
Siting No. PA 78-10A2
Expires: December 31, 2012

PROJECT AND LOCATION

This permit authorizes the construction of a nominal 750 MW pulverized coal-fired supercritical steam generating unit at the existing Seminole Generating Station. The facility is located east of U.S. Highway 17, approximately seven miles north of Palatka, Putnam County.

STATEMENT OF BASIS

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. Pursuant to Chapter 62-17, F.A.C. and Chapter 403 Part II, F.S., the project is also subject to Electrical Power Plant Siting. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

___________DRAFT___________
Joseph Kahn, P.E., Acting Director
Division of Air Resources Management

Date:______________

FACILITY DESCRIPTION

The existing Seminole Generating Station (SGS) consists of: two 714.6 megawatt, electric, coal fired steam electric generators (SGS Units 1 and 2); a coal handling and storage system; a limestone unloading, handling and storage system; and a flue gas desulfurization (FGD) sludge stabilization system. The existing units are currently undergoing pollution control upgrades, including burner replacements, the addition of SCRs, an alkali injection system, a carbon burnout (CBO) unit, as well as improvements to the existing FGD system and steam turbines.

PROJECT DESCRIPTION

Seminole proposes to integrate SGS Unit 3 into the existing, certified SGS Site located north of Palatka in Putnam County. SGS Unit 3 will be a nominal 750 MW (net) pulverized coal-fired supercritical steam generating unit 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). The project also includes a new Zero Liquid Discharge (ZLD) Spray Dryer System, a new emergency generator, and a new 26-cell mechanical draft cooling tower.

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. No. 2 diesel fuel will be used for startup, shutdown and for firing the Zero Liquid Discharge (ZLD) Spray Dryers as well as an Emergency Generator (unregulated emissions unit).

EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units:

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

REGULATORY CLASSIFICATION

Title III: The facility is a "Major Source" of hazardous air pollutants (HAPs).

Title IV: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V: The facility is a Title V or "Major Source" of air pollution in accordance with Chapter 62-213, F.A.C. because the potential emissions of at least one regulated pollutant exceed 100 tons per year. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds (VOC).

PSD: The facility is located in an area that is designated as "attainment", "maintenance", or "unclassifiable" for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a "fossil fuel-fired steam electric plant of more than 250 million BTU per hour of heat input", which is one of the facility categories listed at 62-210.200(Definitions, Major Stationary Source) with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year, therefore the facility is classified as a "Major Stationary Source" with respect to Rule 62-212.400 F.A.C., Prevention of Significant Deterioration (PSD).

NSPS: The following New Source Performance Standards of 40 CFR 60 are applicable to the SGS Unit 3 as described in Section III, Subsection A, Federal Requirements of this permit.

- Subpart Da (Standards of Performance for Electric Utility Steam Generating Units For Which Construction is Commenced After September 18, 1978).

NESHAP: The facility is a "Major Source" of HAPs. The Emergency Generator is subject to the notification requirements of 40 CFR 63, Subpart ZZZZ; there are no applicable NESHAP requirements for the steam generating unit.

CAIR: As an electric generating unit, SGS Unit 3 may be subject to the Clean Air Interstate Rule pending the finalization of DEP rules.

CAMR: SGS Unit 3 is a new coal-fired power plant and will be subject to the Clean Air Mercury Rule pending finalization of DEP rules.

Siting: The facility is a steam electrical generating plant and is subject to the power plant siting provisions of Chapter 62-17, F.A.C.

PERMITTING AUTHORITY

All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority.

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department's Northeast District Office at 7825 Baymeadows Way, Suite B200, Jacksonville, Florida 32256-7577.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix TEBD	Final BACT Determinations and Emissions Standards
Appendix GC	General Conditions

RELEVANT DOCUMENTS:

The documents listed below are not a part of this permit, however they are specifically related to this permitting action and are on file with the Department.

- March 9, 2006: Received Site Certification Application (SCA) including PSD application.
- May 15, 2006: SCA determined to be insufficient by SCO.
- July 3, 2006: Received all responses from applicant.
- August 21, 2006: Intent to Issue PSD Permit distributed.
- December XX, 2006: Final Certification by the Power Plant Siting Board

1. General Conditions: The permittee shall operate under the attached General Conditions listed in Appendix GC of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 63, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.
[Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

3. Construction and Expiration: Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(12)(a), F.A.C.]

4. New or Additional Conditions: For good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

5. Source Obligation.

   a. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

   b. At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by exceeding its projected actual emissions, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification.

   [Rule 62-212.400(12), F.A.C.]

6. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Chapters 62-210 and 62-212, F.A.C.]

7. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]

8. Title V Permit: This permit authorizes construction of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emission units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation and a copy to the Compliance Authority.
[Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

9. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility in accordance with 62-210.370. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year.
[Rule 62-210.370(2), F.A.C.]

A. SGS Unit 3 - Pulverized Coal-Fired Supercritical Steam Generating Unit (EU 014)

The specific conditions of this subsection apply to the following emissions unit after construction is complete.

E.U. ID	Emission Unit Description
014	SGS Unit 3 – Nominal 750 MW (net) Supercritical Pulverized Coal Fired Boiler

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: A determination of the Best Available Control Technology (BACT) was made for carbon monoxide (CO), particulate matter (PM/PM_{10}), fluorides (HF) and volatile organic compounds (VOCs). [Rule 62-210.200 (BACT), F.A.C.]

2. PSD Netting: Emissions caps were accepted on Units 1 and 2, in part for the purpose of ensuring that this project "nets out" with respect to SO_2, SAM, Mercury and NO_X emissions, thus avoiding BACT determinations for those pollutants. The facility-wide annual emission limits are:

Pollutant	Annual Emission Limit[a] (TPY)
SO_2	29,074
SAM	2,129
Hg	0.059
NO_X	23,289

Note [a]: The facility-wide limit includes SGS Units 1, 2, 3, Cooling Towers and the ZLD Spray Dryers.

3. NSPS Requirements: This unit is subject to 40 CFR 60 NSPS Subpart Da, which is applicable to new affected facilities that commence construction after February 28, 2005. The NSPS provisions establish emission limits for PM, SO_2 and NO_X. The PM emission limit is 0.015 lb/MMBtu or 0.03 lb/MMBtu and 99.9 percent reduction. The SO_2 and NO_X emission limits are production-based and are 1.4 and 1.0 pounds per megawatt hour (lb/MW-hr) gross energy output, respectively. In addition, the SO_2 standard allows for either meeting the above production-based limit or a 95 percent reduction. Visible emissions are limited to 20 percent opacity (6-minute average) except up to 27 percent opacity is allowed for one 6-minute period per hour. The NSPS mercury (Hg) emission limit for new sources (40 CFR 60.45a; 71 FR 33388; June 6, 2006) is 20×10^{-6} lb/MW-hr for bituminous coal. [40 CFR 60, Subpart A and Da]

EQUIPMENT DESCRIPTION

4. Steam Generator: The permittee is authorized to construct and operate a pulverized coal, balanced draft type unit employing supercritical steam and equipped with low NO_X burners. The boiler will be fired by either coal or a blend of coal and petroleum coke (up to 30% by weight), with No. 1 or 2 diesel oil for auxiliary purposes. The steam generator shall be designed for a maximum heat input of 7,500 MMBtu per hour of coal. [Application; Design]

5. Electrical Generating Capacity: SGS Unit 3 will have a nominal electrical generating capacity of 750 MW net and 820 MW gross. [Application; Design]

CONTROL TECHNOLOGY

6. Post-Combustion: The emission unit flue shall be equipped with a wet FGD System, a Selective Catalytic Reduction System, an Electrostatic Precipitator and a Wet Electrostatic Precipitator.

   a. *Electrostatic Precipitators (ESP)*: The permittee shall install, operate, and maintain an Electrostatic Precipitator and a Wet Electrostatic Precipitator (WESP) to reduce PM/PM_{10} emissions from SGS Unit 3.

b. *Selective Catalytic Reduction (SCR) System*: The permittee shall install, tune, operate, and maintain an SCR system to control NO_X emissions. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, a urea unloading system, a urea storage area, facilities to convert the urea to ammonia, a monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to meet the permitted levels of NO_X emissions on a continuous basis.

c. *Flue Gas Desulfurization (FGD) System*: The permittee shall install, operate, and maintain a flue gas desulfurization system for the reduction of SO_2 and SAM emissions from SGS Unit 3. The FGD System shall be designed to meet the permitted emission levels of SO_2 on a continuous basis.

Prior to the initial emissions performance tests, the emissions control systems shall be tuned to achieve permitted emissions levels. Thereafter, the systems shall be maintained and tuned in accordance with the manufacturer's recommendations so as to ensure the permitted levels are consistently achieved.

d. The emissions from the CBO™ Process Fluidized Bed Combustor (EU-013) may be routed back to SGS Unit 3 flue gas ductwork, upstream of the ESP, SCR and FGD System, so as to ensure that emissions are minimized. However, the combined emissions from SGS Unit 3 with the CBO™ Unit (when operating) shall comply with the permit standards for SGS Unit 3 as well as the applicable standards in NSPS Subpart Db.

[Design; Rules 62-210.200(PTE and BACT), 62-210.650, 62-212.400(PSD), F.A.C.]

7. Technology Co-benefits: The following technologies shall be installed and operated as described herein.

   a. *Mercury Removal System*: Mercury removal is enhanced when PM controls are used with NO_X and SO_2 controls (ESP, WESP, SCR and FGD). Accordingly, these control technologies shall be designed and tuned to achieve the permitted levels of mercury emissions from SGS Unit 3.

   b. *Fluoride Removal System*: Fluoride removal has recognized co-benefits from an ESP, Wet FGD and WESP. Accordingly, these technologies shall be designed, operated and tuned to achieve the permitted level of fluorides from SGS Unit 3.

   c. *SAM Removal System*: SAM removal shall be accomplished by the use of the FGD system and the Wet ESP. The permittee shall design, install, operate, and maintain these systems in order to achieve the permitted emission level of SAM.

   [Design; Rule 62-212.400(PSD), F.A.C.]

PERFORMANCE REQUIREMENTS

8. Hours of Operation: The coal-fired boiler may operate throughout the year (8,760 hours per year). Restrictions on individual methods of operation are specified in separate conditions.
   [Rules 62-210.200(PTE, and BACT) and 62-212.400 (PSD), F.A.C.]

9. Authorized Fuels:

   a. *Coal* – SGS Unit 3 may combust bituminous coal up to 318.3 tons per hour based upon 11,300 BTU/lb HHV.

   b. *Coal/Pet-coke blend* –SGS Unit 3 may combust coal and pet-coke blend. The pet-coke shall not exceed 30% of the hourly heat input, or 95.5 tons per hour based upon a 12,900 BTU/lb HHV.

   c. *No. 1 or 2 Diesel Oil* – SGS Unit 3 may combust up to 3,320 gallons per hour of 0.05% No. 2 diesel fuel based upon 136 MMBtu/1000 gallons heat value. The combustion of this fuel shall be for the purposes of startups, flame stabilization, limited supplemental load and emergency reserve during statewide capacity shortages.

A. SGS Unit 3 - Pulverized Coal-Fired Supercritical Steam Generating Unit (EU 014)

[Rules 62-210.200(PTE, and BACT) and 62-212.400 (PSD), F.A.C.]

EMISSIONS STANDARDS

10. Emission Standards: Emissions from the pulverized-coal fired boiler shall not exceed the following standards.

Best Available Control Technology (BACT) – Rule 62-210.400, F.A.C.		
Pollutant	**BACT Emission Limits**	**Compliance Method**
PM/PM_{10}	0.013 lb/MMBtu filterable PM; 98 lb/hr equivalent	Annual Stack Test
Opacity	20% with up to 27% for 6-minutes per hour	COMS
CO	0.13 lb/MMBtu (coal only); 975 lb/hr equivalent 0.15 lb/MMBtu 30-day rolling average (all fuels); 1,125 lb/hr equivalent	Initial Stack Test (100% coal) CEMS (all fuels)
VOC	0.0034 lb/MMBtu; 16.7 lb/hr equivalent	Initial Test
HF	0.00023 lb/MMBtu; 1.72 lb/hr equivalent	Initial & T-5 Renewal Test
Pollutant	**Non-BACT Established Emission Limits**	**Compliance Method**
SO_2	0.165 lb/MMBtu 24-hour rolling; 1,238 lb/hr equivalent	CEMS
SAM	0.005 lb/MMBtu; 37.5 lb/hr equivalent	Annual Test
NO_X	0.07 lb/MMBtu; 525 lb/hr equivalent	CEMS
Hg	7.05 E-6 lb/MWh; 0.005 lb/hr equivalent	CEMS or sorbent traps
NH_3	5 ppmvd corrected to 6% O_2	Annual Stack Test

[Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD), F.A.C]

11. Carbon Monoxide (CO): Emissions of CO from SGS Unit 3 shall not exceed the following BACT limits:

    a. Stack test: CO emissions shall not exceed 0.13 lb/MMBtu while firing 100% coal as determined by an initial stack test (average of 3 test runs) in accordance with EPA Method 25, 25A or 25B.

    b. CEMS: CO emissions shall not exceed 0.15 lb/MMBtu as determined by CEMS on a 30-day rolling average, regardless of fuel type. Testing shall be according to EPA Method 10.

    [Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD), F.A.C]

12. Volatile Organic Compounds (VOCs): Emissions of VOC from SGS Unit 3 shall not exceed 0.0034 lb/MMBtu as determined by an initial stack test in accordance with EPA Method 25A and (optionally) EPA Method 18 (to deduct non-VOC methane emissions). Thereafter, compliance with the CO limits herein shall serve as a surrogate for the emissions of VOCs. [Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD), F.A.C]

13. Sulfur Dioxide (SO_2): Emissions of SO_2 from SGS Unit 3 shall not exceed 1.4 pounds per megawatt hour (lb/MW-hr) gross energy output nor 0.165 lb/MMBtu, based upon a 24-hour rolling average as determined by CEMS. In addition, SO_2 emissions shall not exceed 29074 tons per 12-month rolling period (facility-wide), based upon CEMS. [62-210.200 (Net Emissions Increase), and 62-212.400(12) (Source Obligation), F.A.C.]

14. Sulfuric Acid Mist (SAM): Emissions of Sulfuric Acid Mist from SGS Unit 3 shall not exceed 0.005 lb/MMBtu as determined by EPA Method 8A. In addition, SAM emissions shall not exceed 2129 tons per 12-month rolling period (facility-wide), based upon tack testing. The combined total shall be computed by measuring the lb/MMBtu emission rate on each unit, multiplying each unit's emission rate by its annual heat input (MMBtu) and adding the total lbs emitted, divided by 2000. [62-210.200 (Net Emissions Increase), and 62-212.400(12) (Source Obligation), F.A.C.]

15. Particulate Matter (PM/PM_{10}): Emissions of filterable Particulate Matter (PM and PM_{10}) from SGS Unit 3 shall not exceed 0.013 lb/MMBtu while firing 100% coal as determined by EPA Method 5. Condensables shall be captured (from the impingers) and reported (only) in accordance with EPA Method 202. Additionally, opacity shall be limited to 20% except that one 6-minute period per hour may be up to 27%. For opacity, the method of compliance shall be COMS or EPA Method 9 when the COMS data is unavailable. [Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD)]

16. Ammonia: Ammonia slip shall not exceed 5 ppmvd @ 6% O_2 as determined by EPA Conditional Test Method CTM–027.

17. Mercury (Hg): Emissions of mercury from SGS unit 3 shall not exceed 7.05 x 10^{-6} lb/MWh based on a 12-month rolling average as determined by the methods and requirements specified in the NSPS Subpart Da provisions of 40 CFR 60.45(b) and 60.50(g). In addition, mercury emissions shall not exceed 0.059 tons per 12-month rolling period (combined for SGS Units 1, 2 and Unit 3), based upon a CEMS or sorbent trap monitoring system (when operational and certified). Testing of mercury emissions shall be required if installation/certification of the CEMS or sorbent trap monitoring system is delayed. [Rules 62-4.070(3), and 62-212.400(12)(PSD Avoidance), F.A.C, and 40 CFR 60.45Da (b) and 60.50Da(g)]

18. Nitrogen Oxides (NO_X): Emissions of NO_X from SGS Unit 3 shall not exceed 1.0 pounds per megawatt hour (lb/MW-hr) gross energy output nor 0.07 lb/MMBtu, based upon a 30-day rolling average as determined by CEMS. In addition, NOx emissions shall not exceed 23,289 tons per 12-month rolling period (facility- wide), based upon CEMS. [Rules 62-4.070(3), and 62-212.400(12)(PSD Avoidance), F.A.C, Applicant Request]

{Permitting Note: This project did not trigger PSD for SO_2, SAM, Hg and NO_X due to emissions caps taken on existing coal fired boiler steam electric generating Units 1 and Unit 2. The conditions herein establish the requirements for meeting the specified emission limitations for purposes of avoiding PSD preconstruction review. These requirements in no way supersede any federal requirement of applicable NSPS provisions.}

19. Fluorides (HF): Emissions of fluorides from SGS Unit 3 shall not exceed 0.00023 lb/MMBtu as determined by an initial (and Title V renewal) stack test and in accordance with EPA Method 13A or 13B. [Rules 62-4.070(3), 62-210.200 (BACT), and 62-212.400(PSD), F.A.C]

20. Unconfined Particulate Emissions: The following requirements shall be met to minimize fugitive dust emissions from the storage and handling facilities, including haul roads:

    a. All conveyors and conveyor transfer points will be enclosed to the extent practical, so as to preclude PM emissions.
    b. Water sprays or chemical wetting agents and stabilizers will be applied to storage piles, handling equipment, roadways, etc. as necessary to minimize opacity.

    [Rule 62-296.320(4)(c), F.A.C.]

21. Testing Requirements: Initial tests shall be conducted between 90% and 100% of permitted capacity; otherwise, this permit shall be modified to reflect the true maximum capacity as constructed. Subsequent annual tests shall be conducted between 90% and 100% of permitted capacity in accordance with the requirements of Rule 62-297.310(2), F.A.C. For each run during tests for visible emissions and ammonia slip, emissions of CO and NO_X recorded by the CEMS shall also be reported. [Rule 62-297.310(7)(a), F.A.C.; 40 CFR 60.8]

22. Initial Compliance Demonstration: Initial tests when firing 100% coal shall be conducted to demonstrate compliance with the emissions standards for CO, PM, opacity, VOC, HF, SAM, Hg, and ammonia slip. Initial compliance stack tests shall be conducted within 60 days after achieving the maximum production

rate at which SGS Unit 3 will be operated, but not later than 180 days after the initial startup. The initial CO emissions test when firing 100% coal is a one-time validation test. The permittee shall provide the Compliance Authority with any other emissions performance tests conducted to satisfy vendor guarantees. [Rules 62-4.070, 62-297.310(7)(a), F.A.C. and 40 CFR 60.8]

23. Subsequent Compliance Testing: During each federal fiscal year (October 1st, to September 30th), annual tests shall be conducted to demonstrate compliance with the emissions standards for PM, opacity, VOC, SAM, Hg, and ammonia slip. During the year prior to renewal of the Title V Air operation permit, tests shall be conducted to demonstrate compliance with the HF emissions standard. The Department may require additional testing for ammonia slip following catalyst replacement. [Rules 62-4.070, 62-210.200(BACT), and 62-297.310(7)(a)4, F.A.C., and 40 CFR 60.50]

24. Continuous Compliance: Continuous compliance with the permit standards for emissions of CO, Hg, NO_X, and SO_2 shall be demonstrated with data collected from the required continuous monitoring systems. [Rules 62-4.070, and 62-210.200(BACT), F.A.C., 40 CFR 60.50Da]

25. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

EXCESS EMISSIONS

26. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and ensure maintenance of the SGS unit 3 pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods for minimizing excess emissions. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

27. Definitions:

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

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

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

    [Rule 62-210.200(164, 241, and 257), F.A.C.]

28. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

29. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown and malfunction of SGS Unit 3 shall be permitted providing:

    a. Best operational practices to minimize emissions are adhered to, and

b. The duration of excess emissions from startup, shutdown and malfunction of SGA Unit 3 shall be minimized, but in no case exceed 60 hours during any calendar month.

{Permitting Note: 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, this condition provides authorization of 2 hours per 24 hour period of excess emissions related to startup, shutdown, and malfunction to be averaged over a calendar month rather than fixed on a daily basis.} [Rule 62-210.700(5), F.A.C.]

30. Data Exclusion Procedures: Limited amounts of CEMS emissions data collected during startup, shutdown, and malfunction may be excluded from compliance demonstrations (not including annual emissions caps) as approved by the Compliance Authority, provided that best operational practices to minimize emissions are adhered to, they are authorized by this permit and the duration of data excluded is minimized. 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. [Design; Rules 62-210.200(BACT), 62-212.400(PSD), and 62-210.700, F.A.C.]

31. Ammonia Injection: Ammonia injection shall begin as soon as the SCR achieves the operating parameters specified by the manufacturer. Such information shall be provided within the startup and shutdown protocol identified above. [Design; Rules 62-210.200(BACT), 62-212.400(PSD), and 62-210.700, F.A.C.]

32. Notification Requirements: The owner or operator shall notify the Compliance Authority within one working day of discovering any emissions that demonstrate non-compliance for a given averaging period. Within one working day of occurrence, the owner or operator shall notify the Compliance Authority of any malfunction resulting in the exclusion of CEMS data. [Rule 62-4.070, F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

33. CEM Systems: The permittee shall install, calibrate, operate, and maintain continuous emission monitoring systems (CEMS) to measure and record the emissions of CO, NO_X, SO_2, and Hg. Each monitoring system shall be installed, and functioning within the required performance specifications by the time of the initial compliance demonstration.

   a. *CO Monitor:* The CO monitor shall be installed pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

   b. *NO_X Monitor:* A NO_X monitor installed to meet the requirements of 40 CFR 75, and that is continuing to meet the ongoing requirements of Part 75, may be used to meet the requirements of this permit and 40 CFR 60.49(c), Subpart Da, except that the owner or operator shall also meet the requirements of 40 CFR 60.51 and the specific conditions of this permit. Data reported to meet the requirements of 40 CFR 60.51 and the limits of this permit shall not include data substituted using the missing data procedures in Subpart D of Part 75, nor shall the data have been bias adjusted according to Part 75. The RATA tests required for the NOx monitor shall be performed using EPA Method 7 or 7E in Appendix A of 40 CFR 60 or as allowed by Part 75.

   c. *SO_2 Monitor:* The SO_2 monitor shall be installed pursuant to 40 CFR 60, Appendix B, Performance Specification 2. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F. The RATA tests required for the SO_2 monitor shall be performed using EPA Method 6 or 6C in Appendix A of 40 CFR 60. The SO_2 monitor span value shall be set according to 40 CFR 60.49(i).

d. *Mercury Monitor:* Either a mercury CEMS shall be installed to measure mercury emissions pursuant to 40 CFR 60, Performance Specification 12A and to meet the requirements of 40 CFR 60.49(p); or a sorbent trap monitoring system shall be installed pursuant to 40 CFR Part 75, Appendix K.

e. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be continuously monitored at the location where CO, NO_X, and SO_2 are monitored. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

[Rules 62-4.070(3), 62-210.200(BACT), F.A.C., and 40 CFR 60.49 and Part 75]

34. Continuous Flow Monitor: A continuous flow monitor shall be installed to determine stack exhaust flow rate to be used in determining mass emission rates. The flow monitor shall be certified and operated according to the requirements of 40 CFR 75. As an alternative to the stack flow monitor, a fuel flow monitoring system certified and operated according to the requirements of Appendix D of 40 CFR Part 75 may be installed. [Rules 62-4.070(3), 62-210.200(BACT), F.A.C., and 40 CFR 60.49 and Part 75]

35. Wattmeter: A wattmeter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours must be installed, calibrated, maintained, and operated in accordance with the manufacturer's specifications. [40 CFR 60.49]

36. Moisture Correction: If necessary, the owner or operator shall install a system to determine the moisture content of the exhaust gas and develop an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). [Rules 62-4.070(3), 62-210.200(BACT), F.A.C]

37. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system prior to the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the load condition. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

38. CEMS Data Requirements:

a. *Data Collection*: Except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions shall be monitored and recorded during all operation including startup, shutdown, and malfunction.

b. *Operating Hours and Operating Days*: An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Any day with at least one operating hour for an emissions unit is an operating day for that emission unit.

c. *Valid Hour*: Each CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.

1) Hours that are not operating hours are not valid hours.

2) For each operating hour, the 1-hor block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data and the 1-hour block average is not valid.

d. *Rolling 24-Hour Average:* Compliance shall be determined after each valid hourly average is obtained by calculating the arithmetic average of that valid hourly average and the previous 23 valid hourly averages.

e. *Rolling 30-day Average*: Compliance shall be determined after each operating day by calculating the arithmetic average of all the valid hourly averages from that operating day and the prior 29 operating days.

f. *Rolling 12-month Period*: Compliance shall be determined after each calendar month by calculating the total emissions from that calendar month and the last 11 calendar months.

g. *Missing Data/Bias Adjustments:* If the owner or operator has installed a CEMS to meet the requirements of Part 75, data reported to show compliance with any SIP-based limit shall not include data substituted using the missing data procedures in Subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.

h. *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown and malfunction. Limited amounts of CEMS emissions data recorded during these events may be excluded from the corresponding compliance demonstration subject to the provisions of Condition 29 in this section. When authorized, excess emissions data shall be excluded as a continuous block attributable to the startup, shutdown and malfunction event. Valid data shall not be excluded from any annual emissions caps or other annual averages (i.e., mercury).

i. *Availability*: Monitor availability for the Hg CEMS shall be 75% or greater, and for all other CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report shall be used to demonstrate monitor availability. In the event the applicable availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving the required availability and a plan of corrective actions that will be taken to achieve 95% or 75% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

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

REPORTING AND RECORD KEEPING REQUIREMENTS

39. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for the previous month of operation: fuel consumption (tons or gallons as applicable), heat content of each fuel, hours of operation, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

40. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.]

41. CEMS Data Assessment Report: The Data Assessment Report required by 40 CFR 60, Appendix F shall be submitted to the Compliance Authority on a quarterly basis for each CEMS required. Separate reporting may be required for CEMS installed for purposes of compliance with an NSPS limit, or Acid Rain.

42. Excess Emissions Reporting:

    a. *Malfunction Notification:* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

    b. *Quarterly Report*: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of any emissions in excess of the permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. The report shall include a summary of emissions data excluded from compliance calculations due to startup, shutdown, and malfunctions as well as the duration of each event. In addition, the report shall summarize the CO, NO_X, SO_2, and Hg CEMS systems monitor availability for the previous quarter.

    [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7, 60.51, and 60.4375]

43. CBO Configuration: Daily records shall be daily kept of the CBO operation and configuration, such that the permittee can demonstrate compliance with the emission limitations of the affected emissions units.

ID	Emission Unit Description
016	Diesel-Fired Zero Liquid Discharge (ZLD) Spray Dryers (bank of 3)

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for carbon monoxide (CO), volatile organic compounds (VOC) and particulate matter (PM/PM_{10}). [Rule 62-210.200 (BACT), F.A.C.]

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one liquid spray dryer system consisting of a bank of three, diesel-fired liquid spray dryers. This system will be designed to remove the moisture from the wastewater treatment effluent, via a process which involves the atomization of concentrated wastewater into a spray of droplets and contacting the droplets with hot air in a drying chamber. The dryers will be fired by diesel fuel oil. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

4. Authorized Fuels: Only No.1 or No. 2 diesel fuel containing no more than 0.05% sulfur by weight shall be fired in the spray dryers. The maximum design heat input for the bank of spray dryers shall be limited to 50 MMBtu per hour. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

5. Control Equipment: A baghouse will be used to limit PM/PM_{10} emissions, having an efficiency of greater than 99.5 percent. The baghouse must be designed, operated, and maintained to achieve 0.3 lb/hr/dryer. As a work practice standard, an opacity limit of 5% is established. [Application; Rules 62-210.200 (PTE, and BACT) and 62-212.400 (PSD), F.A.C

6. Work Practice: Good combustion practices will be utilized at all times to ensure that CO (and VOC) emissions from the dryer system are minimized. The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and ensure maintenance of the ZLD Spray Dryers in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods for minimizing excess emissions. [Rules 62-4.070(3) and 62-210.200(BACT), F.A.C.]

NOTIFICATION, REPORTING, AND RECORDS

7. Control Device Records: The permittee shall keep readily accessible records which demonstrate that the ZLD Spray Dyer baghouse is operating properly. Such records shall include documentation of daily observations by operators as well as maintenance records on the baghouse and bag replacements. [Rule 62-4.030, F.A.C.]

8. Fuel Records: The permittee shall keep records sufficient to determine the daily throughput of diesel fuel oil for use in ensuring compliance with the heat input limitation. [Rule 62-204.800(7)(b)16, F.A.C]

C. SGS Unit 3 Cooling Tower (EU 015)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
015	SGS Unit 3 Mechanical Draft Cooling Tower – twenty six cells with a 200 HP cooling fan

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for particulate matter (PM/PM_{10}). [Rule 62-210.200 (BACT), F.A.C.]

EQUIPMENT

2. Cooling Tower: The permittee is authorized to install one induced draft, counter-flow, rectangular in-line design mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 360,352 gpm; a design air flow rate of 1,259,541 acfm per cell; drift eliminators; and a drift rate of no more than 0.0005 percent of the circulating water flow. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

3. Drift Rate: Within 60 days of commencing commercial operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. [Rule 62-210.200(BACT), F.A.C.]

{Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on these design criteria, potential emissions are estimated to be less than 10 tons of PM per year and less than 6 tons of PM_{10} per year. Actual emissions are expected to be lower than these rates.}

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a) Have access to and copy and records that must be kept under the conditions of the permit;
b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

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

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

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology (X)
b) Determination of the applicability of Prevention of Significant Deterioration (X); and
c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law, which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

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

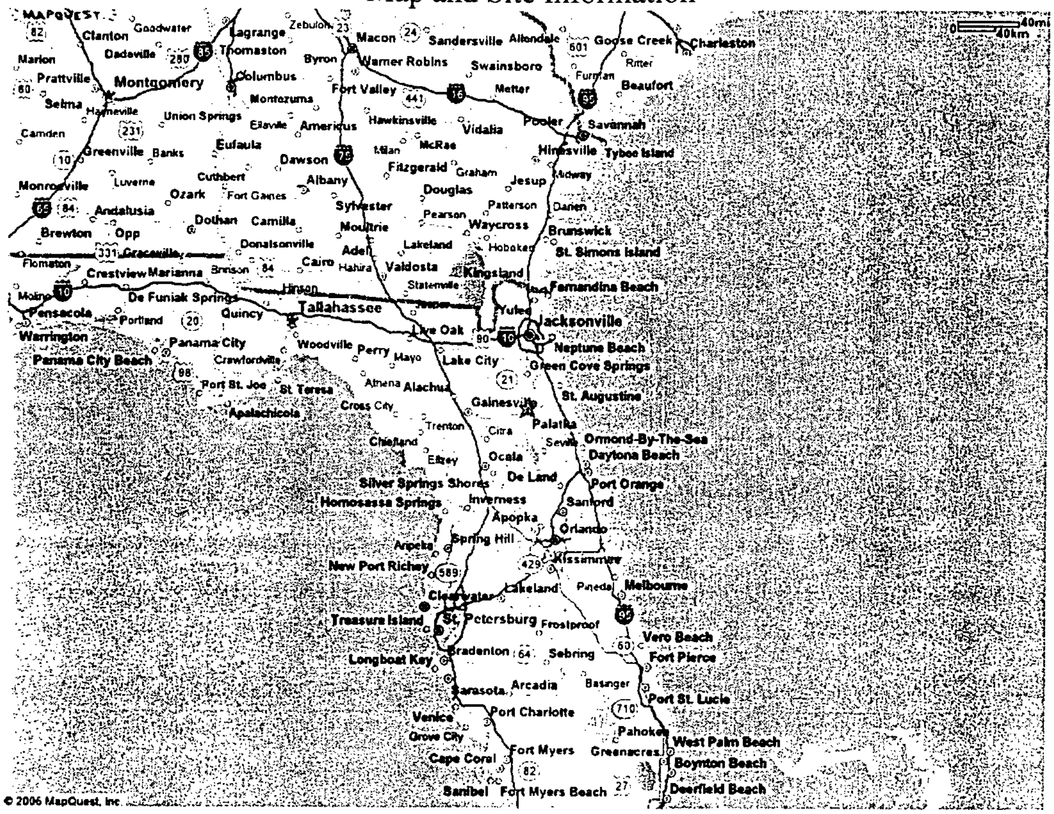
2.3 Facility Category

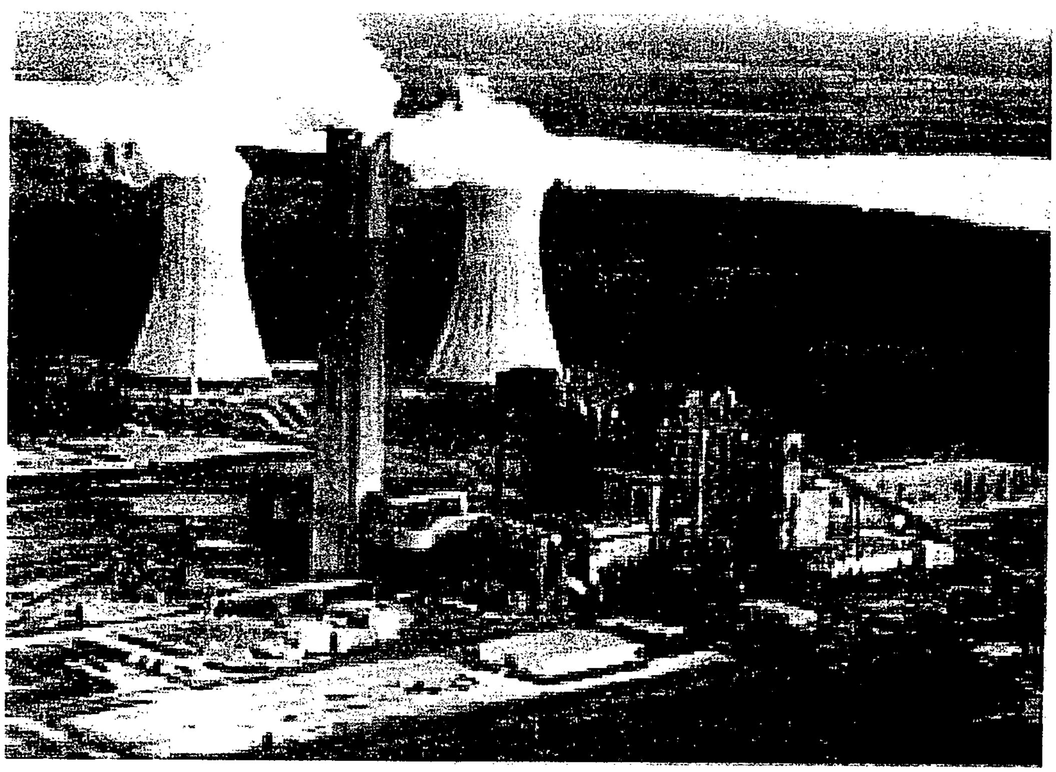
Steam Electric Generator Units 1 and 2 are coal-fired, utility dry bottom wall-fired boilers, each having a maximum generator rating of 714.6 megawatts, electric. The maximum heat input to each emissions unit is 7,172 million Btu per hour. The only fuels allowed to be fired are coal, coal with a maximum 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).

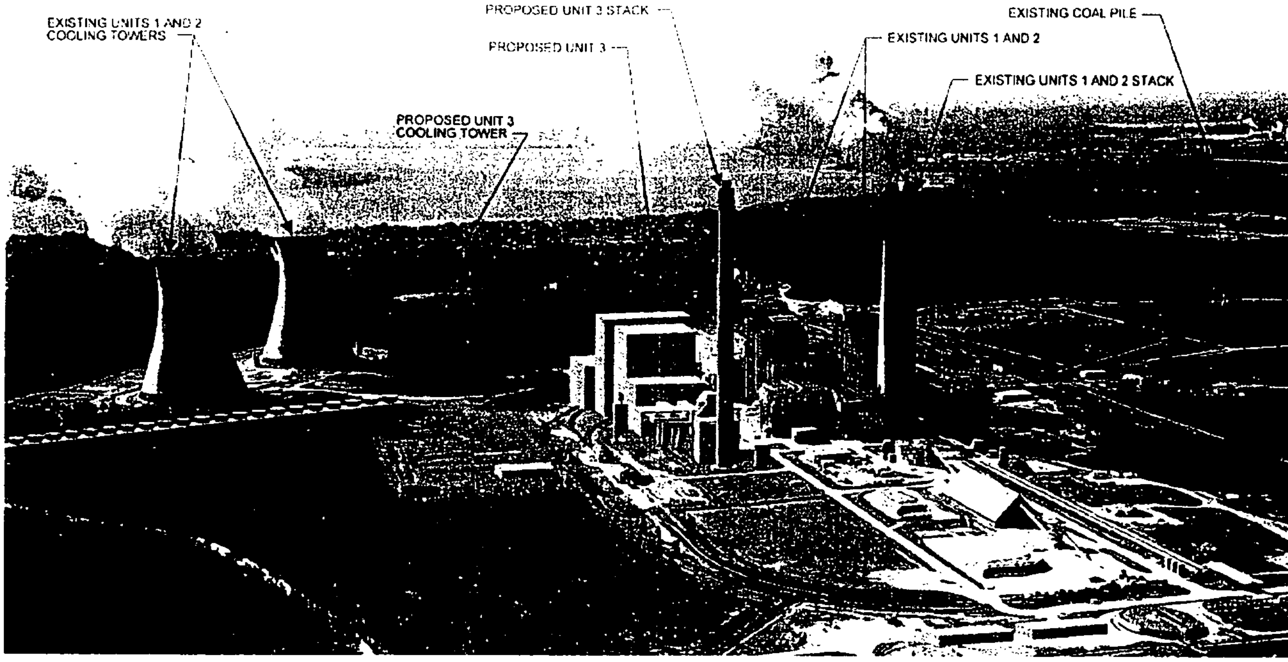
SGS Unit 3 will feature supercritical pulverized coal technology with modern emission controls. The Unit 3 air pollution control equipment will include wet Flue Gas Desulfurization (FGD) for SO_2 removal, selective catalytic reduction (SCR) for control of nitrogen oxides (NO_X), electrostatic precipitator (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 1000°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 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	0.951	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 7.95E-06 lb/MW-hr
Controlled Selenium emissions based on 95% control from FGD system
EPA Emission Factor Rating: A-Excellent
Source: 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

Chapter/Rule	Description
Rule 62-210.350	Public Notice and Comments
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 °F 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	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	Initial Stack Test CEMS Initial Test

Pollutant	BACT Emission Limits	Compliance Method
CO	Emergency Generator: 1.8 lb per hour	Initial Test
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 system's 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 ($\mu g/m^3$)**	**Significant Impact Level ($\mu g/m^3$)**	**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/m³)**	**Impact Greater than Allowable Increment?**	**Allowable Increment (μg/m³)**
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.

Michael P. Halpin, P.E.
Cleve Holladay, Meteorologist

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