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BEFORE THE ENVIRONMENTAL APPEALS BOARD
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY JUL 06 2009
WASHINGTON, D.C.

BUREAU OF AIR REGULATION

In the matter of:

PSD Appeal No. 08-09

In Re Seminole Electric Cooperative, Inc.
_____ /

Motion to Dismiss Sierra Club Appeal as Moot

Seminole Electric Cooperative (Seminole) hereby files this request to dismiss as moot Sierra Club's appeal of Florida Department of Environmental Protection's (FDEP's) issuance of a Prevention of Significant Deterioration (PSD) permit for Seminole Generating Station Unit 3 and in support thereof states:

1. On June 12, 2009, FDEP issued a Draft Permit Revision to Seminole's PSD permit [Exhibit 1], which incorporates the terms and conditions of a Settlement Agreement between Seminole and Sierra Club regarding the PSD permit. Seminole and Sierra Club entered into this Settlement Agreement in March 2007. Final incorporation of the terms of the agreement into the PSD permit was delayed by two events: (1) litigation (not involving the Sierra Club) regarding the certification of Unit 3 pursuant to Florida's Power Plant Siting Act (PPSA)¹ and (2) the PSD permit modification process to incorporate, among other things, the terms of the Settlement Agreement and new limitations on emissions of hazardous air pollutant emissions in light of the intervening vacatur of the Clean Air Mercury Rule.²

¹ See Seminole Elec. Coop. v. Department of Env'tl. Prot., 985 So.2d 615 (Fla. 5th DCA 2008).

² The PSD permitting history for Unit 3, including the modification application, comments submitted by Sierra Club, and FDEP information requests, is accessible at <http://www.dep.state.fl.us/air/permitting/construction/seminole.htm>.

2. In the Settlement Agreement, Seminole agreed “to ask FDEP to include the [Settlement Agreement’s] limits and conditions in the Final PSD permit for Seminole Unit 3 and agree[d] to be bound to these limits and conditions.” [Exhibit 2, p. 3, ¶ 11]. Sierra Club in turn agreed “to not object, challenge, appeal, or initiate or assist in challenge or appeal by others, or in any other way impede or interfere with the issuance of a final PSD permit in accordance with the terms and conditions identified in this Agreement.” [Id.] The Settlement Agreement also stated:

This Agreement reflects the Parties agreement to settle all remaining issues related to the PSD permit for Unit 3. The Parties concur that this Agreement consists of full and fair consideration for the release of all claims of the Sierra Club with respect to issuance of the PSD permit for Unit 3. Provided that the final PSD permit is issued in accordance with the terms and conditions of this Agreement, Sierra Club agrees not to contest FDEP’s issuance of the final PSD permit in any administrative or judicial forum. Seminole agrees not to contest any conditions in the final PSD permit if it is issued in accordance with the terms and conditions of this Agreement.

[Id. at p. 1, ¶ G.]

3. In accordance with its obligations under the Agreement, Seminole requested that FDEP incorporate the Settlement Agreement into the PSD permit in March 2007 and again in September 2008 after the PPSA certification litigation concluded. FDEP responded that the Settlement Agreement would have to be incorporated via permit revision. Seminole thus filed an application for a permit revision.

4. In its November 13, 2008 memorandum to this Board, Sierra Club expressed concerns that FDEP’s then ongoing efforts to amend the PSD permit to incorporate the Settlement Agreement “did not, by any stretch of the imagination, guarantee that FDEP will actually revise the permit to include settlement terms” and that “Sierra Club did not agree to allow FDEP and Seminole to indefinite ‘do-overs’, abandoning any review of the final PSD

permit Seminole holds.”³ [Sierra Club, Reply in Support of its Motion to Hold Proceedings in Abeyance, p. 2].

5. Sierra Club’s fears never materialized; FDEP has issued a Draft PSD Permit Revision that includes the settlement terms. [Exhibit 1, pp. SC-1 – SC-2]. With the Settlement Agreement now expressly incorporated into a modified PSD permit, Seminole has completed compliance with its obligations, and Sierra Club has received the specific outcome it bargained for under the Settlement Agreement. The Draft PSD Permit Revision renders Sierra Club’s appeal of the underlying, unmodified PSD permit moot. See, e.g. ITT Rayonier Inc. v. U.S., 651 F.2d 343, 345 (5th Cir. Unit B Nov. 1981) (“Generally settlement of a dispute between two parties renders moot any case between them growing out of that dispute. A court will find mootness even if the parties remain at odds over the particular issue they are litigating.”); U.S. Fire Ins. Co. v. Caulkins Indiantown Citrus Co., 931 F.2d 744 (11th Cir. 1991). Whatever rights Sierra Club may or may not have had prior to express incorporation of the terms of the Settlement Agreement into the PSD permit are inconsequential to Sierra Club’s inability to continue this appeal. Lewis v. Cont’l Bank Corp., 494 U.S. 472, 477 (U.S. 1990) (“To sustain our jurisdiction in the present case, it is not enough that a dispute was very much alive when suit was filed, or when review was obtained...”). This appeal should be dismissed as moot.

6. Counsel for Seminole has consulted with Counsel for FDEP and is authorized to represent that FDEP does not object to this motion.

WHEREFORE, Seminole respectfully requests that the Environmental Appeals Board dismiss this appeal as moot.

³ Sierra Club’s November 2008 memorandum also refers to an action for Declaratory Judgment in Florida Circuit Court, in which Sierra Club sought to have the Settlement Agreement declared void. [Sierra Club, Reply, p. 1] Significantly, Sierra Club voluntarily dismissed that action on February 19, 2009. [Exhibit 3].

Respectfully submitted this 2^d day of July, 2009.



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Attorneys for Seminole Electric Cooperative, Inc.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Motion to Dismiss Sierra Club Appeal as Moot, has been furnished via U.S. Mail this ___ day of July, 2009 to:

Joanne Spalding, Esq.
Kristen Henry, Esq.
Counsel for Sierra Club
85 Second Street
San Francisco, CA 94105-3441

David G. Guest, Esq.
Counsel for Sierra Club
P. O. Box 1329
Tallahassee, FL 32302

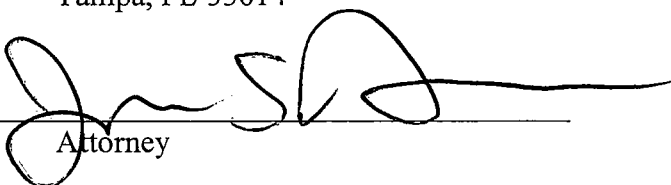
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Trina Vielhauer
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399-3400

Vera Kornylak
Mary J. Wilkes
U.S. EPA, Region 4
61 Forsyth St., S.W.
Atlanta, GA 30303-8960

James R. Frauen, Project Director
Seminole Electric Cooperative, Inc.
1613 North Dale Mabry Highway
Tampa, FL 33614



Attorney

EXHIBIT 1



Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kotkamp
Lt. Governor

Michael W. Soto
Secretary

June 12, 2009

Mr. Mike Roddy, Manager of Environmental Affairs
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, Florida 33618

Re: Project No. 1070025-011-AC
(PSD-FL-375A)
Seminole Electric Cooperative, Inc., Seminole Generating Station
Revisions to Original Permit for Proposed New Unit 3 Project

Dear Mr. Roddy:

On December 22, 2008, you submitted an application requesting several revisions to original Permit No. PSD-FL-375, which authorized the construction of a new nominal 750 megawatt (MW), pulverized coal-fired supercritical steam generating Unit 3 at the existing Seminole Generating Station. This facility is located in Putnam County east of U.S. Highway 17 and approximately seven miles north of Palatka. Enclosed are the following documents: the Technical Evaluation and Preliminary Determination; the Draft Permit and Appendices; the Written Notice of Intent to Issue Air Permit; and the Public Notice of Intent to Issue Air Permit. 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, Jeff Koerner, at 850/921-9536.

Sincerely,

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

TLV/jfk

WRITTEN NOTICE OF INTENT TO ISSUE A REVISED AIR PERMIT

*In the Matter of an
Application for Air Permit by:*

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

Project No. 1070025-011-AC
(PSD-FL-375A)
Seminole Generating Station
Revisions for Proposed Unit 3 Project

Authorized Representative:

Mike Roddy, Manager of Environmental Affairs

Facility Location: Seminole Electric Cooperative, Inc. operates the existing Seminole Generating Station, which is located east of U.S. Highway 17, approximately seven miles north of Palatka, Putnam County.

Project: On September 5, 2008, the Department issued original Permit No. PSD-FL-375, which authorized the construction of a new nominal 750 megawatt, pulverized coal-fired supercritical steam generating unit at the existing Seminole Generating Station. On December 22, 2008, the Seminole Electric Cooperative, Inc. submitted an application to revise the original permit as follows: extend the expiration date; clarify references to the Clean Air Interstate Rule and Clean Air Mercury Rule; clarify that the maximum heat input rate is an enforceable restriction; correct the equivalent emissions rate for volatile organic compounds from 16.7 to 25.5 lb/hour; clarify that the particulate matter filterable limit of 0.013 pounds per million British thermal units applies to all fuel blends; add conditions 44 through 50 in Subsection IIIA of the permit as enforceable requirements for hazardous air pollutants; add Appendix CM identifying requirements for continuous emissions monitoring; add Appendix HP for calculating actual emissions of hazardous air pollutants; and add the Sierra Club Agreement dated March 19, 2007 as Appendix SC.

The project is a minor revision of the original air construction permit for Unit 3, which has not yet been constructed. There will be no emissions increases; therefore, the project is not subject to additional preconstruction review pursuant to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality, but will be a revision of the original air construction permit. Because PSD preconstruction review is not triggered, the Department did not conduct a new review for Best Available Control Technology (BACT) nor make any changes to the prior BACT determinations. The Department's original BACT determinations remain unchanged. For additional details, see the attached Technical Evaluation and Preliminary Determination and Draft Permit.

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 Bureau of Air Regulation is the Permitting Authority responsible for making a permit determination for this project. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida. The Permitting Authority's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone number is 850/488-0114.

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

Notice of Intent to Issue Permit: The Permitting Authority gives notice of its intent to issue an air permit to the applicant for the project described above. The applicant has provided reasonable assurance that operation of the

WRITTEN NOTICE OF INTENT TO ISSUE A REVISED AIR PERMIT

proposed equipment will not adversely impact air quality and that the project will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Public Notice: Pursuant to Section 403.815, F.S. and Rules 62-110.106 and 62-210.350, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Permit (Public Notice). The Public Notice shall be published one time only as soon as possible in the legal advertisement section of a newspaper of general circulation in the area affected by this project. The newspaper used must meet the requirements of Sections 50.011 and 50.031, F.S. in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Permitting Authority at the above address or phone number. Pursuant to Rule 62-110.106(5) and (9), F.A.C., the applicant shall provide proof of publication to the Permitting Authority at the above address within 7 days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rule 62-110.106(11), F.A.C.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit and requests for a public meeting for a period of 30 days from the date of publication of the Public Notice. Written comments must be received by the Permitting Authority by close of business (5:00 p.m.) on or before the end of this 30-day period. In addition, if a public meeting is requested within the 30-day comment period and conducted by the Permitting Authority, any oral and written comments received during the public meeting will also be considered by the Permitting Authority. If timely received comments result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

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

A petition that disputes the material facts on which the Permitting Authority's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner; the name, address and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of when and how each petitioner received notice of the agency action or proposed decision; (d) A statement of all disputed issues of material fact. If there are none, the petition must so state; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends

WRITTEN NOTICE OF INTENT TO ISSUE A REVISED AIR PERMIT

warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action including an explanation of how the alleged facts relate to the specific rules or statutes; and, (g) A statement of the relief sought by the petitioner, stating precisely the action the petitioner wishes the agency to take with respect to the agency's proposed action. A petition that does not dispute the material facts upon which the Permitting Authority's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

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

Mediation: Mediation is not available in this proceeding.

Executed in Tallahassee, Florida:



Trina Vielhauer, Chief
Bureau of Air Regulation

WRITTEN NOTICE OF INTENT TO ISSUE A REVISED AIR PERMIT

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Written Notice of Intent to Issue Air Permit package (including the Written Notice of Intent to Issue Air Permit, the Public Notice of Intent to Issue Air Permit, the Technical Evaluation and Preliminary Determination and the Draft Permit) was sent by electronic mail (or a link to these documents made available electronically on a publicly accessible server) with received receipt requested before the close of business on 6/12/09 to the persons listed below.

Mr. Mike Roddy, SECI (wmroddy@seminole-electric.com)
Mr. James R. Frauen, SECI (jfrauen@seminole-electric.com)
Mr. Scott Osbourn, Golder Associates (sosbourn@golder.com)
Mr. Robert Manning, Hopping, Green & Sams (rmanning@hgslaw.com)
Mr. Jim Alves, Hopping, Green & Sams (jalves@hgslaw.com)
Mr. Mike Halpin, DEP Site Certification (mike.halpin@dep.state.fl.us)
Mr. Chris Kirts, NED (christopher.kirts@dep.state.fl.us)
Ms. Phyllis Fox, Ph.D. (phyllisfox@gmail.com)
Ms. Kathleen Forney, EPA Region 4 (forney.kathleen@epa.gov)
Ms. Heather Abrams, EPA Region 4 (abrams.heather@epamail.epa.gov)
Ms. Kristin Henry, Sierra Club (kristin.henry@sierraclub.org)
Ms. Joanne Spalding, Sierra Club (joanne.spalding@sierraclub.org)
Ms. Catherine Collins, U.S. Fish and Wildlife Service (catherine_collins@fws.gov)
Mr. George Cavros, on behalf of Natural Resources Defense Council and Southern Alliance for Clean Energy
(gcavros@att.net)
Ms. Victoria Gibson, BAR Reading File (victoria.gibson@dep.state.fl.us)

Clerk Stamp

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


(Clerk)

6/12/09
(Date)

PUBLIC NOTICE OF INTENT TO ISSUE A REVISED AIR PERMIT

Florida Department of Environmental Protection
Division of Air Resource Management, Bureau of Air Regulation
Draft Air Construction Permit Revision
Project No. 1070025-011-AC (PSD-FL-375A)
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: Mike Roddy, Manager of Environmental Affairs, Seminole Electric Cooperative, Inc., 16313 North Dale Mabry Highway, Tampa, Florida 33618.

Facility Location: Seminole Electric Cooperative, Inc. operates the existing Seminole Generating Station, which is located east of U.S. Highway 17, approximately seven miles north of Palatka, Putnam County.

Project: On September 5, 2008, the Department issued original Permit No. PSD-FL-375, which authorized the construction of a new nominal 750 megawatt, pulverized coal-fired supercritical steam generating unit at the existing Seminole Generating Station. On December 22, 2008, the Seminole Electric Cooperative, Inc. submitted an application to revise the original permit as follows: extend the expiration date; clarify references to the Clean Air Interstate Rule and Clean Air Mercury Rule; clarify that the maximum heat input rate is an enforceable restriction; correct the equivalent emissions rate for volatile organic compounds from 16.7 to 25.5 lb/hour; clarify that the particulate matter filterable limit of 0.013 pounds per million British thermal units applies to all fuel blends; add conditions 44 through 50 in Subsection IIIA of the permit as enforceable requirements for hazardous air pollutants; add Appendix CM identifying requirements for continuous emissions monitoring; add Appendix HP for calculating actual emissions of hazardous air pollutants; and add the Sierra Club Agreement dated March 19, 2007 as Appendix SC.

The project is a minor revision of the original air construction permit for Unit 3, which has not yet been constructed. There will be no emissions increases; therefore, the project is not subject to additional preconstruction review pursuant to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality, but will be a revision of the original air construction permit. Because PSD preconstruction review is not triggered, the Department did not conduct a new review for Best Available Control Technology (BACT) nor make any changes to the prior BACT determinations. The Department's original BACT determinations remain unchanged.

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 Permitting Authority responsible for making a permit determination for this project is the Bureau of Air Regulation in the Department of Environmental Protection's Division of Air Resource Management. The Permitting Authority's physical address is: 111 South Magnolia Drive, Suite #4, Tallahassee, Florida. The Permitting Authority's mailing address is: 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400. The Permitting Authority's telephone 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 physical address indicated above for the Permitting Authority. The complete project file includes the Draft Permit, the Technical Evaluation and Preliminary Determination, the application and information submitted by the applicant (exclusive of confidential records under Section 403.111, F.S.). Interested persons may contact the Permitting Authority's project engineer for additional information at the address and phone number listed above. In addition, electronic copies of these documents are available on the following web site: <http://www.dep.state.fl.us/air/eproducts/apds/default.asp>.

Notice of Intent to Issue Air Permit: The Permitting Authority gives notice of its intent to issue an air construction 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

(Public Notice to be Published in the Newspaper)

comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297, F.A.C. The Permitting Authority will issue a Final Permit in accordance with the conditions of the proposed Draft Permit unless a timely petition for an administrative hearing is filed under Sections 120.569 and 120.57, F.S. or unless public comment received in accordance with this notice results in a different decision or a significant change of terms or conditions.

Comments: The Permitting Authority will accept written comments concerning the proposed Draft Permit and requests for a public meeting for a period of 30 days from the date of publication of the Public Notice. Written comments must be received by the Permitting Authority by close of business (5:00 p.m.) on or before the end of this 30-day period. In addition, if a public meeting is requested within the 30-day comment period and conducted by the Permitting Authority, any oral and written comments received during the public meeting will also be considered by the Permitting Authority. If timely received comments result in a significant change to the Draft Permit, the Permitting Authority shall revise the Draft Permit and require, if applicable, another Public Notice. All comments filed will be made available for public inspection.

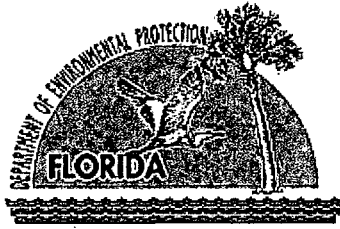
Petitions: A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed with (received by) the Department's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

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

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

Mediation: Mediation is not available for this proceeding.

(Public Notice to be Published in the Newspaper)



**TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION**

APPLICANT

Seminole Electric Cooperative, Inc.
P.O. Box 272000
Tampa, FL 33688-2000

Seminole Generating Station
Facility ID No. 1070025
Palatka, Florida

PROJECT

Project No. 1070025-011-AC (PSD-FL-375A)
Minor Revisions

COUNTY

Putnam County, Florida

PERMITTING AUTHORITY

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

June 12, 2009

1. GENERAL PROJECT INFORMATION

Air Pollution Regulations

Projects at stationary sources with the potential to emit air pollution are subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The statutes authorize the Department of Environmental Protection (Department) to establish regulations regarding air quality as part of the Florida Administrative Code (F.A.C.), which includes the following applicable chapters: 62-4 (Permits); 62-204 (Air Pollution Control – General Provisions); 62-210 (Stationary Sources – General Requirements); 62-212 (Stationary Sources – Preconstruction Review); 62-213 (Operation Permits for Major Sources of Air Pollution); 62-296 (Stationary Sources – Emission Standards); and 62-297 (Stationary Sources – Emissions Monitoring). Specifically, air construction permits are required pursuant to Rules 62-4, 62-210 and 62-212, F.A.C.

In addition, the U. S. Environmental Protection Agency (EPA) establishes air quality regulations in Title 40 of the Code of Federal Regulations (CFR). Part 60 specifies New Source Performance Standards (NSPS) for numerous industrial categories. Part 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP) based on specific pollutants. Part 63 specifies NESHAP based on the Maximum Achievable Control Technology (MACT) for numerous industrial categories. The Department adopts these federal regulations on a quarterly basis in Rule 62-204.800, F.A.C.

Glossary of Common Terms

Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations, which are defined in Appendix A of this permit.

Facility Description and Location

The Seminole Generating Station is an existing coal-fired electric generating station, which is categorized under Standard Industrial Classification Code No. 4911. The facility is located in Putnam County east of U.S. Highway 17 and approximately seven miles north of Palatka. The UTM coordinates of the existing facility are Zone 17, 438.80 km East, and 3289.20 km North. This site is in an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to state and federal Ambient Air Quality Standards (AAQS).

Facility Regulatory Categories

- The facility is a major source of hazardous air pollutants (HAP).
- The facility operates units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

Project Description

In March of 2006, Seminole Electric Cooperative, Inc. submitted an application proposing to add a new coal-fired Unit 3 to the existing, certified Seminole Generating Station site located in Putnam County, north of Palatka. On September 5, 2008, the Department issued final air construction Permit No. PSD-FL-375 (Project No. 1070025-005-AC) to install the proposed Unit 3 adjacent to existing Units 1 and 2. The design of the Unit 3 project is intended to maximize the co-use of existing site facilities to the greatest extent possible, including a common fuel blend and fuel handling facilities for Units 1, 2 and 3. The addition of Unit 3 will increase the total electrical generating output capacity of the existing plant by almost 60%.

Unit 3 features supercritical pulverized coal technology with a maximum heat input rate of 7500 MMBtu per hour and a nominal electrical generating capacity of 750 MW. The primary fuel will be a blend of coal and petroleum coke. The solid fuels for Unit 3 will be delivered by an existing rail system. Modern air pollution control equipment will include a wet flue gas desulfurization (FGD) system for sulfur dioxide (SO₂) removal, a selective

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catalytic reduction (SCR) system to control of nitrogen oxides (NO_x), an electrostatic precipitator (ESP) to collect and remove fine particles, and a wet ESP to control sulfuric acid mist. The control of fluorides and mercury will be accomplished through co-benefits of the above air pollution control technologies. Compliance will be demonstrated by continuous emissions monitoring systems for the following pollutants: carbon monoxide (CO), NO_x, SO₂ and mercury.

On December 22, 2008, Seminole Electric Cooperative, Inc. (the applicant) submitted an application requesting the following specific revisions to the air construction permit.

- Extend the permit expiration date;
- Incorporate the agreement dated March 19, 2007 between the applicant and the Sierra Club (Sierra Club Agreement);
- Revise or remove references to the Clean Air Interstate Rule (CAIR) and the Clean Mercury Rule (CAMR); and
- Revise permit conditions to address comments received from EPA Region 4.

In addition, the applicant requested that the Department concur with its determination that HAP emissions from the Unit 3 project will be less than the major source thresholds of 10 tons per year of any individual HAP emissions and 25 tons per year of total HAP emissions. Such a determination would mean that the project does not require a case-by-case determination of the Maximum Achievable Control Technology (MACT) pursuant to Section 112(g) of the Clean Air Act.

Processing Schedule

12/22/08 Received the application for a minor source air pollution construction permit.
03/25/09 Received additional information; application complete.

2. PSD APPLICABILITY

Original Project for SGS Unit 3, Project No. 1070025-005-AC (PSD-FL-375)

For areas currently in attainment with the state and federal AAQS or areas otherwise designated as unclassifiable, the Department regulates major stationary sources of air pollution in accordance with Florida's PSD preconstruction review program as defined in Rule 62-212.400, F.A.C. Based on emissions decreases from Permit 1070025-004-AC to install air pollution control equipment on Units 1 and 2, the Unit 3 project netted out of PSD preconstruction review for the following pollutants: NO_x, SO₂ and sulfuric acid mist (SAM). Therefore, the original Unit 3 project was subject to PSD preconstruction review only for the following PSD pollutants: CO, fluorides (Fl), particulate matter (PM), particulate matter with a mean particle diameter of 10 microns or less (PM₁₀) and volatile organic compounds (VOC).

Minor Revisions to SGA Unit 3 Project, Project No. 1070025-011-AC (PSD-FL-375A)

The current project is a minor revision of the original air construction permit for Unit 3, which has not yet been constructed. There will be no emissions increases; therefore, the project is not subject to additional PSD preconstruction review, but will be a revision of the original air construction permit. Because PSD preconstruction review is not triggered, the Department did not conduct a new review for Best Available Control Technology (BACT) nor make any changes to the prior BACT determinations. The Department's original BACT determinations remain unchanged.

3. DEPARTMENT REVIEW OF REQUESTED PERMIT REVISIONS

Permit Expiration Date

Applicant Request: The final air construction permit specifies an expiration date of December 31, 2012, which

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was based on the preliminary schedule described in the original application submitted on March 9, 2006. However, intervening events of the site certification process delayed issuance of the final permit until September 5, 2008. The applicant requests an extension of the permit expiration date through December 31, 2016 to provide sufficient time to complete all construction and shutdown activities and obtain a revision of the Title V air operation permit to incorporate the Unit 3 requirements.

Department Review: As previously mentioned, the project was also subject to a site certification process, which typically takes at least a year. Based on that assumption, the final permit could have been issued in March of 2007. This means that the final permit was likely delayed no more than 18 months. Therefore, the Department agrees to extend the air construction permit by 18 months through July 1, 2014. This provides more than five years from the date the permit was first issued.

To make certain that the original BACT determinations do not become outdated, the final permit already includes provisions to ensure that the applicant begins construction in a timely manner and maintains a continuous program of construction. Pursuant to Rule 62-212.400(12)(a), F.A.C., the final permit includes the following requirements in Condition 3 of Section II:

“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.”

Extending the permit through July 1, 2014 will not affect these requirements. As stated above, for good cause, the permittee may request an extension of the permit. Nevertheless, the permittee must begin construction on the project within 18 months after receiving the original air construction permit (September 5, 2008). To make sure that the applicant fully understands this requirement, the Department revised the first sentence in Condition 3 of Subsection II of the permit to, “Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the initial permit (September 5, 2008), if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time.”

Sierra Club Agreement

Applicant Request: The applicant specifically requests the Department incorporate the Sierra Club Agreement into the final PSD permit as enforceable requirements.

Department Review: Seminole Electric Cooperative, Inc. and the Sierra Club entered into a settlement agreement (Sierra Club Agreement) to resolve issues between the two parties. The Department was not a party to the Sierra Club Agreement. For the original project, Seminole Electric Cooperative, Inc. requested that the terms of the Sierra Club Agreement be included in the original Final Permit. The Department’s Final Determination for the original permit stated that this could be accomplished in a subsequent request to revise the permit, which is a part of this current project.

As requested, the Department agrees to incorporate the “Terms and Conditions” of the Sierra Club Agreement as enforceable requirements in Appendix SC of the revised air construction permit. It is also noted that:

- The permittee shall comply with all other conditions of the final permit as drafted by the Department.

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- The Sierra Club Agreement cannot and does not directly modify any permit conditions.
- Only those provisions of the Sierra Club Agreement under “Terms and Conditions” related to and appropriate for the air permit are included in Appendix SC, which is a part of the permit.
- The conditions in Appendix SC are enforceable by the Department as part of the permit. All other provisions of the Sierra Club Agreement are enforceable by the parties to the agreement. In addition, paragraphs 10, 11 and 12 of the “Terms and Conditions” are considered obsolete and are not included in Appendix SC to this permit.

Appendix SC includes several permitting notes that describe how the terms of the Sierra Club Agreement were incorporated.

CAIR and CAMR References

Applicant Request: The applicant requests removal of obsolete references to the CAIR and CAMR programs.

Department Review: The terms CAIR and CAMR are used under the subsection “Regulatory Classification” in Section I of the permit. Since the federal CAIR and CAMR provisions have been vacated and remanded to EPA for reconsideration, the Department will make the following clarifications. Deleted text is shown with ~~strike through~~ and new text is double underlined.

CAIR: ~~As an e~~Electric generating units, ~~SGS Unit 3~~ may be subject to the Clean Air Interstate Rule pending EPA’s reconsideration of the federal rule ~~the finalization of DEP rules.~~

CAMR: ~~SGS Unit 3 is a new e~~Coal-fired units power plant and ~~will may~~ be subject to the Clean Air Mercury Rule pending EPA’s reconsideration of this vacated federal rule ~~finalization of DEP rules.~~

EPA Region 4 Comments

The applicant identified the following comments made by EPA Region 4 on the draft permit and requested corresponding revisions to the air construction permit.

1. Applicant Request: In Condition 4 of Section IIIA of the permit, clarify that the maximum heat input rate is an enforceable restriction. The applicant notes that this is also included in the Sierra Club Agreement.

Department Review: The Department agrees to revise the third sentence in this condition as follows:

“The steam generator ~~shall be designed for a~~ maximum heat input rate shall not exceed of 7,500 MMBtu per hour of coal fuel blend based on fuel sampling and analysis.”

2. Applicant Request: In Condition 10 of Section IIIA of the permit, correct the equivalent “lb/hour” of VOC emissions from 16.7 to 25.5 lb/hour. Since the VOC emissions standard is 0.0034 lb/MMBtu, the correct equivalent mass emissions rate based on a maximum heat input rate of 7500 MMBtu/hour is 25.5 lb/hour. The applicant notes that the correction is also included in the Sierra Club Agreement.

Department Review: The Department agrees to the requested correction.

3. Applicant Request: In Condition 15 of Section IIIA of the permit, clarify that the PM filterable limit of 0.013 lb/MMBtu applies to all fuel blends by deleting the phrase “while firing 100% coal”.

Department Review: The Department agrees to the requested clarification.

4. APPLICANT’S ANALYSIS OF MAJOR/MINOR HAP SOURCE STATUS

The applicant provided estimates for the following categories of controlled HAP emissions: acid gases, organics and metals. In addition to each specific HAP emissions factor, the maximum annual emissions were based on the following information: maximum heat input rate for Unit 3: 7500 MMBtu per hour; 11,780 Btu/lb (23.56 MMBtu per ton) higher heating value of coal blend; 318.3 tons per hour maximum coal blend firing rate; and

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8760 hours per year maximum hours of operation. Summary tables of the applicant's HAP emissions estimates are provided in Attachment A of this Technical Evaluation and Preliminary Determination.

Acid Gas HAP Emissions

To estimate hydrogen chloride (HCl) and hydrogen fluoride (HF) emissions from Unit 3, the applicant used data from the United States Coal Quality Database¹ managed by the United States Geological Survey (USGS). Based on the upper 95% confidence interval for Central Appalachian Region coal, the applicant identified a chloride content of 1040.5 ppmw and a fluoride content of 89.9 ppmw. The applicant assumed a control efficiency of 99.7% for HF and HCl emissions based on the proposed air pollution control equipment (wet FGD system, an SCR system, an ESP and a wet ESP) as well as recent projects with similar acid gas controls (Duke Energy Marshall Unit 4 project in North Carolina and the Spurlock Station Unit 2 project in Kentucky). The applicant estimated maximum annual emissions of 8.71 tons of HCl/year and 0.75 tons of HF/year for total acid gas HAP emissions of 9.46 tons/year. Therefore, the applicant believes there is reasonable assurance that emissions of each individual acid gas HAP will be less than 10 tons per year.

Organic HAP Emissions

The applicant identified and estimated the emissions of 40 individual organic HAP from firing coal using a combination of EPA's "Compilation of Air Pollutant Emission Factors" known as AP-42² and the "Emission Factor Handbook" from the Electric Power Research Institute (EPRI)³. Estimates of organic HAP emissions are based on:

- AP-42 Table 1.1-12: dioxin/furan (PCDD/PCDF);
- AP-42 Table 1.1-14: 2-chloroacetophenone, cumene, cyanide, dimethyl sulfate, ethylene dichloride, ethylene dibromide, hexane, methyl hydrazine, methyl tert butyl ether, polycyclic organic material, and 1,1,1-trichloroethane; and
- EPRI Emission Factors: acetaldehyde, acetophenone, acrolein, benzene, benzyl chloride, biphenyl, bis(2-ethylhexyl) phthalate (DEHP), bromoform, carbon disulfide, chlorobenzene, chloroform, 2,4-dinitrotoluene, ethyl benzene, ethyl chloride, formaldehyde, isophorone, methyl bromide, methyl chloride, methyl methacrylate, methylene chloride, naphthalene, phenol, propionaldehyde, styrene, tetrachloroethylene, toluene, xylenes and vinyl acetate.

Using the emissions factors from the sources identified above and maximum permitted operation, the applicant estimated total organic HAP emissions of 6.14 tons/year. Therefore, the applicant believes there is reasonable assurance that emissions of each individual organic HAP will be less than 10 tons per year.

Metal HAP Emissions

The applicant identified 11 different metal HAP emissions from firing coal. The following summarizes the references and methods for the emissions estimates.

- The equations provided in AP-42 Table 1.1-16 were used to estimate controlled emissions of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese and nickel. This table identifies a unique equation for each metal HAP dependent on the following variables: concentration (ppmw) of given metal HAP, weight fraction of ash in coal blend (e.g., 10% is 0.1 weight fraction) and the site-specific emissions

¹ USGS COAL/QUAL Database (<http://energy.er.usgs.gov/coalqual.htm>); U.S. Coal Quality Database; National Coal Resources Data System; United States Geological Survey (USGS) of the United States Department of the Interior; 2009

² "Compilation of Air Pollutant Emission Factors, AP-42, Volume I: Stationary Point & Area Sources^{2a}"; U.S. Environmental Protection Agency; Chapter 1, Section 1 revised in 1998

³ "Emission Factor Handbook"; Electric Power Research Institute (EPRI), 1995; revised 2002

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limit for particulate matter (0.013 lb/MMBtu). Data for each specific metal HAP concentration and the weight fraction of ash was provided from the USGS Coal Quality Database.

- For mercury, the applicant used the current permitted mercury emissions standard of 7.5×10^{-07} lb/MMBtu.
- For selenium, the applicant used the expected selenium concentration from the USGS Coal Quality Database and assumed a control efficiency of 95%, which is approximately equivalent to that predicted for mercury (95.59%), which is another volatile metal.

Using the emissions factors from the sources identified above and maximum permitted operation, the applicant estimated total metal HAP emissions of 2.24 tons per year. Therefore, the applicant believes there is reasonable assurance that emissions of each individual metal HAP will be less than 10 tons per year.

Total HAP Emissions

Based on the above analysis, the applicant estimates the following total annual HAP emissions.

Table A. Applicant's HAP Emissions Summary

HAP	Tons/Year
Acid Gas HAP	9.46
Organic HAP	6.14
Metal HAP	2.24
Total HAP	17.84

Based on this analysis, each individual HAP is predicted to be less than 10 tons/year and the total combined HAP will be less than 25 tons/year. Therefore, the applicant believes that the Unit 3 project will be a minor source of HAP emissions.

HAP Emissions Limits and Monitoring Proposed by the Applicant

The applicant proposes the following emissions limits and monitoring methods to provide assurance that the project will not result in a major source of HAP emissions.

Acid Gas HAP Emissions

Since HCl emissions are the highest individual HAP, the applicant proposes an emissions standard for HCl of 3.01×10^{-04} lb/MMBtu, which is equivalent to 9.89 tons/year. The applicant proposes initial and annual stack tests for HCl emissions in accordance with EPA Method 26A and initial stack tests for HF emissions in accordance with EPA Methods 13A/13B. The permit requires subsequent stack tests for HF emissions prior to renewing the Title V air operation permit. The Department notes that the current permitted HF emissions limit is 0.00023 lb/MMBtu, which is equivalent to 7.56 tons/year at full permitted capacity.

The applicant states that controlling SO₂ emissions with the wet FGD and wet ESP systems will also result in controlling acid gas emissions. Based on emissions test data from Spurlock Station Unit 2 (East Kentucky Power Cooperative, Inc.), the applicant believes that acid gas HAP emissions will be controlled with an efficiency of at least 99.7%. To ensure low levels of acid gas emissions between tests, the applicant proposes the continuous monitoring of SO₂ emissions as a surrogate for acid gas HAP emissions. The applicant believes that demonstrating compliance with the permitted SO₂ emissions standard of 0.165 lb/MMBtu based on a 24-hour rolling average of CEMS data will provide reasonable assurance that acid gas HAP emissions will be less than predicted.

Organic HAP Emissions

The applicant proposes to use CO emissions as a surrogate for organic HAP emissions. The applicant states that CO emissions will vary in the same manner as organic HAP emissions, which are a function of the coal

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combustion process. The applicant suggests that compliance with the permitted CO emissions standard of 0.15 lb/MMBtu based on a 30-day rolling average of CEMS data will provide reasonable assurance that organic HAP emissions will be less than 6.14 tons per year. No additional testing is proposed.

Metal HAP Emissions

The current air construction permit specifies a mercury emissions standard of 7.05×10^{-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). These provisions require the installation and operation of a CEMS to demonstrate compliance with the mercury emissions standard. At full capacity, this is approximately 46 pounds of mercury per year (0.023 tons/year).

The applicant proposes to use the filterable portion of PM₁₀ as a surrogate for other metal HAP emissions. The applicant suggests that compliance with the filterable PM₁₀ emissions standard of 0.013 lb/MMBtu (a BACT standard) will effectively demonstrate metal HAP emissions no higher than the predicted emissions rates (a total of 2.24 tons/year). Compliance with the PM₁₀ emissions standard will be demonstrated by conducting initial and annual stack tests, as well as implementing the Compliance Assurance Monitoring (CAM) Plan for the ESP and wet ESP that will be developed for the Title V air operation permit. No additional metal HAP testing is proposed.

5. DEPARTMENT'S DETERMINATION OF MAJOR/MINOR HAP SOURCE STATUS

Calculation of Potential Emissions

The determination of major HAP source status for new units undergoing preconstruction review is based on *potential emissions* and not actual emissions. As EPA describes on its web site (<http://www.epa.gov/ttn/atw/112g/112gpg.html>), "Newly constructed facilities or reconstructed units or sources at existing facilities would be subject to 112(g) requirements if they have the *potential to emit* hazardous air pollutants (air toxics) in "major" amounts (10 tons or more of an individual pollutant or 25 tons or more of a combination of pollutants)." Also, Section 40 CFR 63.2 defines a major source as, "... any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the *potential to emit* considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants, unless the Administrator establishes a lesser quantity, or in the case of radionuclides, different criteria from those specified in this sentence." Since SGS Unit 3 has not been constructed, it only has potential emissions at this time.

In Rule 62-210.200(245), F.A.C., the Department defines *potential to emit* as, "The maximum capacity of an emission unit or facility to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the emissions unit or facility to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of an emission unit or facility."

Based on this definition, *potential emissions* calculations for SGS Unit 3 are based on firing 100% of the design coal blend at maximum permitted capacity as intended under its physical and operational design. This includes operation at full load and permitted emissions rates. This calculation is considered to provide a conservative estimate of the potential annual emissions.

Once SGS Unit 3 is constructed, it will have actual emissions including periods of startup, shutdown and malfunction. However, the mass emissions rates during startup and shutdown will likely be much less than the mass emissions rates at full operation since the unit is operating at low load levels. In addition, if the unit is undergoing a startup or shutdown, then it was likely down for several days or will be down for several days with no emissions. Malfunctions could also cause extended shutdowns with no emissions. However, the malfunction of air pollution control equipment could result in considerable amounts of HAP emissions. Therefore, it is

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important to track actual emissions once SGS Unit 3 begins operation.

Department's HAP Emissions Estimates

The Department requested the EPRI report from both the applicant and EPRI to no avail. Therefore, the Department used the AP-42 emissions factors to estimate organic and metal HAP emissions. The AP-42 emissions factors tend to be much more conservative than the EPRI emissions factors. Acid gas HAP emissions were calculated using both the AP-42 emissions factors and the expected chlorine and fluorine concentrations in the coal fuel blend based on the USGS Coal Quality Database. For a full summary of the Department's emissions estimates, see Attachment B to this Technical Evaluation and Preliminary Determination.

Acid Gas HAP Emissions

Uncontrolled acid gas emissions from a coal-fired utility boiler are substantial. Based on the uncontrolled emissions calculated using the chlorine and fluorine contents from the USGS Coal Quality Database and maximum operation of proposed unit 3, uncontrolled HCl emissions are approximately 2983 tons/year and uncontrolled HF emissions are approximately 264 tons/year. Clearly, to be considered a minor source of HAP emissions, SGS Unit 3 must employ outstanding acid gas removal systems and continuously operate such systems. As required by the permit, SGS Unit 3 includes the installation and operation of a wet FGD system and a wet ESP, which both control acid gas emissions. The acid gas controls system will be operated to maintain an SO₂ control efficiency across the wet scrubbing system of 98% based on a 30-day rolling average including startup and shutdown.

As the applicant stated, HCL and HF are stronger acids and more reactive than SO₂, which should result in higher control efficiencies *all other parameters being equal*. Technical literature indicates that HCl emissions can be controlled with wet limestone FGD systems at efficiencies greater than 99% depending on the specifics of the control system, the limestone scrubbing media, flue gas temperature, droplet size, flue gas chemistry and numerous other factors. As supporting documentation, the applicant provided a recent stack test conducted at the Spurlock Station owned by the East Kentucky Power Cooperative, Inc. and located in Maysville, Kentucky. In January of 2009, tests were conducted on Unit 2, which is a 600 MW pulverized coal-fired utility boiler. Similar to the proposed SGS Unit 3, it is controlled by an ESP, an SCR system, a FGD system and wet ESP. The following table summarizes the results of these tests.

Table B. Summary of Acid Gas HAP Emissions Test Results for Spurlock Unit 2

Sampling Location	HCl	HF
FGD Inlet (uncontrolled)	0.0490 lb/MMBtu	0.0066 lb/MMBtu
FGD Outlet (after FGD)	0.0015 lb/MMBtu	0.0001 lb/MMBtu*
FGD Control Efficiency	96.9%	98.5%
Stack (after Wet ESP)	0.0001 lb/MMBtu	0.0001 lb/MMBtu
Wet ESP	93.3%	NA
Overall Control Efficiency	99.8%	98.5%

* HF results are reported as less than the RDL (reportable detection limit) of 200 and 400 µg, respectively.

The applicant did not provide similar SO₂ emissions data from Spurlock Unit 2 conducted during the test period and did not provide any documentation to support a correlation between SO₂ and HCl emissions. The applicant stated that this correlation would have to be developed once Unit 3 is operating.

The applicant also mentioned the Duke Energy Marshall Unit 4, which is designed for wet FGD with a control efficiency of 95% to 96% for SO₂ emissions and a control efficiency of 99.7% for HCl and HF emissions. The applicant notes that SGS Unit 3 is being designed for a greater SO₂ control efficiency of 98% and will also employ a wet ESP for additional acid gas control. The applicant states that the HCl and HF control efficiencies

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for SGS Unit 3 will both be greater than 99.7%.

To estimate HCl and HF emissions, the Department used the following methods:

- Uncontrolled acid gas emissions based on the emissions factors identified in AP-42 Table 1.1-15.
- Uncontrolled acid gas emissions based on the concentrations of chlorine and fluorine in the coal fuel blend identified in the USGS Coal Quality Database.
- Controlled acid gas emissions based on the applicant's stated design acid gas control efficiency of 99.7%.

The following tables summarize the Department's acid gas HAP emissions estimates.

Table C. Acid Gas HAP Emissions Based on AP-42

Pollutant	Uncontrolled lb/MMBtu	Control Efficiency	Controlled lb/MMBtu	Potential Annual Emissions, Tons/Year
HCl	0.050930	99.7%	0.0001528	5.02
HF	0.006367	99.7%	0.0000191	0.63
Total Acid Gas HAP Emissions				5.65

Table D. Acid Gas HAP Emissions Based on USGS Coal Quality Database

Pollutant	Uncontrolled lb/MMBtu	Control Efficiency	Controlled lb/MMBtu	Potential Annual Emissions, Tons/Year
HCl	0.0883	99.7%	0.000265	8.95
HF	0.0076	99.7%	0.0000228	0.79
Total Acid Gas HAP Emissions				9.74

In this case, the acid gas emissions predicted with data from the USGS Coal Quality Database are more conservative than those predicted with AP-42 emissions factors. The above calculations show that potential emissions of each acid gas HAP after the air pollution control systems will be less than 10 tons per year.

Organic HAP Emissions

The Department estimated organic HAP emissions based on AP-42 Tables 1.1-12, 1.1-13 and 1.1-14. This analysis includes methyl ethyl ketone identified in AP-42 Table 1.1-14, which was not included in the applicant's review. The AP-42 tables state that the emission factors are applicable to coal-fired boilers using FGD and particulate controls or to units with just particulate controls. Organic HAP emissions rely primarily on the quality of the fuel combustion. Therefore, the Department used these factors to represent both "controlled" and "uncontrolled" emissions.

The Department estimates total organic HAP emissions from SGS Unit 3 to be 12.90 tons/year compared to the applicant's estimate of 6.14 tons/year. The Department's review indicates that emissions of each organic HAP will be less than 10 tons per year. For 28 of the organic HAP, the applicant used EPRI emissions factors. The following table summarizes the primary differences for nine of the organic HAP where the AP-42 emissions factor was at least 5 times higher than the corresponding EPRI factor.

Table E. Comparison of Ten Organic HAP Emissions Factors, AP-42 vs. EPRI

Pollutant	Department's Estimate		Applicant's Estimate		Difference
	Reference	Tons/Year	Reference	Tons/Year	
Acetaldehyde	AP-42	0.79	EPRI	0.12	+0.67
Acrolein	AP-42	0.40	EPRI	0.07	+0.33

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Pollutant	Department's Estimate		Applicant's Estimate		Difference
	Reference	Tons/Year	Reference	Tons/Year	Tons/Year
Benzene	AP-42	1.81	EPRI	0.15	+1.66
Benzyl chloride	AP-42	0.98	EPRI	0.01	+0.97
Isophorone	AP-42	0.81	EPRI	0.05	+0.76
Methyl bromide	AP-42	0.22	EPRI	0.03	+0.19
Methyl chloride	AP-42	0.74	EPRI	0.04	+0.70
Propionaldehyde	AP-42	0.53	EPRI	0.07	+0.46
Toluene	AP-42	0.33	EPRI	0.07	+0.26
Total Difference in Organic HAP Emissions					+6.00

The pollutants identified above account for 90% of the difference between the applicant's and Department's organic HAP emissions estimates.

Metal HAP Emissions

As did the applicant, the Department used the following methodology to estimate metal HAP emissions:

- The equations provided in AP-42 Table 1.1-16 were used to estimate controlled emissions of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese and nickel. This table identifies a unique equation for each metal HAP dependent on the following variables: concentration (ppmw) of given metal HAP, weight fraction of ash in coal blend (e.g., 10% is 0.1 weight fraction) and the site-specific emissions limit for particulate matter (0.013 lb/MMBtu). Data for each specific metal HAP concentration and the weight fraction of ash was provided from the USGS Coal Quality Database.
- Mercury emissions were calculated based on the current permitted mercury emissions standard of 7.5×10^{-07} lb/MMBtu.
- Selenium emissions were calculated based on the expected selenium concentration from the USGS Coal Quality Database and an assumed control efficiency of 95%, which is approximately equivalent to that predicted for mercury (95.59%), which is another volatile metal.

Based on the emissions factors identified above, the Department estimates total potential metal HAP emissions will be 2.23 tons per year. The above calculations show that potential emissions of each metal HAP after control will be less than 10 tons per year.

HAP Emissions Summary

The following table summarizes the Department's more conservative estimates of potential HAP emissions.

Table F. Department's HAP Emissions Summary

HAP	Uncontrolled		Controlled	
	Tons/Year	Tons/Year	Tons/Year	Tons/Year
Acid Gas HAP	1,882.32 ^a	3,247.30 ^b	5.65 ^{a, c}	9.74 ^{b, c}
Organic HAP ^d	12.90	12.90	12.90	12.90
Metal HAP	249.99	249.99	2.23	2.23
Total HAP	2,145.21	3,510.19	20.78	24.87

^a Uncontrolled acid gas HAP emissions are based on AP-42 emissions factors.

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- b. Uncontrolled acid gas HAP emissions are based on the expected chlorine and fluorine concentrations for the design coal fuel blend and the USGS Coal Quality Database.
- c. Controlled acid gas HAP emissions factors are based on the uncontrolled emissions and a design control efficiency of 99.7%.
- d. As previously mentioned, the Department used the same estimates for "controlled" and "uncontrolled" organic HAP emissions since organics are primarily a function of the quality of fuel combustion.

As shown, uncontrolled HAP emissions from a coal-fired utility boiler are substantial. The extensive air pollution control systems are designed to remove more than more than 2100 tons/year of acid gas and metal HAP emissions. The Department concludes that potential emissions of each individual HAP emissions will be less than 10 tons/year and the total combination of HAP will be less than 25 tons/year based on the design of the required air pollution controls and full operation. However, it is critical to make sure that this equipment is fully functional at all times and that emissions are carefully monitored to ensure that Unit 3 remains a minor source of actual HAP emissions.

Department's Conclusion

The Department believes that there is reasonable assurance that SGS Unit 3 will be a minor HAP source based on the extensive air pollution control equipment proposed and the available data for determining potential emissions. However, the applicant's proposed plan for verifying the minor HAP source status based on actual emissions is inadequate. The Department will add emissions limits and monitoring provisions to ensure that SGS Unit 3 is and remains a minor HAP source.

Acid Gas HAP Limits and Monitoring

Issue: The applicant proposes an HCl limit of 3.01×10^{-4} lb/MMBtu, which is equivalent to 9.89 tons/year with annual emissions determined by initial and annual testing combined with actual annual operations data (MMBtu/year). No new limit is proposed for HF emissions, but the applicant offers initial and renewal tests combined with actual annual operations data to determine annual emissions. To ensure that HCl and HF emissions will be less than 9.46 tons per year, the applicant proposes to use continuous monitoring to demonstrate compliance with the permitted SO₂ standard of 0.165 lb/MMBtu as a surrogate for acid gas HAP emissions. Note that this is not a BACT standard for SO₂ emissions. The applicant did not provide any supporting documentation to correlate SO₂ emissions with acid gas HAP emissions from similar projects or identify any specific correlation for using SO₂ emissions as a surrogate for acid gas HAP emissions.

The Department notes that the current permit emissions limit for HF is 0.00023 lb/MMBtu, which is equivalent to potential emissions of 7.56 tons/year at full permitted capacity. Combined with the HCl limit of 9.89 tons/year proposed by the applicant, total potential acid gas HAP emissions will be 17.45 tons per year. The result is total potential HAP emissions of 25.83 tons/year when combined with the applicant's other HAP estimates. So, the applicant's requested HAP limits for acid gases actually qualify SGS Unit 3 as a major HAP source based on potential emissions.

The applicant does not believe that HCl CEMS are appropriate or reasonable for verifying the minor HAP status. The applicant's primary reasons for rejecting CEMS are: EPA does not have any federal regulations requiring CEMS for HCl emissions; EPA has yet to develop a performance specification for continuously monitoring HCl emissions; there are serious technical feasibility issues; and expected emissions levels will not only be less than the CEMS practical quantification limits, but even less than the analyzer's detection limits. In support of these claims, the applicant identified two recent coal-fired projects (Big Stone and Duke Cliffside) that were not required to install HCl CEMS to verify that the projects will be minor sources of HAP emissions.

Resolution: The applicant estimated total acid gas HAP emissions of 9.46 tons/year based on USGS Coal Quality Database. Department estimated total acid gas HAP emissions of 9.74 tons/year based on data from the USGS Coal Quality Database. The Department also estimated total acid gas HAP emissions of 5.65 tons/year based on

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

AP-42 factors. Because the uncontrolled emissions of each pollutant are well above 10 tons/year, the Department will include the following emissions limits and monitoring provisions in the draft permit.

- Establish a requirement for a design control efficiency of 99.7% or better for HCl and HF emissions;
- Require an initial test to demonstrate compliance with the design control efficiency of 99.7% or better;
- Require CEMS for both HCl and HF emissions and submittal of a monitoring protocol for approval by the Emissions Monitoring Section of the Department's Division of Air Resource Management;
- Limit combined acid gas emissions (HCl + HF) < 9.75 tons per consecutive rolling 12 months including startup, shutdown and malfunction;
- Require the development of performance curves to determine the correlation between SO₂ emissions with HCl and HF emissions for use when HCl and HF CEMS data is not available; and
- Require record keeping and reporting to confirm that HCl and HF emissions will each be less than 10 tons during any consecutive 12 month period and that total HAP emissions will be less than 25 tons during any consecutive 12 month period.

The Department believes that CEMS for HCl and HF emissions will provide reliable data with regard to determining the annual emissions of these pollutants. CEMS are appropriate because of the very high uncontrolled emissions levels as well as the importance in making a minor HAP determination for such a large coal-fired utility boiler. On May 6, 2009, EPA proposed changes to the NESHAP regulating the Portland cement manufacturing industry, which requires:

- HCl standard of ≤ 0.1 ppmv with compliance demonstrated by CEMS;
- The CEMS must meet Performance Specification 15 in Appendix B of 40 CFR Part 60;
- The CEMS must be maintained to meet quality assurance requirements in Procedure 1 in Appendix F of 40 CFR Part 60; and
- Revised portions of the Test Method 321 for the Measurement of Gaseous "Emissions at Portland Cement Kilns by Fourier Transform Infrared (FTIR) Spectroscopy".

In addition, the Department discussed HCl and HF monitoring with equipment vendors. From these discussions, monitors are available with measurement ranges of 2 and 5 ppm with accuracies within this range of $\pm 1\%$ (0.02 ppm and 0.05 ppm, respectively). HF emissions can be monitored similarly to HCl emissions for a relatively small additional cost. Many industries, such as Portland cement manufacturing, use these monitors to ensure product quality. The equipment is capable of meeting the quality assurance and quality control provisions in 40 CFR 60.

On April 30, 2009, EPA Region 4 sent a letter to the North Carolina Department of Environment and Natural Resources regarding the Duke Energy Cliffside project, which was cited by the applicant as one of the recent coal-fired utility projects determined to be a minor HAP source. In this letter, EPA recommends revising the permit to require a CEMS for monitoring HCl emissions based on concerns about: the expected high uncontrolled HCl emission rate; the very high removal efficiency required to be minor; the high controlled HCl emission rate; and the excess emissions during startup, shutdown and malfunction. EPA states, "These technological considerations and the associated assumptions make it prudent to continuously monitor HCl on Unit 6 to assure compliance with Unit 6's area source status." The Department believes there is clear direction on this issue from EPA. These recent developments clearly refute the applicant's concerns for using HCl CEMS.

Organic HAP Limits and Monitoring

Issue: To provide assurance that organic HAP emissions will be low, the applicant proposes to comply with the CO emissions standard of 0.15 lb/MMBtu as determined by CEMS on a 30-day rolling average. The CO limit is

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

a BACT standard and the applicant stated that there is a direct correlation between CO emissions and organic HAP emissions. However, the applicant was unable to explain this correlation in either numerical terms or with existing emission data from similar units. Based on AP-42 Table 1.1-3, the average CO emissions from a similar pulverized coal-fired boiler is 0.5 lb/tons of coal, which is equivalent to 0.021 lb/MMBtu based on the design coal blend. Assuming this was the average CO emissions rate during the tests for organic HAP emissions used to develop emissions factors, compliance with the permitted CO limit of 0.15 lb/MMBtu will not necessarily ensure low organic HAP emissions. The applicant proposed no other testing to verify organic HAP emissions.

The applicant's analysis estimated a total of 6.14 tons/year of organic HAP emissions based on a combination of AP-42 and EPRI emissions factors with quality ratings ranging from A to E. Using the EPRI emissions factors for 28 individual organic HAP resulted in 6.69 tons/year less than the Department's estimate based on the corresponding AP-42 emissions factors.

Resolution: Based on the available emissions data, the Department believes that there is reasonable assurance that no individual organic HAP will be 10 tons/year or greater. However, total actual organic HAP emissions could cause the project to exceed 25 tons/year for total HAP emissions. The Department considered a CEMS to monitor total non-methane organic compounds as a surrogate, but could not identify a satisfactory correlation with HAP emissions levels. Therefore, the Department will include the following emissions limit and monitoring provisions in the draft permit.

- Limit individual HAP emissions to < 10.00 tons per consecutive rolling 12 months and total HAP emissions to < 25 tons per consecutive rolling 12 months;
- Conduct initial and annual stack tests for acetaldehyde, benzene, benzyl chloride, cyanide, isophorone, methyl chloride, methyl ethyl ketone, and propionaldehyde emissions; and
- Show by record keeping that individual HAP emissions are < 10.00 tons per consecutive rolling 12 months and that total HAP emissions are < 25.00 tons per consecutive rolling 12 months based on the combination of actual tested emissions rates and AP-42 emissions factors.

The eight individual organic HAP identified for stack testing represent 75% of the Department's estimated potential emissions for all 41 identified organic HAP. This will provide reasonable assurance of low levels of total organic HAP and that total combined HAP are less than 25 tons/year. As emissions tests are completed, the test results will be averaged to determine annual emissions. The permittee may elect to test for other organic HAP emissions to determine the actual annual emissions.

Metal HAP Limits and Monitoring

Issue: Consistent with the current permit, the applicant proposed compliance with the permitted PM₁₀ emissions limit as a surrogate for ensuring low levels of metal HAP emissions. The applicant stated that a CAM plan would be developed for PM₁₀ emissions in the Title V air operation permit, but provided no specific details. The Department also recognizes the correlation between PM₁₀ emissions and metal HAP emissions. The AP-42 emissions factors are based on relational equations developed for individual metal HAP that are dependent on the PM₁₀ emissions rate as well as the metal concentrations in the coal fuel blend. However, additional monitoring is necessary to better determine the actual PM₁₀ emissions and the relationships for this unit and fuel.

Resolution: Based on the available emissions data, the Department believes that there is reasonable assurance that no individual metal HAP will be 10 tons/year or greater. However, metal HAP emissions could cause the project to exceed 25 tons/year for total HAP emissions. Therefore, the Department will include the following emissions limit and monitoring provisions in the draft permit.

- Limit individual HAP emissions to < 10.00 tons per consecutive rolling 12 months and total HAP emissions to < 25 tons per consecutive rolling 12 months;
- Require fuel sampling and analysis for antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead,

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manganese, nickel, mercury, and selenium;

- Conduct initial and annual stack tests for arsenic, manganese, nickel and selenium emissions; and
- Show by record keeping that individual HAP emissions are < 10.00 tons per consecutive rolling 12 months and that total HAP emissions are < 25.00 tons per consecutive rolling 12 months based on the combination of actual tested emissions rates and AP-42 emissions factors.

The four metal HAP identified for stack testing represent 75% of the total emissions from all 11 identified metal HAP. As emissions tests are completed, the test results will be averaged to determine annual emissions. The permittee may elect to test for other metal HAP emissions to determine the actual annual emissions. Combined with the fuel sampling and analysis, the actual tested metal emissions will provide reasonable assurance of low levels of metal HAP and that total combined HAP are less than 25 tons per consecutive rolling 12 months.

6. OTHER MINOR PERMIT CHANGES

In addition to the revisions described above, the Department notes the following additional changes:

- The PSD tracking number was changed from PSD-FL-375 to PSD-FL-375A to denote the minor revision.
- The project number was changed throughout from 1070025-005-AC to 1070025-011-AC to denote the revision.
- The heading for the first column of the "emissions unit tables" in each section were revised for consistency to "ID No."
- In the subsection called "Regulatory Classification" in Section I of the permit, "Subpart A (General Provisions)" was added under the NSPS heading.
- In Section I of the permit, the subsection "Relevant Documents" was replaced with "Permitting History" to describe the revision.
- In Section II of the permit, Condition 1 was revised to identify all of the permit appendices. Also, the relationship between the permit conditions and the terms of the Sierra Club Agreement (Appendix SC) was clarified.
- In Subsection IIIA of the permit, Condition 3 was revised to add, "The full provisions of Subparts A and Da may be provided in full upon request and are also available at the following link:
<http://www.dep.state.fl.us/air/permitting/writertools/t3nsps.htm>."
- In Subsection IIIB of the permit, the following text was added above the emissions unit table similar to Subsection IIIC, "This section of the permit addresses the following emissions unit."

7. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the complete application, reasonable assurances provided by the applicant, and the conditions specified in the draft permit. No air quality modeling analysis is required because the project does not result in a significant increase in emissions. Jeff Koerner is the project engineer responsible for reviewing the application and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

Attachment A. Applicant's HAP Emissions Summary Tables

Table A-1. Applicant's Summary of HAP Emissions from SGS Unit 3

**SUMMARY OF HAP EMISSIONS
SECI SGS UNIT 3**

Total HAPs	
Acid Gas HAPs ^a	9.46 TPY
Trace Metal HAPs ^b	2.24 TPY
Organic HAPs ^c	6.14 TPY
Dioxin/Furan HAPs ^d	2.45E-06 TPY
TOTAL	17.84 TPY
 Highest Individual HAP (HCl) =	
8.70 TPY	
 Main Boiler Heat Input Rate =	
7,500 MMBtu/hr	
Main Boiler Hours of Operation =	
8,760 hours/year	
Heat Content of Coal, HHV =	
11,780 Btu/lb	
Maximum Coal Consumption =	
318.3 TPH	

^a Refer to Table 2-4 for emission calculations.^b Refer to Table 2-3 for emission calculations.^c Refer to Table 2-6 for emission calculations.^d Refer to Table 2-5 for emission calculations.

Attachment A. Applicant's HAP Emissions Summary Tables

**REPLACEMENT TABLE 2-3
TRACE METAL HAP EMISSION ESTIMATES
SECLSGS UNIT 3**

[illegible]

Legend for source: EM = Eastern Interior Region (Illinois, Indiana, Western Kentucky), CAP = Central Appalachians, NAP = Northern Appalachians

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

Attachment A. Applicant's HAP Emissions Summary Tables

Table A-3. Applicant's Estimates of Acid Gas HAP Emissions

**REPLACEMENT TABLE 2-4
ACID GAS HAP EMISSION ESTIMATES
SECI SGS UNIT 3**

	HCl	HF
Halogen Emission Calculation		
Concentration (ppm)	1040.5	89.9
Maximum Fuel Input (lb/hr)	636,672	636,672
Uncontrolled Emissions (lb/hr)	662	57
Removal	99.7%	99.7%
Emissions (lb/hr)	1.99	0.172
Heat Input (MMBtu/hr)	7,500	7,500
Emissions (lb/MMBtu)	2.65E-04	2.29E-05
Net Power Output (MW)	750.0	750.0
Emissions (lb/MW-hr)	0.00265	0.000229
Estimated Emissions (tons/year)	8.70	0.75
TOTAL ACID GAS =	9.46 TPY	
Potential Emissions (lb/MMBtu) ^a	3.01E-04	2.30E-04

^a Rates correspond to the current permit limit for HF and < 10 TPY for HCl

Sources: CL and F Concentrations based on upper 95% Confidence Interval from USES COEQUAL Database Trace Elements for the Central Appalachian Region
<http://energy.er.usgs.gov/coalqual.htm>

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

Attachment A. Applicant's HAP Emissions Summary Tables

Table A-4. Applicant's Estimates of Dioxin/Furan HAP Emissions

**REPLACEMENT TABLE 2-5
DIOXIN/FURAN AND RADIONUCLIDES HAP EMISSIONS ESTIMATES
SECI SGS UNIT 3**

Organic Compound	Emission Factor	Emission Factor Units	Rating	Emissions per Unit		Emissions per Unit	
				Amount	Units	Amount	Units
Total PCDD/PCDF	1.8E-09	lb/ton	D	5.6E-07	lb/hr	2.45E-06	tons/year
Radionuclides	52.8	picoCuri/gram PM	NA	2.34E+06	piC/hr	2.05E+10	piC/yr
Data used in Calculation:							
Maximum Fuel Input (lb/hr)	636,672						
Maximum Fuel Input (ton/hr)	318.3						
Heat Input (MMBtu/hr)	7,500						
PM Emissions (lb/MMBtu)	0.013						
PM Emissions (lb/hr)	97.5						
PM Emissions (grams/hr)	44,226						

Note: ESP = Electrostatic precipitator.

FF = Fabric Filter.

PCDD = Polychlorinated Dibenzo-P-Dioxins and PCDF=Polychlorinated Dibenzofurans.

pico = 10⁻¹².

Sources: EPA, AP-42 1998, Table 1.1-12 for PCDD and PCDF (with ESP or FF); EPRI, 1994 for Radionuclides

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

Attachment A. Applicant's HAP Emissions Summary Tables

Table A-5. Applicant's Estimates of Organic HAP Emissions

REPLACEMENT TABLE 2-6
ORGANIC HAP EMISSION ESTIMATES
SECI SGS UNIT 3

Organic Compound	Emission Factor (lb/ton) ^a	Rating	Emissions (lb/hr)	Emissions (TPY)	Emission Factor Reference
Acetaldehyde	8.87E-05	A	0.028	0.12	EPRI Emission Factor Handbook - 1995, revised 2002
Acetophenone	3.33E-05	A	0.011	0.05	EPRI Emission Factor Handbook - 1995, revised 2002
Acrolein	5.27E-05	B	0.017	0.07	EPRI Emission Factor Handbook - 1995, revised 2002
Benzene	1.08E-04	A	0.034	0.15	EPRI Emission Factor Handbook - 1995, revised 2002
Benzyl chloride	7.77E-06	C	0.002	0.01	EPRI Emission Factor Handbook - 1995, revised 2002
Biphenyl	4.44E-06	B	0.001	0.01	EPRI Emission Factor Handbook - 1995, revised 2002
Bis(2-ethylhexyl)phthalate (DEHP)	9.98E-05	A	0.032	0.14	EPRI Emission Factor Handbook - 1995, revised 2002
Bromoform	4.23E-05	E	0.013	0.06	EPRI Emission Factor Handbook - 1995, revised 2002
Carbon disulfide	3.05E-05	B	0.010	0.04	EPRI Emission Factor Handbook - 1995, revised 2002
2-Chloroacetophenone	7.00E-06	E	0.002	0.01	EPA, AP-42 1998; Tables 1.1-13 and 1.1-14.
Chlorobenzene	4.44E-06	D	0.001	0.01	EPRI Emission Factor Handbook - 1995, revised 2002
Chloroform	2.21E-05	D	0.007	0.03	EPRI Emission Factor Handbook - 1995, revised 2002
Cumene	5.30E-06	E	0.002	0.01	EPA, AP-42 1998; Tables 1.1-13 and 1.1-14.
Cyanide	2.50E-03	D	0.796	3.49	EPA, AP-42 1998; Tables 1.1-13 and 1.1-14.
2,4-Dinitrotoluene	5.54E-06	C	0.002	0.01	EPRI Emission Factor Handbook - 1995, revised 2002
Dimethyl sulfate	4.80E-05	E	0.015	0.07	EPA, AP-42 1998; Tables 1.1-13 and 1.1-14.
Ethyl benzene	2.21E-05	C	0.007	0.03	EPRI Emission Factor Handbook - 1995, revised 2002
Ethyl chloride	1.46E-05	D	0.005	0.02	EPRI Emission Factor Handbook - 1995, revised 2002
Ethylene dichloride	4.00E-05	E	0.013	0.06	EPA, AP-42 1998; Tables 1.1-13 and 1.1-14.
Ethylene dibromide	1.20E-06	E	0.000	0.00	EPA, AP-42 1998; Tables 1.1-13 and 1.1-14.
Formaldehyde	7.20E-05	B	0.023	0.10	EPRI Emission Factor Handbook - 1995, revised 2002
Hexane	6.70E-05	D	0.021	0.09	EPA, AP-42 1998; Tables 1.1-13 and 1.1-14.
Isophorone	3.33E-05	D	0.011	0.05	EPRI Emission Factor Handbook - 1995, revised 2002
Methyl bromide	2.46E-05	C	0.008	0.03	EPRI Emission Factor Handbook - 1995, revised 2002
Methyl chloride	3.05E-05	C	0.010	0.04	EPRI Emission Factor Handbook - 1995, revised 2002
Methyl hydrazine	1.70E-04	E	0.054	0.24	EPA, AP-42 1998; Tables 1.1-13 and 1.1-14.
Methyl Methacrylate	3.05E-05	D	0.010	0.04	EPRI Emission Factor Handbook - 1995, revised 2002
Methyl tert butyl ether	3.50E-05	E	0.011	0.05	EPA, AP-42 1998; Tables 1.1-13 and 1.1-14.
Methylene chloride	9.98E-05	C	0.032	0.14	EPRI Emission Factor Handbook - 1995, revised 2002
Napthalene	1.71E-05	A	0.005	0.02	EPRI Emission Factor Handbook - 1995, revised 2002
Phenol	9.14E-05	B	0.029	0.13	EPRI Emission Factor Handbook - 1995, revised 2002
Propionaldehyde	5.27E-05	B	0.017	0.07	EPRI Emission Factor Handbook - 1995, revised 2002
Styrene	1.94E-05	C	0.006	0.03	EPRI Emission Factor Handbook - 1995, revised 2002
Tetrachloroethylene	1.16E-05	C	0.004	0.02	EPRI Emission Factor Handbook - 1995, revised 2002
Toluene	4.71E-05	A	0.015	0.07	EPRI Emission Factor Handbook - 1995, revised 2002
1, 1, 1 - Trichloroethane	2.00E-05	E	0.006	0.03	EPA, AP-42 1998; Tables 1.1-13 and 1.1-14.
Vinyl acetate	8.59E-06	D	0.003	0.01	EPRI Emission Factor Handbook - 1995, revised 2002
Xylenes	1.21E-05	C	0.004	0.02	EPRI Emission Factor Handbook - 1995, revised 2002
Total Non-Metal HAP Emissions	NA	NA	1.40	6.14	
Maximum Fuel Input (lb/hr)	636,672				
Maximum Fuel Input (ton/hr)	318.3				
Heat Input (MMBtu/hr)	7,500				

EPA Emission Factor Ratings: A-Excellent; B-Above Average; C-Average; D-Below Average; E-Poor

^a Emission factors from EPRI modified by heat content ratio of coal fuel.

The EPRI Data Quality (DQ) Ratings for Organic Compounds from Coal-Fired Boilers

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

Attachment B. Department's HAP Emissions Summary Tables

Table B-1. Department's Summary of HAP Emissions

Summary of HAP Emissions

Pollutant	Uncontrolled		Controlled	
	Tons/Year ^a	Tons/Year ^b	Tons/Year ^{a, c}	Tons/Year ^{b, c}
Acid Gas Emissions	1,882.32	3,247.30	5.65	9.74
Organic HAP Emissions	12.90	12.90	12.90	12.90
Metal HAP Emissions	249.99	249.99	2.23	2.23
Total Combined HAP Emissions	2,145.21	3,510.19	20.78	24.87

- a. Uncontrolled acid gas HAP emissions are based on AP-42 emissions factors.
- b. Uncontrolled acid gas HAP emissions are based on data from the USGS COALQUAL database.
- c. Controlled acid gas HAP emissions are based on uncontrolled emissions and a control efficiency of 99.7%. Controls include FGD+ESP+SCR+WESP.

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

Attachment B. Department's HAP Emissions Summary Tables

Table B-2. Department's Estimates of Acid Gas HAP Emissions Based on USGS Coal Quality Database

Estimates of Acid Gas HAP Emissions Based on USGS Coal Quality Data

Pollutant	Uncontrolled Emissions ^a					Controlled Emissions ^b			
	lb/ton coal ^a	Reference	Rating	lb/MMBtu ^c	Tons/Year ^d	Control Efficiency ^b	lb/ton coal	lb/MMBtu ^c	Tons/Year ^d
Hydrogen Chloride	2.140E+00	USGS COALQUAL	A	9.082E-02	2,983.41	99.70%	6.419E-03	2.725E-04	8.95
Hydrogen Fluoride	1.893E-01	USGS COALQUAL	A	8.033E-03	263.89	99.70%	5.678E-04	2.410E-05	0.79
Total Acid Gas HAP Emissions					3,247.30	—	—	—	9.74

a. Uncontrolled emissions are based on following concentrations in the coal blend identified as the upper 95% confidence interval in the USGS COAL/QUAL Database: 1040.5 ppmw chlorine and 89.9 ppmw fluorine. The molecular weights are: 1 for hydrogen; 35.45 for chlorine; and 19 for fluoride.

b. Controls include FGD+ESP+SCR+WESP. Design control efficiency claimed by applicant based on proposed controls.

c. Based on 23.56 MMBtu/ton of coal based on the design blend specifications (11,780 Btu/lb).

d. Based on a maximum heat input rate of 7500 MMBtu/hour, 8760 hours/year and 2000 lb/ton.

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

Attachment B. Department's HAP Emissions Summary Tables

Table B-3. Department's Estimates of Acid Gas HAP Emissions Based on AP-42 Emissions Factors

Estimates of Acid Gas HAP Emissions Based on AP-42

Pollutant	Uncontrolled Emissions ^a					Controlled Emissions ^b			
	lb/ton coal ^a	Reference	Rating	lb/MMBtu ^c	Tons/Year ^d	Control Efficiency ^b	lb/ton coal	lb/MMBtu ^c	Tons/Year ^d
Hydrogen Chloride	1.200E+00	AP-42, Table 1.1-15	B	5.093E-02	1,673.17	99.70%	3.600E-03	1.528E-04	5.02
Hydrogen Fluoride	1.500E-01	AP-42, Table 1.1-15	B	6.367E-03	209.15	99.70%	4.500E-04	1.910E-05	0.63
Total Acid Gas HAP Emissions					1,882.32	---	---	---	5.65

a. Uncontrolled emissions based on the AP-42 emissions factors.

b. Controls include FGD+ESP+SCR+WESP. Design control efficiency stated by applicant based on proposed controls.

c. Based on 23.56 MMBtu/ton of coal based on the design blend specifications (11,780 Btu/lb).

d. Based on a maximum heat input rate of 7500 MMBtu/hour, 8760 hours/year and 2000 lb/ton.

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

Attachment B. Department's HAP Emissions Summary Tables

Table B-4. Department's Estimates of Organic HAP Emissions Based on AP-42 Emissions Factors

Estimates of Uncontrolled and Controlled Organic HAP Emissions^a

Pollutant	lb/ton ^b	lb/MMBtu ^b	Reference	Rating	Tons/Year ^c
Biphenyl	1.70E-06	7.22E-08	AP-42, Table 1.1-13	D	0.002
Naphthalene	1.30E-05	5.52E-07	AP-42, Table 1.1-13	C	0.018
Acetaldehyde	5.70E-04	2.42E-05	AP-42, Table 1.1-14	C	0.795
Acetophenone	1.50E-05	6.37E-07	AP-42, Table 1.1-14	D	0.021
Acrolein	2.90E-04	1.23E-05	AP-42, Table 1.1-14	D	0.404
Benzene	1.30E-03	5.52E-05	AP-42, Table 1.1-14	A	1.813
Benzyl chloride	7.00E-04	2.97E-05	AP-42, Table 1.1-14	D	0.976
Bis(2-ethylhexyl)phthalate (DEHP)	7.30E-05	3.10E-06	AP-42, Table 1.1-14	D	0.102
Bromoform	3.90E-05	1.66E-06	AP-42, Table 1.1-14	E	0.054
Carbon disulfide	1.30E-04	5.52E-06	AP-42, Table 1.1-14	D	0.181
2-Chloroacetophenone	7.00E-06	2.97E-07	AP-42, Table 1.1-14	E	0.010
Chlorobenzene	2.20E-05	9.34E-07	AP-42, Table 1.1-14	D	0.031
Chloroform	5.90E-05	2.50E-06	AP-42, Table 1.1-14	D	0.082
Cumene	5.30E-06	2.25E-07	AP-42, Table 1.1-14	E	0.007
Cyanide	2.50E-03	1.06E-04	AP-42, Table 1.1-14	D	3.486
2,4-Dinitrotoluene	2.80E-07	1.19E-08	AP-42, Table 1.1-14	D	0.000
Dimethyl sulfate	4.80E-05	2.04E-06	AP-42, Table 1.1-14	E	0.067
Ethyl benzene	9.40E-05	3.99E-06	AP-42, Table 1.1-14	D	0.131
Ethyl chloride	4.20E-05	1.78E-06	AP-42, Table 1.1-14	D	0.059
Ethylene dichloride	4.00E-05	1.70E-06	AP-42, Table 1.1-14	E	0.056
Ethylene dibromide	1.20E-06	5.09E-08	AP-42, Table 1.1-14	E	0.002
Formaldehyde	2.40E-04	1.02E-05	AP-42, Table 1.1-14	A	0.335
Hexane	6.70E-05	2.84E-06	AP-42, Table 1.1-14	D	0.093
Isophorone	5.80E-04	2.46E-05	AP-42, Table 1.1-14	D	0.809
Methyl bromide	1.60E-04	6.79E-06	AP-42, Table 1.1-14	D	0.223
Methyl chloride	5.30E-04	2.25E-05	AP-42, Table 1.1-14	D	0.739
Methyl ethyl ketone	3.90E-04	1.66E-05	AP-42, Table 1.1-14	D	0.544
Methyl hydrazine	1.70E-04	7.22E-06	AP-42, Table 1.1-14	E	0.237
Methyl methacrylate	2.00E-05	8.49E-07	AP-42, Table 1.1-14	E	0.028
Methyl tert butyl ether	3.50E-05	1.49E-06	AP-42, Table 1.1-14	E	0.049
Methylene chloride	2.90E-04	1.23E-05	AP-42, Table 1.1-14	D	0.404
Phenol	1.60E-05	6.79E-07	AP-42, Table 1.1-14	D	0.022
Propionaldehyde	3.80E-04	1.61E-05	AP-42, Table 1.1-14	D	0.530
Tetrachloroethylene	4.30E-05	1.83E-06	AP-42, Table 1.1-14	D	0.060
Toluene	2.40E-04	1.02E-05	AP-42, Table 1.1-14	A	0.335
1,1,1-Trichloroethane	2.00E-05	8.49E-07	AP-42, Table 1.1-14	E	0.028
Styrene	2.50E-05	1.06E-06	AP-42, Table 1.1-14	D	0.035
Xylenes	3.70E-05	1.57E-06	AP-42, Table 1.1-14	C	0.052
Vinyl acetate	7.60E-06	3.23E-07	AP-42, Table 1.1-14	E	0.011
Polycyclic Organic Material (POM)	4.90E-05	2.08E-06	AP-42, Table 1.1-17	E	0.068
Total PCDD/PCDF	1.76E-09	7.47E-11	AP-42, Table 1.1-12	D	2.45E-06
Total Organic HAP Emissions					12.90

- Except for PCDD/PCDF and POM, the AP-42 emissions factors apply to units with: wet FGD plus an ESP or fabric filter; a spray dryer plus an ESP or fabric filter; and only an ESP or fabric filter. The AP-42 emissions factor for PCDD/PCDF applies to control with ESP. The AP-42 emissions factor for POM is for uncontrolled units. The proposed controls include FGD+ESP+SCR+WESP. Since organic HAP emissions are primarily a function of the combustion process, these emissions factors will be used to represent both uncontrolled and controlled emissions.
- Based on 23.56 MMBtu/ton of coal based on the design blend specifications (11,780 Btu/lb).
- Based on a maximum heat input rate of 7500 MMBtu/hour, 8760 hours/year and 2000 lb/ton.
- The eight highest HAP are: acetaldehyde, benzene, benzyl chloride, cyanide, isophorone, methyl chloride, methyl ethyl ketone and propionaldehyde. Combined emissions are 9.69 TPY, which is 75% of the total organic HAP estimate.

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

Attachment B. Department's HAP Emissions Summary Tables

Table B-5. Comparison of AP-42 vs. EPRI Organic HAP Emissions Factors

Comparison of AP-42 and EPRI Organic HAP Emissions Factors

Pollutant	AP-42			EPRI			Difference Tons/Year °
	lb/ton	Rating	Tons/Year	lb/ton	Rating	Tons/Year	
Acetaldehyde	5.70E-04	C	0.79	8.87E-05	A	0.12	0.670
Acetophenone	1.50E-05	D	0.02	3.33E-05	A	0.05	-0.030
Acrolein	2.90E-04	D	0.40	5.27E-05	B	0.07	0.330
Benzene	1.30E-03	A	1.81	1.08E-04	A	0.15	1.660
Benzyl chloride	7.00E-04	D	0.98	7.77E-06	C	0.01	0.970
Biphenyl	1.70E-06	D	0.00	4.44E-06	B	0.01	-0.010
Bis(2-ethylhexyl)phthalate (DEHP)	7.30E-05	D	0.10	9.98E-05	A	0.14	-0.040
Bromoform	3.90E-05	E	0.05	4.23E-05	E	0.06	-0.010
Carbon disulfide	1.30E-04	D	0.18	3.05E-05	B	0.04	0.140
Chlorobenzene	2.20E-05	D	0.03	4.44E-06	D	0.01	0.020
Chloroform	5.90E-05	D	0.08	2.21E-05	D	0.03	0.050
2,4-Dinitrotoluene	2.80E-07	D	0.00	5.54E-06	C	0.01	-0.010
Ethyl benzene	9.40E-05	D	0.13	2.21E-05	C	0.03	0.100
Ethyl chloride	4.20E-05	D	0.06	1.46E-05	D	0.02	0.040
Formaldehyde	2.40E-04	A	0.33	7.20E-05	B	0.1	0.230
Isophorone	5.80E-04	D	0.81	3.33E-05	D	0.05	0.760
Methyl bromide	1.60E-04	D	0.22	2.46E-05	C	0.03	0.190
Methyl chloride	5.30E-04	D	0.74	3.05E-05	C	0.04	0.700
Methyl methacrylate	2.00E-05	E	0.03	3.05E-05	D	0.04	-0.010
Methylene chloride	2.90E-04	D	0.40	9.98E-05	C	0.14	0.260
Naphthalene	1.30E-05	C	0.02	1.71E-05	A	0.02	0.000
Phenol	1.60E-05	D	0.02	9.14E-05	B	0.13	-0.110
Propionaldehyde	3.80E-04	D	0.53	5.27E-05	B	0.07	0.460
Styrene	2.50E-05	D	0.03	1.94E-05	C	0.03	0.000
Tetrachloroethylene	4.30E-05	D	0.06	1.16E-05	C	0.02	0.040
Toluene	2.40E-04	A	0.33	4.71E-05	A	0.07	0.260
Vinyl acetate	7.60E-06	E	0.01	8.59E-06	D	0.01	0.000
Xylenes	3.70E-05	C	0.05	1.21E-05	C	0.02	0.030
Total Organic HAP Emissions			8.21	---	---	1.52	6.69

The AP-42 factors for the following organic HAP are 5 times greater than the corresponding EPRI factor: acetaldehyde, acrolein, benzene, benzyl chloride, isophorone, methyl bromide, methyl chloride, propionaldehyde and toluene. The difference in emissions from these nine HAP are 6.0 TPY, which represents 90% of the difference.

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

Attachment B. Department's HAP Emissions Summary Tables

Table B-6. Department's Estimates of Metal HAP Emissions

Estimates of Metal HAP Emissions

Metal HAP	Uncontrolled Emissions ^a			Controlled Emissions ^b								
	lb/10 ¹² Btu ^c	lb/ton coal ^c	Tons/Year ^d	a	b	C	A	PM	lb/10 ¹² Btu ^c	lb/ton coal ^c	Tons/Year ^d	Control Efficiency ^d
Antimony	684.00	1.612E-02	22.47	0.92	0.63	1.64	0.1273	0.013	0.298	7.021E-06	0.01	99.96%
Arsenic	14.90	3.510E-04	0.49	3.1	0.85	29.72	0.1273	0.013	7.965	1.877E-04	0.26	46.54%
Beryllium	81.00	1.908E-03	2.66	1.2	1.1	3.33	0.1273	0.013	0.366	8.623E-06	0.01	99.55%
Cadmium	44.40	1.046E-03	1.46	3.3	0.5	0.72	0.1273	0.013	0.895	2.109E-05	0.03	97.98%
Chromium	1570.00	3.699E-02	51.57	3.7	0.58	19.21	0.1273	0.013	5.469	1.288E-04	0.18	99.65%
Cobalt	76.40	1.800E-03	2.51	1.7	0.69	8.39	0.1273	0.013	1.528	3.600E-05	0.05	98.00%
Lead	507.00	1.194E-02	16.65	3.4	0.8	22.89	0.1273	0.013	6.706	1.580E-04	0.22	98.68%
Manganese	2980.00	7.021E-02	97.89	3.8	0.6	44.97	0.1273	0.013	9.484	2.234E-04	0.31	99.68%
Nickel	1290.00	3.039E-02	42.38	4.4	0.48	172.057	0.1273	0.013	17.416	4.103E-04	0.57	98.65%
Mercury	16.00	3.770E-04	0.53	---	---	---	---	---	0.705	2.992E+04	0.02	95.59%
Selenium	346.35	8.160E-03	11.38	---	---	---	---	---	17.317	4.080E-04	0.57	95.00%
Total Metal HAP Emissions			249.99	---	---	---	---	---	---	---	2.23	---

a. Except for selenium, arsenic and cobalt, uncontrolled emissions factors are based on AP-42 Table 1.1-17 (Rating: E). The highest uncontrolled emissions factor was used. For selenium, the uncontrolled emissions factor was based on a concentration of 4.08 ppmw, which is identified as the upper 95% confidence interval of the USGS COAL/QUAL Database. For arsenic and cobalt, uncontrolled emissions were based on an assumed control efficiency of 98%.

b. Except for mercury and selenium, controlled emissions factors are based on equation in AP-42 Table 1.1-16 (Rating: A): $a^*(C/A*PM)^b$, where:

a = metal-specific factor

b = metal-specific factor

C = concentration of metal in coal from USGS COAL/QUAL Database, upper 95% confidence interval

A = weight fraction of ash in coal e.g. 10% = 0.1 weight fraction)

PM = Site specific controlled PM emissions rate regardless of PM controls

Controlled selenium emissions are based on applicant's estimated control efficiency of 95%, which is similar to another volatile metal, mercury.

Controlled mercury emissions are based permit limit of 7.05 x 10⁻⁶ lb/MW-hour.

c. Based on 23.56 MMBtu/ton of coal based on the design blend specifications (11,780 Btu/lb).

d. Based on a maximum heat input rate of 7500 MMBtu/hour, 8760 hours/year and 2000 lb/ton.

DRAFT PERMIT REVISION

{Permitting Note: In the draft permit revision, changes are highlighted with shading. In addition, deletions are shown with ~~striketrough~~ and additions are shown with double underline. Upon issuance, all highlighting will be removed from the final permit revision.}

PERMITTEE:

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

Authorized Representative:

Mike Roddy, Manager of Environmental Affairs

Permit No. PSD-FL-375A Project No. 1070025-011-AC Seminole Generating Station SGS Unit 3 Siting No. PA 78-10A2 Expires: December 31, 2012 <u>July 1, 2014</u>
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PROJECT AND LOCATION

This permit authorizes the construction of a nominal 750 megawatt (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., Director
Division of Air Resource Management

Effective Date: _____

SECTION I. GENERAL INFORMATION (DRAFT)

FACILITY DESCRIPTION

The existing Seminole Generating Station (SGS) consists of: two 714.6 megawatt MW 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 SO₂ removal, selective catalytic reduction (SCR) for control of nitrogen oxides (NO_x), electrostatic precipitator (ESP) for collection and removal of fine particles particulate matter (PM/PM₁₀), a Wet ESP (WESP) for control of sulfuric acid mist (SAM), with hydrogen chloride (HCl), hydrogen 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). Continuous emissions monitoring systems (CEMS) are required for: carbon monoxide (CO), NO_x, SO₂, HCl, HF and Hg.

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). The Unit 3 project has been determined to be minor with respect to HAP emissions.

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/PM₁₀), sulfur dioxide (SO₂), 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,

SECTION I. GENERAL INFORMATION (DRAFT)

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 A (General Provisions); and 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 EPA's reconsideration of the federal rule the finalization of DEP rules.

CAMR: SGS Unit 3 is a new coal-fired unit power plant and will may be subject to the Clean Air Mercury Rule pending EPA's reconsideration of this vacated federal rule 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 CM. CEMS Requirements
- Appendix GC. General Conditions
- Appendix HP. HAP Emissions Methodology and Summary
- Appendix SC. Enforceable Conditions from the Sierra Club Agreement
- Appendix TEBD. Final BACT Determinations and Emissions Standards

PERMITTING HISTORY

- Project No. 1070025-005-AC (PSD-FL-375): Permit issued on September 5, 2008 authorized the construction of proposed new Unit 3 at existing Seminole Generating Station.
- Project No. 1070025-011-AC (PSD-FL-375A): Permit revision made the following changes: extended the expiration date; clarified references to the CAIR and CAMR programs; clarified that the maximum heat input rate is an enforceable restriction; corrected the equivalent VOC emissions rate from 16.7 to 25.5 lb/hour; clarified that the PM filterable limit of 0.013 lb/MMBtu applies to all fuel blends; added conditions 44 through 50 in Subsection IIIA of the permit as enforceable HAP requirements; added Appendix CM identifying CEMS requirements; added Appendix HP for calculating actual HAP emissions; and added provisions of the Sierra Club Agreement dated March 19, 2007 as Appendix SC.

SECTION II. ADMINISTRATIVE REQUIREMENTS (DRAFT)

1. General Conditions Appendices: The permittee shall comply with the provisions specified in the attached Appendices; operate under the attached General Conditions listed in Appendix CM (CEMS Requirements); Appendix GC (General Conditions); Appendix HP (HAP Emissions Methodology and Summary); Appendix SC (Enforceable Conditions from the Sierra Club Agreement); and Appendix TEBD (Final BACT Determinations and Emissions Standards). of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.] The permittee shall comply with all conditions of this final permit. The terms specified in the Sierra Club Agreement (Appendix SC) shall not modify any conditions of this air construction permit including any BACT determinations; however, the permittee shall also comply with the provisions of the Sierra Club Agreement as additional requirements.
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 initial permit (September 5, 2008), 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.

SECTION II. ADMINISTRATIVE REQUIREMENTS (DRAFT)

- 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.]

SECTION III. EMISSIONS UNITS SPECIFIC CONDITIONS (DRAFT)

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.

<u>E.U. ID No.</u>	<u>Emission Unit Description</u>
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/PM₁₀), 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 SO₂, 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, SO₂ and NO_x. The PM emission limit is 0.015 lb/MMBtu or 0.03 lb/MMBtu and 99.9 percent reduction. The SO₂ 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 SO₂ 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 x 10⁻⁶ lb/MW-hr for bituminous coal. The full provisions of Subparts A and Da may be provided in full upon request and are also available at the following link: <http://www.dep.state.fl.us/air/permitting/writertools/t3nsps.htm>. [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 rate shall not exceed of 7,500 MMBtu per hour of coal~~ fuel blend based on fuel sampling and analysis. [Application; Design]
5. **Electrical Generating Capacity:** For informational purposes, 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

SECTION III. EMISSIONS UNITS SPECIFIC CONDITIONS (DRAFT)

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

Precipitator and a Wet Electrostatic Precipitator (WESP) to reduce PM/PM₁₀ 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 (NH₃) 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 SO₂ and SAM emissions from SGS Unit 3. The FGD System shall be designed to meet the permitted emission levels of SO₂ 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 SO₂ 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

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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.

[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 25.5 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:
- 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.
 - 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 (SO₂): Emissions of SO₂ 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, SO₂ emissions shall not exceed 29,074 tons per 12-month rolling period (facility-wide), based upon CEMS. [Rules 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

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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/PM₁₀): Emissions of filterable Particulate Matter (PM and PM₁₀) 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% O₂ as determined by EPA Conditional Test Method CTM-027.
17. Mercury (Hg): Emissions of mercury from SGS unit 3 shall not exceed 7.05×10^{-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, NO_x 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 SO₂, 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

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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 SO₂ 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,

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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:
- Best operational practices to minimize emissions are adhered to, and
 - 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, SO₂, and Hg. Each monitoring system shall be installed, and functioning within the required performance specifications by the time of the initial compliance demonstration.
- 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.
 - 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.

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The RATA tests required for the NO_x monitor shall be performed using EPA Method 7 or 7E in Appendix A of 40 CFR 60 or as allowed by Part 75.

- c. *SO₂ Monitor:* The SO₂ 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 SO₂ monitor shall be performed using EPA Method 6 or 6C in Appendix A of 40 CFR 60. The SO₂ 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 (O₂) or carbon dioxide (CO₂) content of the flue gas shall be continuously monitored at the location where CO, NO_x, and SO₂ 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

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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-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data 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

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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, SO₂, 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.

HAP MINOR SOURCE REQUIREMENTS

44. Total HAP Emissions: Total HAP emissions shall be less than 25.00 tons during any consecutive 12-month rolling total as determined by the methods specified in Appendix HP. [Rule 62-4.070(3), F.A.C.]

45. Individual HAP Emission: Emissions of each individual HAP shall be less than 10.00 tons during any consecutive 12-month rolling total as determined by the methods specified in Appendix HP. [Rule 62-4.070(3), F.A.C.]

46. Acid Gas HAP Emissions:

- a. In accordance with good operating practices and the manufacturer's recommendations, the permittee shall operate the FGD system and wet ESP at all times including startup and shutdown.
- b. As determined by CEMS, total acid gas emissions (HCl + HF) shall not exceed 9.75 tons during any consecutive rolling 12-month rolling total including startup, shutdown and malfunction. To demonstrate compliance with this standard, the permittee shall install CEMS to continuously monitor and record emissions of HCl and HF in accordance with the requirements specified in Appendix CM of this permit. The actual CEMS emissions data shall be used to demonstrate compliance with the HAP emissions limits as specified in Appendix HP of the permit.
- c. Total acid gas HAP emissions (HCl + HF) shall be controlled with an efficiency of at least 99.7% as determined by initial performance tests conducted before and after the acid gas scrubbing equipment.

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HCl and HF emissions shall be determined in accordance with EPA Method 26/26A or 320. The initial performance tests shall be conducted after completing shakedown of all equipment and beginning commercial operation with the HCl, HF and SO₂ CEMS fully functional. Shakedown shall not exceed 180 days after first fire. Tests shall be conducted simultaneously before and after the acid gas controls and shall consist of three, 1-hour test runs. Emissions of HCl, HF and SO₂ from the CEMS shall be reported for each test run.

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

47. Organic HAP Emissions:

- a. In accordance with EPA Method 320, the permittee shall conduct initial and annual performance tests to determine emissions of acetaldehyde, benzene, benzyl chloride, isophorone, methyl chloride, methyl ethyl ketone and propionaldehyde. Tests conducted pursuant to EPA Method 320 shall consist of at least three, 20-minute test runs. In accordance with CARB 426, the permittee shall conduct initial and annual performance tests to determine emissions of cyanide. Tests conducted pursuant to CARB 426 shall consist of at least three, 1-hour test runs.
- b. The initial performance tests shall be conducted after completing shakedown of all equipment and beginning commercial operation with the CO CEMS fully functional. Shakedown shall not exceed 180 days after first fire. CO emissions from the CEMS shall be reported for each test run. Annual performance tests shall be conducted during each federal fiscal year (October 1 – September 30).

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

48. Metal HAP Emissions:

- a. In accordance with good operating practices and the manufacturer's recommendations, the permittee shall operate the ESP, SCR, FGD system and wet ESP at all times including startup and shutdown.
- b. The permittee shall conduct initial and annual stack tests in accordance with EPA Method 29 to determine emissions of arsenic, manganese, nickel and selenium. Tests shall consist of at least three, 1-hour test runs. The initial performance tests shall be conducted after completing shakedown of all equipment and beginning commercial operation with the COMS fully functional. Shakedown shall not exceed 180 days after first fire.
- c. During each calendar quarter of operation and each EPA Method 29 test, the permittee shall obtain a representative sample of the coal fuel blend fired. The sample shall be analyzed for the following: higher heating value (Btu/lb); weight fraction of ash; concentrations (ppmw) of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, mercury, and selenium.

49. Test Requirements: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report shall provide the information identified in Rule 62-297.310(8), F.A.C.

50. Monthly HAP Emissions Summaries: Within ten calendar days following each month, the permittee shall record the information specified in Appendix HP of this permit to demonstrate that SGS Unit 3 remains a minor HAP source based on actual emissions. [Rule 62-4.070(3), F.A.C.]

SECTION III. EMISSIONS UNITS SPECIFIC CONDITIONS (DRAFT)

B. ZLD Spray Dryers (EU 016)

This section of the permit addresses the following emissions unit.

ID No.	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/PM₁₀). [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/PM₁₀ 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.]

SECTION III. EMISSIONS UNITS SPECIFIC CONDITIONS (DRAFT)

C. SGS Unit 3 Cooling Tower (EU 015)

This section of the permit addresses the following emissions unit.

ID No.	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/PM₁₀). [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/PM₁₀ 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 PM₁₀ per year. Actual emissions are expected to be lower than these rates.}

APPENDICES

Appendix CM. CEMS Requirements

Appendix GC. General Conditions

Appendix HP. HAP Emissions Methodology and Summary

Appendix SC. Enforceable Conditions from the Sierra Club Agreement

Appendix TEBD. Final BACT Determinations and Emissions Standards

Permitting Note: Appendices CM, HP and SC are new in this revised draft permit.

APPENDIX CM

CEMS Requirements

In addition to the specifically cited rules in the following conditions, the requirements of this Appendix are required pursuant to Rule 62-4.070(3), F.A.C.

AFFECTED UNIT

1. Affected Unit: This Appendix applies to the CEMS required for monitoring HCl and HF emissions as specified in Subsection IIIA of the permit for SGS Unit 3 (EU-014).

CEMS OPERATION PLAN

2. CEMS Operation Plan: The owner or operator shall create and implement a facility-wide plan for the proper installation, calibration, maintenance and operation of each CEMS required by this permit. The owner or operator shall submit the CEMS Operation Plan to the Bureau of Air Monitoring and Mobile Sources for approval at least 60 days prior to CEMS installation. The CEMS Operation Plan shall become effective 60 days after submittal or upon its approval. If the CEMS Operation Plan is not approved, the owner or operator shall submit a new or revised plan for approval. Copies of this plan shall be provided to the Compliance Authority and kept on site for review. The owner or operator shall revise this plan as necessary and provide updates to the Compliance Authority.

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

INSTALLATION, PERFORMANCE SPECIFICATIONS AND QUALITY ASSURANCE

3. Installation Deadline: The owner or operator shall install each CEMS required by this permit prior to initial startup of the unit. The owner or operator shall conduct the appropriate performance specification for each CEMS within 90 operating days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup. Each CEMS shall be installed and operated in accordance with the appropriate provisions of 40 CFR 60 and the CEMS Operation Plan. [40 CFR 60 and Rule 62-4.070(3), F.A.C.]
4. Installation: All CEMS shall be installed such that representative measurements of emissions or process parameters from the facility are obtained. The owner or operator shall locate the CEMS by following the procedures contained in the applicable performance specification of 40 CFR Part 60, Appendix B or as otherwise specified in the CEMS Operation Plan.
5. Span Values and Dual Range Monitors: The owner or operator shall set appropriate span values for the CEMS. The owner or operator shall install dual range monitors if required by and in accordance with the CEMS Operation Plan.
6. Continuous Flow Monitor: For compliance with mass emission rate standards, the owner or operator shall install a continuous flow monitor to determine the stack exhaust flow rate. The flow monitor shall be certified pursuant to Performance Specification 6 in Appendix B of 40 CFR Part 60. Alternatively, the owner or operator may install a fuel flow monitor and use an appropriate F-Factor computational approach to calculate stack exhaust flow rate.
7. Diluent Monitor: If it is necessary to correct the CEMS output to the oxygen concentrations specified in this permit's emission standards, the owner or operator shall either install an oxygen monitor or install a CO₂ monitor and use an appropriate F-Factor computational approach.
8. Moisture Correction: If necessary, the owner or operator shall determine the moisture content of the exhaust gas and develop an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). *{Permitting Note: The CEMS Operation Plan will contain additional CEMS-specific details and procedures for installation.}*
9. Performance Specifications: The owner or operator shall evaluate the acceptability of each CEMS by conducting the appropriate performance specification, as follows. CEMS determined to be unacceptable shall not be considered installed for purposes of meeting the timelines of this permit. For HCl and HF monitors, the owner or operator shall conduct the Performance Specification 15 in Appendix B of 40 CFR part 60.
10. Quality Assurance: The owner or operator shall follow the quality assurance procedures in Appendix F of 40 CFR Part 60. The required RATA tests shall be performed using EPA Method 26/26A or 320 in Appendix A of 40 CFR Part 60 or as otherwise specified in the CEMS Operation Plan.

APPENDIX CM
CEMS Requirements

CALCULATION APPROACH

11. CEMS Used for Compliance: Once adherence to the applicable performance specification for each CEMS is demonstrated, the owner or operator shall use the CEMS to demonstrate compliance with the applicable emission standards as specified by this permit.
12. CEMS Data: Each CEMS shall monitor and record emissions during all periods of operation and whenever emissions are being generated, including during episodes of startups, shutdowns, and malfunctions. All data shall be used, except for invalid measurements taken during monitor system breakdowns, repairs, calibration checks, zero adjustments and span adjustments, and except for allowable data exclusions as per Condition 19 of this Appendix.
13. Operating Hours and Operating Days: For purposes of this Appendix, the following definitions shall apply. An hour is the 60-minute period beginning at the top of each hour. Any hour during which an emissions unit is in operation for more than 15 minutes is an operating hour for that emission unit. A day is the 24-hour period from midnight to midnight. Unless otherwise specified by this permit, any day with at least one operating hour for an emissions unit is an operating day for that emission unit.
14. Valid Hourly Averages: Each CEMS shall be designed and operated to sample, analyze and record data evenly spaced over the hour at a minimum of one measurement per minute. All valid measurements collected during an hour shall be used to calculate a 1-hour block average that begins at the top of each hour.
 - a. Hours that are not operating hours are not valid hours.
 - b. For each operating hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, there is insufficient data, the 1-hour block average is not valid, and the hour is considered as "monitor unavailable."
15. Calculation Approaches: The owner or operator shall implement the calculation approach specified by this permit for each CEMS. For each rolling 12-month total, compliance shall be determined after each operating month by adding the valid hourly averages from that operating month to the prior 11 operating months.

MONITOR AVAILABILITY

16. Monitor Availability: The quarterly excess emissions report shall identify monitor availability for each quarter in which the unit operated. Monitor availability for the Hg 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 the appropriate monitor 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.

EXCESS EMISSIONS

17. Definitions:
 - a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.
 - b. *Shutdown* means the cessation of the operation of an emissions unit for any purpose.
 - c. *Malfunction* means any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.
18. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
19. Data Exclusion Procedures for SIP Compliance: Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown and malfunction. Valid data shall not be excluded from any annual emissions caps or other annual averages.

APPENDIX CM
CEMS Requirements

20. Notification Requirements: The owner or operator shall notify the Compliance Authority within one working day of discovering any emissions that demonstrate noncompliance for a given averaging period. Within one working day of occurrence, the owner or operator shall notify the Compliance Authority of any malfunction resulting in the exclusion of CEMS data.

ANNUAL EMISSIONS

21. CEMS Used for Calculating Annual Emissions: All valid data, as defined in Condition 14 of this Appendix, shall be used when calculating annual emissions.
- a. Annual emissions shall include data collected during startup, shutdown and malfunction periods.
 - b. Annual emissions shall include data collected during periods when the emission unit is not operating but emissions are being generated (for example, when firing fuel to warm up a process for some period of time prior to the emission unit's startup).
 - c. Annual emissions shall not include data from periods of time where the monitor was functioning properly but was unable to collect data while conducting a mandated quality assurance/quality control activity such as calibration error tests, relative accuracy test audits (RATA), calibration gas audit or relative accuracy audit (RAA). These periods of time shall be considered missing data for purposes of calculating annual emissions.
 - d. Annual emissions shall not include data from periods of time when emissions are in excess of the calibrated span of the CEMS. These periods of time shall be considered missing data for purposes of calculating annual emissions.
22. Accounting for Missing Data: All valid measurements collected during each hour shall be used to calculate a 1-hour block average. For each hour, the 1-hour block average shall be computed from at least two data points separated by a minimum of 15 minutes. If less than two such data points are available, the owner or operator shall account for emissions during that hour using the method specified in Appendix HP of this permit.
23. Emissions Calculation: Hourly emissions shall be calculated for each hour as the product of the 1-hour block average and the duration of pollutant emissions during that hour. Annual emissions shall be calculated as the sum of all hourly emissions occurring during the year.

APPENDIX GC

General Conditions - Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations and restrictions set forth in this permit, are "permit conditions" and are binding and enforceable pursuant to Sections 403.141, 403.727, or 403.859 through 403.861, F.S. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
3. As provided in subsections 403.987(6) and 403.722(5), F.S., the issuance of this permit does not convey any 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 of or approval of any other department permit that may be required for other aspects of the total project which are not addressed in this permit.
4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.
6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed and used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at reasonable times, access to the premises where the permitted activity is located or conducted to:
 - a. Have access to and copy any records that must be kept under conditions of the permit;
 - b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and
 - c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules. Reasonable time may depend on the nature of the concern being investigated.
8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:
 - a. A description of and cause of noncompliance; and
 - b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the noncompliance. The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.
9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.111 and 403.73, F.S. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.
10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules. A reasonable time for compliance with a new or amended surface water quality standard, other than

APPENDIX GC

General Conditions - Rule 62-4.160, F.A.C.

those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard.

11. This permit is transferable only upon Department approval in accordance with Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
 - a. Determination of Best Available Control Technology;
 - b. Determination of Prevention of Significant Deterioration; and
 - c. Compliance with New Source Performance Standards.
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 for 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:
 - (a) The date, exact place, and time of sampling or measurements;
 - (b) The person responsible for performing the sampling or measurements;
 - (c) The dates analyses were performed;
 - (d) The person responsible for performing the analyses;
 - (e) The analytical techniques or methods used;
 - (f) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware the 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.

APPENDIX HP

HAP Emissions Methodology and Summary

GENERAL REQUIREMENTS

1. The permittee shall demonstrate that SGS Unit 3 remains a minor source of actual HAP emissions by following the calculation methods, conducting the monitoring, keeping the records and submitting the reports specified in this Appendix. [Rule 62-4.070(3), F.A.C.]

ACID GAS HAP EMISSIONS

2. Within ten calendar days following each month, the permittee shall calculate and record the HCl and HF emissions as determined by CEMS for the previous 12 months of operation. For periods in which CEMS data is not available or not valid, the permittee shall calculate the missing emissions by using the actual heat input rate for the missing period and the highest monthly emissions factor average (lb/MMBtu) within the 12-month period for the emissions rate. The actual heat input rate shall be the sum of all fuels fired during the reporting period. [Rule 62-4.070(3), F.A.C.]

ORGANIC HAP EMISSIONS

3. The permittee shall use the following emissions factors to determine the 12-month rolling total emissions of organic HAP.

Organic HAP	AP-42 Factor	Test
	lb/MMBtu	lb/MMBtu
Biphenyl ^a	7.22E-08	---
Naphthalene ^a	5.52E-07	---
Acetaldehyde ^b	2.42E-05	Test Average
Acetophenone ^a	6.37E-07	---
Acrolein ^a	1.23E-05	---
Benzene ^b	5.52E-05	Test Average
Benzyl chloride ^b	2.97E-05	Test Average
Bis(2-ethylhexyl)phthalate (DEHP) ^a	3.10E-06	---
Bromoform ^a	1.66E-06	---
Carbon disulfide ^a	5.52E-06	---
2-Chloroacetophenone ^a	2.97E-07	---
Chlorobenzene ^a	9.34E-07	---
Chloroform ^a	2.50E-06	---
Cumene ^a	2.25E-07	---
Cyanide ^b	1.06E-04	Test Average
2,4-Dinitrotoluene ^a	1.19E-08	---
Dimethyl sulfate ^a	2.04E-06	---
Ethyl benzene ^a	3.99E-06	---
Ethyl chloride ^a	1.78E-06	---
Ethylene dichloride ^a	1.70E-06	---
Ethylene dibromide ^a	5.09E-08	---
Formaldehyde ^a	1.02E-05	---
Hexane ^a	2.84E-06	---
Isophorone ^b	2.46E-05	Test Average
Methyl bromide ^a	6.79E-06	---
Methyl chloride ^b	2.25E-05	Test Average
Methyl ethyl ketone ^b	1.66E-05	Test Average
Methyl hydrazine ^a	7.22E-06	---
Methyl methacrylate ^a	8.49E-07	---

APPENDIX HP

HAP Emissions Methodology and Summary

Organic HAP	AP-42 Factor	Test
	lb/MMBtu	lb/MMBtu
Methyl tert butyl ether ^a	1.49E-06	---
Methylene chloride ^a	1.23E-05	---
Phenol ^a	6.79E-07	---
Propionaldehyde ^b	1.61E-05	Test Average
Tetrachloroethylene ^a	1.83E-06	---
Toluene ^a	1.02E-05	---
1,1,1-Trichloroethane ^a	8.49E-07	---
Styrene ^a	1.06E-06	---
Xylenes ^a	1.57E-06	---
Vinyl acetate ^a	3.23E-07	---
Polycyclic Organic Material (POM) ^a	2.08E-06	---
Total PCDD/PCDF ^a	7.47E-11	---

- ^a. In combination with the actual heat input rate, the AP-42 emissions factors for these organic HAP shall be used to determine the 12-month rolling totals. The permittee may elect to conduct stack testing for these organic HAP to determine actual emissions. Actual emissions for tested pollutants shall be calculated as specified in Note "b" of this condition.
- ^b. The following organic HAP require initial and annual stack testing: acetaldehyde, benzene, benzyl chloride, cyanide, isophorone, methyl chloride, methyl ethyl ketone and propionaldehyde. For any operation before the initial stack tests are conducted, actual emissions for these organic HAP shall be calculated based on the corresponding AP-42 emissions factors as specified above in Note "a" of this condition. Thereafter, test results in combination with the actual heat input rate shall be used to determine these actual organic HAP emissions. Each subsequent test result shall be averaged with the previous test results to determine the actual emissions for the period between tests. After five stack tests have been conducted, actual emissions shall be determined based on the average of the five most recent test results.
- ^c. The actual heat input rate shall be the sum of all fuels fired during the reporting period.

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

METAL HAP EMISSIONS

4. The permittee shall use the following emissions factors to determine the 12-month rolling total emissions of metal HAP. The actual heat input rate shall be the sum of all fuels fired during the reporting period.

Metal HAP	Emissions Factors ^c lb/10 ¹² Btu	Comment
Antimony ^a	$0.92 \cdot (C/A \cdot PM)^{0.63}$	Equation from AP-42 Table 1.1-16
Arsenic ^b	$3.1 \cdot (C/A \cdot PM)^{0.85}$	Equation from AP-42 Table 1.1-16 and Stack Test
Beryllium ^a	$1.2 \cdot (C/A \cdot PM)^{1.1}$	Equation from AP-42 Table 1.1-16
Cadmium ^a	$3.3 \cdot (C/A \cdot PM)^{0.5}$	Equation from AP-42 Table 1.1-16
Chromium ^a	$3.7 \cdot (C/A \cdot PM)^{0.38}$	Equation from AP-42 Table 1.1-16
Cobalt ^a	$1.7 \cdot (C/A \cdot PM)^{0.69}$	Equation from AP-42 Table 1.1-16
Lead ^a	$3.4 \cdot (C/A \cdot PM)^{0.80}$	Equation from AP-42 Table 1.1-16
Manganese ^b	$3.8 \cdot (C/A \cdot PM)^{0.60}$	Equation from AP-42 Table 1.1-16 and Stack Test
Nickel ^b	$4.4 \cdot (C/A \cdot PM)^{0.48}$	Equation from AP-42 Table 1.1-16 and Stack Test
Mercury	---	CEMS ^d
Selenium ^b	---	Stack Test

APPENDIX HP

HAP Emissions Methodology and Summary

- a. In combination with the actual heat input rate and the quarterly fuel sampling and analysis, the AP-42 equations in Table 1.1-16 shall be used to determine these actual metal HAP emissions. Each subsequent emissions factor calculated from the fuel analysis data shall be averaged with the previous emissions factors to determine the actual emissions for that quarter. After five fuel samples have been analyzed, actual emissions shall be determined based on the average results of the five most recent sampling and analyses. If the permittee elects to conduct stack testing for one or more of these metals, actual emissions shall be determined as specified below in Note "b" of this condition.
- b. Stack tests are required for the following metal HAP: arsenic, manganese, nickel and selenium. For any operation before the initial stack tests are conducted, actual emissions of arsenic, manganese and nickel shall be calculated based on the corresponding AP-42 equations as described above in Note "a". For any operation before the initial stack tests are conducted, actual selenium emissions shall be based on fuel sampling and analysis and the assumption of 95% control. Thereafter, test results in combination with the actual heat input rate shall be used to determine these actual emissions of arsenic, manganese, nickel and selenium. Each subsequent test result shall be averaged with the previous test results to determine the actual emissions for the period between tests. After five stack tests have been conducted, actual emissions shall be determined based on the average of the five most recent test results.
- c. "C" means the concentration of metal in the coal fuel blend as determined by fuel sampling and analysis. "A" means the weight fraction of ash in the coal fuel blend as determined by fuel sampling and analysis. "PM" means the permitted PM/PM₁₀ emissions limit (0.013 lb/MMBtu).
- d. Within ten calendar days following each month, the permittee shall calculate and record the mercury mass emission rate as determined by CEMS for the previous 12 months of operation. For periods in which CEMS data is not available or not valid, the permittee shall calculate the missing emissions by using the actual heat input rate for the missing period and the highest monthly emissions factor average (lb/MMBtu) within the 12-month period for the emissions rate. For informational purposes, the permittee shall determine the uncontrolled mercury emissions based on the fuel sampling and analysis and calculate the approximate control efficiency.

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

MONTHLY RECORDS

5. Based on the requirements, methods and provisions of the permit and this Appendix, the permittee shall calculate and record the following information in a written or electronic log.
 - a. Demonstrate that actual acid gas emissions do not exceed 9.75 tons during any consecutive 12-month period.
 - b. Demonstrate that actual mercury emissions do not exceed 7.05×10^{-6} lb/MWh based on a 12-month rolling average.
 - c. Demonstrate that each individual HAP emission is less than 10.00 tons during any consecutive 12-month period.
 - d. Demonstrate that total HAP emissions are less than 25.00 tons during any consecutive 12-month period.

This information shall be available for review within 10 calendar days following each month.

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

APPENDIX SC
Sierra Club Agreement

Background

Seminole Electric Cooperative, Inc. and the Sierra Club entered into a settlement agreement (Sierra Club Agreement) to resolve issues between the two parties. The Department was not a party to the Sierra Club Agreement. For the original project, Seminole Electric Cooperative, Inc. requested that the terms of the Sierra Club Agreement be included in the original Final Permit. The Department's Final Determination for the original permit stated that this could be accomplished in a subsequent request to revise the permit, which is a part of this current project.

Enforceable Conditions

The permittee shall comply with all other conditions of the final permit as drafted by the Department. The Sierra Club Agreement cannot and does not directly modify any permit conditions. Only those provisions of the Sierra Club Agreement under "Terms and Conditions" related to and appropriate for the air permit are included in this Appendix, which is a part of the permit. Permitting notes describe how the terms of the Sierra Club Agreement are incorporated. The conditions in this Appendix are enforceable by the Department as part of the permit. All other provisions of the Sierra Club Agreement are enforceable by the parties to the agreement.

1. Following the commencement of commercial operation of Unit 3, the permittee shall comply with the following system-wide emission limits for Units 1, 2, and 3, combined:
 - (a) Sulfur Dioxide (SO₂) 95 percent control efficiency across the scrubbers based on a 30-day rolling average, including periods of startup and shut down, and annual emissions of no more than 17,900 tons per year based on a 12-month rolling average, including periods of startup and shut down.
 - (b) Nitrogen Oxides (NO_x) 0.07 lb/MMBtu based on a 30-day rolling average, and annual emissions of no more than 5,450 tons per year based on a 12-month rolling average. The "tons per year" limit includes periods of startup and shut down; the "lb/MMBtu" limit does not.
 - (c) Sulfuric Acid Mist (SAM) 1,665 tons per year
 - (d) Mercury (Hg) 118 pounds per year
 - (e) Particulate Matter (PM) 1,470 tons per year
 - (f) Volatile Organic Compounds (VOC) 259 tons per year
 - (g) Carbon Monoxide (CO) 17,493 tons per year
2. Following the commencement of full-time commercial operation of Unit 3, the permittee shall comply with the following emissions limits for SGS Unit 3:
 - (a) Sulfur Dioxide (SO₂) 98 percent control efficiency across the scrubber based on a 30-day rolling average, including periods of startup and shut down.
 - (b) Nitrogen Oxides (NO_x) 0.05 lb/MMBtu based on a 30-day rolling average, excluding periods of startup and shut down.
 - (c) Total PM (filterable + condensable) 0.030 lb/MMBtu, based on a 3-hour performance test conducted in accordance with modified Method 202.
 - (d) Opacity 10 percent
3. *Permitting Note: The Sierra Club Agreement proposed to revise Condition 4 in Subsection IIIA to, "The steam generator maximum heat input rate shall not exceed 7500 MMBtu per hour of coal based on fuel sampling and analysis." This was done as a clarification pursuant to the applicant's request based on comments from EPA Region 4.*
4. The Department revised Condition 5 in Subsection IIIA to, "Electrical Generating Capacity: For informational purposes, SGS Unit 3 will have a nominal electrical generating capacity of 750 MW net and 820 MW gross. [Application; Design]" *Permitting Note: The Sierra Club Agreement proposed to delete Condition 5 in Subsection*

APPENDIX SC

Sierra Club Agreement

IIIA, which identifies the "nominal" electrical generating capacity of SGS Unit 3 as 750 MW net and 820 MW gross. This is an important description of the capacity for SGS Unit 3 and was not deleted, but was clarified by inserting the introductory phrase, "For informational purposes".

5. SAM removal shall be accomplished by the use of the FGD system and the wet ESP, which shall be operated at all times, including startup and shutdown in accordance with good operating practices and manufacturer requirements. *Permitting Note: The Sierra Club Agreement proposed to revise Condition 7c in Subsection IIIA to specify this requirement; however, it is added in this Appendix as an enforceable requirement of the permit.*
6. SGS Unit 3 may combust bituminous coal up to 318.3 tons per hour based upon 11,780 BTU/lb HHV. *Permitting Note: The Sierra Club Agreement proposed to revise Condition 9a in Subsection IIIA to specify this requirement; however, it is added in this Appendix as an enforceable requirement of the permit.*
7. *Permitting Note: The Sierra Club Agreement proposed to revise Condition 10 in Subsection IIIA to revise the "lb/hour" equivalent VOC emission limit from 16.7 to 25.5. This was done as a correction pursuant to the applicant's request based on comments from EPA Region 4.*
8. Sulfur Dioxide (SO₂): Emissions of SO₂ from SGS Unit 3 shall not exceed 1.4 pounds per megawatt hour (lb/MW-hr) gross energy output or 98% reduction on a 30-day rolling average basis including periods of startup and shut down, nor 0.165 lb/MMBtu, based upon a 24-hour rolling average as determined by CEMS. In addition, SO₂ emissions shall not exceed 17,900 tons per 12-month rolling period (facility-wide), based upon CEMS. *Permitting Note: The Sierra Club Agreement proposed to revise Condition 13 in Subsection IIIA to specify this requirement; however, it is added in this Appendix as an enforceable requirement of the permit.*
9. The permittee shall maintain monthly records describing the actions taken to comply with Condition 20 (Unconfined Particulate Emissions) in Subsection IIIA of the permit. *Permitting Note: The Sierra Club Agreement proposed to revise Condition 20 in Subsection IIIA to specify this requirement; however, it is added in this Appendix as an enforceable requirement of the permit.*

Permitting Note: Paragraphs 10, 11 and 12 under "Terms and Conditions" of the Sierra Club Agreement are considered obsolete.

APPENDIX TEBD

Final BACT Determinations and Emissions Standards

See attached document, Appendix TEBD, from original permit package.

**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, PM₁₀, CO, VOC and HF, and that netting will be used to avoid a PSD/BACT Review for SO₂, 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).

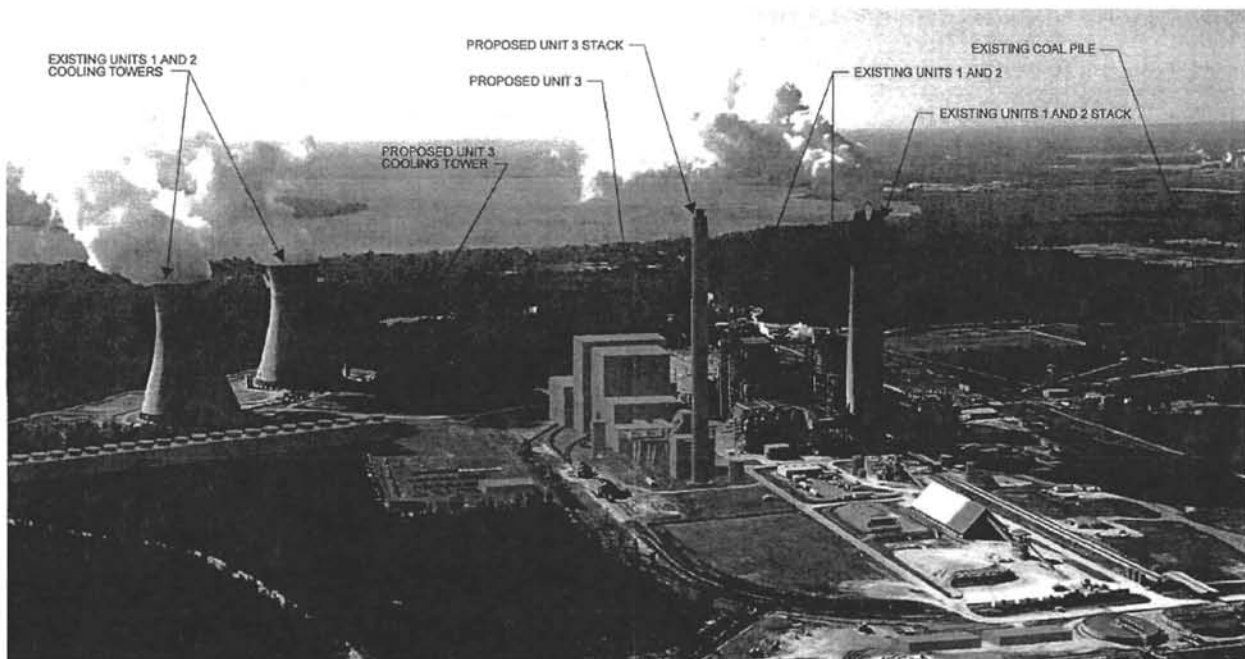
SGS Unit 3 will feature supercritical pulverized coal technology with modern emission controls. The Unit 3 air pollution control equipment will include wet Flue Gas Desulfurization (FGD) for SO₂ removal, selective catalytic reduction (SCR) for control of nitrogen oxides (NO_x), electrostatic precipitator (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 SO₂, NO_x, SAM, and mercury when compared to historical (baseline) air emissions.
- 2) PSD-Significant increases in facility-wide PM/PM₁₀, 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 SO₂, 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/PM₁₀

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/PM₁₀. The combination of the ESP and WESP will achieve a high degree of PM/PM₁₀ emission reduction. The annual PTE is proposed as 493 TPY of PM/PM₁₀.

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/PM₁₀).

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/PM₁₀) is 3.9 TPY.

Annual PM/PM₁₀ emissions from the diesel-fired Caterpillar Emergency Generator are 0.04 TPY. Fugitive emissions account for the remainder of the PM/PM₁₀ 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 SO₂ to SO₃ 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 than 500 horsepower. The emergency generator will only be subject to the notification requirements of the RICE MACT (i.e., no emissions limitations will apply) since it would qualify for the following rule exemption:

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

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

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

TRACE METAL HAP EMISSIONS ESTIMATES FOR SECI SGS UNIT 3

	Trace Metal in Coal											
	Antimony	Arsenic	Beryllium	Cadmium	Chromium	Cobalt	Lead	Manganese	Mercury	Nickel	Selenium	Vanadium
Emissions-EPA Factors (EF = a x (C/A x PM) ^b												
Multiplier - a	0.92	3.1	1.2	3.3	3.7	1.7	3.4	3.8		4.4		3.8
Exponent - b	0.63	0.85	1.1	0.5	0.58	0.69	0.8	0.6		0.48		0.6
Concentration (C) (ppm)	1.64	29.72	3.330	0.72	19.21	8.39	22.890	44.97		172.057	4.08	520.736
Actual PM Concentration (PM) (lb/mmBtu)	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150		0.0150		0.0150
Ash Concentration (A) (fraction)	0.1273	0.1273	0.1273	0.1273	0.1273	0.1273	0.1273	0.1273		0.1273		0.1273
Emission Factor (lb/10 ⁶ Btu)	0.327	8.996	0.429	0.961	5.943	1.687	7.520	10.335	0.707	18.654	17.317	44.927
Heat Input (mmBtu/hr)	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500
Maximum Fuel Input (lb/hr)	636.672	636.672	636.672	636.672	636.672	636.672	636.672	636.672	636.672	636.672	636.672	636.672
Emissions (lb/hr)	0.002	0.067	0.003	0.007	0.045	0.013	0.056	0.078	0.005	0.140	0.130	0.337
Uncontrolled (lb/hr)	1.044	18.922	2.120	0.458	12.230	5.342	14.573	28.631		109.544	2.598	331.538
Removal	99.77%	99.64%	99.85%	98.43%	99.64%	99.76%	99.61%	99.73%		99.87%	95.00%	99.90%
Emissions (tons/yr)	0.011	0.296	0.014	0.032	0.195	0.055	0.247	0.339	0.023	0.613	0.569	1.476

Sources: EPA, 1998, AP-42, Table 1.1-16 (all metals except mercury, selenium and vanadium), Trace Metal Concentration based on upper 95% Confidence Interval from USGS COALQUAL Database Trace Elements for the Central Appalachian Region

<http://energy.er.usgs.gov/coalqual.htm>

Controlled Mercury emissions based on 7.05E-06 lb/MW-hr

Controlled Selenium emissions based on 95% control from FGD system

EPA Emission Factor Rating: A-Excellent

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
Rule 62-210.350	Public Notice and Comments

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

4.2 Federal Regulations

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

4.3 NSPS Limits

The Unit 3 boiler will be subject to emission limitations covered under 40 CFR Subpart Da, which limits Hg, NO_x, SO₂ 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, SO₂ 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 x 10 ⁻⁶ lb/MWh	7.05 x 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 SO₂ 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 SO₂ 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 NO_x and SO₂ 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, SO₂, 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/PM₁₀ 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 SO₂ 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/PM₁₀

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 : 0.012 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 PM₁₀ is from 0.012 to 0.02 lb/MMBtu. Therefore, the applicant's proposed filterable BACT limit of 0.015 lb/MMBtu for PM/PM₁₀ 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 PM₁₀ 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 CO₂ 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 CO₂ 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 SO₂ 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 Emergency Generator: 1.8 lb per hour	Initial Stack Test CEMS Initial Test Initial Test

Pollutant	BACT Emission Limits	Compliance Method
VOC	SGS Unit 3: 0.0034 lb/MMBtu	Initial Test
HF	SGS Unit 3: 0.00023 lb/MMBtu	Initial & T-5 Renewal Test
Pollutant	Non-BACT Established Emission Limits	Compliance Method
SO ₂	SGS Unit 3: 0.165 lb/MMBtu 24-hour rolling via wet FGD ZLD Spray Dryers & Emergency Generator: 0.05% sulfur fuel	CEMS Fuel specifications
SAM	SGS Unit 3: 0.005 lb/MMBtu via wet FGD and WESP	Annual Test
NO _x	SGS Unit 3: 0.07 lb/MMBtu via SCR	CEMS
Hg	SGS Unit 3: 7.05 E-6 lb/MWh 12 month rolling	CEMS or Sorbent Traps (App K)

5.5.1 Startup and Shutdown Emissions

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

Emissions during startup of the proposed unit will be minimized by the use of existing onsite steam and the use of No. 2 distillate oil igniters in the boiler to warm the boiler and steam turbine. The use of No. 2 fuel, along with the operation of the WESP and wet FGD systems will minimize emissions of those pollutants associated with contaminants in the fuel (PM and SO₂).

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 PM₁₀, CO, HF and VOC emissions at levels in excess of PSD significant amounts. PM₁₀ 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 SO₂ 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. SO₂ 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 PM₁₀, CO, HF and VOC;
- A significant impact analysis for PM₁₀, CO, NO_x and VOC;
- A PSD increment analysis for PM₁₀ and SO₂;
- An Ambient Air Quality Standards (AAQS) analysis for PM₁₀ and SO₂;
- 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 (µg/m³)	Impact Greater than De Minimis? (Yes/No)	De Minimis Concentration (µg/m³)
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 SO₂ AAQS analysis as part of this application, appropriate background concentrations for use in this analysis were established from SO₂ data, which was collected in Palatka. These SO₂ concentrations are shown in the table below.

BACKGROUND CONCENTRATIONS FOR USE IN AAQS ANALYSES		
Pollutant	Averaging Time	Background Concentration (µg/m³)
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 ($\mu\text{g}/\text{m}^3$)	Significant Impact Level ($\mu\text{g}/\text{m}^3$)	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 ($\mu\text{g}/\text{m}^3$)	Significant Impact Level ($\mu\text{g}/\text{m}^3$)	Significant Impact? ($\mu\text{g}/\text{m}^3$)
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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ (the baseline year was 1975 for existing major sources of SO₂). 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 SO₂ 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 (SO₂), caused predicted violations of the PSD Class II and Class I increments for the 3-hour and 24-hour averaging times. For the Unit 1 and 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 SO₂ 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 SO₂ 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, SO₂ emission 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?
SO ₂	Annual	0.00	1	No
	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 SO₂ 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 SO₂ increments are predicted to be exceeded. Therefore, this project will improve overall air quality in this area.

The results of SO₂ AAQS and Class II PSD increment modeling for the Unit 3 project are shown in the tables below. The results show that the SO₂ impacts for SGS, together with other sources, will comply with the AAQS and PSD Class II increments.

MAXIMUM PREDICTED AMBIENT AIR QUALITY IMPACTS (AAQS) IN THE VICINITY OF THE PROJECT						
Pollutant	Averaging Time	Modeled Sources (µg/m ³)	Background Concentration (µg/m ³)	Total Impact (µg/m ³)	Total Impact Greater than AAQS	AAQS (µg/m ³)
SO ₂	Annual	23	6	29	No	60
	24-hour	165	34	199	No	260
	3-hour	563	128	691	No	1300

PSD CLASS II INCREMENT ANALYSIS IN THE VICINITY OF THE PROJECT				
Pollutant	Averaging Time	Maximum Predicted Impact (µg/m ³)	Impact Greater than Allowable Increment?	Allowable Increment (µg/m ³)
SO ₂	Annual	8	No	20
	24-hour	60	No	91
	3-hour	152	No	512

6.6 Additional Impacts Analysis

6.6.1 Impacts on Soils, Vegetation, Wildlife, and Visibility

The maximum ground-level concentrations predicted to occur due to PM₁₀, NO_x 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 SO₂ 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 SO₂ and NO_x 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

EXHIBIT 2

SETTLEMENT AGREEMENT

This Settlement Agreement ("Agreement") is entered into by and between Seminole Electric Cooperative, Inc. ("Seminole") and the Sierra Club ("Sierra Club"). Seminole and Sierra Club shall be referred to herein collectively as the "Parties" for the purposes of this Agreement.

RECITALS

A. Seminole operates two existing electrical generating units at the Seminole Generating Station site ("Site") in unincorporated Putnam County, Florida. Those existing units, referred to as Units 1 and 2, originally were licensed pursuant to the Florida Power Plant Siting Act (PPSA) Certification Order PA-10 and PSD permit PSD-FL-018.

B. On March 9, 2006, Seminole filed a site certification application ("SCA") under the PPSA, with the Florida Department of Environmental Protection ("FDEP") seeking approval for the construction and operation of the proposed Unit 3 Project. The new proposed Unit 3 will be located adjacent to the existing two units and will utilize some of the existing facilities and infrastructure at the Site. The SCA was assigned FDEP number PA78-10A2; FDEP OGC Case No. 06-0780 and Florida Division of Administrative Hearings Case No. 06-0929EPP.

C. The Sierra Club was a party to the original PPSA site certification proceeding for the existing two units at the Site as well as the current site certification proceeding for the proposed Unit 3 Project.

D. On March 9, 2006, Seminole also filed with FDEP a separate application for a prevention of significant deterioration ("PSD") permit to authorize construction of Unit 3. The PSD permit is being processed by FDEP pursuant to its authority to issue such federally-required PSD permits in Florida. A draft PSD permit was issued by FDEP on August 24, 2006; the FDEP PSD permit number is PSD-FL-375.

E. On October 9, 2006, the Sierra Club submitted written comments to the FDEP Bureau of Air Regulation concerning FDEP's proposed PSD permit for the Unit 3 Project.

F. In a separate Settlement Agreement signed by both Parties on January 7, 2007, the Parties resolved all issues raised or which could be raised concerning Seminole's Unit 3 Project in the PPSA proceeding, except for issues related to the PSD permit. The Parties also set a framework for continued settlement negotiations concerning the PSD permit.

G. This Agreement reflects the Parties agreement to settle all remaining issues related to the PSD permit for Unit 3. The Parties concur that this Agreement consists of full and fair consideration for the release of all claims of the Sierra Club with respect to issuance of the PSD permit for Unit 3. Provided that the final PSD permit is issued in accordance with the terms and conditions of this Agreement, Sierra Club agrees not to contest FDEP's issuance of the final PSD permit in any administrative or judicial forum. Seminole agrees not to contest any conditions in the final PSD permit if it is issued in accordance with the terms and conditions of this Agreement.

TERMS AND CONDITIONS

1. Following the commencement of commercial operation of Unit 3, it is agreed that Seminole will be subject to the following system-wide emission rates for Units 1, 2, and 3, combined:

- | | |
|---|--|
| (a) Sulfur Dioxide (SO ₂) | 95 percent control efficiency across the scrubbers based on a 30-day rolling average, including periods of start-up and shut down, and annual emissions of no more than 17,900 tons per year based on a 12-month rolling average, including periods of start-up and shut down. |
| (b) Nitrogen Oxides (NO _x) | 0.07 lb/MMBtu based on 30-day rolling average, and annual emissions of no more than 5,450 tons per year based on a 12-month rolling average. The tons per year limit includes periods of startup and shutdown; the lb/MMBtu does not. |
| (c) Sulfuric Acid Mist
(H ₂ SO ₄) | 1,665 Tons Per Year |
| (d) Mercury (Hg) | 118 Pounds Per Year |
| (e) Particulate Matter (PM) | 1,470 Tons Per Year |
| (f) Volatile Organic
Compounds (VOC) | 259 Tons Per Year |
| (g) Carbon Monoxide (CO) | 17,493 Tons Per Year |

2. Following the commencement of full-time commercial operation of Unit 3, the following emission rates shall apply specifically to Unit 3:

- | | |
|--|---|
| (a) Sulfur Dioxide (SO ₂) | 98 percent control efficiency across the scrubber based on a 30-day rolling average, including periods of start-up and shut down. |
| (b) Nitrogen Oxides (NO _x) | 0.05 lb/MMBtu, based on a 30-day rolling average, excluding periods of start-up and shut down |
| (c) Total PM (filterable +
condensable) | 0.030 lb/MMBtu, based on a 3-hour performance test, based on modified Method 202 test |

(d) Opacity 10 percent

3. The last sentence of Draft Permit Condition III.A.4. shall be amended to read as follows: "The steam generator shall be designed for a maximum heat input of maximum heat input rate shall not exceed 7,500 MMBtu per hour of coal, based on fuel sampling and analysis."

4. Draft Permit Condition III.A.5. shall be deleted.

5. Draft Permit Condition III.7.c. shall be revised as follows: "SAM removal shall be accomplished by the use of the FGD system and the wet ESP, which shall be operated at all times, including startup and shutdown, in accordance with good operating practices and manufacturer requirements."

6. Draft Permit Condition III.A.9.a. shall be amended to read as follows: "Coal-SGS Unit 3 may combust bituminous coal, up to 318.3 tons per hour based upon ~~11,300~~ 11,780 Btu/lb HHV."

7. In Draft Permit Condition III.A.10., the "lb/hr equivalent VOC emission limit" shall be changed from 16.7 to 25.5.

8. Draft Permit Condition III.A.13. shall be amended to read as follows: "Sulfur Dioxide (SO₂): Emissions of SO₂ from SGS Unit 3 shall not exceed 1.4 pounds per megawatt hour (lb/MW-hr) gross energy output or 98% reduction on a 30-day rolling average basis including periods of start-up and shut down, nor 0.165 lb/MMBtu, based upon a 24-hour rolling average as determined by CEMS. In addition, SO₂ emissions shall not exceed ~~29,074~~ 17,900 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.]

9. New Permit Condition III.A.20.c. shall be included as follows: "The permittee shall maintain monthly records describing actions taken to comply with this condition."

10. The parties agree that all other conditions in the Draft Permit shall be included in the Final Permit.

11. Seminole agrees to ask FDEP to include the foregoing limits and conditions in the Final PSD permit for Seminole Unit 3 and agrees to be bound to these limits and conditions. Sierra Club agrees to not object, challenge, appeal, or initiate or assist in any challenge or appeal by others, or in any other way impede or interfere with the issuance of a final PSD permit in accordance with the terms and conditions identified in this Agreement.

12. By September 1, 2007, Seminole agrees to publish a Request for Proposal (RFP) soliciting bids for up to 100 MW of renewable energy, which may include solar, wind, geothermal and/or biomass. Seminole is committed to pursuing renewable energy opportunities, and agrees to evaluate and implement, in good faith, viable bids. In accordance with Seminole's existing bid evaluation policy, a viable bid is one that is reasonable based on an analysis of

technical, commercial and economic issues, including reliability, fuel supply (as applicable), siting issues, transmission, and financial viability of vendor, and whether the project is in the best interest of Seminole and its members. If Seminole does not receive viable bids in response to this RFP, Seminole will publish another such RFP within eighteen months of the first. Seminole will continue to actively pursue renewable energy opportunities, and will evaluate and implement, in good faith, viable bids in the manner described above.

GENERAL PROVISIONS

13. This Settlement Agreement represents a complete settlement of all Unit 3 issues related to issuance of the PSD permit.

14. Each of the signatories hereto warrants and represents that he or she is competent and authorized to enter into this Agreement on behalf of the party for whom he or she purports to sign.

15. This Agreement shall never at any time or for any purpose be considered an admission of liability or responsibility on the part of any party herein released.

16. This Agreement is the product of negotiation and preparation by and among each party hereto and his or her respective attorneys. Accordingly, all Parties hereto acknowledge and agree that the Agreement shall not be deemed prepared or drafted by one party or another, or the attorneys for one party or another, and the Agreement shall be construed accordingly.

17. This Agreement shall be interpreted in accordance with and governed in all respects by the laws of the State of Florida. Exclusive jurisdiction and venue for any litigation brought to enforce this Agreement shall be in the Circuit Court for Putnam County, Florida, and the Parties do hereby specifically waive any other jurisdiction and venue. In any such litigation, the parties shall seek only declaratory or injunctive relief or specific performance. Neither party shall file any lawsuit to enforce this Agreement unless it has first provided written notice of the alleged violation to the other party thirty days prior to filing suit and the other party has failed to cure the alleged violation.

18. If any provision or any part of any provision of this Agreement is for any reason held by a court of competent jurisdiction to be invalid, unenforceable or contrary to public policy or any law, then the remainder of this Agreement shall not be affected thereby and shall remain in full force and effect.

19. No amendments or modifications of this Settlement Agreement shall be valid unless set forth in writing and signed by the duly authorized representatives of each Party.

20. This Agreement shall be deemed to be effective immediately upon its full execution by all Parties.

21. This Agreement contains the entire understanding among the Parties with regard to the matters herein set forth, and is intended to be and is a final integration thereof. There are no representations, warranties, agreements, arrangements, undertakings, oral or written, between or among the Parties hereto relating to this Agreement which are not fully expressed herein.

SEMINOLE ELECTRIC COOPERATIVE, INC.

Date: 3/9/07

By: M.P. O'Neil

Its: VICE President, Technical Services

SIERRA CLUB

Date: 3/9/07

By: Kristin A. Henry

Its: Staff attorney

EXHIBIT 3

IN THE CIRCUIT COURT FOR THE SEVENTH JUDICIAL CIRCUIT
IN AND FOR PUTNAM COUNTY, FLORIDA

SIERRA CLUB,

Plaintiff,

v.

Case No. 08-CA-3561

SEMINOLE ELECTRIC
COOPERATIVE, INC.,

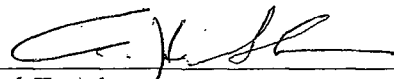
Defendant.

_____ /

NOTICE OF VOLUNTARY DISMISSAL

Please take notice that Plaintiff, Sierra Club, hereby voluntarily dismisses the above-styled action without prejudice pursuant to Fla.R.Civ.P. 1.420(a)(1).

Respectfully submitted this 19th day of February, 2009.

By 
Samuel T. Adams
Post Office Box 191
Panama City, Florida 32402-0191
(850) 785-3469
(850) 763-6653 – Facsimile
Florida Bar No. 160184
Attorney for Plaintiff, Sierra Club

Colin H. Adams
Florida Bar No.
0058110

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of this document has been furnished to Carolyn S. Raeppe, Esquire; James S. Alves, Esquire; and David W. Childs, Esquire, of Hopping Green & Sams, Attorneys for Defendant, Seminole Electric Cooperative, Inc., by U.S. Mail to 123 South Calhoun Street, Tallahassee, Florida 32301, this 19th day of February, 2009.