Department of Environmental Protection

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

Jeb Bush
Governor

Colleen M. Castille
Secretary

May 2, 2006

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

James R. Frauen, Manager of Environmental Affairs
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry
Tampa, FL 33618

Re: Draft Air Permit No. 1070025-004-AC
Seminole Generating Station ["SGS"]
Units 1 and 2 Pollution Controls Upgrade

Dear Mr. Frauen:

Enclosed is one copy of the draft permit to make upgrades to the pollution controls on SGS Units 1 and 2 so as to meet the CAIR/CAMR requirements, as well as to provide selected emission reductions for a proposed Unit 3. The new equipment will be installed at the existing Seminole Generating Station, which is located at 890 North U.S. Highway 17, north of Palatka, in Putnam County, Florida. The Department's "Technical Evaluation and Preliminary Determination", "Intent to Issue Permit", and the "Public Notice of Intent to Issue Permit" are also included.

The "Public Notice of Intent to Issue Permit" must be published one time only, as soon as possible, in the legal advertisement section of a newspaper of general circulation in the area affected, pursuant to the requirements Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit. The Department will accept comments on the draft permit for a period of 14 days as described in the attached notice.

Please submit any written comments you wish to have considered concerning the Department's proposed action to J. F. Koerner, Administrator of the North Permitting Section, at the above letterhead address. If you have any other questions, please contact Michael P. Halpin at 850/245-8993.

Sincerely,

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

Enclosures

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

In the Matter of an
Application for Air Permit by:

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

Authorized Representative:
James R. Frauen, Manager of Environmental Affairs

Draft Permit No. 1070025-004-AC
Seminole Electric Cooperative
Seminole Generating Station
Units 1 and 2 Pollution Controls Upgrade
Putnam County, Florida

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of Draft Permit attached) for the proposed project as detailed in the application and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below. Seminole Electric Cooperative applied on February 13, 2006 to the Department for a permit to upgrade the pollution controls for Units 1 and 2. The new equipment will be installed at the existing Seminole Generating Station, which is located at 890 North U.S. Highway 17, north of Palatka, in Putnam County, Florida.

The Department has permitting jurisdiction under the provisions of Chapter 403, F.S., and Chapters 62-4, 62-210, and 62-212, F.A.C. The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit is required to perform the proposed work. The Department intends to issue this air construction permit based on the belief that the applicant has provided reasonable assurances to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting 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 Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in Section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) and (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of fourteen (14) days from the date of publication of Public Notice of Intent to Issue Air Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S. before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S. must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S.

however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action 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 Department'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 Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit package (including the Public Notice of Intent to Issue Air Construction Permit, Technical Evaluation and Preliminary Determination, and the Draft Permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 5/3/06 to the persons listed:

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

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Mary L Harvey (Clerk) 5/3/06 (Date)

DRAFT PERMIT

PERMITTEE

Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, FL 33618
Authorized Representative:
James R. Frauen, Manager of Environmental Affairs

Seminole Generating Station Units 1-2 Pollution Controls Upgrade Facility ID No. 1070025 SIC No. 4911 Air Permit No. 1070025-004-AC

PROJECT AND LOCATION

This permit authorizes the construction and/or upgrade of pollution control equipment for Units 1 and 2 at the existing Seminole Generating Station, which is located at 890 North U.S. Highway 17, north of Palatka, in Putnam County, Florida. The map coordinates are: Zone 17; 438.80 km East; and 3289.20 km North.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403, F.S., and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. 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. This air construction permit supplements all other valid air construction and operation permits.

CONTENTS

Michael G. Cooke, Director (Date)
Division of Air Resources Management

FACILITY AND PROJECT DESCRIPTION

The existing Seminole Generating Station (SGS) consists of two 714.6 megawatt, electric, coal fired steam electric generators; a coal handling and storage system; a limestone unloading, handling and storage system; a flue gas desulphurization (FGD) sludge stabilization system; and a rail car maintenance facility.

This project includes improvements to the existing steam turbines, a proposed warehouse expansion, the addition of two new auxiliary transformers and related appurtenances, a parking lot and an employee car rinse area. The following units are affected by this air construction permit:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
001	Steam Generation	SGS (Existing) Unit 1 upgraded to 735.9 MW
002	Steam Generation	SGS (Existing) Unit 2 upgraded to 735.9 MW
009	Materials Handling	Carbon Burn-Out (CBO™) Feed Fly Ash Silo (New)
010	Materials Handling	CBO™ Product Fly Ash Storage Dome (New)
011	Materials Handling	CBO™ Product Fly Ash Loadout Storage Silo (New)
012	Materials Handling	CBO™ Product Fly Ash Fugitives (New)
013	Hot Water Generation	CBO™ Process Fluidized Bed Combustor (New) NSPS Subpart Db

REGULATORY CLASSIFICATION

Title III: The existing facility is a major source of hazardous air pollutants (HAP).

Title IV: The existing facility operates units subject to the acid rain provisions of the Clean Air Act.

Title V: The existing facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The existing facility is a PSD-major facility in accordance with Rule 62-212.400, F.A.C., although this project does not trigger a PSD Review.

1. Permitting Authority: All documents related to applications for permits to construct, modify, or operate emissions units at this facility 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 permit applications shall also be sent to the Compliance Authority.

2. 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.

3. Appendices: The following Appendices are attached as part of this permit: Appendix GC (General Conditions).

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C. 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 62-4, 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

5. 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.]

6. Construction Approval: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Rule 62-210.200(76), F.A.C. defines *construction* as, "Construction –

   (a) The act of performing on-site fabrication, erection, installation or modification of an emissions unit or facility of a permanent nature, including installation of foundations or building supports; laying of underground pipe work or electrical conduit; and fabrication or installation of permanent storage structures, component parts of an emissions unit or facility, associated support equipment, or utility connections. Land clearing and other site preparation activities are not a part of the construction activities.

   (b) For the purposes of Rules 62-212.300, 62-212.400, 62-212.500, and 62-212.720, F.A.C., construction means any physical change or change in the method of operation (including fabrication, erection, installation, or modification of an emissions units) that would result in a change in emissions.

   (c) For the purposes of the provisions of 40 CFR Parts 60 and 61, adopted by reference in Rule 62-204.800, F.A.C., construction means fabrication, erection, or installation of an affected facility.

   (d) For the purposes of the provisions of 40 CFR Part 63, adopted by reference in Rule 62-204.800, F.A.C., construction means the on-site fabrication, erection, or installation of an affected source. Construction does not include the removal of all equipment comprising an affected source from an existing location and reinstallation of such equipment at a new location. The owner or operator of an existing affected source that is relocated may elect not to reinstall minor ancillary equipment including piping, ductwork, and valves. However, removal and reinstallation of an affected source will be construed as reconstruction if it satisfies the criteria for reconstruction as defined in this section. The costs of replacing minor ancillary equipment must be considered in determining whether the existing affected source is reconstructed." Such permits shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

7. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions units. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. 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. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. EU 001 and 002 – Boilers No. 1 and 2

This section of the permit addresses the following existing emissions units:

Emissions Unit Nos. 001 and 002
Steam Electric Generator Nos. 1 and 2 are existing, 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. Steam Electric Generator Nos. 1 and 2 are each equipped with an electrostatic precipitator (ESP) to control particulate matter, a wet limestone flue gas desulphurization (FGD) unit to control sulfur dioxide, and low NO_X burners and low excess-air firing to control nitrogen oxides. {Permitting note(s): IMPORTANT REGULATORY CLASSIFICATIONS - The emissions units are regulated under Acid Rain, Phase II and 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(5), F.A.C., Prevention of Significant Deterioration (PSD); and Rule 62-212.400(6), 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.}

PREVIOUS APPLICABLE REQUIREMENTS

1. Other Permits: The conditions of this permit supplement all previously issued air construction and operation permits for this emissions unit. Unless otherwise specified, these conditions are in addition to all other applicable permit conditions and regulations. [Rule 62-4.070, F.A.C.]

EQUIPMENT AND CONSTRUCTION

2. Flue Gas Desulphurization System (FGD) Upgrade: In order to reduce the emissions of sulfur dioxide, the permittee shall make upgrades to the existing Units 1 and 2 scrubbers so as to improve the SO_2 removal efficiency from approximately 87 to 95%. The improvements include the following types of work: scrubber module modifications, upgrades to the modules mist eliminator wash system, expansion of the oxidation air system, modifications to the existing sparger rings in the absorber recycle tanks, upgrades to the Effluent Processing Facility (EPF) System and a new gypsum conveyor system. The upgrades will allow SGS to meet the 0.67 lb/MMBtu SO_2 emission limits specified in this permit.
3. Selective Catalytic Reduction (SCR) Systems: The permittee shall construct, tune, operate, and maintain a new SCR system for Units 1 and 2, to reduce emissions of nitrogen oxides (NO_X) as described in the application, approved drawings, plans, and other documents on file with the Department. The SCR system shall be designed to achieve a NO_X emission rate of no more than 0.07 lb/MMBtu. An SCR reagent system shall be installed, consisting of a new urea to ammonia processing system and associated bulk storage systems. The SCR system shall be designed for a maximum ammonia slip rate of 5 ppmvd @ 15% O_2.
4. Low NO_X Burner Replacement: The permittee shall replace, tune, operate and maintain low NO_X burners on Units 1 and 2. Additionally, the existing burner inlet systems will be modified to ensure even air flow, and the Overfire Air System (OFA) will be modified to utilize at least six ports per wall compared with the existing system design of four ports per wall. These replacements are designed to achieve the Acid Rain Program NO_X annual average emission limit of 0.46 lb/MMBtu, which will be effective in 2008.
5. Alkali Injection System: The permittee shall construct and operate a new alkali injection system on Units 1 and 2 to mitigate the potential impacts of SO_3 formation resulting from the operation of the SCR control systems. The design criteria shall ensure that sulfuric acid mist emissions do not increase above the sulfuric acid mist emissions baseline.
6. Turbine Upgrade: Each existing steam turbine for Units 1 and 2 shall be upgraded for increased unit

efficiency, and in order to recover portions of the lost electrical output from powering the above additions. Such efficiency improvements may include blade and/or rotor redesigns and replacements. Each boiler maximum heat input will remain at 7,172 MMBtu/hr.

PERFORMANCE REQUIREMENTS

This permit does not alter any specifications or limitations included in previous permits that define permitted capacities such as heat input rates, fuel consumption, or hours of operation. It does not authorize any additional fuels or such other methods of operation.

EMISSIONS STANDARDS

Note: A concurrent application is being processed for a new SGS Unit 3. Where affected, the below emission standards are shown for this project (Pollution Control Upgrades) as "interim" limits. As of the first monitoring period following the establishment of initial coal fires in SGS Unit 3, the latter "permanent" emission limits will become effective.

7. Sulfur Dioxide (SO_2):

   a. The interim Sulfur Dioxide emissions from Units 1 and 2 shall not exceed 0.67 lb/MMBtu (combined for Units 1 and 2), based upon a 24 hour block average via CEMS.

   b. The permanent limits shall be 0.38 lb/MMBtu (combined for Units 1 and 2), based upon a 24 hour block average via CEMS.

   c. The combined total shall be computed by adding the total lbs emitted for both Units 1 and 2, divided by the total MMBtu heat input for both Units 1 and 2 for each 24-hour block period.

   [PSD Avoidance]

8. Nitrogen Oxides (NO_X):

   a. The interim Nitrogen Oxide emissions from Units 1 and 2 shall not exceed 0.46 lb/MMBtu, based upon a 30 day rolling average. Compliance shall be determined by data collected from the certified continuous emissions monitor (CEM).

   b. The permanent limits shall be 0.33 lb/MMBtu (combined for Units 1 and 2), based upon a 30 day rolling average via CEMS.

   c. The combined total shall be computed by adding the total lbs emitted for both Units 1 and 2, divided by the total MMBtu heat input for both Units 1 and 2 for each 30-day rolling period.

   [PSD Avoidance]

9. Carbon Monoxide (CO)/Volatile Organic Compounds (VOC): The emission of Carbon Monoxide and Volatile Organic Compounds shall not exceed 0.20 lb/MMBtu (12-month rolling average) and 0.06 lb/ton coal respectively. For VOC, an initial stack test (only) shall be required in order to demonstrate compliance. Testing shall be according to EPA Method 18, 25, 25A or 25B. For CO, the existing emission monitors which are installed in the ductwork shall be certified according to 40 CFR Part 60 and the data collected shall be combined and utilized to demonstrate compliance.
   [PSD Avoidance]

10. Sulfuric Acid Mist (SAM):

    a. The interim Sulfuric Acid Mist emissions from Units 1 and 2 shall not exceed 0.096 lb/MMBtu, based upon an initial stack test (only) via EPA Method 8.

    b. The permanent limits shall be 0.031 lb/MMBtu (combined for Units 1 and 2), based upon annual stack test via EPA Method 8.

c. The combined total shall be computed measuring the lb/MMBtu emission rate on each unit, multiplying each unit's emission rate by its maximum annual heat input (MMBtu), adding the total lbs emitted for both Units 1 and 2, and dividing by the total MMBtu heat input for both Units 1 and 2.
[PSD Avoidance]

11. Particulate Matter (PM/PM_{10}): The emission limit for particulate matter shall not exceed 0.03 lb/MMBtu on each individual unit, as measured by an annual stack test via EPA Method 5B. [PSD Avoidance]

12. Mercury (Hg): The permanent emission limitation for mercury shall be 0.036 tons per year (combined for Units 1 and 2), based upon annual stack test via EPA Method 101A or 108. The combined total shall be computed by measuring the lb/MMBtu emission rate on each unit, multiplying each unit's emission rate by its annual heat input (MMBtu) and adding the total lbs emitted for both Units 1 and 2, divided by 2000. [PSD Avoidance]

EMISSIONS PERFORMANCE TESTING

13. Test Notification: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. The notification shall include: the scheduled date, approximate start time, test team, contact name and phone number, description of unit to be tested, and the tests to be performed. [Rule 62-297.310(7)(a)9, F.A.C.]

14. Ammonia Slip, Performance Tests: Within 60 days after completing construction of each SCR system and bringing each unit on line, the permittee shall conduct tests to determine the ammonia slip rate in accordance with EPA Method CTM-027 or other methods approved by EPA. Subsequent tests shall be conducted during each federal fiscal year. If tests show ammonia slip emissions are greater than 5 ppmvd @ 15% O_2, the permittee shall take corrective actions such as repair, addition of catalyst, replacement of catalyst, etc. The corrective actions which are taken shall be submitted with the test data. [Rules 62-4.070(3) and 62-297.310(7), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

15. NO_X and SO_2 CEMS: The permittee shall demonstrate compliance with the emissions standards specified in this permit with data collected from the existing NOx, SO_2, CO_2, and stack gas flow rate continuous monitors installed pursuant to the Acid Rain requirements. [Rules 62-4.070(3) and 62-212.400, F.A.C.]

16. CO CEMS: To demonstrate compliance with the emissions standards, the permittee shall certify, calibrate, operate and maintain a continuous emissions monitoring system (CEMS) to continuously monitor and record the emissions of carbon monoxide. The existing Thermo Electron Corp Model 48C monitors may be utilized for this purpose, provided that they are able to demonstrate compliance with 40 CFR 60 Appendix B, Performance Specification 4. CEMS shall monitor and record data during all periods of Units 1 and 2 operation, including startup, shutdown, malfunction or emergency conditions, but not including continuous monitoring system breakdowns, repairs, calibration checks, or zero and span adjustments. For each calendar quarter, monitor availability shall be 95% or greater. If unable to achieve this level, the permittee shall submit a report identifying the problems in achieving 95% monitor availability and a plan of corrective actions. The permittee shall implement the reported corrective actions within the next calendar quarter. [Rules 62-4.070(3) and 62-212.400 (Source Obligation), F.A.C.]

RECORDS AND REPORTS

17. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the provisions of Rule 62-297.310(8), F.A.C. The report shall include copies of the continuous monitoring records. Additionally, an official notification shall be made to the Compliance Authority 72 hours prior to the establishment of initial coal fires in SGS Unit 3, for the purpose of complying with the limits herein.

This section of the permit addresses the following emissions units:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
009	Materials Handling	Carbon Burn-Out (CBO™) Feed Fly Ash Silo
010	Materials Handling	CBO™ Product Fly Ash Storage Dome
011	Materials Handling	CBO™ Product Fly Ash Loadout Storage Silo
012	Materials Handling	CBO™ Product Fly Ash Fugitives
013	Hot Water Generation	CBO™ Process Fluidized Bed Combustor NSPS Subpart Db

DESIGN AND ESSENTIAL POTENTIAL TO EMIT (PTE) PARAMETERS

1. CBO™ Process Fluidized Bed Combustor: The maximum design heat input rate to the CBO™ Process Fluidized Bed Combustor (EU-012) shall be 114.7 MMBtu/hr. The emissions from the CBO™ Process Fluidized Bed Combustor (EU-012) shall be routed back to Units 1 and 2 flue gas ductwork, upstream of the ESP, SCR and FGD System, so as to ensure that no additional emissions occur. [Design; Rules 62-210(PTE) and 62-4.070(3), F.A.C.]
2. Baghouse Controls: Particulate emissions from Emission Units Nos. 009, 010 and 011 shall be controlled by baghouses that are designed, operated, and maintained to achieve a particulate matter design specification of 0.01 grains/acf of exhaust. New and replacement bags shall meet these specifications based on vendor design information. No particulate matter emissions tests are required. The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Design; Rules 62-4.070(3) and 62-210.650, F.A.C.]
3. Hours of Operation: Emission Unit Numbers 009, 010, 011, 012 and 013 associated with the Carbon Burnout Unit are each allowed to operate continuously (8760 hrs/yr). [Rule 62-210.200(PTE), F.A.C.]

EMISSION LIMITATIONS AND PERFORMANCE STANDARDS

4. Authorized Fuels: Only fly ash generated from EU-001 and 002 may be used as fuel for the CBO™ Process Fluidized Bed Combustor (EU-012), except for the purposes of start-up. Start-up fuel shall be distillate fuel oil, limited to 0.5% sulfur and 14,300 gallons per calendar year. Records of fuel oil consumed for EU-013, demonstrating compliance with this condition shall be kept on-site so as to be readily available for review. Additionally, SGS shall totalize fuel usage data for annual (AOR) reporting. [Design; Rule 62-4.070(3), F.A.C.]
5. NSPS Provisions: EU-012 shall comply with the requirements of 40 CFR 60, Subpart Db. As a result of the configuration identified in above Condition 1, demonstration of the Subpart limits shall be allowed via the existing SGS Units 1 and 2 CEMS and stack testing. SGS shall include this demonstration upon initial installation and annually thereafter. [Note: Due to the configuration, there will be no practical method to test the CBO™ Unit separately. However, the combined emissions from the steam generating unit will be less than the NSPS as indicated by the limits described in Section 3.A. of this permit and the Technical Evaluation. The demonstration of those limits shall satisfactorily demonstrate compliance with the NSPS limits.]
6. Baghouse Exhausts: As determined by EPA Method 9 observations, visible emissions shall not exceed 5% opacity from each baghouse exhaust point for Emissions Unit Nos. 009, 010 and 011. [Design; Rules 62-4.070(3), 62-210.650, and 62-297.620(4) F.A.C.]

7. Fugitive Dust Control: The following requirements shall be met to minimize fugitive dust emissions from the storage and handling facilities, including haul roads and CBO-related operations:
   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.

8. Maximum Expected Emissions: The following table identifies the maximum expected emissions, design specifications and fugitives associated with the CBO™ Process. This table is shown for convenience purposes and do not represent additional, allowable emission limitations beyond those listed within the permit. [Design]

Emissions Unit No.	Control Device	Exhaust Flow Rate (dscfm)	PM Emission Rate (gr/dscf)	PM Emission Rate (lb/hr)	PM Emission Rate (TPY)
009	Baghouse	3,000	0.01	0.3	1.1
010	Baghouse	6,000	0.01	0.5	2.3
011	Baghouse	6,000	0.01	0.5	2.3
012	Paved Roads; Watering	---	---	0.1	0.2
TOTALS				1.4	5.8

TEST METHODS AND PROCEDURES

9. Test Notification: At least 15 days prior to the date on which each formal compliance test is to begin, the permittee shall notify the Compliance Authority of: the date, time, and place of the test; and the contact person who will be responsible for coordinating and having the test conducted. [Rule 62-297.310(7)(a)9, F.A.C.]

10. Compliance Tests: Each baghouse exhaust point for EU-009, EU-010, and EU-011 shall be tested to demonstrate initial compliance with the specified opacity standard. The initial tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial operation of the unit. Thereafter, each baghouse exhaust point for EU-009, EU-010, and EU-011 shall be tested to demonstrate compliance with the specified opacity standard during each federal fiscal year (October 1st to September 30th) and within the 12-month period prior to renewing the operation permit. [Rule 62-297.310(7)(a)1 and 4, F.A.C.]

11. Test Procedures: All tests shall be conducted in accordance with EPA Method 9, which is described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Tests shall also comply with the applicable requirements of Rule 62-297.310, F.A.C. Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. [Rules 62-204.800 and 62-297.310(4) and (5), F.A.C.; 40 CFR 60, Appendix A]

12. Special Compliance Tests: When the Compliance Authority, 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 Compliance Authority. [Rule 62-297.310(7)(b), F.A.C.]

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Seminole Generating Station Units 1 and 2

Palatka, Putnam County
Florida

Pollution Control Upgrades and
Proposed CAIR/CAMR Improvements

DEP File No. 1070025-004-AC

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

May 1, 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, Managing of Environmental Affairs

1.2 Reviewing and Process Schedule

02-13-06:	Date of Receipt of Application
03-01-06:	Request for Additional Information
04-14-06:	Application Complete

2. FACILITY INFORMATION

2.1 Facility Location

The Seminole Generating Station (SGS) is located 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

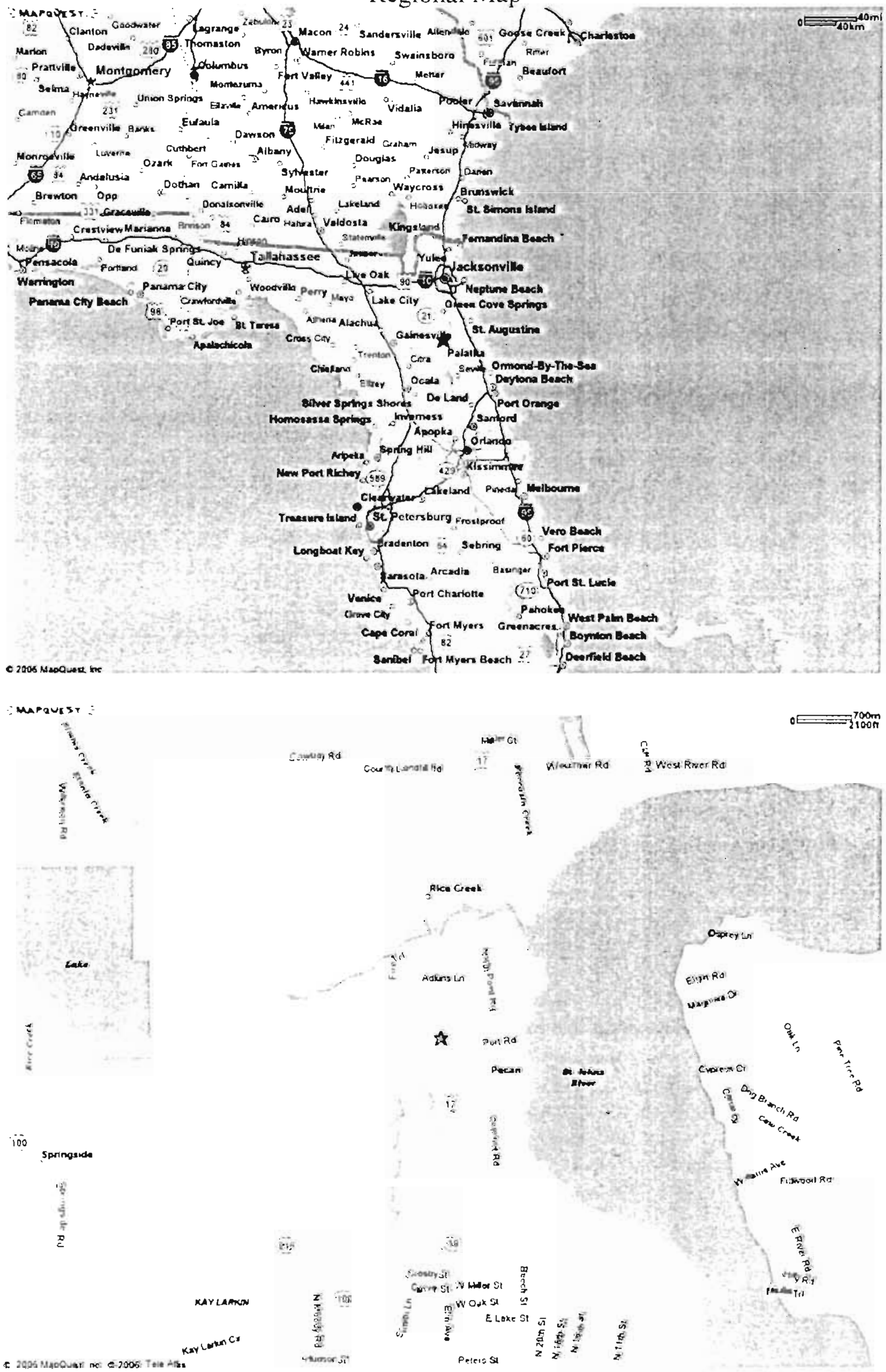
2.3 Facility Category

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. Steam Electric Generator Nos. 1 and 2 are each equipped with an electrostatic precipitator (ESP) to control particulate matter, a wet limestone flue gas desulphurization (FGD) unit to control sulfur dioxide, and low NO_X burners with low excess-air firing to control nitrogen oxides.

The emissions units are regulated under Acid Rain, Phase II and 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 "Pollution Control Upgrade" of Units 1 and 2 is considered a "minor modification" with respect to Rule 62-212.400(PSD), Prevention of Significant Deterioration, based on potential emission increases at rates less than the PSD Significant Emission Rates defined in Rule 62-210.200(243), F.A.C.

Figure TE-1
Regional Map



According to the application, emission reductions will occur in the way of federally enforceable, multi-unit emissions caps for Units 1 and 2 in order to accommodate the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR) as well as to provide for select air emission increases associated with an anticipated (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. This review does not include an evaluation of the anticipated emissions resulting from the proposed coal-fired Unit 3. A separate application has been submitted for the project and it will undergo a separate review process.

3. PROJECT DESCRIPTION

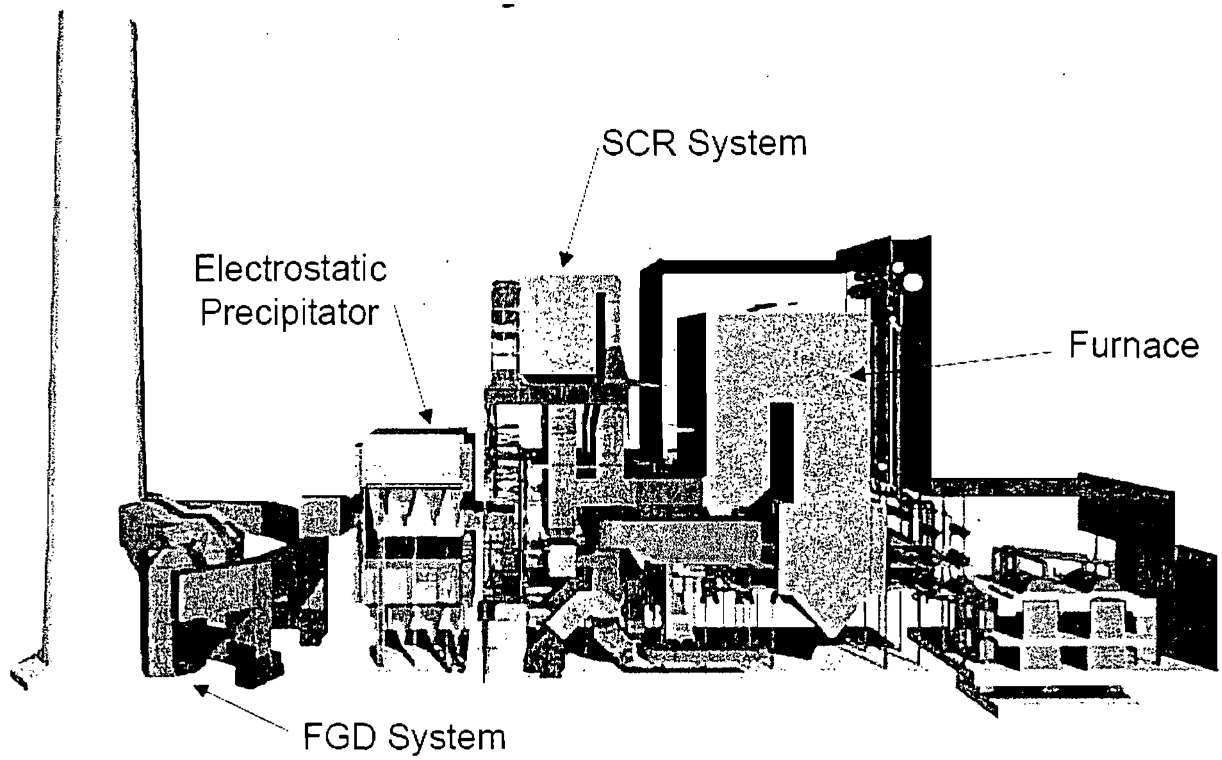
This project addresses the following emissions units:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
001	Steam Generation	SGS (Existing) Unit 1 upgraded to 735.9 MW
002	Steam Generation	SGS (Existing) Unit 2 upgraded to 735.9 MW
009	Materials Handling	Carbon Burn-Out (CBO™) Feed Fly Ash Silo (New)
010	Materials Handling	CBO™ Product Fly Ash Storage Dome (New)
011	Materials Handling	CBO™ Product Fly Ash Loadout Storage Silo (New)
012	Materials Handling	CBO™ Product Fly Ash Fugitives (New)
013	Hot Water Generation	CBO™ Process Fluidized Bed Combustor (New) NSPS Subpart Db

SGS is proposing to make the following pollution control equipment upgrades to Units 1 and 2:

1) Replace the existing low NO_X burners and modify the existing overfire air system;
2) Add selective catalytic reduction systems (SCR) for NO_X removal;
3) Add an alkali injection system to reduce SO_3 emissions and negate opacity effects that may be caused by the above SCR systems;
4) Install a carbon burnout (CBO™) unit to reburn flyash generated by SGS, minimizing on-site landfilling, recover available heat value and provide a saleable material for use in Portland cement. The CBO™ will assist in minimizing any adverse effects of the SCR systems and burner upgrades, such as elevated ammonia and carbon content within the flyash;
5) Upgrade the existing Units 1 and 2 steam turbines to increase unit efficiency, recover some of the lost electrical output from powering the above additions, and utilize the heat generated by the CBO™ process. Each boiler maximum heat input rate will remain at 7,172 MMBtu/hr.

The figure below provides a general overview of how each of the units (SGS units 1 and 2) will be configured, following the pollution control upgrades.



These upgrades will accomplish several environmental benefits, namely:

1) Comply with the new Acid Rain NO_X limitation effective in 2008;
2) Provide for the reduction of NO_X and SO_2 emissions to meet anticipated allowance allocations under CAIR, effective in 2009 and 2010;
3) Provide for the reduction of mercury emissions to meet the anticipated allowance allocations under CAMR, effective in 2010;
4) Reduce the mass of flyash waste produced; and
5) Provide for emission "offsets" such that a new electrical steam generating unit (SGS Unit 3) may be constructed with minimal net air emission impacts.

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 historical emission data has been provided by SGS as a means of establishing Baseline Actual Emission levels:

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	2001-2002	0.065	Stack testing

The table below illustrates the applicant's estimate of the "post-change" emissions as compared to the Baseline Actual Emissions. Based upon the applicant's submittals, no pollutant is expected to exceed the significant emission rate, and thus trigger a PSD/BACT review.

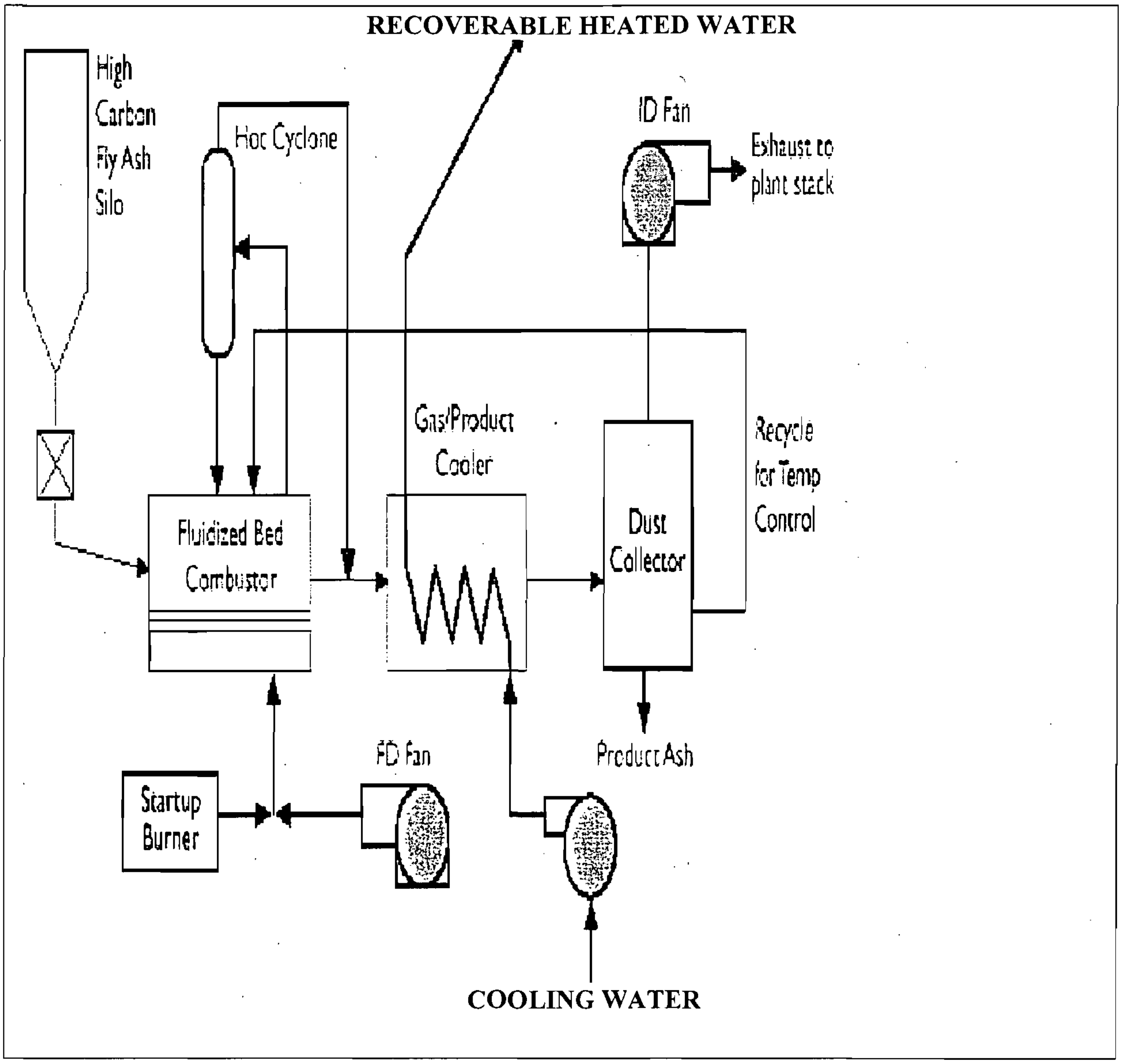
Pollutant	Baseline Actual Emissions (TPY)	Projected Actual Emissions (TPY)	Net Emissions Change (TPY)	Significant Emission Rate (TPY)	PSD Review Required?
SO_2	29074	29113	39	40	NO
NO_X	23289	21638	39	40	NO
CO	13451	13550	99	100	NO
VOC	108	147	39	40	NO
PM	822	846	24	25	NO
PM_{10}	822	836	14	15	NO
SAM	2129	2135	6	7	NO
Mercury	0.065	0.065	0	0.1	NO

3.2. Carbon Burnout Unit (CBO™)

CBO™ technology is a proprietary, patented technology whose primary function is the production of low carbon, low ammonia flyash material suitable for commercial use as a partial replacement for Portland cement. Major components of the CBO™ process planned for SGS include a feed fly ash silo, a product flyash storage dome, a fluidized bed combustor (FBC), hot cyclones for fly ash recycle to the FBC, a heat recovery heat exchanger, cold cyclones and a fabric filter bag-house for product flyash recovery, and product flyash truck loading. The CBO Unit is subject to the NSPS (Subpart Db), with limits of 0.05 lb/MMBtu (PM), 1.20 lb/MMBtu (SO_2) and 0.70 lb/MMBtu (NO_X). Since the CBO Unit flue gas will be routed through the clean-up equipment for Units 1 and 2 (with permitted emission limits less than the above NSPS limits) compliance with the NSPS may be demonstrated by compliance with the Units 1 and 2 permit limits.

A flow diagram of the CBO™ process proposed for SGS is shown below.

CBO™ SCHEMATIC



Flyash from SGS Units 1 and 2 will be conveyed pneumatically to the High Carbon (Feed Flyash) Silo, EU-009. The silo will vent through a bag-house prior to any discharge to the atmosphere. Flyash will then be fed to the Fluidized Bed Combustor (FBC), EU-013. A forced draft (FD) fan provides fluidization and combustion air to the FBC, whereas an induced draft (ID) fan maintains the FBC pressure slightly below atmospheric. No auxiliary fuel is required to operate, with the limited exception of a minimal amount of startup fuel to initiate the combustion process. The FBC exhaust gases will include combustion by-products such as NO_X, CO, SO_2, PM_{10} and VOC. The gases are routed through hot cyclones to capture the flyash, and sent to a gas/product cooler for heat recovery. The recovered heat will be exchanged to the LP Feed Water heaters on SGS Units 1 and 2. Following heat recovery, the cooled FBC exhaust gases will be routed through a cold cyclone and fabric filter bag-house (Dust Collector) for Product Flyash removal, before being returned to the inlet of SGS Units 1 and 2 pollution control equipment, namely the SCR, FGD, ESP and alkali injection systems.

Product flyash will be sent to a surge bin, with a portion of the product flyash being returned to the FBC for temperature control. From the surge bin, the product flyash is routed to a Loadout Storage Silo (EU-011) for truck transfer by off-site customers. Excess product will be stored in the Product Flyash Storage Dome, EU-010. The product flyash trucks will travel on paved roads within SGS, after which exiting the plant for delivery offsite. Fugitive particulate matter (PM/PM_{10}) emissions associated with product flyash truck traffic will be controlled by periodic watering as needed.

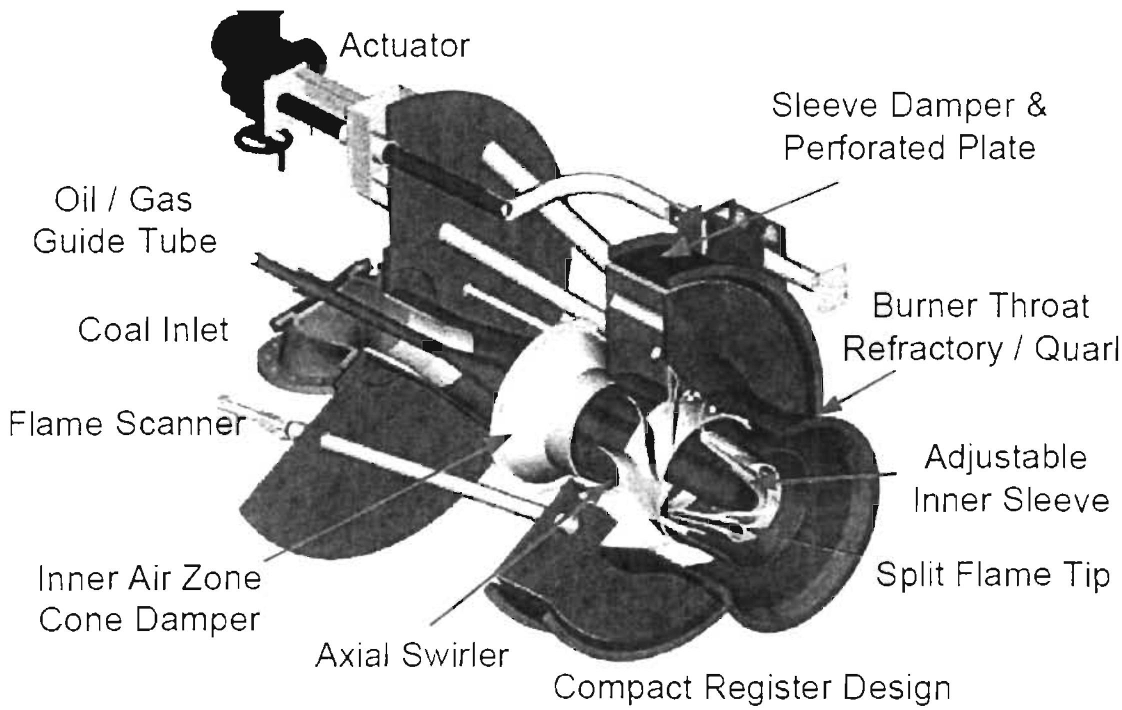
The table below represents the expected maximum emission rates from the CBO Unit (only), prior to any reductions from the Units 1 and 2 pollution control systems. Note that this table does not include the ancillary equipment emissions (i.e., baghouses) of PM/PM_{10}.

Pollutant	Emission Rate (lb/MMBtu) *	CBO™ Emission Rate (lb/hr) *	CBO™ Emission Rate to EU001 and EU002 (TPY) *	EU001 & EU002 Increases With CBO™ (TPY)
SO_2	5.20	596.3	2611.8	39
NO_X	0.782	89.7	392.9	39
CO	0.244	28.0	122.6	99
VOC	0.018	2.1	9.0	9.0
PM	0.024	2.8	12.1	6.4
PM_{10}	0.024	2.8	12.1	6.4

3.3. Low NO_X Burner (LNB) Replacement

Seminole is proposing to install new low NO_X burners with a modified overfire air (OFA) system, replacing the existing low NO_X burners, in order to meet the Acid Rain Program NO_X annual average emission limit of 0.46 lb/MMBtu, which will be effective in 2008. Additionally, the existing burner inlet systems will be modified to ensure even air flow, and the proposed OFA design will utilize at least six ports per wall compared with the existing system design of four ports per wall.

Foster Wheeler's Vortex Series/Split Flame (VS/SF) low NO_X burners are proposed as the burners of choice for SGS Units 1 and 2. The diagram below details the burner arrangement.



What follows is reprinted from a paper co-authored by Foster Wheeler and Formosa Heavy Industries (http://www.fwc.com/publications/tech_papers/powgen/pdfs/NewVortexResults.pdf):

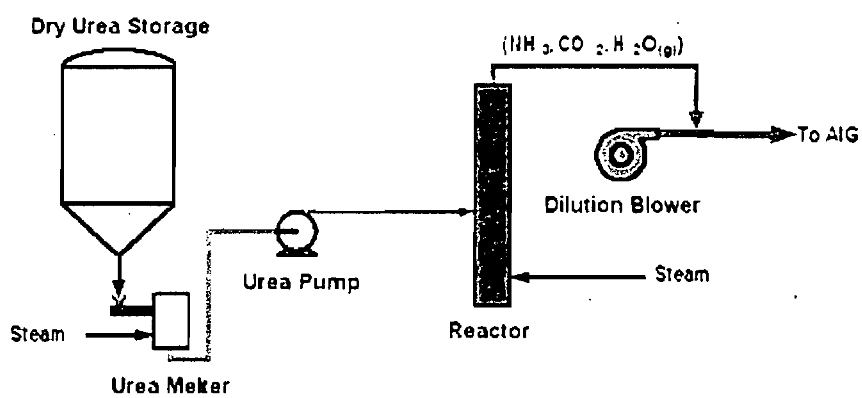
"In 1971 Foster Wheeler began development of low NO_X burners for coal fired boilers with the promulgation of New Source Performance Standards (NSPS). The first generation Controlled Flow (CF) design burner was demonstrated in 1976. Three years later the second generation Controlled Flow/Split Flame Burner (CF/SF) was commercially operational. More than two thousand burners are successfully operating domestically and worldwide. It is an extremely rugged and flexible burner design that can produce up to 60% NO_X reduction. Foster Wheeler's objective has always been to provide its clients with a high value burner design which has greater flexibility and capability. In this tradition the Vortex Series/Split Flame Low NO_X burner was developed and introduced in 1998. As its predecessors this low NO_X burner controls secondary air flow and internally stages the fuel and primary air flows such that co-axial low NO_X flames are developed within the near-burner region.

Foster Wheeler's Vortex Series Split Flame Low NOx Burner is designed to meet the environmental and operating needs of utility and industrial power producers worldwide. This unique register and Split Flame fuel injector combination minimizes conversion costs and provides exceptional performance with low maintenance. It is particularly suited for close burner spacing, providing high swirl and low NO_X flame shaping capability without high windbox pressure requirements. They can also be used in combination with overfire air to further enhance NO_X reduction potential. The register alone can be applied as an upgrade to improve air flow control of most existing burners."

3.4. Selective Catalytic Reduction (SCR) System

Seminole is proposing to install an SCR control system on each of the existing two units. The SCR will be placed at the exit of the boiler and upstream of each unit's air heater. The SCR reactor vessel will be composed of two independent reactor "trains" consistent with the unit's current design which use separate "A" and "B" flues after leaving the boiler. Upstream of the SCR system's catalyst will be an ammonia injection grid (AIG) and mixing grid to facilitate a homogeneous mixture of ammonia and flue gas.

Ammonia used in the SCRs will be provided from the plant's new urea to ammonia processing system and associated bulk storage systems. A typical urea to ammonia system is shown below:



The SCR's will be designed to achieve a NO_X emission rate of 0.07 lb/MMBtu from each unit.

3.5. Flue Gas Desulphurization (FGD) System Upgrade

Seminole is proposing to upgrade its existing FGD systems associated with Units 1 and 2, in order to improve performance and reliability. Currently, SGS is achieving approximately 87 percent removal from its FGD systems and gains another approximately four percent removal from coal washing. The proposed upgrades, as detailed below, are intended to increase SO_2 removal from approximately 87 to 95 percent.

The improvements include the following types of work: scrubber module modifications, upgrades to the modules mist eliminator wash system, expansion of the oxidation air system, modifications to the existing sparger rings in the absorber recycle tanks, upgrades to the Effluent Processing facility (EPF) System and a new gypsum conveyor system. The upgrades will allow SGS to meet the proposed 0.67 lb/MMBtu SO_2 emission limit as compared to the current limit of 1.2 lb/MMBtu. Construction for the upgrades is expected to commence in January of 2007 and to be completely operational by December 2008.

3.6. Alkali Injection System

High levels of sulfur in bituminous coals present a challenge to minimizing the formation of sulfuric acid (H_2SO_4). A small portion of SO_2 is oxidized to SO_3 in the boiler; however, due to the presence of vanadium in the SCR's catalyst, additional SO_2 oxidation occurs across an SCR. When the SO_3 combines with H_2O vapor it forms sulfuric acid, which can cause corrosion of air heaters, fabric filter components, flues and the stack. As little as 5 ppm of sulfuric acid in the stack gas can begin produce a blue plume from the stack.

Although the formation of sulfuric acid can be prevented by increasing the air heater outlet temperature, this lowers the thermal efficiency of the boiler. However, if the amount of SO_3 formed in the catalyst and the boiler is reduced it is possible to have a lower air heater outlet temperature. Reducing the amount of SO_3 can be accomplished by injecting an alkali reagent just after the SCR, at a targeted location within the flue gas stream. Final polishing of the H_2SO4 takes place downstream in the wet FGD absorber tower.

An alkali injection system will be installed on units 1 and 2 to mitigate the impacts of SO_3 formation resulting from the operation of the SCR control systems. Design criteria will ensure that sulfuric acid mist emissions do not increase above the current units 1 and 2 sulfuric acid mist emissions baseline.

3.7. CAIR/CAMR

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

The CAIR cap-and-trade model includes a formula for allocating SO_2 and NOx 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	NOx	SO2	NOx	SO2	NOx	SO2
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 emission from electric generating units. Unlike CAIR, CAMR applies only to electric generating units. Compliance with the first phase of CAMR, 2010 through 2017, is expected to be achieved in large part by the pollution control equipment required to limit emissions of NOx and SO_2 under CAIR. The second phase of CAMR begins in 2018. Compliance with Phase II requirements of CAIR and CAMR may require separate retrofit projects.

To summarize thus far, there is currently no state rule that imposes the emission reductions in CAIR and CAMR. This can only be accomplished by modifying Florida's SIP or having the FIP imposed on Florida. Therefore, the implementation strategy that will be adopted in Florida is uncertain at this time as are specific emission limits for specific electric generating units. However, SGS Units 1 and 2 are listed by FDEP as sources which will be subject to CAIR and CAMR, and the information below is presented as current based upon this issuance date:

Implementation of Clean Air Interstate Rule (CAIR)
Affected FAC Chapters 62-4 (06-0191), 62-204 (06-0327), 62-210 (06-0193), 62-213 (06-0196), & 62-296 (06-0195)
Proposed SIP Revision
Mar. 17: Notices of rule development published
Apr. 13: Rulemaking workshop - Tallahassee

Implementation of Clean Air Mercury Rule (CAMR)
Affected FAC Chapters 62-204 (06-0328), 62-210 (06-0197) & 62-296 (06-0198)
Proposed 111(d) State Plan Revision
Mar. 17: Notices of rule development published
Apr. 13: Rulemaking workshop - Tallahassee

Seminole asserts that the changes identified herein will allow for SGS units 1 and 2 to meet the proposed CAIR.

4. RULE APPLICABILITY

The SGS Pollution Control upgrades are 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, 62-214, 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. Although no PSD review is required, previous air modeling analyses have shown that SGS, when emitting at its allowable limit for sulfur dioxide (SO_2), may cause predicted violations of the PSD Class II and Class I increments for the 3-hour and 24-hour averaging times. Accordingly, modeling analyses were conducted to address compliance of the project with the AAQS for SO_2. The analyses demonstrate that the SO_2 impacts for SGS at the proposed emission rate, together with other sources, will comply with the AAQS, PSD Class II increments, and (generally) the PSD Class I increments. Section 6 of this evaluation addresses this in more detail.

A determination of Maximum Achievable Control Technology (MACT) 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
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 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)

5.0 DEPARTMENT REVIEW

The Department accepts the SGS proposal, as no air emission increases above the PSD thresholds are being sought. However, since a separate application has been received for the construction and operation of a new coal-fired steam generating unit at the facility, and since "netting" has been requested by the applicant, the construction permit for the changes to Units 1 and 2 will include a phasing of "permanent" emission limits associated with the construction of the new unit.

Additionally, with respect to the proposed CAIR/CAMR emission requirements, the Department is aware that plants equipped with SCRs and scrubbers achieve a co-benefit of high (70 to 90%)

mercury reductions when burning bituminous coal. The below table summarizes this information for Units 1 and 2:

Pollutant	Short-Term Emission Rate	Combined Annual Emissions TPY
SO_2	0.067 lb/MMBtu combined 24-hour block	29,074
NO_X	0.46 lb/MMBtu 30-day rolling	23,289
CO	0.20 lb/MMBtu 12-month rolling	13,451
VOC	0.06 lb/ton coal initial stack test	108
PM	0.03 lb/MMBtu annual stack test	822
PM_{10}	0.03 lb/MMBtu annual stack test	822
SAM	0.096 lb/MMBtu initial stack test	2,129
Mercury	0.94 lb/TBtu annual stack test	0.065

6. SOURCE IMPACT ANALYSIS

6.1 Air Quality Modeling Results

The proposed project will not increase any pollutant emissions at levels in excess of PSD significant amounts. However, when the application for this project was first submitted, CO was proposed to be emitted at levels in excess of PSD significant amounts; therefore, a CO air quality analysis to determine maximum impacts in the PSD Class II area in the vicinity of the project was performed. No PSD Class I analysis is required for CO, since there are no PSD increments for CO. A preliminary modeling analysis for the project only, which shows an insignificant impact for a PSD significant pollutant, is accepted as the required air quality analysis (AAQS and any applicable PSD increments) for that pollutant and no further modeling for comparison to the AAQS and PSD increments is required for that pollutant. The maximum predicted impacts of the project are shown in the table below. This analysis showed that predicted maximum CO impacts were well below the modeling significant impact levels. These model results were based on a CO emission rate of 0.15 lb/MMBtu, but the Draft permit allows 0.20 lbs/MMBtu. Even at the higher rate, the modeling results demonstrate that the impact of this increase will still be well below the significant impact levels for CO.

MAXIMUM PREDICTED PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS IN THE VICINITY OF THE FACILITY				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Significant Impact Level ($\mu g/m^3$)**	**Significant Impact?**
CO	8-hr	0.6	500	NO
	1-hr	1.0	2,000	NO

In addition, previous air modeling analyses for other projects have shown that SGS, when emitting at its allowable limit for sulfur dioxide (SO_2), caused predicted violations of the PSD Class II and Class I increments for the 3-hour and 24-hour averaging times. For this project, SGS proposed reducing the emission limits for Units 1 and 2 to 0.67 lb/MMBtu, 24-hour average, (9610 lbs/hr, 24-hour average, for Units 1 and 2 combined). These limits were based on results of air modeling analyses performed to ensure that the maximum SO_2 concentrations from SGS alone would not exceed the allowable PSD Class I increments in the Okefenokee and Chassahowitzka National Wilderness (NWA) areas, the two PSD Class I areas closest to SGS. The applicant is proposing to reduce Units 1 and 2 SO_2 emissions further based on information contained in the recent submission of their Unit 3 application (6647 lbs/hr, 24-hour average for Units 1, 2 and 3 combined). These reductions, as proposed in that application, would ensure that the maximum concentrations from SGS sources, along with all other increment affecting sources, in the vicinity of the Okefenokee NWA would not be exceeded. 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. Therefore, this project will improve overall air quality in this area. In addition, the results of SO_2 AAQS and Class II PSD increment modeling, based on the 0.67 lb/MMBtu limits for Units 1 and 2, are shown in the tables below. The results show that the SO_2 impacts for SGS, together with other sources, will comply with the AAQS and PSD Class II increments. For the AAQS analysis a background SO_2 concentration based on data collected from an existing SO_2 monitor in Palatka was used to represent the concentrations due to sources other than those specifically included in the modeling analysis.

MAXIMUM PREDICTED AMBIENT AIR QUALITY IMPACTS (AAQS)						
Pollutant	**Averaging Time**	**Modeled Sources ($\mu g/m^3$)**	**Background Concentration ($\mu g/m^3$)**	**Total Impact ($\mu g/m^3$)**	**Total Impact Greater than AAQS**	**AAQS ($\mu g/m^3$)**
SO_2	Annual	24	5	29	No	60
	24-hour	156	37	193	No	260
	3-hour	233	110	343	No	1300

PSD CLASS II INCREMENT ANALYSIS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Impact Greater than Allowable Increment?**	**Allowable Increment ($\mu g/m^3$)**
SO_2	Annual	11	No	20
	24-hour	85	No	91
	3-hour	233	No	512

6.2 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.

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 and Waycross, Georgia, respectively (surface and upper air data). The 5-year period of meteorological data was from 1986 through 1990 and is considered to be representative of the general meteorology in the area. 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 occurring 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.

6.3 PSD Class I Area Model

Since the closest PSD Class I areas, the Okefenokee National Wilderness Area (NWA) and the Chassahowitzka 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), namely regional haze, nitrogen deposition 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. Meteorological data were obtained and processed for the calendar years of 1990, 1992 and 1996, the years for which MM4 and MM5 data are available. The three years of data are considered to be representative of the meteorology of the area. The CALMET wind field and the CALPUFF model options used were consistent with the suggestions of the federal land managers.

7. 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

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft Air Permit No. 1070025-004-AC

Seminole Electric Cooperative
Seminole Generating Station
Units 1 and 2 Pollution Control Upgrades

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to Seminole Electric Cooperative, Inc. to upgrade the pollution controls for Units 1 and 2. The upgrades include replacing the existing Low NO_X burners and modifying the existing Over-Fire Air System, upgrading the existing Flue Gas Desulphurization System, and adding Selective Catalytic Reduction Systems, Alkali Injection Systems and a Carbon Burnout Unit™. The new equipment will be installed at the existing Seminole Generating Station, which is located at 890 North U.S. Highway 17, north of Palatka, in Putnam County, Florida. The applicant's authorized representative is James R. Frauen, Manager of Environmental Affairs. The applicant's mailing address is SECI, 16313 North Dale Mabry Highway, Tampa, FL 33618.

The project is being proposed so as to comply with proposed Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) as well as to create selected air emission reductions in order to prepare for the potential installation of a new steam generating unit. In accordance with the specific conditions, the draft permit authorizes the construction and installation of these pollution controls. Actual emissions of all regulated air pollutants are expected to remain the same or decrease.

The Department will issue the Final Permit with the attached conditions unless a response received in accordance with the following procedure results in a different decision or significant change of terms or conditions. The Department will accept written comments concerning the proposed permit issuance action for a period of fourteen (14) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

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

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action 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 Department'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 Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
(111 S. Magnolia Drive, Suite 4)
2600 Blair Stone Road, MS #5505
Tallahassee, Florida, 32399-2400
Telephone: 850/488-0114

Department of Environmental Protection
Northeast District Office
Air Resources Section
7825 Baymeadows Way, Suite B200
Jacksonville, Florida 32256-7577
904-807-3371

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Department's reviewing engineer for this project for additional information at the address and phone numbers listed above or the following website: http://www.dep.state.fl.us/Air/permitting/construction.htm

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

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

G.14 The permittee shall comply with the following:

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

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

c) Records of monitoring information shall include:

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

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

P.E. Certification Statement

Seminole Electric Cooperative, Inc.
Seminole Generating Station
Putnam County

DEP File No.: 1070025-004-AC
Facility ID No.: 1070025

Project: Air Construction Permit

I HEREBY CERTIFY that the engineering features described in the above referenced application and related additional information submittals, if any, and subject to the proposed permit conditions, provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).

(Seal)

Michael P. Halpin, P.E.
Registration Number: 31970

5-1-06
Date

Permitting Authority:
Florida Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
North Permitting Section
Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-0114
Fax: 850/922-6979

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

1. Article Addressed to:

Mr. Jim Frauen
Seminole Electric Cooperative, Inc.
Payne Creek Generating Station
16313 North Dale Mabry Highway
Tampa, Florida 33618

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number
(Transfer from service label) 7000 1670 0013 3110 0208

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7000 1670 0013 3110 0208

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	

Postmark Here

Mr. Jim Frauen
Seminole Electric Cooperative, Inc.
Payne Creek Generating Station
16313 North Dale Mabry Highway
Tampa, Florida 33618

PS Form 3800, May 2000 See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Jim Frauen
Seminole Electric Cooperative, Inc.
Payne Creek Generating Station
16313 North Dale Mabry Highway
Tampa, Florida 33618

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) T. BUNYAN

C. Date of Delivery 5/5/06

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (*Extra Fee*) ☐ Yes

2. Article Number
(*Transfer from service label*) 7000 1670 0013 3110 0208

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

OFFICIAL USE

7000 1670 0013 3110 0208

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	

Postmark
Here

Mr. Jim Frauen
Seminole Electric Cooperative, Inc.
Payne Creek Generating Station
16313 North Dale Mabry Highway
Tampa, Florida 33618

PS Form 3800, May 2000 See Reverse for Instructions

Jeb Bush
Governor

Department of Environmental Protection

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

Colleen M. Castille
Secretary

February 24, 2006

CERTIFIED MAIL – RETURN RECEIPT REQUESTED

Mr. James Frauen
Manager, Environmental Affairs
Seminole Electric Cooperative, Inc.
P.O. Box 272000
Tampa, Florida 33688-2000

RE: Seminole Electric Cooperative, Inc.
Seminole Generating Station Units 1 and 2
1070025-004-AC, PSD-FL-372

Dear Mr. Frauen:

The Bureau of Air Regulation received the above referenced application for processing on February 13, 2006. Included with the application was check no. 192302 for $7,500 to cover the permit processing fee. Since a $10,000 fee was submitted to the DEP Power Plant Siting Office to process this request, no additional fee is required for the PSD permit and your check is being returned with this letter. Please call me at 850/921-9505 if you have any questions.

Sincerely,

Patty Adams

Patty Adams
Bureau of Air Regulation

/pa
Enclosure
cc: M. Halpin

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. James Frauen
Manager, Environmental Affairs
Seminole Electric Cooperative, Inc.
P.O. Box 272000
Tampa, Florida 33688-2000

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Katie Cramer
☒ Agent
☐ Addressee

B. Received by (Printed Name)
K Cramer

C. Date of Delivery

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

FEB 28 2006

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7005 1160 0004 3034 3267

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

7005 1160 0004 3034 3267

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Mr. James Frauen, Manager, Environ. Affairs

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

Sent To
Mr. James Frauen, Manager, Environ. Affairs
Street, Apt. No.; or PO Box No. P. O. Box 272000
City, State, ZIP+4
Tampa, Flroida 33688-2000

PS Form 3800, June 2002 See Reverse for Instructions

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

March 1, 2006

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. James R. Frauen, Manager of Environmental Affairs
Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, FL 33618

Re: Request for Additional Information
Pollution Controls Upgrade Project
Seminole Generating Station, Units 1 and 2
DEP File 1070025-004-AC

Dear Mr. Frauen:

The Department is in receipt of your application dated February 13th which details several pollution control upgrades planned for Units 1 and 2. In order to continue processing the application, we will need the additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. The Department notes that on Table B-4 entitled "PSD Netting Analysis", one PSD pollutant (CO) is expected to cause a BACT Review and every other PSD pollutant shows an increase. Please address the following issues relative to Table B-4:

   A. It is unclear which part of the project is responsible for the increase in CO emissions. Please provide specific information on where this increase originates. For example, if the applicant has deemed that the replacement burners will generate the additional CO, the Department will require support for this increase in the way of supplying detailed manufacturer burner specifications for the new as well as existing burners. Upon receipt of such information, the Department will be better positioned to evaluate whether the selected burners meet the Department's BACT Standard for CO emissions.

   B. Contemporaneous Emission Changes are defined in Rule 62-212.500(1)(e)3 as follows:

      3. Contemporaneous Emissions Changes. An increase or decrease in the actual emissions, or in the quantifiable fugitive emissions, of a facility is contemporaneous with a particular modification if it occurs within the period beginning five years prior to the date on which the owner or operator of the facility submits a complete application for a permit to modify the facility, and ending on the date on which the owner or operator of the modified facility projects the new or modified facility to begin operation.

      Also, 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 Department notes that based upon the above definitions, the Baseline Actual Emissions which are allowable for forming the basis of a netting analysis, cannot precede February 13, 2001; however, emissions for calendar year 2000 have been included within your application. The Department requests that the applicant indicate which 24-month period(s) following January 2001 is to be utilized for the baseline emission calculations of this project.

C. The following tables compare Departmental AOR records (TPY) of Unit 1 plus Unit 2 emissions to your TPY submittals:

	2001		2002		2003		2004		2005	
Pollutant	Dept.	SECI	Dept.	SECI	Dept.	SECI	Dept.	SECI	Dept.	SECI
SO2	29832	29832	24090	24090	27360	27360	26704	26704	???	31444
NOx	20621	24408	18614	22170	22204	21560	19122	19967	???	23230
CO	2098	2609	2125	2592	3978	5400	2482	4552	???	5375
VOC	108	108	99	99	115	116	96	96	???	96
PM	431	498	664	721	1128	922	660	598	???	685
PM_{10}	431	498	664	721	1128	922	660	598	???	685

	2001 Plus 2002 Avg.		2002 Plus 2003 Avg.		2003 Plus 2004 Avg.		2004 Plus 2005 Avg.	
Pollutant	Dept.	SECI	Dept.	SECI	Dept.	SECI	Dept.	SECI
SO2	26961	26961	25725	25725	27032	27032	???	26704
NOx	19618	23289	20409	21865	20663	20764	???	19967
CO	2111	2600	3052	3996	3230	4976	???	4552
VOC	104	104	107	108	105	106	???	96
PM	548	610	896	822	894	760	???	598
PM_{10}	548	610	896	822	894	760	???	598

In summary, after SECI has selected the baseline period(s) from the table above, any TPY values which are shaded, represent areas where the applicant is required to provide further supporting data for the higher than AOR values. If stack test data is utilized (e.g. CO, PM or H_2SO_4), the Department requires that certified summaries of all stack tests conducted during the subject calendar years be submitted; where AP-42 emission factors are utilized, the Department requires calculations along with the supporting data (i.e. annual heat input by fuel type, etc). Where CEMS data is utilized, the Department requires that the applicant provide supporting documentation from EPA's Acid Rain database demonstrating that the data matches. For the year 2005, the DARM/BAR is not in receipt of a copy of the AOR; hence no comparison can be made. Should SECI determine that 2004/2005 represents the baseline period, supporting data shall be required for all 2005 TPY emission data.

2. Please confirm the Department's understanding of the permit limits you are seeking for Units 1 & 2. The Department notes that in order to "carve out" emission reductions so as to make room for Unit 3, federally enforceable permit limits will need to be established for those pollutants where netting is desired.

Pollutant	Current Limit	Proposed Limit
SO2	1.20 lb/MMBtu – 30 day rolling	0.67 lb/MMBtu – 30 day rolling
NOx	0.60 lb/MMBtu - 30 day rolling	0.46 lb/MMBtu - 30 day rolling
PM/PM10	0.03 lb/MMBtu stack test	same
CO	NA	0.146 lb/MMBtu
VOC	NA	0.06 lb/ton coal
SAM	NA	0.096 lb/MMBtu

Please note that EPA and NPS have been copied on your application, and should FDEP receive questions or comments from them, we will forward you a copy.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): "The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department.......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."

If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9519.

Sincerely,

Michael P. Halpin, P.E.
FDEP/DARM
North Permitting Section

Hamilton Oven, DEP-SCO
Chris Kirts, DEP-NED
Scott Osbourn, Golder
PSRC c/o Pillsbury Winthrop Shaw Pittman, LLP

Mr. Jim Frauen
Seminole Electric Cooperative, Inc.
Payne Creek Generating Station
16313 North Dale Mabry Highway
Tampa, Florida 33618

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Articl
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PS Form

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Mr. Jim Frauen
Seminole Electric Cooperative, Inc.
Payne Creek Generating Station
16313 North Dale Mabry Highway
Tampa, Florida 33618

PS Form 3800, May 2000 See Reverse for Instructions

Golder Associates Inc.

5100 West Lemon Street, Suite 114
Tampa, FL USA 33609
Telephone (813) 287-1717
Fax (813) 287-1716
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FEB 13 2006

BUREAU OF AIR REGULATION

February 13, 2006

Mr. Jeff Koerner
DEP/DARM
North Permitting Section
Division of Air Resource Management
2600 Blair Stone Road MS 5500
Tallahassee, Florida 32399-2400

**RE: SEMINOLE ELECTRIC COOPERATIVE, INC (SECI)
SEMINOLE GENERATING STATION, UNITS 1 AND 2
PSD PERMIT APPLICATION**

Dear Mr. Koerner:

This application proposes numerous environmentally-beneficial upgrades to Seminole Electric Cooperative, Inc. (Seminole) Units 1 and 2, located on U.S. Highway 17 approximately five miles north of the City of Palatka in Putnam County, Florida. Specifically, Seminole proposes to further improve the environmental performance of the existing units by installing new/upgraded air emission control devices, efficiency upgrades to the steam turbines and a new fly ash beneficiation system.

Enclosed are the original and three copies of the application package. We have also enclosed a check in the amount of $7,500.00 to cover the application fee and would very much appreciate your expedited processing of the application, as discussed during our pre-application meeting of February 9, 2006.

Thank you for your help in this matter. Please contact me at (813) 287-1717 if you have any questions.

Sincerely,

Scott Osbourn, P.E.
Senior Consultant

cc: Messrs. Mike Opalinski and Jim Frauen, SECI
Messrs. Jim Alves and Robert Manning, HG&S

H:\PROJECTS\2005proj\053-9540 SECI Palatka Licensing\Correspondence\DEP Transmittal Letterrev.doc

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

February 17, 2006

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
P. O. Box 25287
Denver, Colorado 80225

RE: Seminole Electric Cooperative, Inc.
Seminole Generating Station Units 1 and 2
1070025-004-AC, PSD-FL-372

Dear Mr. Bunyak:

Enclosed for your review and comment is a PSD application submitted by Seminole Electric Cooperative, Inc. to authorize upgrades for Units 1 and 2 at the Seminole Generating Station in Putnam County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/921-9533. If you have any questions, please contact Mike Halpin, review engineer, at 850/921-9519 or 850/245-8993.

Sincerely,

Patty Adams

for Jeffery F. Koerner, P.E., Administrator
North Permitting Section

JFK/pa

Enclosure

cc: M. Halpin

From: DEP AIR RESOURCE MGMT
P. Adams
DIRECTOR OFFICE STE 23
111 S MAGNOLIA DR
TALLAHASSEE, FL 32301
UNITED STATES Tel:850-921-9505

EXP

Parcels: 1/1

ORIGIN: TLH

Sender's ref 37550201000 A7 AP255

To: National Park Service
Mr. John Bunyak
12795 W. Alameda Parkway
Air Division
Lakewood, CO 80228
UNITED STATES

Tel: 303-966-2818

POSTCODE: 80228

Description: PSD-FL-372 application

Weight: 5 lbs for 1 pcs
Date: 2006-02-17

DHL standard terms and conditions apply.

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(2L)US80228

WAYBILL: 29976502555 (Non-Negotiable)

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To(Company):
National Park Service
Air Division
12795 W. Alameda Parkway

Lakewood, CO 80228
UNITED STATES

Attention To: Mr. John Bunyak
Phone#: 303-966-2818

Sent By: P. Adams
Phone#: 850-921-9505

Rate Estimate: 29.37
Protection: Not Required
Description: PSD-FL-372 application

Weight (lbs.): 5
Dimensions: 0 x 0 x 0

Ship Ref: 37550201000 A7 AP255
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P. Adams
DIRECTOR OFFICE STE 23
111 S MAGNOLIA DR
TALLAHASSEE, FL 32301
UNITED STATES Tel:850-921-9505

ORIGIN: TLH

Sender's ref
37550201000 A7 AP255

To: U.S. EPA Region 4
Mr. Gregg M. Worley
61 Forsyth Street
Air Permits Section
Atlanta, GA 30303
UNITED STATES

POSTCODE:
30303

Tel: 404-562-9141

Description: PSD-FL-372 application

Weight: 5 lbs for 1 pcs
Date: 2006-02-17

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(2L)US30303

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To(Company):
U.S. EPA Region 4
Air Permits Section
61 Forsyth Street

Atlanta, GA 30303
UNITED STATES

Attention To: Mr. Gregg M. Worley
Phone#: 404-562-9141

Sent By: P. Adams
Phone#: 850-921-9505

Rate Estimate: 17.63
Protection: Not Required
Description: PSD-FL-372 application

Weight (lbs.): 5
Dimensions: 0 x 0 x 0

Ship Ref: 37550201000 A7 AP255
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From DEP AIR RESOURCE MGMT
P. Adams
DIRECTOR OFFICE STE 23
111 S MAGNOLIA DR
TALLAHASSEE, FL 32301
UNITED STATES Tel:850-921-9505

ORIGIN: TLH

Sender's ref
37550201000 A7 AP255

To: DEP Northeast District Office
Mr. Chris Kirts
7825 Baymeadows Way
Air Section, Suite 200B
Jacksonville, FL 32256
UNITED STATES

POSTCODE:
32256

Tel: 904-807-3235

Description: PSD-FL-372 Application

Weight: 5 lbs for 1 pcs
Date: 2006-02-17

DHL standard terms and conditions apply.

ASHX 7D
FSC

(2L)US32256

WAYBILL: 29976630655 (Non-Negotiable)

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SENDER'S RECEIPT
Waybill #: 29976630655

To(Company):
DEP Northeast District Office
Air Section, Suite 200B
7825 Baymeadows Way

Jacksonville, FL 32256
UNITED STATES

Attention To: Mr. Chris Kirts
Phone#: 904-807-3235

Sent By: P. Adams
Phone#: 850-921-9505

Rate Estimate: 14.59
Protection: Not Required
Description: PSD-FL-372 Application

Weight (lbs.): 5
Dimensions: 0 x 0 x 0

Ship Ref: 37550201000 A7 AP255
Service Level: Next Day 12:00 (Next business day by 12 PM)

Special Svc:

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Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

February 13, 2006

Mr. Hamilton S. Oven
Siting Coordination Office
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 48
Tallahassee, FL 32399-2400

Re: Seminole Electric Cooperative, Inc.
Power Plant Certification No. PA78-10
Units 1 and 2 Pollution Control Upgrade Projects
Request for Modification of Certification
Seminole Generating Station
Putnam County, Florida

Dear Mr. Oven:

Pursuant to Section 403.516(1)(b), Florida Statutes and Rule 62-17.211, Florida Administrative Code, please accept this letter and Attachment A hereto as Seminole Electric Cooperative's (Seminole's) Request for Modification of Site Certification for the Seminole Generating Station in Putnam County. As explained in more detail in Attachment A, Seminole requests that the Department of Environmental Protection (DEP) issue a proposed order modifying the conditions of certification, as authorized by the cited statute and regulation, to install significant pollution control upgrades associated with existing Units 1 and 2.

By way of background, Seminole Generating Station Units 1 and 2 originally were certified under the Power Plant Siting Act (PPSA) by the Governor and Cabinet, sitting as the Siting Board, in 1979. Both units were in commercial operation by the end of 1984. The air emission limitations originally applicable to Units 1 and 2 were based on a Best Available Control Technology (BACT) demonstration pursuant to the federal Clean Air Act Prevention of Significant Deterioration (PSD) program, and also Subpart Da of the federal New Source Performance Standards. Seminole has continued to undertake environmental improvements since the original certification. As just one example, in 2000, at Seminole's request, the Conditions of Certification were modified to authorize Seminole to install an oxidation system that converts the output from the Flue Gas Desulfurization (FGD) air pollution control system to gypsum reused for wallboard manufacturing, thereby eliminating the disposal of hundreds of thousands of tons per year of solid waste.

16313 North Dale Mabry Highway P.O. Box 272000 Tampa, Florida 33688-2000
Telephone 813.963.0994 Fax 813.264.7906 www.seminole-electric.com

The inter-related pollution control upgrades proposed in this Request for Modification include the following:

- Installation of low NOx burners and modified overfire air systems on Units 1 and 2, in order to comply with the annual average emission limitation of 0.46 lb/mmBtu that will become applicable in 2008 pursuant to Title IV of the federal Clean Air Act and corresponding state regulations.

- Installation of a state-of-the-art, urea-based selective catalytic reduction (SCR) control system on both units. This will include new urea unloading systems, a urea storage area, and facilities to convert the urea to ammonia for injection into the SCRs. The proposed SCR systems are being designed to be capable of achieving substantial NOx reductions (to 0.07 lb/mmBtu) so that Seminole will have the option of meeting its projected NOx allocations under Phases I and II of the federal Clean Air Interstate Rule through actual emission reductions instead of purchasing allowances. (For example, the SCR technology would make it possible for Seminole to reduce current NOx emissions by approximately 13,000 tons per year to meet its anticipated Phase I allocations.) Reductions associated with the SCR systems also will make it possible to offset NOx air emission increases that would be associated with a new proposed Unit 3 at the Seminole Generating Station.[1]

- Upgrades to the FGD systems for Units 1 and 2 are being proposed so that Seminole will have the capacity to achieve up to 95% post-combustion SO_2 removal efficiency. Related appurtenances will include expansion of the air compressor building, the addition of an air compressor, additional FGD dewatering appurtenances, and additional gypsum conveyance capability. With the improvements to the FGD system, Seminole would have the option of meeting its projected Phase I (in 2010) and Phase II (in 2015) Clean Air Interstate Rule SO_2 allocations through emission reductions instead of purchasing allowances. (For example, with the FGD upgrades Seminole could achieve SO_2 reductions of approximately 10,000 tons per year to meet Phase I requirements.) Once again, this new air pollution control technology will be relied on to offset SO_2 air emission increases associated with Unit 3.

- An alkali injection air pollution control system is proposed for each unit to control for potential SO_3 formation by the SCR systems. The alkali injection technology will be designed to ensure that the installation and operation of the SCR systems do not result in an increase in sulfuric acid mist emissions.

---

[1] Unit 3 will be the subject of a separate Request for Modification and air permit application. Seminole seeks to install several air pollution control upgrades in advance of Unit 3 certification and construction in order to assure that it will be prepared to meet the requirements of the Clean Air Interstate Rule through emission reductions.

- A carbon burnout (CBO) system is proposed to produce a final fly ash product that will have substantially lower carbon and ammonia levels and therefore will be suitable for beneficial reuse. The CBO system also will recover energy from the high-carbon fly ash from Units 1 and 2 (this will improve the heat rate of Units 1 and 2). The CBO system also will offset the adverse effects that the new NOx control systems otherwise would have on fly ash reuse. The CBO system will minimize the need to landfill solid waste. The CBO system will include a bulk storage facility, silos, loading and conveyance systems, and a small truck rinse station.

- The steam turbines associated with Units 1 and 2 are proposed to undergo blade efficiency improvements that will be designed to obtain greater electric generating output per unit of fuel burned and also accommodate the CBO unit. The current nominal gross MW rating would increase from 714.6 MW to 735.9 MW per unit. These changes will compensate for the energy penalties associated with the pollution control upgrades.

- This project also includes a proposed warehouse expansion, the addition of two new auxiliary transformers and related appurtenances, an parking lot and employee car rinse area.

- Seminole also proposes the installation of wet detention stormwater management and control systems to comply with the requirements of Chapter 40C-42, F.A.C. and the St. Johns River Applicant's Handbook with respect to stormwater management and control. As explained more fully in the attached materials, the stormwater system will be designed such that it will have the capacity to accommodate stormwater associated with the appurtenances proposed in this submittal, and the projected stormwater impacts associated with Unit 3.

The pollution upgrade package will not require additional groundwater usage that is greater than the existing consumptive use limitations in the SGS Conditions of Certification.

In accordance with DEP's regulations, we have forwarded copies of this Request for Modification of Certification to those parties in the original certification proceedings and to the persons and agencies identified below.

We have enclosed an original and four copies of the Request for Modification of Certification along with an application fee in the amount of $10,000 payable to DEP.

Sincerely,

James R Frauen

James Frauen
Manager, Environmental Affairs

Enclosures

cc: (by certified mail)
James Alves, Esq.
Hopping Green & Sams
Post Office Box 32314

Craig Varn, Assistant General Counsel
Department of Community Affairs
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2100

Sheauching Yu, Assistant General Counsel
Department of Transportation
Haydon Burns Bldg., M.S. 58
605 Suwannee Street
Tallahassee, FL 32399-0450

Mary Ann Helton
Division of Legal Services
Florida Public Service Commission
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Tallahassee, FL 32399-0850

James V. Antista, General Counsel
Fish & Wildlife Conservation Commission
Bryant Building
620 South Meridian Street
Tallahassee, FL 32399-1600

Mr. Wayne Smith, Chairman
Board of County Commissioners
Union County
15 Northeast First Street
Lake Butler, FL 32054

Mr. Patrick Gilligan
City of Ocala
Seven East Silver Springs Blvd.
Suite 405
Ocala, FL 34471

Mr. Charles Justice
Executive Director
N. Central Florida Regional Planning Council
2009 Northwest 67th Place
Suite A
Gainesville, FL 32653-1603

Mr. Kirby B. Green, III
Executive Director
St. Johns River Water Management District
Post Office Box 1429
Palatka, FL 32178

Mr. Ronald Williams, Chairman
Board of County Commissioners
Columbia County Courthouse
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Lake City, FL 32056
Mark Scruby
Clay County Attorney
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Green Cove Springs, FL 32043

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Board of County Commissioners
Putnam County
Post Office Box 758
Palatka, FL 32178

Mr. Gordon B. Johnston
Marion County Attorney
601 Southeast 25th Avenue
Ocala, FL 34471

Lynne C. Capehart, Esq.
1601 Northwest 35th Way
Gainesville, FL 32605

Golder Associates Inc.

3730 Chamblee Tucker Road
Atlanta, GA USA 30341
Telephone (770) 496-1893
Fax (770) 934-9476

Golder Associates

AIR CONSTRUCTION PERMIT
SEMINOLE GENERATING STATION
UNITS 1 AND 2

RECEIVED
FEB 13 2006
BUREAU OF AIR REGULATION

Submitted to:

Florida Department of Environmental Protection

Submitted on behalf of:

Seminole Electric Cooperative
16313 North Dale Mabry Highway
Tampa, Florida 33688

Submitted by:

Golder Associates Inc.
5100 West Lemon Street
Suite 114
Tampa, Florida 33609

Distribution:

4 Copies	-	Florida Department of Environmental Protection
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1 Copy		Hopping Green & Sams
1 Copy	-	Golder Associates Inc.

February 2006 053-9540

TABLE OF CONTENTS

LIST OF APPENDICES

1.0 INTRODUCTION

This application proposes numerous environmentally-beneficial upgrades to Seminole Electric Cooperative, Inc. (Seminole) Units 1 and 2, located on U.S. Highway 17 approximately five miles north of the City of Palatka in Putnam County, Florida. Seminole currently operates two solid fuel-fired steam boilers (Emission Units ID Nos. 001 and 002) at the Seminole Generating Station (SGS), and proposes to further improve the environmental performance of the existing units by installing new/upgraded air emission control devices, efficiency upgrades to the steam turbines, a new fly ash beneficiation system and new storm water treatment facilities. In addition to the two solid fuel-fired boilers, SGS emission sources include solid fuel (coal and petroleum coke), limestone, and flue gas desulfurization (FGD) sludge handling and storage activities.

Units 1 and 2 were permitted under the Prevention of Significant Deterioration (PSD) program and the Power Plant Siting Act (PPSA) in 1979, and installed the Best Available Control Technology, including a Flue Gas Desulfurization (FGD or scrubber) system and an electrostatic precipitator (ESP). These units are also subject to New Source Performance Standards (40 CFR Part 60, Subpart Da). Seminole is now proposing to add new emission control technologies, as well as upgrade existing control equipment, as follows:

- Replace the existing low-NO_X burners and modify the existing overfire air system;
- Add selective catalytic reduction (SCR) systems for nitrogen oxide (NO_X) removal;,
- Upgrade the existing FGD system for improved sulfur dioxide (SO_2) control;
- Add an alkali injection system to reduce SO_3 emissions and negate opacity effects that are expected to be caused by the new SCR systems,
- Install a carbon burn out (CBO) unit to reburn fly ash generated by SGS, minimizing the onsite landfilling of this fly ash, recovering its available heating value, and providing a partial replacement to Portland cement. The CBO will also assist in minimizing adverse effects of the SCR systems and burner upgrades, such as elevated ammonia and carbon content in the fly ash, and
- Upgrade the existing Units 1 and 2 steam turbines to increase the efficient use of the existing steam, as well as utilize the heat generated by the CBO process, resulting in approximately 21.3 additional MWs of generation per unit. This increased generation will be achieved with no increase in heat input.

These proposed activities will accomplish substantial environmental goals, namely: (1) comply with the new Acid Rain program NO_X limitation, effective for Seminole in 2008, (2) allow for the reduction of NO_X and SO_2 emissions to meet the expected allowance allocations under the Clean Air Interstate Rule (CAIR), effective in 2009 and 2010, (3) allow for the reduction of mercury emissions to meet the expected allowance allocations under the Clean Air Mercury Rule (CAMR), effective in 2010, (4) reduce SO_3 emissions, which increases as a consequence of operating the SCRs, resulting in no increase in H_2SO_4 emissions, (5) allow for the further reduction of NO_X, SO_2, H_2SO_4 and mercury emissions to levels needed to offset the construction and operation of a new Unit 3, which will be described in detail in a separate PSD permit application and PPSA modification package, (6) lower the heat rate via more efficient use of steam, meaning more megawatts (MWs) can be produced with the same amount of heat input to Units 1 and 2, and (7) maximize the reuse of fly ash, and thereby minimize the landfilling of this material.

The SGS facility is currently authorized to operate under FDEP Title V Air Operation FINAL Permit No. 1070025-002-AV, with an effective date of January 1, 2005 and expiration date of December 31, 2009. This application contains the information required by Rule 62-213.420(3), F.A.C., including FDEP Form No. 62-210.900(1), Effective: 02/02/06, Application for Air Permit – Long Form.

This application also provides additional background on the proposed control equipment upgrades and additions (Section 1.1), the CBO unit (Section 2.0), a discussion of regulatory applicability (Section 3.0) and the results of the air quality modeling analysis with respect to current and proposed operations (Section 4.0).

Additional attachments and appendices to this application package are organized as follows:

Appendix A	Application for Air Permit – Long Form
Appendix B	Application Attachments (B-1 through B-11, see Table of Contents); and
Appendix C	Air Quality Modeling Analysis.

1.1 Proposed Control Equipment Upgrades and Additions

As mentioned above, Seminole is planning specific additions and upgrades to Units 1 and 2 which include burner modifications, the addition of SCR systems, FGD system upgrades, a CBO unit, and upgrades to the steam turbines. The proposed schedule for these modifications was developed to minimize Unit 1 and 2 down time, and is proposed (approximately) as follows:

Proposed Modification	Commence Construction	Commence Operation
Unit 1 LNB	September 2006	October 2006
Unit 2 LNB	March 2007	April 2007
Unit 1 SCR/Alkali Injection	June 2007	December 2008
Unit 2 SCR/Alkali Injection	January 2008	December 2009
Unit 1 FGD Upgrade	January 2007	December 2008
Unit 2 FGD Upgrade	January 2007	December 2008
CBO Process	June 2007	December 2008
Unit 1 Steam Turbine Upgrades	January 2007	June 2008
Unit 2 Steam Turbine Upgrades	January 2008	June 2009

1.1.1 Low NO_X Burners

Seminole is proposing to install new low NO_X burners with a modified overfire air (OFA) system, replacing the existing low-NO_X burners, to meet the Acid Rain program NO_X annual average emission limit of 0.46 lb/MMBtu, which will be effective in 2008. The burners will optimize the fuel and air flows and be of a proven design previously utilized to achieve emissions requirements when firing fuels similar to those fired at the SGS, and will be engineered by Foster Wheeler Energy Corporation (Foster Wheeler) (See Appendix B-3). The existing burner inlet system will be modified to ensure even airflow distribution with the new burners. The proposed OFA design will utilize at least six ports per wall compared with the existing system design of four ports per wall. Emissions of NO_X will be reduced and other pollutant emissions will be comparable to emissions associated with the existing design.

Foster Wheeler's Vortex Series Split-Flame (VS/SF) Low NO_X Burner uses an axial-swirl generator to produce air and fuel mixing. This ensures reliable operation and flame stability over the entire boiler load range. The VS/SF uses only three moving components:

1) Aerodynamic stationary vanes on an adjustable hub from the "axial-swirl generator" in the outer air-register zone. This allows significant flame shape control without needing high windbox pressures. Following initial optimization, no further adjustment should be necessary unless dictated by major fuel changes.

2) Within the inner air register, a conical air damper regulates the flow of the secondary air around the perimeter of the coal jet, optimizing combustion efficiency and flame front position.

3) A sliding-sleeve damper provides initial light-off, main fuel, and out-of-service airflow control to each burner. This sleeve damper also serves as a means to provide burner-to-burner balancing and the necessary cooling when burners are out of service. An automated drive is used for sleeve-damper operation.

The nozzle's "split-flame" design produces fuel rich/fuel lean condition cut NO_X emissions while minimizing unburned carbon.

1.1.2 SCR System

Seminole is proposing to install an SCR control system on each of the existing two units. The SCR will be placed at the exit of the boiler and upstream of each unit's air heater. The SCR reactor vessel will be composed of two independent reactor "trains" consistent with the unit's current design which uses separate "A" and "B" flues after leaving the boiler. Upstream of the SCR system's catalyst will be an ammonia injection grid and a mixing grid to facilitate a homogeneous mixture of ammonia and flue gas. Ammonia used in the SCRs will be provided from the plant's new urea to ammonia processing system and associated bulk storage tank systems. The SCRs will be designed to achieve a NOx emission rate of 0.07 lb/mmBtu from each unit.

A urea-to-ammonia system will be used for the SCR's. A urea-to-ammonia system stores liquid urea (typically a 40-50 percent solution) and hydrolyzes or thermally decomposes the urea into NH_3, H_2O and CO_2. Urea is transported to the site via truck or rail as a dry solid in a prilled or granular form that will be mixed with demineralized water and stored as a 40-50 percent wet solution in storage tanks. The dry urea is fed from the supply truck or railcar, by use of a pneumatic unloader, to the dissolving tank with mounted agitators which mixes the urea with hot water. A recirculation pump sends the urea solution through a heat exchanger to maintain the urea in the dissolver at the desired mixing temperature. Within the dissolver tank, the concentration of the urea solution is controlled by level and density controls, with make up water being supplied from the demineralized water system. The recirculation pumps also act as transfer pumps to transfer the solution from the dissolving tank to the storage tanks. The urea solution from the storage tanks is then pumped through a pre-heater to increase the temperature to approximately 400°F. From the pre-heater, the heated solution goes to the hydrolyzer where steam is used to decompose the urea solution into ammonia and carbon dioxide. Any liquid phase leaving the hydrolyzer is sent to a flash separator that vaporizes the ammonia and combines it with the main hydrolyzer vapor flow. The ammonia gas is then mixed with air in the ammonia flow control units and sent to the ammonia injection grid.

To maintain reliability and minimize unit down time, Seminole is planning to commence construction on the SCR for Unit 1 in June 2007, and it will be operational by December 2008. Seminole plans to commence construction on the SCR for Unit 2 as early as January 2008, and it will be operational by December 2009.

These SCRs, in addition to the low-NO_X burner installation described above, will allow Seminole to substantially reduce NO_X emissions from SGS for several purposes. First, Seminole is requesting a new NO_X limit for the emissions from Units 1 and 2 of 0.46 lb/mmBtu, on an annual average basis, monitored by the existing CEMs, as required by the Acid Rain program. Also, installation of the SCRs will allow Seminole to meet its annual obligation under the Clean Air Interstate Rule by reducing NO_X emissions as opposed to relying on the purchase of allowances. The SCRs will also provide a co-benefit of assisting the existing (and proposed to be upgraded) FGD system in reducing mercury emissions, allowing Seminole to meet its annual obligation under the Clean Air Mercury Rule by reducing emissions as opposed to relying on the purchase of allowances. Finally, as part of a separate application to install a new Unit 3, Seminole will propose a new, lower NO_X limit at the level needed to provide a creditable offset of the potential increase from the new Unit 3. In sum, the SCRs will allow Seminole to reliably meet its current and pending regulatory obligations, and increase the electricity generation at the site by approximately 60 percent while decreasing SGS NO_X emissions.

1.1.3 FGD System

Seminole is proposing to upgrade its existing FGD systems, associated with Units 1 and 2, to improve existing performance and reliability. SGS currently is achieving approximately 87 percent removal from its FGD systems and utilizes another approximately four percent removal from coal washing credit. The proposed upgrades are intended to increase the FGD removal from approximately 87 to 95 percent.

Options for these improvements include, (1) scrubber module modifications (such as the installation of perforated trays or internal wall rings) to provide better liquid-to-flue gas contact, (2) upgrades to the module's mist eliminator wash system including such items as a new wash tank, larger pumps, and more internal spray headers and spray nozzles, (3) expansion of the oxidation air compressor building to accommodate the installation of a fourth air compressor, and (4) the installation of additional holes in the existing sparger rings in the absorber recycle tanks to deliver higher air volume. Upgrades to the solids handling portion of the plant called the Effluent Processing Facility (EPF System) will be required to handle the higher levels of gypsum produced by the module improvements and to insure the production of a commercial-grade gypsum. This will require the addition of a new building and the addition of a new gypsum conveyor form the new building to the existing gypsum conveyor system. The FGD system upgrade details will be determined precisely in the near future when a vendor is selected.

These upgrades will allow Seminole to meet the proposed 0.67 lb/mmBtu SO_2 limit, as described below to show that SGS' emissions do not cause a modeled exceedance of the SO_2 Class I increment. The 0.67 lb/mmBtu limit will be monitored with the existing CEMs, with a proposed effective date upon completion of the upgrades. These upgrades will also allow Seminole, as part of the separate application to install a new Unit 3, to propose a new, lower SO_2 limit at the level needed to provide a creditable offset of the potential increase from the new Unit 3.

Seminole intends to commence construction on these upgrades in January 2007, and expects the upgraded systems to be operational by December 2008. The existing systems will continue to achieve approximately 87 percent removal until the upgrades are completed.

1.1.4 Alkali Injection System

An alkali injection system (e.g., ammonia) will be installed on Units 1 and 2 to mitigate the impacts of SO_3 formation resulting from the operation of the SCR control systems. Final vendor selection of the alkali injection system has not yet been made; however, design criteria will ensure that sulfuric acid mist emissions do not increase above the current Unit's 1 and 2 sulfuric acid mist emissions baseline.

1.1.5 CBO Process

The installation of combustion modifications and SCR systems to reduce NO_X emissions from SGS Units 1 and 2 has the potential to adversely impact Seminole's beneficial reuse of its fly ash. The planned NO_X control systems for Units 1 and 2 will increase the fly ash carbon and ammonia concentrations to levels that could make the fly ash unusable as a partial replacement for Portland cement. Currently all fly ash generated at the facility is disposed in the station's permitted landfill.

CBO™ technology, as described further in Section 2.1 below, will produce low-carbon, low-ammonia fly ash material suitable for commercial use as a partial replacement for Portland cement. Seminole plans to begin construction of the CBO project no later than June 2007 in order for the CBO to be operational prior to the first SCR going into operation by December 2008.

1.1.6 Steam Turbine Upgrades

The purpose of this project is to improve steam turbine blade efficiency in order to increase the Units 1 and 2 electrical output by approximately 14.8 MWs each without an increase in fuel burn and stack emissions. An additional approximately 6.5 MW can be realized from efficiency achieved with the CBO unit, when it is in operation (The CBO system will consume approximately 2 MW). These steam turbine upgrades compensate for the substantial energy penalties associated with the operation of the pollution control equipment, such as the SCR and FGD systems. These steam turbine upgrades (and increased generation without additional heat input) will result in a heat rate improvement of approximately 1.4 percent (140 Btu/kw-hr).

The turbine improvements with include the replacement of the LP turbine L-0 and L-1 rotating blades, L-0 blade carriers, G-0 and G-1 stationary blades, inter-stage seal strips, rotor hub covers, and modifications to the inner casing horizontal joint. The new L-O blades will be slightly longer thereby reducing kinetic energy exhaust losses, the exit area of the new L-O blade carrier will be increased, and the new L-1 blades will be shrouded to allow for more efficient blade geometry and to reduce blade tip losses. The inner casing horizontal joint will be modified to reduce the amount of steam that currently bypasses blades.

There will be no increase in stack emissions from the steam turbine upgrades as the increased generator output will result from more effective use of the heat energy in the steam and not from increased furnace heat input, or fuel burned. The current nominal unit gross MW rating of 714.6 MWs is estimated to increase to approximately 735.9 MWs per unit (which Seminole will propose as revision in the Title V permit).

2.0 CBO PROCESS

CBO™ technology will be installed to produce a low-carbon, low-ammonia, fly ash material suitable as a partial replacement for Portland cement (in lieu of landfilling the ash). The CBO™ project will combust the carbon in the fly ash from each of the two existing SGS Units. The CBO™ will also have the potential capacity to process fly ash from the proposed electric utility steam generating Unit No. 3. Accordingly, construction of the CBO™ project should commence no later than June 2007 in order to be operational prior to completion of the first SGS SCR installation in December 2008.

CBO™ technology will also recover a significant portion of the energy contained in the high-carbon fly ash for beneficial use at the SGS. More specifically, the heat from the CBO system will replace steam currently being extracted from the Units 1 and 2 LP turbines to heat water in the condensate cycle. Although the CBO™ process will cause small collateral increases in PM, VOC and CO emissions, it is an important element of the significant emission reductions of the SGS environmental improvement project.

2.1 CBO Process Description

CBO™ technology is a proprietary, patented, environmentally beneficial technology whose primary function is the production of low-carbon, low-ammonia fly ash material suitable for commercial use as a partial replacement for Portland cement. Major components of the CBO™ process planned for the SGS include a feed fly ash silo, product fly ash storage dome, fluidized bed combustor (FBC), hot cyclones for fly ash recycle to the FBC, heat recovery heat exchanger, cold cyclone and fabric filter bag house for product fly ash recovery, and product fly ash truck loading. A flow diagram of the CBO™ process proposed for the SGS is provided in Appendix B (Attachment B-2C). A plan view of the SGS showing the locations of the CBO™ process emission points is provided in Figure B-1.

Fly ash from Units 1 and 2 will be conveyed pneumatically to the CBO™ feed fly ash silo. The CBO feed fly ash silo will vent through a bag house prior to discharging to the atmosphere (Attachment B-1, Item 21; Emission Unit (EU) ID CBO-001).

Fly ash from the feed silo will then be fed to the FBC. The CBO™ technology does not require any auxiliary fuel to operate, with the limited exception of a minimal amount of start up fuel to initiate the combustion process. As with any fossil fuel combustion process, the FBC combustion gases will also contain combustion by-products including NO_X, carbon monoxide (CO), SO_2, particulate matter less than or equal to 10 micrometers (PM_{10}), and volatile organic compounds (VOCs). The CBO™ process includes a forced draft fan to provide fluidization and combustion air to the FBC. An induced draft fan maintains the FBC freeboard pressure slightly below atmospheric pressure.

The FBC exhaust stream will be routed through hot cyclones to capture fly ash entrained in the FBC exhaust stream. Fly ash captured by the hot cyclones is returned to the FBC. The hot cyclones' exhaust and FBC low carbon product ash streams are combined and sent to the gas/product cooler heat exchanger for heat recovery. Thermal energy recovered from the CBO™ process will be used to heat condensate from the Units 1 and 2 low-pressure feed water systems. The improvements in Units 1 and 2 heat rates due to the use of recovered energy from the CBO™ process will compensate in part, for the energy penalties associated with the operation of the low NO_X burners and SCR systems. The low-NO_X burners also lower the combustion efficiency as a consequence of the lower flame temperatures and lower oxygen available in the combustion zone. This is the reason for the increase in fly ash carbon content.

Following heat recovery, the cooled FBC combustion gases, containing entrained product fly ash, will be routed through a cold cyclone and fabric filter bag house for product fly ash separation. The exhaust from the fabric filter bag house (i.e., the CBO™ return) will be routed back to Units 1 and 2, upstream of the SCR, FGD, ESP and alkali injection systems, and subsequently discharged to the atmosphere through the existing Units 1 and 2 stacks.

Product fly ash separated by the cold cyclone and fabric filter bag house will be sent to a surge bin. A portion of the cooled, low-carbon product will be recycled to the FBC for temperature control. The remaining product ash is then conveyed pneumatically to the product fly ash storage dome or directly to a truck loadout silo. The product fly ash storage dome will vent through a bag house prior to discharging to the atmosphere (Attachment B-1, Item 23, EU ID CBO-002). The product fly ash storage dome will be used to provide flexibility in product fly ash marketing. Product fly ash will be conveyed to the truck loadout silo for subsequent transfer to trucks for shipment to offsite customers. The PM_{10} emissions captured during the truck loading process will be routed to the truck loadout silo which will vent through a bag house prior to discharging to the atmosphere (Attachment B-1; Item 24; EU ID CBO-003).

The product fly ash trucks will travel on paved roads within the SGS and then exit the plant for delivery to offsite customers. Fugitive particulate matter (PM/PM_{10}) emissions associated with product fly ash truck traffic on the SGS paved roads (EU ID CBO-004) will be controlled by periodic watering on an as-needed basis.

2.2 CBO Emission Characteristics

Emissions associated with the CBO™ process include PM_{10} due to fly ash handling and storage and NO_X, CO, SO_2, PM_{10}, and VOC due to combustion of high-carbon fly ash in the CBO™ FBC. Detailed emission rate calculations are provided in Appendix B (Tables B-4A and B-4B). Each of these CBO™ emission areas is discussed in the following sections.

The CBO™ material handling and storage activities will include four PM_{10} emission points, including a (1) feed fly ash silo (Emission Point CBO-001), (2) product fly ash storage dome (Emission Point CBO-002), (3) product fly ash truck loading operation (Emission Point CBO-003), and (4) fugitive emissions associated with product fly ash truck traffic on paved roads (Emission Point CBO-004).

The feed fly ash silo, product fly ash storage dome, and product fly ash truck loadout silo will each be equipped with fabric filter bag houses designed to achieve an outlet PM_{10} concentration of no more than 0.010 grains per dry standard cubic foot (gr/dscf). The truck loading operation will include a telescoping chute with local ventilation designed to capture the fugitive PM_{10} emissions. The PM_{10} emissions captured during the truck loading process will be routed to the truck loadout silo. Fugitive PM_{10} emissions associated with product fly ash truck traffic on paved roads will be minor due to relatively short travel distances. Potential PM_{10} emissions, based on the conservative premise of continuous operation, total 6.4 tons per year (tpy) for these CBO™ emission sources, including the CBO FBC, summarized below.

The CBO™ FBC combustion gases will contain combustion by-products including NO_X, CO, SO_2, PM_{10}, and VOCs and trace quantities of mercury. The CBO™ FBC will utilize good combustion practices to minimize emissions of CO and VOCs. NO_X emissions from the SGS CBO™ system will be reduced using the proposed SCR systems for SGS Units 1 and 2. Extensive testing conducted by the CBO process vendor, Progress Materials, Inc. (PMI), has confirmed that essentially all of the mercury present in the feed fly ash to the CBO process should remain with the CBO product fly ash; therefore, mercury emissions are minimal (See Appendix B4-D). Following product fly ash separation by the cold cyclone and fabric filter bag house, this exhaust stream will be routed back to Units 1 and 2, upstream of the SCR systems, prior to discharging to the atmosphere through existing Units 1 and 2 stacks. Emissions estimates for these combustion by-products, provided in Appendix B (Table B-4A), were developed based on data provided by PMI.

3.0 REGULATORY APPLICABILITY ANALYSIS

Various regulatory programs have the potential to affect the development of the SGS Units 1 and 2 controls/upgrade project, including:

- Prevention of Significant Deterioration (PSD) requirements at Rule 62-212.400, F.A.C;
- Ambient Air Quality Standards and PSD Increments at Rules 62-204.240 and 62-204.260, respectively;
- Federal New Source Performance Standards (NSPS) for electric utility steam generating units and industrial boilers (40 CFR Part 60, Subparts Da and Db, respectively);
- Federal Acid Rain program requirements for NO_X (Title IV of the Clean Air Act);
- Florida air pollution control regulations requiring a permit to construct; and
- The effects of the EPA's recently promulgated Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR).

3.1 Ambient Air Quality Standards and PSD Increments

The federal Clean Air Act (CAA) requires that National Ambient Air Quality Standards (NAAQS) be set for "criteria" pollutants, defined as air contaminants that have been demonstrated to have the potential for widespread adverse impacts on human health. In response, the EPA has identified six criteria pollutants and established corresponding NAAQS. These pollutants are SO_2, NO_2, PM_{10}, CO, ozone (O_3) and lead (Pb). In addition, the EPA promulgated a new NAAQS for particulate matter sized 2.5 microns and less ($PM_{2.5}$) on July 17, 1997. Compliance with the $PM_{2.5}$ standard at the federal level is not yet required (the EPA policy is to use compliance with PM_{10} as a surrogate). The NAAQS are designed to protect the public health and welfare with an adequate margin of safety. EPA has classified the area that the SGS is located as an attainment area for all of the criteria pollutants. The FDEP has also established Ambient Air Quality Standards for the criteria pollutants. This proposed project will result in no net overall increase of NO_X, SO_2 and mercury, minor increases in PM and VOCs and a significant emission rate increase in CO, associated with the addition of the CBO unit. Consequently, modeling was conducted to address CO impacts on the NAAQS, as well as

SO_2 impacts due to the known existing circumstance encountered with PSD Class I SO_2 increments at Okeefenokee. Those results are presented in Section 4.0.

3.2 Prevention of Significant Deterioration

SGS is classified as an existing major facility. A modification to an existing major facility that results in a significant net emissions increase equal to or exceeding the significant emissions rates (SER) listed in Section 62-212.400, Table 212.400-2, F.A.C., is classified as a major modification and will be subject to the PSD New Source Review (NSR) preconstruction permitting program for those pollutants that exceed the PSD SERs. EPA has approved Florida's State Implementation Plan (SIP), which contains PSD regulations; therefore, PSD approval authority has been granted to the FDEP.

The procedures for determining applicability of the PSD NSR permitting program to the SGS Units 1 and 2 controls/upgrade project are specified in Rule 62-212.400(2), F.A.C. For each regulated pollutant, PSD is triggered as a result of a modification at an existing unit if the difference between the projected actual emissions and the baseline actual emissions equals or exceeds the significant emissions rate for that pollutant, as defined at Rule 62-210.200(243), F.A.C.

As described previously, the "project" for PSD review purposes consists of the replacement of low NO_X burners and the installation of SCR systems to reduce NO_X emissions, upgrades to the existing FGD systems to reduce SO_2 emissions, addition of an alkali injection system for reducing SO_3 formation in the SCR catalyst, installation of a CBO unit and steam turbine improvements. Projected actual emissions for the project, as shown in Table B-4, will not exceed the PSD significant emission rates for SO_2, NO_x, PM/PM_{10}, VOCs, mercury and H_2SO_4. Therefore, PSD review is not applicable for these pollutants.

The proposed condition offered for consideration related to these pollutants is:

> The applicant shall maintain monthly and submit to the Department on an annual basis for a period of ten years from the date the project is completed, information demonstrating in accordance with Rule 62-212.300(1)(e)(1), F.A.C. that the modification did not result in significant emissions increases of NO_X, SO_2, PM/PM_{10}, VOCs, mercury or H_2SO_4, as defined in Rule 62-210.200(234). The emissions computation and reporting shall be based on the requirements of Rule 62-210.370 F.A.C. The basis for evaluating an emission increase is on a tons-per-calendar-year basis.

The emission increases of CO are a result of the operation of CBO process, and are greater than the PSD significance thresholds. Therefore, PSD review is applicable for CO and this application provides the information required pursuant to Rule 62-212.400 F.A.C. A Best Available Control Technology (BACT) analysis and an air quality modeling analysis were conducted for CO emissions for the proposed project, and are discussed in Sections 3.2.1 and 4.0, respectively.

The recent Department rulemaking with respect to new source review (NSR) reform provides for consideration of startup and shutdown emissions, as well as fugitive emissions, in NSR applicability determinations (FDEP Rule 210.200(34)(a)(1), Definitions). Seminole does not anticipate that the Units 1 and 2 emissions characteristics during startup and shutdown operations, or the number of startups and shutdowns, post-change will be any different than current operations. An established startup and shutdown procedure 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 Title V permit. This procedure will continue to guide the post-change operations. The potential fugitive emissions will be slightly higher than the current baseline, due to the material handling associated with the CBO unit. These fugitive emissions have been quantified in Table B-4A.

3.2.1 CO BACT Analysis

Carbon monoxide (CO) is emitted from the boilers as a result of incomplete combustion of fuels. Incomplete combustion also leads to emissions of particulate matter, volatile organic compounds (VOC), and organic hazardous air pollutants. Therefore, the most direct approach for reducing CO emissions (and also reduce other related pollutants) is to maximize combustion efficiency. Combustion controls, low boiler loads, and the use of post-combustion control systems are discussed below.

There are no specific state implementation plan (SIP) requirements nor NSPS requirements for CO emissions from coal-fired boilers. Therefore, baseline emissions are simply the uncontrolled emissions from the boilers. Based on sound engineering judgment, the combustion controls proposed to be used to minimize NO_X emissions will have uncontrolled emission rates of approximately 0.15 lb/MMBtu heat input.

3.2.1.1 CO Control Alternatives

The technologies used to control CO emissions from pulverized coal (PC) boilers were first reviewed in the U.S. EPA's RACT/BACT/LAER (RBLC) database and the EPA Utility Coal Project database. Good combustion control was the only technology selected as CO BACT. The most stringent emission limit for CO that was found was in the RBLC at 0.10 lb/mmBtu, and other recently permitted and proposed BACT limits from the EPA Coal Utility Project database ranged from 0.15 to 0.27 lb/mmBtu for PC boilers.

Even though the only control technology identified was good combustion practice, the following four technologies were evaluated:

1. Oxidation Catalysts;
2. Thermal Oxidation;
3. Good Combustion Control; and
4. Low Boiler Load Operations.

3.2.1.2 Oxidation Catalysts

For natural gas and oil-fired combustion turbine applications, the lowest CO emission levels have been achieved using oxidation catalysts that are installed as a post combustion control system. However, while oxidation catalysts have been used to reduce CO emissions by more than 95 percent in natural gas and oil-fired combustion turbines applications, oxidation catalysts have never been used for solid fuel-fired boiler applications. Solid fuel-fired boilers have several severe technical problems related to the use of oxidation catalysts, including:

1. Catalyst fouling and poisoning by fuel sulfur, fly ash, and limestone;
2. Low excess oxygen levels in the flue gas; and
3. Low temperature levels of the flue gas.

In combustion turbine applications, the typical oxidation catalyst is a rhodium or platinum (noble metal) catalyst on an alumina support material. This catalyst is typically installed in an enlarged duct or reactor with flue gas inlet and outlet distribution plates. CO reacts with oxygen (O_2) in the presence of the catalyst to form carbon dioxide according to the following general equation:

$$CO + \frac{1}{2} O_2 \rightarrow CO_2$$

Acceptable catalyst operating temperatures range from 400 - 1250 °F, with the optimum temperature range of 850 - 1,100 °F. Below 600°F, greater catalyst volumes are required to achieve the same reduction. Below approximately 400 °F, catalyst activity (and CO oxidation potential) is negligible. To achieve this temperature range in a PC boiler, the catalyst would either need to be installed *inside* the boiler before the economizer and air heater, or the flue gas would require reheating after the other pollution control systems. Installation of the catalyst inside of the boiler would result in rapid poisoning and deactivation of the catalyst by sulfur containing compounds and alkaline metals. Furthermore, oxidation catalysts can be effective in reducing CO emissions in combustion turbines because of the relatively high levels of oxygen in the flue gas. However, PC boilers maximize efficiency by minimizing excess air levels. These low excess air levels mean that very little oxygen would be available inside the boiler to oxidize CO in the catalyst bed.

Multiple catalyst vendors have been contacted for this type of BACT analysis. No vendor has been willing to offer their catalyst for a coal-fired boiler application due to the concentration of contaminants in the flue gas, even after all pollution control systems. In addition, because the catalyst would oxidize a high percentage of the flue gas SO_2 to sulfur trioxide (SO_3), the oxidation catalyst would increase stack opacity and reduce the overall SO_2 control efficiency of the wet scrubber. Finally, the short catalyst life caused by fouling and poisoning would result in a significant and ongoing generation of catalyst waste which would probably be classified as a hazardous waste. For these reasons, and because oxidation catalysts have never been used or demonstrated in practice on coal-fired boilers, catalytic oxidation is not considered a technically feasible CO control option for these boilers.

3.2.1.3 Thermal Oxidation

An alternate control process for CO reduction would be thermal oxidation. Thermal oxidation reduces CO emissions by heating the flue gas and supplying adequate oxygen to convert CO to CO_2. Since particulate matter present in the flue gas could accumulate in the thermal oxidation combustion chamber and other system components and cause significant system downtime, the thermal oxidation system must be placed downstream of the ESP. At this location, the gas temperature must be increased from the typical ESP outlet temperature of 300°F to the thermal oxidation operating temperature of 1,500°F, requiring a gas-gas heat exchanger and a natural gas-fired burner.

As noted above, thermal oxidation requires an operating temperature of at least 1,500°F to achieve 90 percent conversion of CO to CO_2. However, since thermal oxidation has never been used on a coal-fired boiler, actual emission reductions are difficult to predict. In any case, actual CO emissions are not likely to be less than the CO emission rate from the thermal oxidizer burner itself. Assuming a CO emission rate typical of combustion turbine heat recovery steam generator (HRSG) applications, the outlet CO emission rate would be expected to be about 0.06 lb/mmBtu, or a 60% reduction from 0.15 lb/mmBtu.

Thermal oxidation is not a cost effective method for the control of CO emissions from the PC boilers. In addition, this control technology has significant additional environmental impacts, and has never been demonstrated or used on any other coal-fired boiler. As a result, thermal oxidation is not considered as a technically or economically feasible control option.

3.2.1.4 Good Combustion Control

Combustion controls generally include the following components or characteristics:

1. Staged combustion to minimize NO_x formation.
2. Good air/fuel mixing in the combustion zone.
3. High temperatures and low oxygen levels in the primary combustion zone.
4. Overall excess oxygen levels high enough to complete combustion.
5. Sufficient residence time to complete combustion.

In PC boilers, combustion control is the most effective means for reducing CO emissions. Combustion efficiency is directly related to the three "T's" of combustion: Time, Temperature, and Turbulence. These components of combustion efficiency are designed into utility scale PC boilers to maximize fuel efficiency and reduce the highest single operating cost of utility boilers: fuel. A fourth important parameter is the level of oxygen in the boiler, often referred to as the excess air or excess oxygen level. Therefore, combustion control is accomplished primarily through boiler design (as it relates to time, temperature, and turbulence) and boiler operation (as it relates to excess oxygen levels). It is important to note that the combustion design for modern, low emitting coal-fired boilers is intended to simultaneously minimize formation of CO and NO_X emissions. Therefore, the boiler design to minimize CO emissions is interrelated with the boiler design to minimize NO_X formation.

Pulverized coal-fired boilers burn coal in suspension in large, open furnace volumes. The advanced low NO_x burners for these boilers are designed to burn the coal in a slow, controlled manner using diffusion-flame type combustion processes. These burners result in the minimum possible quantity of combustion air in the primary combustion zone. Normally, the amount of primary air is maintained below the stoichiometric requirement. Thus, the fuel is initially combusted under fuel-rich conditions. This initial combustion zone helps to reduce NO_X formation. Using this advanced low NO_X burner technology, the primary unburned combustible by-product produced from this primary combustion zone is carbon monoxide. Carbon monoxide formation in this zone reduces NO_X formation during the initial combustion process, and provides an easier fuel to be burned to completion in the second stage or over fire air injection portion of the furnace. Secondary air is then introduced into the area above the primary fireball. This additional air is called overfire air. The overfire air brings the total amount of combustion air up to the level needed to achieve complete combustion and minimize emissions of CO. The total amount of oxygen measured at the outlet of the boiler is typically 2 – 6 percent oxygen.

Changes in excess air affect the availability of oxygen and combustion efficiency. Very low or very high excess air levels may cause high CO formation, and may also affect NO_X formation. Increased excess air levels will reduce CO emissions until so much excess air is introduced that the overall combustion temperatures begin to drop significantly. Because of these interrelationships, PC boilers typically operate within a narrow range of excess air levels.

3.2.1.5 Low Boiler Load Operations

At low boiler loads, combustion temperatures decrease and this reduction in temperature may result in increased CO emissions. Information from similar operating PC boilers indicates that low load operation may result in CO emission rates (in terms of pounds per million Btu of heat input) approximately twice as high as those that can be achieved at full load conditions. CO formation can be minimized in PC boilers by taking pulverizers and the associated burners out of service. This is a normal operating mode for reducing boiler output.

3.2.1.6 Conclusion

Good combustion practices are the only technically feasible method of controlling CO emissions from the proposed boilers. The use of good combustion controls has been identified as BACT for CO control for every major coal-fired boiler identified in the U.S. EPA's RACT/BACT/LAER clearinghouse database. This control technology is technically feasible, and is identified as BACT for these PC boilers.

Because of lower furnace temperatures at low loads, low boiler loads can result in elevated CO emissions in terms of pounds per million Btu of heat input. However, the overall mass emission rate is relatively constant over the entire boiler operating range from initial ignition at startup to full load. Therefore, the allowable emission limit representing BACT should reflect the constant mass output equal to a full load emission rate of 0.15 pounds per hour, or a mass emission rate of 1,076 pounds per hour.

3.2.1.7 Rank Feasible Control Technologies

Based on the above analysis, good combustion practices are the only technically feasible method of controlling CO emissions from the proposed PC boilers. Catalytic and thermal oxidation were rejected as technically infeasible due to the rapid poisoning and deactivation of the catalyst material from exposure to SO_2 and SO_3 contained in the flue gas, significant, adverse environmental impacts, economically infeasible control costs, and because these technologies are not commercially available for the proposed PC boilers.

3.2.1.8 Proposed BACT Limit for CO Emissions

Based on the above analysis, good combustion control is proposed as BACT for CO emissions. Based on the review of CO emission limitations currently established and proposed for similar PC boilers, as well as the boiler manufacturer's information on these PC boilers, Seminole proposes the following emission limits:

- Carbon monoxide emissions shall be controlled using good combustion practices.
- Carbon monoxide emissions shall be limited to the higher of 0.15 pounds per million Btu of heat input or 1,076 pounds per hour, based on a 3-hour test average, whichever is greater.

The limitation is stated in terms of the higher of pounds per million Btu or pounds per hour to address low boiler load operations.

3.3 New Source Performance Standards

The SGS Units 1 and 2 boilers are affected facilities under NSPS Subpart Da, as promulgated in 1979. The proposed upgrades to Units 1 and 2 do not constitute reconstruction, so applicability of the emission standards to Units 1 and 2 in Subpart Da is unchanged by the proposed project. Units 1 and 2, therefore, are not subject to the new mercury emission standard at 40 CFR 60.45Da or to the 0.15 lb/MMBtu NOx limit at 40 CFR 60.44Da(d)(2).

The CBO FBC, by virtue of its heat input exceeding 100 MMBtu/hr, is subject to the requirements of the NSPS, Subpart Db. The CBO FBC exhaust, therefore, will be subject to a 0.20 lb/mmBtu NO_X limit and an SO_2 standard requiring at least 90 percent removal. SGS will demonstrate compliance with the NOx limit using its existing NO_X CEMs. The SCR installations will sufficiently reduce the NO_X from the CBO FBC exhaust to achieve compliance with this standard, as well as reduce the projected future actual NO_X emissions to offset the construction/operation of Unit 3, which will be addressed in a separate application. The 0.20 lb/mmBtu limit is applicable to the exhaust from the CBO FBC, and not the exhaust from Units 1 and 2. Practically, however, Seminole proposes to demonstrate compliance with this 0.20 limit on the CBO FBC with its existing CEMs, which can only measure the NO_X in the entire gas stream. As stated previously, Seminole intends to utilize the NO_X reductions from the SCRs (and accept an appropriate limit at the appropriate time) to obtain a creditable offset of the potential increase from the installation of a new Unit 3. The imposition of a limit on the CBO exhaust does not hinder the full use of these NO_X reductions for Unit 3 because (a) the 0.20 limit does not apply to Units 1 and 2, and (b) even if it could be argued that it does apply, Florida's PSD rules, as clarified in the recent revisions, defines the baseline actual emissions for Units 1 and 2 as the 24-month period in the prior five years that the source chooses, and does not require that this baseline be adjusted/reduced by the imposition of any recent limit.

Consistent with current testing requirements, initial testing for PM will also be conducted downstream of the Units 1 and 2 FGD systems to measure PM from Units 1 and 2 while the CBO™ is in operation.

3.4 CAIR and CAMR- Future Considerations

On May 12, 2005, EPA promulgated a rule to reduce emissions of SO_2 and NO_X from electric generating units located in 29 eastern states, including Florida. This rule was codified as a revision to Subpart G of 40 CFR Part 51. The stated objective of the Clean Air Interstate Rule (CAIR), is to assist eastern states in achieving attainment with the new, more stringent $PM_{2.5}$ and the 8-hour ozone National Air Quality Standards (NAAQS) by reducing precursor emissions in upwind areas. Seminole is proposing to install the SCRs and scrubber upgrades, in part, to allow it to reduce NO_X and SO_2 emissions such that it will not have to buy allowances. Compliance of the SGS with Florida's CAIR implementing regulations will be addressed following their finalization, in a separate subsequent application package as required by rules that the Department is planning to promulgate in 2006.

In addition to CAIR, EPA also promulgated a rule to limit mercury emissions from all new and existing coal-fired utility boilers on May 18, 2005. This rule was codified as a revision to Subpart B of 40 CFR Part 60. This Clean Air Mercury Rule (CAMR) will set an initial nation-wide cap on mercury emissions from coal-fired boilers of 38 TPY beginning in 2010, with an additional decrease to 15 TPY by 2018. Seminole is proposing to install the SCRs and scrubber upgrades, in part, to achieve the co-benefit of reducing mercury emissions to levels that will allow it to not have to buy allowances. Compliance of the SGS with the CAIR rule will be addressed in a separate subsequent application package as required by rules that the Department is planning to promulgate in 2006.

4.0 AIR QUALITY MODELING ANALYSIS

As part of the air construction permit application, air dispersion modeling analyses were performed to address compliance with the sulfur dioxide (SO_2) ambient air quality standards (AAQS) and allowable Class I and Class II prevention of significant deterioration (PSD) increments. These analyses included the SGS, the nearby Georgia Pacific (GP) Palatka Mill, and other major SO_2 emission sources. The results of the modeling assessment are presented in Appendix C of this application package. In addition, the proposed project will show a significant emission rate increase for CO. Therefore, a modeling assessment was conducted for compliance with the CO NAAQS. The results of the modeling conducted show compliance with applicable standards for CO.

Previous air modeling analyses have shown that the SGS, when estimated to be emitting at 1.2 lb/MMBtu for SO_2, was predicted to be causing exceedances of the PSD Class II and Class I increments for the 3-hour and 24-hour averaging times.

The purpose of the present modeling analyses is to present SO_2 AAQS and PSD increment consumption impacts based on the proposed revised SO_2 emission limits for the SGS. These analyses demonstrate that the SO_2 impacts for the SGS together with other sources would comply with the AAQS PSD Class II increments and, in general, with the PSD Class I increments. The maximum SO_2 concentrations from the SGS alone do not exceed the allowable PSD Class I increment. The combined predicted impacts from other PSD increment consuming sources and SGS slightly exceed the 3-hour and 24-hour PSD Class I increment during some meteorological conditions. However, other sources and not SGS dominate the predicted concentrations and such impacts are not attributable to SGS.

The nearest PSD Class I areas are 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. Because these PSD Class I areas are within 200 km of the SGS, air impact modeling analyses were performed at each PSD Class I area. Air impact analyses were not performed for other PSD Class I areas since they are located more than 200 km from the SGS.

Based on these analyses, the SGS' impacts were predicted to be at or below the PSD Class I increment. As a result, the SO_2 impacts from the SGS will comply with the PSD Class I increments when using a maximum SO_2 emission rate from Units 1 and 2 of 4,805 lb/hr (0.67 lb/MMBtu). This is reflected in the attached application form.

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APPENDIX A

APPLICATION FOR AIR PERMIT- LONG FORM

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

RECEIVED
FEB 13 2006
BUREAU OF AIR REGULATION

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:
- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:
- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Seminole Electric Cooperative, Inc.**	
2. Site Name: **Seminole Generating Station**	
3. Facility Identification Number: **1070025**	
4. Facility Location Street Address or Other Locator: **890 North U.S. Highway 17** City: **7 miles north of Palatka** County: **Putnam** Zip Code: **32177**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Michael P. Opalinski**
2. Application Contact Mailing Address Organization/Firm: **Seminole Electric Cooperative, Inc.** Street Address: **16313 North Dale Mabry Highway** City: **Tampa** State: **FL** Zip Code: **33618**
3. Application Contact Telephone Numbers... Telephone: **(813) 963-0994** ext. Fax: **(813) 264- 7906**
4. Application Contact Email Address: **MOpalinski@seminole-electric.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	2-13-06
2. Project Number(s):	1070025-034-AC
3. PSD Number (if applicable):	PSD-FL-372
4. Siting Number (if applicable):	

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

☒ Air construction permit.

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.

☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

This application serves to address the following activities at existing Units 1 and 2:

- **Replacement of existing burners with a low NOx design with Overfire Air;**
- **Installation of SCR control systems on each unit;**
- **Installation of an alkali injection system on each unit;**
- **Upgrade of existing FGD control systems for greater control efficiency;**
- **Installation of a carbon burn out (CBO) unit, capable of operating with either unit 1 or 2**
- **Steam turbine upgrade to Units 1 and 2**

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
001	Steam Electric Generator No. 1	AC1A	See Below
002	Steam Electric Generator No. 2	AC1A	See Below
009	CBO™ Feed Fly Ash Silo	N/A	N/A
010	CBO™ Product Fly Ash Storage Dome	N/A	N/A
011	CBO™ Product Fly Ash Loadout Storage Silo	N/A	N/A
012	CBO™ Product Fly Ash Fugitives	N/A	N/A
013	CBO™ Process Fluidized Bed Combustor	N/A	N/A

Application Processing Fee

Check one: ☒ Attached - Amount: $__**7,500**____________ ☐ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : **James R. Frauen, Manager of Environmental Affairs**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Seminole Electric Cooperative, Inc.** Street Address: **16313 North Dale Mabry** City: **Tampa** State: **FL** Zip Code: **33618**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(813)963-9940** ext. Fax: **(813)264-7906**
4.	Owner/Authorized Representative Email Address: **JFrauen@seminole-electric.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.* James R Frauen — Signature; 2-13-06 — Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):
   - ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
   - ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
   - ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
   - ☐ The designated representative at an Acid Rain source.

3. Application Responsible Official Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) -

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:

   I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

   Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **Scott H. Osbourn** Registration Number: **57557**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **5100 West Lemon St., Suite 114** City: **Tampa** State: **FL** Zip Code: **33609**
3.	Professional Engineer Telephone Numbers... Telephone: **(813) 287-1717** ext.**211** Fax: **(813) 287-1716**
4.	Professional Engineer Email Address: **sosbourn@golder.com**
5.	Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

[signature] 2/10/06

Signature Date

(seal)

SCOTT OSBOURN LICENSE NO. 57557 STATE OF FLORIDA PROFESSIONAL ENGINEER

* Attach any exception to certification statement.

**** Board of Professional Engineers Certificate of Authorization #00001670**

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **438.80** North (km) **3289.20**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s):
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Ms. Brenda Shiver, Environmental Compliance Specialist**
2. Facility Contact Mailing Address... Organization/Firm: **Seminole Electric Cooperative, Inc.** Street Address: **890 North U.S. Hwy 17** City: **Palatka** State: **FL** Zip Code: **32177-8647**
3. Facility Contact Telephone Numbers: Telephone: **(386) 328-9255** ext.**2174** Fax: **(386) 328-5571**
4. Facility Contact Email Address: **BShiver@seminole-electric.com**

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☒ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: **Units 1 and 2 subject to CAMR rule in 2010** *** NESHAP applicability for the CBO Unit is under consideration at the federal level.**	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
CO	A	
NOX	A	
PM10	A	
PM	A	
SO2	A	
VOC	A	
SAM	A	

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **B-1** ☐ Previously Submitted, Date:____
2.	Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **B-2A through C** ☐ Previously Submitted, Date:_____
3.	Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **B-7** ☐ Previously Submitted, Date:____

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☐ Attached, Document ID:_____ ☒ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction or Modification: ☒ Attached, Document ID: **See Text**
3.	Rule Applicability Analysis: ☒ Attached, Document ID: **B-10**
4.	List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☒ Attached, Document ID: **B-5** ☐ Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
6.	Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
7.	Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): ☒ Attached, Document ID: **Appendix C** ☐ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): ☒ Attached, Document ID: **Appendix C** ☐ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:____ ☐ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications

1. List of Insignificant Activities (Required for initial/renewal applications only): ☐ Attached, Document ID:____ ☐ Not Applicable (revision application)
2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought): ☐ Attached, Document ID:____ ☐ Not Applicable (revision application with no change in applicable requirements)
3. Compliance Report and Plan (Required for all initial/revision/renewal applications): ☐ Attached, Document ID:____ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4. List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only): ☐ Attached, Document ID:____ ☐ Equipment/Activities On site but Not Required to be Individually Listed ☐ Not Applicable
5. Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) : ☐ Attached, Document ID:____ ☐ Not Applicable
6. Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:____ ☐ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   Steam Electric Generator No. 1

3. Emissions Unit Identification Number: **001**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A			**49**	☒ Yes ☐ No

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: **735.9** MW

11. Emissions Unit Comment:
   Unit No. 1 is a "regulated" emissions unit.
   Generator nameplate rating will be 735.9 after upgrades are complete.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
Existing Control Equipment:

Electrostatic Precipitator (10)
Wet Limestone Flue Gas Desulfurization or FGD (67)

Proposed Control Equipment:

Low NOx Burners (205)
Low Excess-Air Firing (204)
Selective Catalytic Reduction or SCR (139)
Alkali Injection (70)

2. Control Device or Method Code(s): **10, 67, 70, 139, 204 and 205**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: 7,172 million Btu/hr		
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment:		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **U-001**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **695** feet	7. Exit Diameter: **26.5** feet
8. Exit Temperature: **128** °F	9. Actual Volumetric Flow Rate: **1,987,064** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude… Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 4

1. Segment Description (Process/Fuel Type): **Bituminous Coal**		
2. Source Classification Code (SCC): **1-01-002-02**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **326.00**	5. Maximum Annual Rate: **2,855,760**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **3.30**	8. Maximum % Ash: **11.00**	9. Million Btu per SCC Unit: **22**
10. Segment Comment: **Coal sulfur content is 3.0 wt percent on a monthly average basis. Million Btu per SCC Unit is based on nominal 11,000 Btu/lb (as-received basis). Max hourly and annual rates based on nominal fuel heating value and unit max heat input of 7,172 MMBtu/hr.**		

Segment Description and Rate: Segment 2 of 4

1. Segment Description (Process/Fuel Type): **Petroleum coke**		
2. Source Classification Code (SCC): **1-01-008-01**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **93.00**	5. Maximum Annual Rate: **814,680**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **7.0**	8. Maximum % Ash: **1.0**	9. Million Btu per SCC Unit: **26**
10. Segment Comment: **Max pet coke content of coal/pet coke blend is 30 percent by wt.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 3 of 4

1. Segment Description (Process/Fuel Type): **Distillate Oil (Nos. 1 and 2)**		
2. Source Classification Code (SCC): **1-01-005-01**	3. SCC Units: **1000 Gallons Burned**	
4. Maximum Hourly Rate: **3.32**	5. Maximum Annual Rate: **1,664.2**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.50**	8. Maximum % Ash: **0.10**	9. Million Btu per SCC Unit: **136**
10. Segment Comment: **Distillate oil is used for startups, flame stabilization, emergency reserve capacity during statewide energy shortages, and limited supplemental load.**		

Segment Description and Rate: Segment 4 of 4

1. Segment Description (Process/Fuel Type): **On-specification Used Oil**		
2. Source Classification Code (SCC): **1-01-013-02**	3. SCC Units: **1000 Gallons Burned**	
4. Maximum Hourly Rate: **3.30**	5. Maximum Annual Rate: **500**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.50**	8. Maximum % Ash: **0.10**	9. Million Btu per SCC Unit: **142**
10. Segment Comment: **On-spec used oil max levels: arsenic- 5 ppm; cadmium- 2 ppm; chromium- 10 ppm; lead- 100 ppm; total halogens- 1,000 ppm; flash point- 100 F; and PCBs- < 50 ppm.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
SO2	67		EL
PM/PM10	10		EL
NOX	139	204 and 205	EL
CO			NS
VOC			NS
SAM	70		NS

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control: **90%**
3. Potential Emissions: **4,805.2** lb/hour **21,047** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.67 lb/MMBtu** Reference: **Proposed emissions**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **See Appendix B-4.** **The results of air quality modeling for the existing SGS facility indicate that, at the allowable SO2 emission rate of 1.2 lb/MMBtu, the SGS facility may be contributing to impacts at the Okeefenokee Class I area above increments. Reducing emissions from Units 1 and 2 to an SO2 emission rate of 0.67 lb/MMBtu results in no impact above increments (see Appendix C).**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Potential emissions set equal to allowable emissions.** **Emission factor based on raw coal characteristics and overall 90% removal efficiency.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.67 lb/MMBtu**	4. Equivalent Allowable Emissions: **4,805** lb/hour **21,047** tons/year
5. Method of Compliance: **Continuous Emissions Monitoring System (CEMS).**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control: **65 %**
3. Potential Emissions: **3,299** lb/hour **14,450** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.46 lb/MMBtu** Reference: **Proposed emissions**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **See Appendix B-4.** **Allowable Acid Rain limit of 0.46 lb/MMBtu (annual average) is effective 1/1/08.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.46 lb/MMBtu**	4. Equivalent Allowable Emissions: **3,299** lb/hour **14,450** tons/year
5. Method of Compliance: **Continuous Emissions Monitoring System (CEMS)**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM/PM10**	2. Total Percent Efficiency of Control: **99.60 %**
3. Potential Emissions: **215.20** lb/hour **942.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.03 lb/MMBtu** Reference: **Allowable emissions**	7. Emissions Method Code:
8. Calculation of Emissions: **See Appendix B-4.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **NSPS 40 CFR 60, Subpart Da. Potential Emissions set equal to allowable emissions.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **846 / 836 tons/yr**	4. Equivalent Allowable Emissions: lb/hour **846/836** tons/year
5. Method of Compliance: **See Text and Table B-4**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1,047.1** lb/hour **4,586** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.146 lb/MMBtu** Reference: **Test Data**	7. Emissions Method Code:
8. Calculation of Emissions: **See Appendix B-4** **Based on results of CO testing from 1998-2002. Max values were 0.146 lb/MMBtu for 100% coal; 0.069 lb/MMBtu for 70/30% coal/pet coke blend. Avg values for the 5-yr test period were 0.096 lb/MMBtu for 100% coal; 0.045 lb/MMBtu for 70/30% coal/pet coke blend.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **There is no allowable CO emissions limitation.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **5,099** tons/yr	4. Equivalent Allowable Emissions: lb/hour **5,099** tons/year
5. Method of Compliance: **.See Text and Table B-4**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control: %
3. Potential Emissions: **19.60** lb/hour **85.7** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.06 lb/ton coal** Reference: **Estimated emissions**	7. Emissions Method Code:
8. Calculation of Emissions: **See Appendix B-4.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **There is no allowable VOC emissions limitation.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **147** tons/yr	4. Equivalent Allowable Emissions: lb/hour **147** tons/year
5. Method of Compliance: **See Text and Table B-4.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control: **50** %
3. Potential Emissions: **688.5** lb/hour **3,016** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.096 lb/MMBtu** Reference: **Test Data**	7. Emissions Method Code:
8. Calculation of Emissions: **See Appendix B-4** **Based on results of SAM testing from 1998-2002. Max values were 0.081 lb/MMBtu for 100% coal; 0.096 lb/MMBtu for 70/30% coal/pet coke blend. Avg values for the 5-yr test period were 0.043 lb/MMBtu for 100% coal; 0.049 lb/MMBtu for 70/30% coal/pet coke blend.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **There is no allowable SAM emissions limitation.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2,135** tons/yr	4. Equivalent Allowable Emissions: lb/hour **2,135** tons/year
5. Method of Compliance: **See Text and Table B-4.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **Continuous Opacity Monitoring System (COMS).**	
5. Visible Emissions Comment: **40 CFR 60, Subpart Da while firing all fuels; standards do not apply during periods of startup, shutdown or malfunction.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 4

1. Parameter Code: **SO2**	2. Pollutant(s): **SO2**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Thermo-Environmental Instruments, inc.** Model Number: **43B**	Serial Number: **43B-46935-277**
5. Installation Date: **05/31/1994**	6. Performance Specification Test Date: **10/19/1994**
7. Continuous Monitor Comment: **40 CFR 60, Subpart Da and 40 CFR Part 75.**	

Continuous Monitoring System: Continuous Monitor 2 of 4

1. Parameter Code: **NOX**	2. Pollutant(s): **NOX**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Thermo-Environmental, Inc.** Model Number: **42D**	Serial Number: **42D-46961-277**
5. Installation Date: **05/31/1994**	6. Performance Specification Test Date: **10/19/1994**
7. Continuous Monitor Comment: **40 CFR 60, Subpart Da and 40 CFR Part 75.**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 3 of 4

1. Parameter Code: **VE**	2. Pollutant(s): **VE**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **KVB/MIP** Model Number: **LM3086EPA3**	Serial Number: **730097**
5. Installation Date: **05/31/1994**	6. Performance Specification Test Date: **11/07/1995**
7. Continuous Monitor Comment: **40 CFR 60, Subpart Da and 40 CFR Part 75.**	

Continuous Monitoring System: Continuous Monitor 4 of 4

1. Parameter Code:	2. Pollutant(s): **CO2**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo-Environmental Instruments, Inc.** Model Number: **41H**	Serial Number: **41H-42927-268**
5. Installation Date: **05/31/1994**	6. Performance Specification Test Date: **10/19/1994**
7. Continuous Monitor Comment: **40 CFR Part 75.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **B-2A through B-2C** ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **B-6** ☐ Previously Submitted, Date _____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **B-3** ☐ Previously Submitted, Date _____

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **B-8 and B-9** ☐ Previously Submitted, Date _____
   ☐ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ☒ Previously Submitted, Date **July 2004**
   ☐ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ To be Submitted, Date (if known): _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: **See Text** ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: **See App. C** ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ☒ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: _____ ☐ Not Applicable	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: _____ ☐ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: _____ ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _____ ☐ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Not Applicable	

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
Steam Electric Generator No. 2

3. Emissions Unit Identification Number: **002**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A			**49**	☒ Yes ☐ No

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: **735.9** MW

11. Emissions Unit Comment:
Unit No. 2 is a "regulated" emissions unit.
Generator nameplate rating will be 735.9 MW after the upgrades are complete.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
   Existing Control Equipment:

   Electrostatic Precipitator (10)
   Wet Limestone Flue Gas Desulfurization or FGD (67)

   Proposed Control Equipment:

   Low NOx Burners (205)
   Low Excess-Air Firing (204)
   Selective Catalytic Reduction or SCR (139)
   Alkali Injection (70)

2. Control Device or Method Code(s): **10, 67, 70, 139, 204, and 205**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: 7,172 million Btu/hr		
4. Maximum Incineration Rate:	pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8,760 hours/year
6. Operating Capacity/Schedule Comment:		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: U-002		2. Emission Point Type Code: 1
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: V	6. Stack Height: 695 feet	7. Exit Diameter: 26.5 feet
8. Exit Temperature: 128 °F	9. Actual Volumetric Flow Rate: 1,987,064 acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 4

1. Segment Description (Process/Fuel Type): **Bituminous Coal**		
2. Source Classification Code (SCC): **1-01-002-02**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **326**	5. Maximum Annual Rate: **2,855,760**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **3.30**	8. Maximum % Ash: **11.00**	9. Million Btu per SCC Unit: **22**
10. Segment Comment: **Coal sulfur content is 3.0 weight percent on a monthly average basis. Million Btu per SCC Unit is based on 11,000 Btu/lb (as-received basis). Max hourly and annual rates based on nominal fuel heating value and unit max heat imput of 7,172 MMBtu/hr.**		

Segment Description and Rate: Segment 2 of 4

1. Segment Description (Process/Fuel Type): **Petroleum Coke**		
2. Source Classification Code (SCC): **1-01-008-01**	3. SCC Units: **Tone Burned**	
4. Maximum Hourly Rate: **93.00**	5. Maximum Annual Rate: **814,680**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **7.0**	8. Maximum % Ash: **1.0**	9. Million Btu per SCC Unit: **26**
10. Segment Comment: **Max pet coke content of coal/pet coke blend is 30 percent by wt.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 3 of 4

1. Segment Description (Process/Fuel Type): **Distillate Oil (Nos. 1 and 2)**		
2. Source Classification Code (SCC): **1-01-005-01**	3. SCC Units: **1000 Gallons Burned**	
4. Maximum Hourly Rate: **3.32**	5. Maximum Annual Rate: **1,664.2**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.50**	8. Maximum % Ash: **0.10**	9. Million Btu per SCC Unit: **136**
10. Segment Comment: **Distillate oil is used for startups, flame stabilization, emergency reserve capacity during statewide energy shortages, and limited supplemental load.**		

Segment Description and Rate: Segment 4 of 4

1. Segment Description (Process/Fuel Type): **On-specification Used Oil**		
2. Source Classification Code (SCC): **1-01-013-02**	3. SCC Units: **1000 Gallons Burned**	
4. Maximum Hourly Rate: **3.30**	5. Maximum Annual Rate: **500**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.50**	8. Maximum % Ash: **0.10**	9. Million Btu per SCC Unit: **142**
10. Segment Comment: **On-spec used oil max levels: arsenic- 5 ppm; cadmium- 2 ppm; chromium- 10 ppm; lead- 100 ppm; total halogens- 1,000 ppm; flash point- 100 F; and PCBs- < 50 ppm.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
SO2	67		EL
PM/PM10	10		EL
NOX	139	204 and 205	EL
CO			NS
VOC			NS
SAM	70		NS

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO2**

2. Total Percent Efficiency of Control: **90%**

3. Potential Emissions: **4,805.2** lb/hour **21,047** tons/year

4. Synthetically Limited? ☐ Yes ☒ No

5. Range of Estimated Fugitive Emissions (as applicable): to tons/year

6. Emission Factor: **0.67 lb/MMBtu**
   Reference: **Proposed emissions**

7. Emissions Method Code: **0**

8. Calculation of Emissions:
   See Appendix B-4.

   The results of air quality modeling for the existing SGS facility indicate that, at the allowable SO2 emission rate of 1.2 lb/MMBtu, the SGS facility may be contributing to impacts at the Okeefenokee Class I area above increments. Reducing emissions from Units 1 and 2 to an SO2 emission rate of 0.67 lb/MMBtu results in no impact above increments (see Appendix C)

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
   Potential emissions set equal to allowable emissions.
   Emission factor based on raw coal characteristics and overall 90% removal efficiency.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.67 lb/MMBtu**	4. Equivalent Allowable Emissions: **4,805** lb/hour **21,047** tons/year
5. Method of Compliance: **Continuous Emissions Monitoring System (CEMS).**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control: **65 %**
3. Potential Emissions: **3,299** lb/hour **14,450** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.46 lb/MMBtu** Reference: **Proposed emissions**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **See Appendix B-4.** **Allowable Acid Rain limit of 0.46 lb/MMBtu (annual average) is effective 1/1/08.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.46 lb/MMBtu**	4. Equivalent Allowable Emissions: **3,299** lb/hour **14,450** tons/year
5. Method of Compliance: **Continuous Emissions Monitoring System (CEMS)**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control: **99.60 %**
3. Potential Emissions: **215.20** lb/hour **942.40** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.03 lb/MMBtu** Reference: **Allowable emissions**	7. Emissions Method Code:
8. Calculation of Emissions: **See Appendix B-4.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **NSPS 40 CFR 60, Subpart Da. Potential Emissions set equal to allowable emissions.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **846 / 836 tons/yr**	4. Equivalent Allowable Emissions: lb/hour **846 / 836** tons/year
5. Method of Compliance: **See Text and Table B-4.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1,047.1** lb/hour **4,586** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.146 lb/MMBtu** Reference: **Test Data**	7. Emissions Method Code:
8. Calculation of Emissions: **See Appendix B-4** **Based on results of CO testing from 1998-2002. Max values were 0.146 lb/MMBtu for 100% coal; 0.069 lb/MMBtu for 70/30% coal/pet coke blend. Avg values for the 5-yr test period were 0.096 lb/MMBtu for 100% coal; 0.045 lb/MMBtu for 70/30% coal/pet coke blend.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **There is no allowable CO emissions limitation.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **5,099** tons/yr.	4. Equivalent Allowable Emissions: lb/hour **5,099** tons/year
5. Method of Compliance: **.See Text and Table B-4**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

<u>Potential/Estimated Fugitive Emissions</u>

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control: %
3. Potential Emissions: **19.60** lb/hour **85.7** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.06 lb/ton coal** Reference: **Estimated emissions**	7. Emissions Method Code:
8. Calculation of Emissions: **See Appendix B-4.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **There is no allowable VOC emissions limitation.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **147** tons/yr	4. Equivalent Allowable Emissions: lb/hour **147** tons/year
5. Method of Compliance: **See Text and Table B-4.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control: **50** %
3. Potential Emissions: **688.5** lb/hour **3,016** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.096 lb/MMBtu** Reference: **Test Data**	7. Emissions Method Code:
8. Calculation of Emissions: **See Appendix B-4** **Based on results of SAM testing from 1998-2002. Max values were 0.081 lb/MMBtu for 100% coal; 0.096 lb/MMBtu for 70/30% coal/pet coke blend. Avg values for the 5-yr test period were 0.043 lb/MMBtu for 100% coal; 0.049 lb/MMBtu for 70/30% coal/pet coke blend.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **There is no allowable SAM emissions limitation.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2,135** tons/yr	4. Equivalent Allowable Emissions: lb/hour **2,135** tons/year
5. Method of Compliance: **See Text and Table B-4.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **Continuous Opacity Monitoring System (COMS).**	
5. Visible Emissions Comment: **40 CFR 60, Subpart Da while firing all fuels; standards do not apply during periods of startup, shutdown or malfunction.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 4

1. Parameter Code: **SO2**	2. Pollutant(s): **SO2**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo-Environmental Instruments, inc.** Model Number: **43B**	Serial Number: **43B-46935-277**
5. Installation Date: **05/31/1994**	6. Performance Specification Test Date: **10/19/1994**
7. Continuous Monitor Comment: **40 CFR 60, Subpart Da and 40 CFR Part 75.**	

Continuous Monitoring System: Continuous Monitor 2 of 4

1. Parameter Code: **NOX**	2. Pollutant(s): **NOX**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo-Environmental, Inc.** Model Number: **42D**	Serial Number: **42D-46961-277**
5. Installation Date: **05/11/1994**	6. Performance Specification Test Date: **10/19/1994**
7. Continuous Monitor Comment: **40 CFR 60, Subpart Da and 40 CFR Part 75.**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 3 of 4

1. Parameter Code: **VE**	2. Pollutant(s): **VE**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **KVB/MIP** Model Number: **LM3086EPA3**	Serial Number: **730097**
5. Installation Date: **05/31/1994**	6. Performance Specification Test Date: **11/07/1995**
7. Continuous Monitor Comment: **40 CFR 60, Subpart Da and 40 CFR Part 75.**	

Continuous Monitoring System: Continuous Monitor 4 of 4

1. Parameter Code:	2. Pollutant(s): **CO2**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo-Environmental Instruments, Inc.** Model Number: **41H**	Serial Number: **41H-42927-268**
5. Installation Date: **05/31/1994**	6. Performance Specification Test Date: **10/19/1994**
7. Continuous Monitor Comment: **40 CFR Part 75.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **B-2A through B-2C** ☐ Previously Submitted, Date ____
2.	Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **B-6** ☐ Previously Submitted, Date ____
3.	Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **B-3** ☐ Previously Submitted, Date ____
4.	Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **B-8 and B-9** ☐ Previously Submitted, Date ____ ☐ Not Applicable (construction application)
5.	Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ____ ☒ Previously Submitted, Date **July 2004** ☐ Not Applicable
6.	Compliance Demonstration Reports/Records ☐ Attached, Document ID: ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ Previously Submitted, Date: ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ To be Submitted, Date (if known): ____ Test Date(s)/Pollutant(s) Tested: ____ ☐ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7.	Other Information Required by Rule or Statute ☐ Attached, Document ID: ____ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: **See Text** ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: **See App. C** ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ☒ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☐ Attached, Document ID: _____ ☐ Not Applicable	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: _____ ☐ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: _____ ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _____ ☐ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Not Applicable	

Additional Requirements Comment

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:

CBO™ Feed Fly Ash Silo

3. Emissions Unit Identification Number: **09**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**06/01/07**	**12/31/08**	**49**	☐ Yes ☒ No

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Fabric Filter-Low Temperature** **(Control Device Code 018)**
2. Control Device or Method Code(s): **018**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **75 tons/hr**		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: million Btu/hr		
4. Maximum Incineration Rate: pounds/hr tons/day		
5. Requested Maximum Operating Schedule:	**24** hours/day **52** weeks/year	7 days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment:		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **CBO-001**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: **H**	6. Stack Height: **93 feet**	7. Exit Diameter: **1.3 feet**
8. Exit Temperature: **77 °F**	9. Actual Volumetric Flow Rate: **3,040 acfm**	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: Dscfm **3,000**		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **Feed Fly Ash Storage**		
2. Source Classification Code (SCC): **3-05-009-99**	3. SCC Units: **Tons Transferred or Handled**	
4. Maximum Hourly Rate: **75**	5. Maximum Annual Rate: **657,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

Segment Description and Rate: Segment _ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	**018**		**EL**
PM10	**018**		**NS**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control: **99 percent**
3. Potential Emissions: **0.3** lb/hour **1.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.01 gr/dscf** Reference: **Vendor Data**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Attachment B for emission rate calculations.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **5% Opacity**	4. Equivalent Allowable Emissions: **0.3** lb/hour **1.1** tons/year
5. Method of Compliance: **EPA Reference Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-297.620(4), F.A.C.**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control: **99 percent**
3. Potential Emissions: **0.3** lb/hour **1.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.01 gr/dscf** Reference: **Vendor Data**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Attachment B for emission rate calculations.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _ of _N/A

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **5% Opacity**	4. Equivalent Allowable Emissions: **0.3** lb/hour **1.1** tons/year
5. Method of Compliance: **EPA Reference Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-297.620(4), F.A.C.**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE05**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 5 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Rule 62-297.620(4), F.A.C.**	

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor ___ of ___N/A

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **B-2A—B-2C** ☐ Previously Submitted, Date ________

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: ________ ☒ Not Applicable

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **See Text**___ ☐ Previously Submitted, Date ________

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: ________ ☐ Previously Submitted, Date ________
☒ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: ________ ☐ Previously Submitted, Date ________
☒ Not Applicable

6. Compliance Demonstration Reports/Records
☐ Attached, Document ID: ________
Test Date(s)/Pollutant(s) Tested: ________________
☐ Previously Submitted, Date: ________
Test Date(s)/Pollutant(s) Tested: ________________
☐ To be Submitted, Date (if known): ________
Test Date(s)/Pollutant(s) Tested: ________________
☒ Not Applicable
Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
☐ Attached, Document ID: ________ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: ___________ ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: ___________ ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ___________ ☒ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications N/A

1. Identification of Applicable Requirements ☐ Attached, Document ID: ___________	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: ___________ ☐ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: ___________ ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: ___________ ☐ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID:_ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Not Applicable	

Additional Requirements Comment

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:

   CBO™ Product Fly Ash Storage Dome

3. Emissions Unit Identification Number: **010**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**060/01/07**	**12/31/08**	**49**	☐ Yes ☒ No

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Fabric Filter-Medium Temperature** **(Control Device Code 017)**	
2. Control Device or Method Code(s): **017**	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **75 tons/hr**	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment:	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **CBO-002**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: **H**	6. Stack Height: **106 feet**	7. Exit Diameter: **2.2 feet**
8. Exit Temperature: **200 °F**	9. Actual Volumetric Flow Rate: **7,600 acfm**	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: Dscfm **6,000**		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **Product Fly Ash Storage**		
2. Source Classification Code (SCC): **3-05-009-99**	3. SCC Units: **Tons Transferred or Handled**	
4. Maximum Hourly Rate: **75**	5. Maximum Annual Rate: **657,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	017		EL
PM10	017		NS

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control: **99 percent**
3. Potential Emissions: **0.5** lb/hour **2.3** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.01 gr/dscf** Reference: **Vendor Data**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Attachment B for emission rate calculations.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **5% Opacity**	4. Equivalent Allowable Emissions: **0.5** lb/hour **2.3** tons/year
5. Method of Compliance: **EPA Reference Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-297.620(4), F.A.C.**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control: **99 percent**
3. Potential Emissions: **0.5** lb/hour **2.3** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.01 gr/dscf** Reference: **Vendor Data**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Attachment B for emission rate calculations.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _ of _N/A

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **5% Opacity**	4. Equivalent Allowable Emissions: **0.5** lb/hour **2.3** tons/year
5. Method of Compliance: **EPA Reference Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-297.620(4), F.A.C.**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE05**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **5** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Rule 62-297.620(4), F.A.C.**	

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor ___ of __N/A

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **B-2A—B-2C** ☐ Previously Submitted, Date ________
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: __________ ☒ Not Applicable
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **See Text** ☐ Previously Submitted, Date ________
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: __________ ☐ Previously Submitted, Date ________ ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: __________ ☐ Previously Submitted, Date ________ ☒ Not Applicable
6. Compliance Demonstration Reports/Records ☐ Attached, Document ID: __________ Test Date(s)/Pollutant(s) Tested: ____________ ☐ Previously Submitted, Date: _______ Test Date(s)/Pollutant(s) Tested: ____________ ☐ To be Submitted, Date (if known): __________ Test Date(s)/Pollutant(s) Tested: ____________ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute ☐ Attached, Document ID: __________ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: ____________ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: ____________ ☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ____________ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications N/A

1. Identification of Applicable Requirements ☐ Attached, Document ID: ____________
2. Compliance Assurance Monitoring ☐ Attached, Document ID: ___________ ☐ Not Applicable
3. Alternative Methods of Operation ☐ Attached, Document ID: ___________ ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: ___________ ☐ Not Applicable
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID:_ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID:____________ ☐ Previously Submitted, Date:_________ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID:____________ ☐ Previously Submitted, Date:_________ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID:____________ ☐ Previously Submitted, Date:_________ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID:____________ ☐ Previously Submitted, Date:_________ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID:____________ ☐ Previously Submitted, Date:_________ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID:____________ ☐ Previously Submitted, Date:_________ ☐ Not Applicable

Additional Requirements Comment

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:

   CBO™ Product Fly Ash Loadout Storage Silo

3. Emissions Unit Identification Number: **011**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**06/01/07**	**12/31/08**	**49**	☐ Yes ☒ No

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Fabric Filter-Medium Temperature** **(Control Device Code 017)**
2. Control Device or Method Code(s): **017**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **75 tons/hr**		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: million Btu/hr		
4. Maximum Incineration Rate: pounds/hr tons/day		
5. Requested Maximum Operating Schedule:	**24** hours/day **52** weeks/year	**7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment:		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **CBO-003**		2. Emission Point Type Code: **2**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **Product Fly Ash Truck/Rail Loading Silo** **Product Fly Ash Truck/Rail Loading**		
5. Discharge Type Code: **H**	6. Stack Height: **87 feet**	7. Exit Diameter: **1.9 feet**
8. Exit Temperature: **200 °F**	9. Actual Volumetric Flow Rate: **7,600 acfm**	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: Dscfm **6,000**		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **Product Fly Ash Storage and Handling**		
2. Source Classification Code (SCC): **3-05-009-99**	3. SCC Units: **Tons Transferred or Handled**	
4. Maximum Hourly Rate: **75**	5. Maximum Annual Rate: **657,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

Segment Description and Rate: Segment _ of _

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	**017**		**EL**
PM10	**017**		**NS**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control: **99 percent**
3. Potential Emissions: **0.5** lb/hour **2.3** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.01 gr/dscf** Reference: **Vendor Data**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Attachment B for emission rate calculations.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **5% Opacity**	4. Equivalent Allowable Emissions: **0.5** lb/hour **2.3** tons/year
5. Method of Compliance: **EPA Reference Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-297.620(4), F.A.C.**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control: **99 percent**
3. Potential Emissions: **0.5** lb/hour **2.3** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.01 gr/dscf** Reference: **Vendor Data**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See Attachment B for emission rate calculations.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _ of _N/A

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **5% Opacity**	4. Equivalent Allowable Emissions: **0.5** lb/hour **2.3** tons/year
5. Method of Compliance: **EPA Reference Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-297.620(4), F.A.C.**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE05**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 5 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Rule 62-297.620(4), F.A.C.**	

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor ___ of ___N/A

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **B-2A—B-2C** ☐ Previously Submitted, Date ________

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: __________ ☒ Not Applicable

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Text** ☐ Previously Submitted, Date ________

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: __________ ☐ Previously Submitted, Date ________
   ☒ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: __________ ☐ Previously Submitted, Date ________
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: __________
   Test Date(s)/Pollutant(s) Tested: ______________________________

   ☐ Previously Submitted, Date: _______
   Test Date(s)/Pollutant(s) Tested: ______________________________

   ☐ To be Submitted, Date (if known): __________
   Test Date(s)/Pollutant(s) Tested: ______________________________

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: __________ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: ___________ ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: ___________ ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ___________ ☒ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications N/A

1. Identification of Applicable Requirements ☐ Attached, Document ID: ___________	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: __________ ☐ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: __________ ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: __________ ☐ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID:_ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Not Applicable	

Additional Requirements Comment

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☐ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☒ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:

   CBO™ Product Fly Ash Fugitives

3. Emissions Unit Identification Number: **012**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**06/01/07**	**12/31/08**	**49**	☐ Yes ☒ No

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Watering of roadways, as necessary** **(Control Device Code 062)**
2. Control Device or Method Code(s): **062**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **657,000 tons/yr of product fly ash**		
2. Maximum Production Rate:		
3. Maximum Heat Input Rate: million Btu/hr		
4. Maximum Incineration Rate: pounds/hr tons/day		
5. Requested Maximum Operating Schedule:	**24** hours/day **52** weeks/year	**7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment:		

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **CBO-004**		2. Emission Point Type Code: **4**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: **F**	6. Stack Height:	7. Exit Diameter:
8. Exit Temperature: **77 °F**	9. Actual Volumetric Flow Rate: Acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: Dscfm		12. Nonstack Emission Point Height: **0 feet**
13. Emission Point UTM Coordinates... Zone: East (km): North (km):		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **Product Fly Ash Handling**		
2. Source Classification Code (SCC): **3-05-009-99**	3. SCC Units: **Tons Transferred or Handled**	
4. Maximum Hourly Rate: **104**	5. Maximum Annual Rate: **657,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment: **Max hourly rate based on 8 trucks per hour, each containing 13 tons of product fly ash.**		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	**062**		**NS**
PM10	**062**		**NS**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control: **90 percent**
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **0.2 tons/year**	
6. Emission Factor: **N/A** Reference: **AP-42, Section 13.2.1**	7. Emissions Method Code: **3**
8. Calculation of Emissions: **See Attachment B for emission rate calculations.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _ of __N/A

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control: **90 percent**
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **0.2 tons/year**	
6. Emission Factor: **N/A** Reference: **AP-42, Section 13.2.1**	7. Emissions Method Code: **3**
8. Calculation of Emissions: **See Attachment B for emission rate calculations.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _ of _N/A

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation _of __N/A

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor ___ of ___N/A

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **B-2A—B-2C** ☐ Previously Submitted, Date ______
2.	Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ______ ☒ Not Applicable
3.	Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **See Text** ☐ Previously Submitted, Date ______
4.	Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ______ ☐ Previously Submitted, Date ______ ☒ Not Applicable (construction application)
5.	Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ______ ☐ Previously Submitted, Date ______ ☒ Not Applicable
6.	Compliance Demonstration Reports/Records ☐ Attached, Document ID: ______ Test Date(s)/Pollutant(s) Tested: ______ ☐ Previously Submitted, Date: ______ Test Date(s)/Pollutant(s) Tested: ______ ☐ To be Submitted, Date (if known): ______ Test Date(s)/Pollutant(s) Tested: ______ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7.	Other Information Required by Rule or Statute ☐ Attached, Document ID: ______ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: ___________ ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: ___________ ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ___________ ☒ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications N/A

1. Identification of Applicable Requirements ☐ Attached, Document ID: ___________	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: ___________ ☐ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID: ___________ ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: ___________ ☐ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID:_ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID:___________ ☐ Previously Submitted, Date:________ ☐ Not Applicable	

Additional Requirements Comment

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:

   CBO™ Fluidized Bed Combustor (FBC)- FBC Return to Units 1 and 2

3. Emissions Unit Identification Number: **013**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**06/01/07**	**12/31/08**	**49**	☐ Yes ☒ No

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

Fabric Filter for CBO- 017, Exhaust ducted through Units 1 and 2 Controls:

Selective Catalytic Reduction (SCR)- 139
Electrostatic Precipitator (ESP)- 010
Flue Gas Desulfurization (FGD)- 067

2. Control Device or Method Code(s): **017, 139, 010, and 067**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **114.7 MMBtu/hr**	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7** days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment:	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **CBO-005**	2. Emission Point Type Code: **2**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **001-Unit No. 1 Steam Generator** **002-Unit No. 2 Steam Generator** **013-CBO™ FBC Return**	

5. Discharge Type Code: **V**	6. Stack Height: **490 feet**	7. Exit Diameter: **24 feet**
8. Exit Temperature: **127 °F**	9. Actual Volumetric Flow Rate: **38,300** acfm	10. Water Vapor: **5 %**

11. Maximum Dry Standard Flow Rate: Dscfm **32,273**	12. Nonstack Emission Point Height: Feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Exhaust gases for CBO will through either Unit 1 or 2 prior to the SCR systems.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Feed fly ash burned in the CBO™ FBC**		
2. Source Classification Code (SCC): **1-02-002-17**	3. SCC Units: **Tons Burned**	
4. Maximum Hourly Rate: **75**	5. Maximum Annual Rate: **657,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.41**	8. Maximum % Ash: **100**	9. Million Btu per SCC Unit: **2.76**
10. Segment Comment:		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Distillate fuel oil burned in the CBO FBC (start-up fuel)**		
2. Source Classification Code (SCC): **1-02-005-02**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **0.25**	5. Maximum Annual Rate: **14.3**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.5**	8. Maximum % Ash: **0.1**	9. Million Btu per SCC Unit: **140**
10. Segment Comment: **Field 5 based on four cold starts per year.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	017/010	067	NS
PM10	017/010	067	NS
SO2	067		EL
NOX	139		EL
CO			NS
VOC			NS

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control: **95 percent**
3. Potential Emissions: **2.8** lb/hour **12.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.024 lb/MMBtu** Reference: **Vendor Data**	7. Emissions Method Code: **5**
8. Calculation of Emissions: **See Attachment B for emission rate calculations. The 12.1 tons/yr is prior to control with the Units 1 and 2 ESPs.** **In accordance with the requirements of Rule 62-297.310(7)(a)4.b., F.A.C., SECI proposes to conduct initial and annual PM sampling of the combined CBO™ return and Units 1 and 2 exhaust streams downstream of the Units 1 and 2 FGD control systems using EPA reference methods.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Field 2 is conservative estimate of PM removal for Units 1 and 2 ESP/FGD control systems.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _of __N/A

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control: **95 percent**
3. Potential Emissions: **2.8** lb/hour **12.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.024 lb/MMBtu** Reference: **Vendor Data**	7. Emissions Method Code: **5**
8. Calculation of Emissions: **See Attachment B for emission rate calculations. The 12.1 tons/yr estimate is prior to control with the Units 1 and 2 ESPs.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Field 2 is a conservative estimate of PM_{10} removal for Units 1 and 2 ESP/FGD control systems.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _ of _N/A

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control: **90 percent**
3. Potential Emissions: **596.3** lb/hour **2,612** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **5.2 lb/MMBtu** Reference: **Vendor Data**	7. Emissions Method Code: **5**

8. Calculation of Emissions:

See Attachment B for emission rate calculations. The 2,612 tons/yr estimate is prior to control in Units 1 and 2 FGDs.

SECI proposes to conduct continuous SO_2 monitoring of the combined CBO™ return and Units 1 and 2 exhaust streams using the existing SO_2 CEMS located downstream of the Units 1 and 2 FGD control systems.

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
Field 2 is estimate of SO_2 removal for Units 1 and 2 FGD control systems.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _ of _N/A

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **90% removal**	4. Equivalent Allowable Emissions: **59.6** lb/hour **261** tons/year
5. Method of Compliance: **CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **40 CFR Subpart Db**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **89.7** lb/hour **393** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.782 lb/MMBtu** Reference: **Vendor Data**	7. Emissions Method Code: **5**
8. Calculation of Emissions: **See Attachment B for emission rate calculations. The 393 tons/yr estimate is before control in the Units 1 and 2 SCRs.** **In accordance with the requirements of Rule 62-297.310(7)(a)4.b., F.A.C., SECI proposes to conduct initial NO_x testing of the CBO™ process.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _ of _N/A

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.2 lb/MMBtu**	4. Equivalent Allowable Emissions: **22.9** lb/hour **100.5** tons/year
5. Method of Compliance: **CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **40 CFR Subpart Db**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **28.0** lb/hour **122.6** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.24 lb/MMBtu** Reference: **Vendor Data**	7. Emissions Method Code: **5**
8. Calculation of Emissions: **See Attachment B for emission rate calculations.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _ of _N/A

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.244 lb/MMBtu**	4. Equivalent Allowable Emissions: **28.0** lb/hour **122.6** tons/year
5. Method of Compliance: **EPA Reference Method 10 test on Units 1 and/or 2**	
6. Allowable Emissions Comment (Description of Operating Method): **Proposed as BACT for Units 1 and 2**	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.1** lb/hour **9.0** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.018 lb/MMBtu** Reference: **Vendor Data**	7. Emissions Method Code: **5**
8. Calculation of Emissions: **See Attachment B for emission rate calculations.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions _ of _N/A

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation __of __N/A

1. Visible Emissions Subtype: **VE05**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 5 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: ***EPA Method 9***	
5. Visible Emissions Comment: **Rule 62-297.620(4), FAC**	

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor ___ of ___N/A

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **B-2A—B2-C** ☐ Previously Submitted, Date ________

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **B-6** ☐ Not Applicable

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See Text** ☐ Previously Submitted, Date ________

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ________ ☐ Previously Submitted, Date ________
   ☒ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ________ ☐ Previously Submitted, Date ________
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: ________
   Test Date(s)/Pollutant(s) Tested: ________
   ☐ Previously Submitted, Date: ________
   Test Date(s)/Pollutant(s) Tested: ________
   ☐ To be Submitted, Date (if known): ________
   Test Date(s)/Pollutant(s) Tested: ________
   ☒ Not Applicable
   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: ________ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: ________ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: ________ ☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ________ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications N/A

1. Identification of Applicable Requirements ☐ Attached, Document ID: ________
2. Compliance Assurance Monitoring ☐ Attached, Document ID: ________ ☐ Not Applicable
3. Alternative Methods of Operation ☐ Attached, Document ID: ________ ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: ________ ☐ Not Applicable
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID:_ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________ ☐ Not Applicable

Additional Requirements Comment

APPENDIX B

APPLICATION ATTACHMENTS

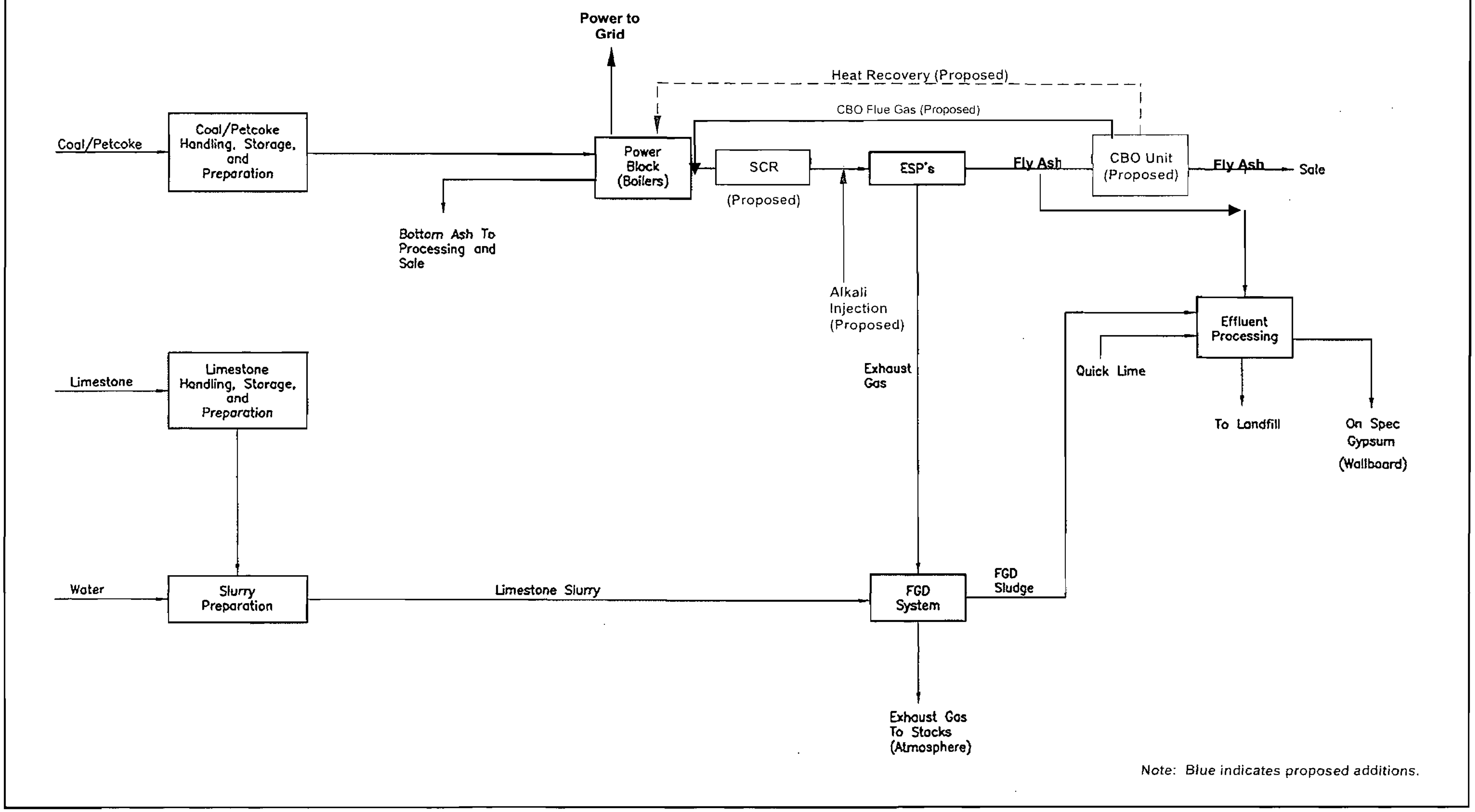
APPENDIX B-1

FACILITY PLOT PLANS

(SEE FIGURE GS-1)

APPENDIX B-2A

PROCESS FLOW DIAGRAM – OVERALL



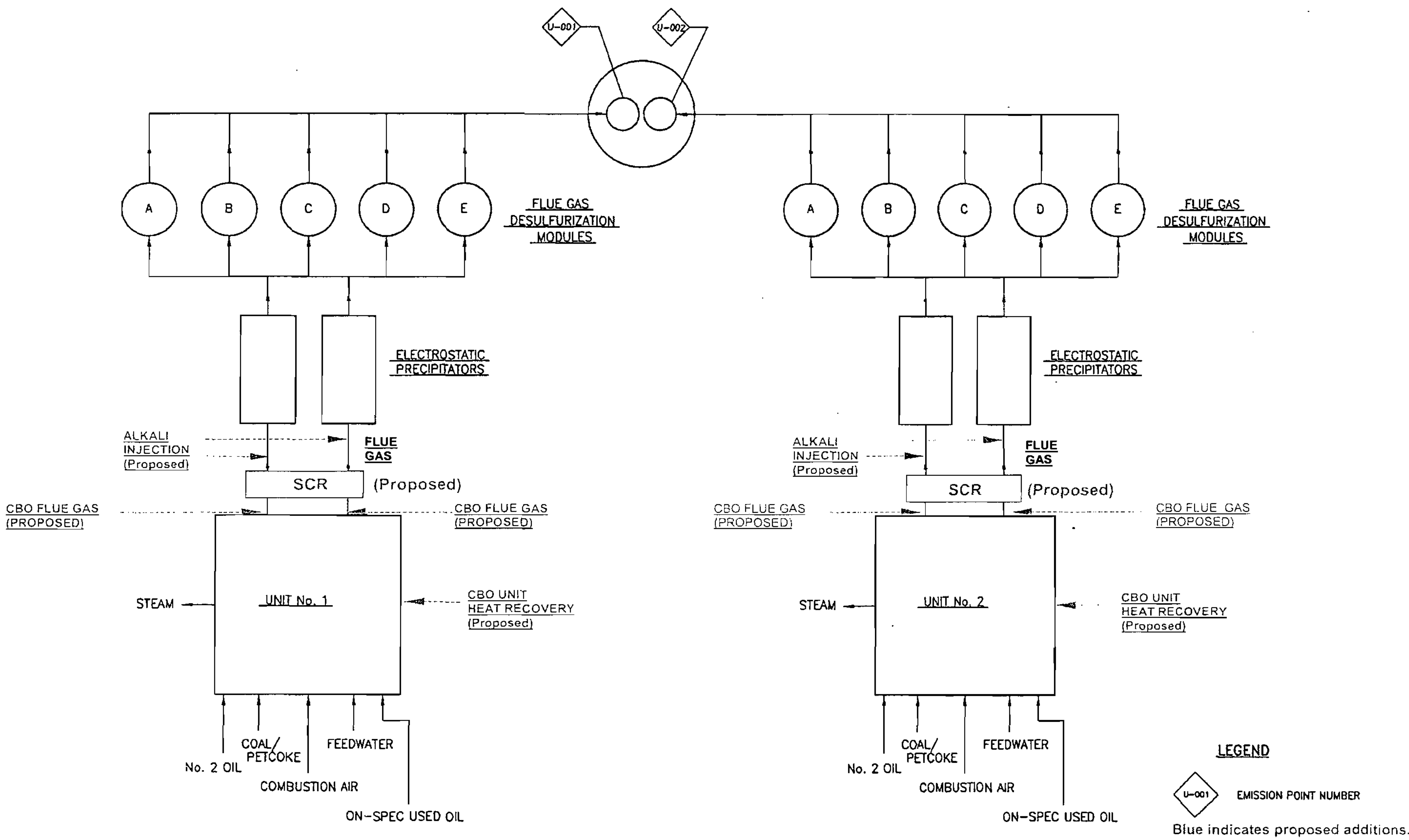
Attachment B-2A
Overall Facility Process Flow Diagram
Seminole Electric Cooperative, Inc.

Source: ECT, 2004; Golder, 2005.

Seminole Electric COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

APPENDIX B-2B

PROCESS FLOW DIAGRAM – MAIN BOILERS



Attachment B-2B
Boiler Process Flow Diagram
Seminole Electric Cooperative, Inc.

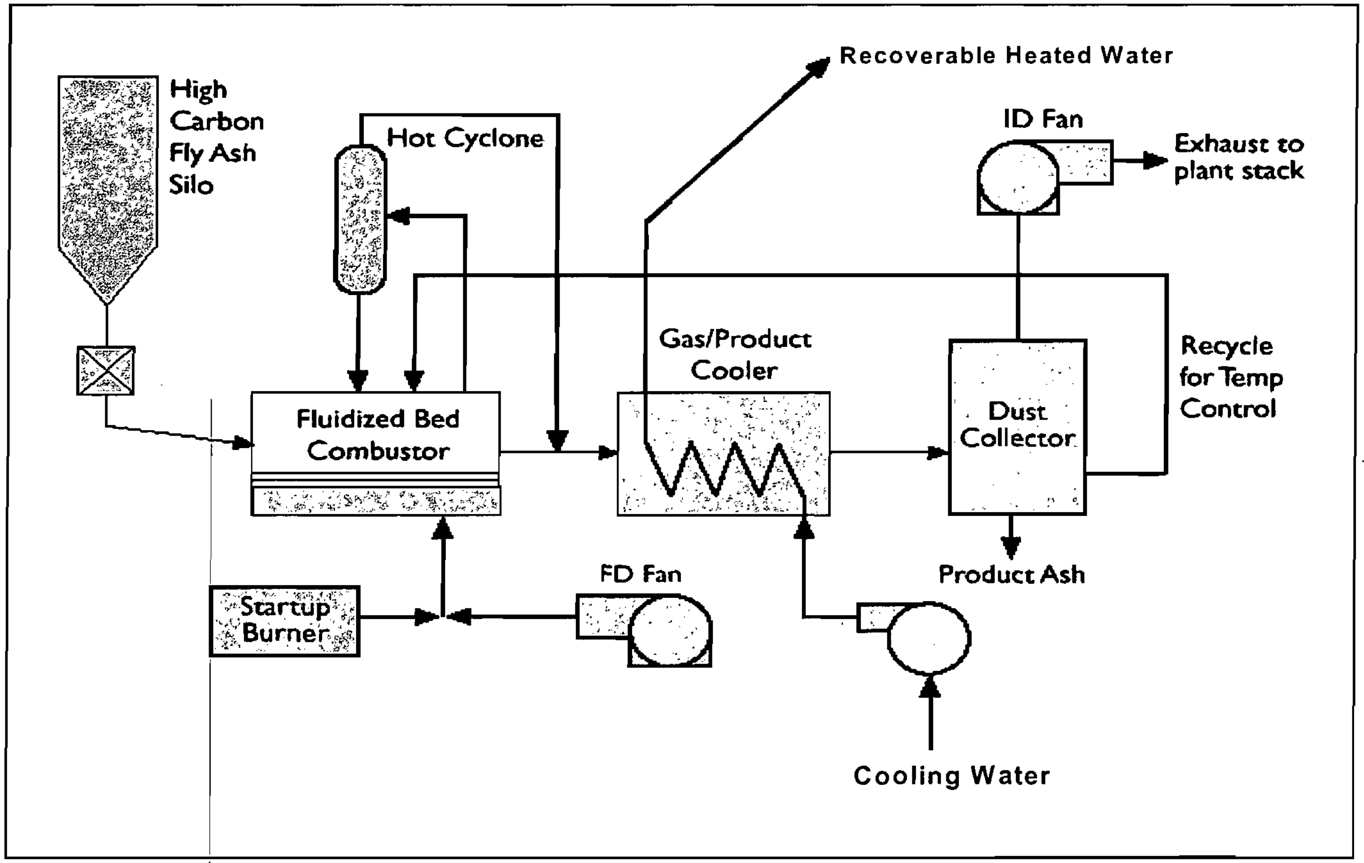
Source: Seminole Electric, 1984; ECT, 2004; Golder, 2005.

Seminole Electric COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

APPENDIX B-2C

PROCESS FLOW DIAGRAM – CBO UNIT

Carbon Burn-Out Schematic



PMI

A Progress Fuels Company

APPENDIX B-3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT
MAIN BOILERS

ELECTROSTATIC PRECIPITATOR

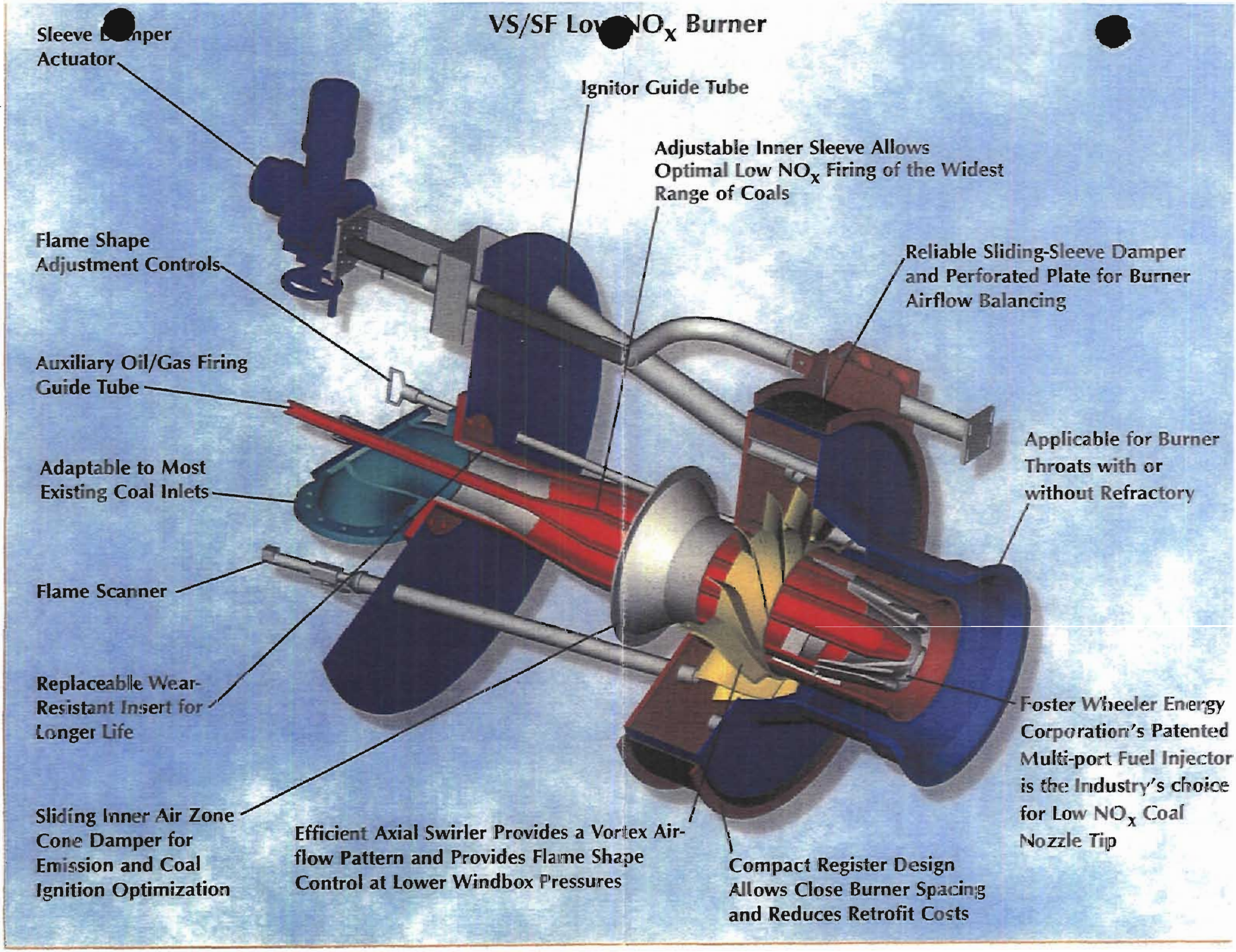
Control Equipment ID No.:	Unknown
Emission Point ID No.:	U-001
Manufacturer:	Research-Cottrell
Model No.:	UP-6032A
Control Efficiency (%):	99.7
Pressure Drop (in H_2O), operating:	12
Temperature, operating (°F):	200 to 300
Temperature, design (°F):	500
Inlet Air Flow Rate (acfm):	2,132,000/boiler
Collection Plate Area (ft^2):	984,960
Plate Cleaning Procedures:	Rappers

FLUE GAS DESULFURIZATION (FGD)

Control Equipment ID No.:	Unknown
Emission Point ID No.:	U-001
Manufacturer:	Peabody Process Systems
Description of Control Equipment:	Five absorber modules
Inlet Temperature (°F):	200 to 300
Outlet Temperature (°F):	110 to 135
Inlet Air Flow Rate (acfm):	2,132,000
Gas Velocity (ft/sec):	12.29
Additive Liquid Scrubbing Medium:	Limestone Slurry
Total Liquid Injection Rate (gpm):	37,165

APPENDIX D

SUMMARIES OF THE AERMOD AND CALPUFF MODEL RESULTS AND EXAMPLE MODEL INPUT FILES


VS/SF Lo O$_X$ Burner
Sleeve mper Actuator
Ignitor Guide Tube
Adjustable Inner Sleeve Allows Optimal Low NO$_X$ Firing of the Widest Range of Coals
Flame Shape Adjustment Controls
Reliable Sliding-Sleeve Damper and Perforated Plate for Burner Airflow Balancing
Auxiliary Oil/Gas Firing Guide Tube
Adaptable to Most Existing Coal Inlets
Applicable for Burner Throats with or without Refractory
Flame Scanner
Replaceable Wear-Resistant Insert for Longer Life
Foster Wheeler Energy Corporation's Patented Multi-port Fuel Injector is the Industry's choice for Low NO$_X$ Coal Nozzle Tip
Sliding Inner Air Zone Cone Damper for Emission and Coal Ignition Optimization
Efficient Axial Swirler Provides a Vortex Air-flow Pattern and Provides Flame Shape Control at Lower Windbox Pressures
Compact Register Design Allows Close Burner Spacing and Reduces Retrofit Costs

APPENDIX B-4

EMISSIONS CALCULATIONS

Table B-4 PSD Netting Analysis

Pollutant	Units 1 and 2 Baseline Actual Emissions (tpy)	Projected Actual Emissions with Project (tpy)	Net Emissions Increase with Project (tpy)	Significant Emission Rates (tpy)	PSD Review Required?
SO_2	29,074	29,113	39.0	40	No
NOx	23,289	21,638	39.0	40	No
PM	822	846	24.4	25	No
PM_{10}	822	836	14.4	15	No
H_2SO_4	2,129	2,135	6.4	7	No
VOC	108	147	39.0	40	No
CO	4,976	5,099	122.6	100	Yes
Hg	0.065	0.065	<0.1	<0.1	No

* Units 1 and 2 baseline actual emissions are based on Tables B-4E through B-4S.

Table B-4A CBO Project - Fluidized Bed Emission Estimates

Pollutant	Emission Rate (lb/MMBtu)	CBO Emission Rate (lb/hr)	CBO Emission Rate (TPY) to Units 1 and 2	Material Handling Emissions (TPY)	Net Emissions Increase with Units 1 and 2 (TPY)	PSD Significant Emission Rates (TPY)	PSD Review Required?
SO_2	5.200	596.3	2,611.8		39*	40	No
NO_x	0.782	89.7	392.9		39*	40	No
CO	0.244	28.0	122.6		122.6	100	Yes
VOCs	0.018	2.1	9.0		9.0	40	No
PM	0.024	2.8	12.1**	5.8	6.4**	25	No
PM_{10}	0.024	2.8	12.1**	5.8	6.4**	15	No

* See Table B-4. Projected actual emissions will be limited to baseline actual emissions.

** CBO emissions before Units 1 and 2 ESPs. Based on a conservative 95% removal, PM/PM10 emissions from the CBO FBC will be 0.6 TPY.

Table B-4B CBO Material Handling Emissions

Emission Source	Control Device	Exhaust Flow Rate (dscfm)	PM Emission Rate (gr/dscf)	PM Emission Rate (lb/hr)	PM Emission Rate (TPY)
Feed Fly Ash Silo	Baghouse	3,000	0.01	0.3	1.1
Product Fly Ash Storage Dome	Baghouse	6,000	0.01	0.5	2.3
Product Fly Ash Loadout Silo & Truck Loading	Baghouse	6,000	0.01	0.5	2.3
Fly Ash Fugitives (Truck Traffic)	Paved Roads; Watering	NA		0.1	0.2
Totals				1.4	5.8

APPENDIX B4-D

MERCURY EMISSIONS

The Fate of Ammonia and Mercury in the Carbon Burn-Out (CBO™) Process

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KEYWORDS: mercury, ammonia, carbon burn-out, fly ash

INTRODUCTION

Carbon Burn-Out (CBO™) has long been known as a very robust system for carbon removal for various types of ash feed stocks. Ash feed stocks with carbon contents ranging from 7% to 90% have been successfully processed. To date, over one million tons of coal fly ash have been processed using CBO™.

CBO™ processed coal fly ash exhibits excellent pozzolanic activity, consistent air entrainment, consistent LOI at 2.5% or less, and has gained excellent market acceptance.

Recently, there has been much discussion in the fly ash industry about the fate of ammonia and mercury on fly ash. These two parameters are present in coal fly ash via different mechanisms. Mercury is inherent to the coal while ammonia originates from post-combustion NOx reduction techniques using ammonia.

Ammonia on fly ash is primarily a result of recent pollution abatement techniques. Coal fired power generation facilities are under increasing pressure for NOx emission reductions. Recent United States EPA rule changes will require many coal fired utilities to meet NOx emissions limitations of 0.15 lbs./MBTU or less. In order to meet these requirements, many utilities will use a combination of combustion management and post-combustion processes. Combustion management techniques include low NOx burners, over-fire air systems, gas re-burning technology and flue gas re-circulation. These methods can contribute to higher residual carbon levels in fly ash, especially when operating for maximum NOx removal.

Post-combustion processes include Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). Use of either of these treatment technologies will result in fly ash contaminated with ammonia slip, which may then be un-marketable, depending on the concentration.

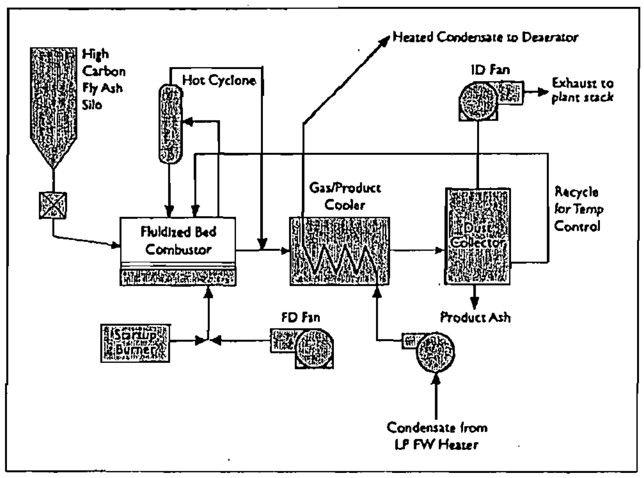
Mercury on the other hand is inherent or naturally occurs in coal. The average value for fly ash from Bituminous coal combustion is .41 ppm[1].

Given the industry's concerns, Progress Materials recently conducted investigations as to the fate of ammonia and mercury in the Carbon Burn-Out process. This paper presents recent findings concerning ammonia and mercury in the Carbon Burn-Out process.

THE CARBON BURN-OUT PROCESS

The Carbon Burn-Out process is a thermal process specifically designed for the reduction of carbon in fly ash.

FIGURE 1: <u>CBO™ Process Diagram</u>



Referring to Figure 1, the CBO™ process flow may be easily summarized:

- High-carbon ash is pneumatically transported to the high carbon fly ash silo.
- FD fan provides fluidization and combustion air to CBO™ fluid bed combustor.
- Start-Up Burner is used only during start up to heat bed to ignition temperature.
- High Carbon feed ash is metered into the combustor.
- Carbon combusts in the FBC on a continuous basis.
- Hot cyclones remove most elutriated particles from FBC flue gas.
- Low carbon fly ash exits FBC via level control weirs.
- Flue gas pneumatically conveys low carbon fly ash, both at about 1300° F through the Gas/Product Cooler.
- In the Gas/Product cooler, heat transfer occurs from hot product ash and hot flue gas to the condensate from the power plant.
- Product ash and flue gas exit at < 300° F.
- Heated condensate returns to power plant's feedwater heater system.

- Product ash is separated from flue gas via cyclone and baghouse.
- ID fan maintains entire CBO™ system at a slight negative pressure, transports product ash through the heat exchanger, and transports cooled, particulate-free flue gas to power plant stack.
- Product ash is pneumatically conveyed to storage for subsequent load out.
- Product ash is also recycled for FBC temperature control.

AMMONIA AND THE CARBON BURN-OUT PROCESS

Progress Materials' ammonia removal investigation approach was developed to accomplish two primary goals. The first goal was to determine Carbon Burn-Out's efficiency in removing ammonia from fly ash. Data would be generated to determine fly ash ammonia concentrations after Carbon Burn-Out processing. The second goal was to determine the fate of the ammonia in the Carbon Burn-Out process. This investigation step involved measuring gas phase ammonia concentrations thereby providing information as to whether the ammonia is exhausted or thermally decomposed within the CBO™ system.

This work on the fate of ammonia in the CBO™ builds on the work previously reported by PMI [2].

Ammonia Testing Procedures and Results

In order to determine the effectiveness of ammonia removal by Carbon Burn-Out, several fly ash feed stocks of differing ammonia contents were processed. Processing was accomplished using Progress Materials' one ton per hour pilot facility located in Tampa, Florida.

Ammonia containing fly ash samples from several Eastern United States utilities were selected for processing. Fly ash ammonia concentrations ranged between 50 and 750 ppmw. Ammoniated fly ash used in this study was generated in both SCR and SNCR systems. Ammonia or Urea was used as the process reagent.

Carbon Burn-Out's fluid bed technology provides heat and residence time dictated by conditions for optimal combustion of carbon found in fly ash. Fly ash residence times of forty-five minutes and temperatures in the 1300°F range are characteristic of the CBO™ process. Kinetic theory suggest that CBO™ conditions should be ideal for ammonia removal and decomposition.

Both feed and product samples were analyzed for ammonia content. Ammoniated fly ash was tested by several different methods. Testing methodology for ammonia in fly ash is not well defined. However, well-defined methods have been used for solid matrices in environmental testing. EPA methods 350.2, 350.3 and a rapid field technique developed by Boral Materials Technologies Inc. were selected for use in our testing program.

Table 1 illustrates results of four different, as-received fly ashes tested using the three methods. EPA methods 350.2 and 350.3 produced similar results. EPA 350.2 uses an aggressive acid distillation step while method 350.3 uses only distilled water for the dissolution of ammonia. The similarity of results between the two methods indicates that the ammonia is water-soluble. The Boral method, which is a simpler-to-run field test, also produced reasonably similar results.

Table1: Ammonia Method Comparison

	EPA 350.2 (PPM)	EPA 350.3 (PPM)	Boral Procedure (PPM)
Sample 1	300	306	320
Sample 2	351	300	250
Sample 3	534	660	525
Sample 4	735	610	720

Table 2 illustrates ammoniated fly ash samples before and after processing by Carbon Burn-Out. Ammonia content of the feed and product, type of NOx control device used and NOx reagent are shown.

Table 2: Ammonia in Fly Ash Feed

Feed Ash (PPM)	Product Ash (PPM)*	Control Device	Reagent
60	< 5	SCR	Ammonia
230	< 5	SNCR	Ammonia
300	< 5	SNCR	Ammonia
500	< 5	SNCR	Ammonia
650	< 5	SNCR	Ammonia
700	< 5	SNCR	Urea
735	< 5	SNCR	Urea

* < Indicates detection limit of the method

Results indicate that under normal Carbon Burn-Out operating conditions essentially all ammonia was removed from the fly ash feed material.

The second goal of the study involved the determination of the fate of released ammonia in the flue gas. To quantify the extent of thermal decomposition of ammonia, flue gas ammonia concentrations were measured at the fluid bed exhaust and the exhaust stack.

The test method selected for ammonia concentration in flue gas was EPA CTM 027, "Procedure for Collection and Analysis of Ammonia in Stationary Sources."

Sampling was conducted after the CBO™ system achieved steady state operation and recycle ash was used for FBC cooling. Such conditions closely simulate large scale CBO™ operation in the pilot facility.

Results of testing indicate that between 94% and 98% of the ammonia introduced into the system is being thermally decomposed. That is, the mass of ammonia in the FBC flue gas was between 4% and 8% of that in the feed ash. Both sampling points produced similar concentrations and decomposition efficiency.

MERCURY AND THE CARBON BURN-OUT PROCESS

Mercury as a trace element in coal is now coming under increasing investigation, particularly as a contaminant in flue gas from coal-fired power plants. Technology is being developed to capture mercury (Hg) contained in this flue gas.

Processes that absorb mercury from the flue gas by injecting carbon (typically activated carbon) into the gas ducting show significant promise. In these processes, the mercury containing carbon may be captured with the fly ash by existing particulate control devices. These processes report capture rates of up to 90% of the total Hg contained in the coal. The relatively small amount of carbon used in mercury capture is co-mingled with normally occurring fly ash.

Addition of even very small amounts of activated carbon to fly ash can reduce the value of the fly ash as a pozzolan used in concrete manufacturing. Activated carbon has been found to interfere greatly with the air entrainment reagents used in concrete mix designs[3].

While most of the regulatory effort has been on removing mercury from flue gas, the presence of mercury on either fly ash or on mixtures of fly ash and activated carbon slated for disposal is of significant concern. This scenario has the potential to change once marketable fly ash into a solid waste.

It was clear that the CBO™ process would combust the small amounts of activated carbon, along with the carbon in the co-mingled ash, and that the mercury would be vaporized at the FBC temperature. What was not clear was what the final fate of that mercury would be. One possibility was that it could simply remain in the vapor state and exit the CBO process in the flue gas. However, since the flue gas is cooled in the G/P Cooler, another possibility was that some fraction of the mercury would condense on the product fly ash and become sequestered when the fly ash was bound in the concrete matrix.

Mercury Testing Procedures and Results

A testing program was designed to determine the fate of mercury in the CBO™ process. A commercial scale CBO™ system was used for this testing program. Fly ash processed in this study was from a utility boiler without activated carbon mercury control equipment so the mercury represents only that captured by the fly ash. Various studies indicate that this can represent 30% to 100% of the total mercury from the coal. [4,5]

Table 3 illustrates sampling points used in this program, sample matrix and the sample type

Table 3: Mercury Sampling Locations

Sampling Point	Matrix	Sample Type
Fly Ash Feed	Solid	Grab
Fly ash product	Solid	Grab
Fluid Bed	Solid	Grab
Hot cyclone Inlet	Gas, Solid	Ontario Hydro
Hot Cyclone Outlet	Gas, Solid	Ontario Hydro
Baghouse Inlet	Gas, Solid	Ontario Hydro
Baghouse Exhaust	Gas, Solid	Ontario Hydro

A mercury balance of the CBO™ process was constructed by examining the mercury concentration of the high carbon feed, low carbon CBO™ product and the exhaust gas of the CBO™ system.

Table 4 illustrates the results of this approach. Three separate runs were used to determine the CBO™ system mass balance for mercury. The data shows excellent mass balance recovery ranging from a low of 94% to a high value of 109% with the average being 101%.

As the data indicates, virtually all of the mercury entering the CBO™ system on the high carbon fly ash feed is found on the low carbon fly ash product. Only .02% of the total mercury entering the CBO™ process is found in the exhaust gas of the system. The remaining 99.98% of the mercury entering the CBO™ process on the high carbon fly ash exits the system with the low carbon CBO™ fly ash product.

Table 4: <u>Mercury Mass Balance for CBO™ Process</u>

Run	Hg-Feed Mg/hr	Hg-Product Mg/hr	Hg-BHO Mg/hr	Prod+BHO Mg/hr	Material Balance %
1	13159	12395	12	12407	94
2	9899	9778	19	9797	99
3	11193	12119	37	12156	109
Average					101

Considering the operational temperatures of the CBO™ process, normally in the 1300° F range, one would assume that mercury would volatize and might exit the CBO™ process in the vapor phase. Indeed, fly ash samples taken from the fluid bed contain essentially no mercury. However, the mass balance information presented in table 4 does not support the assumption that mercury exits the CBO™ system along with the flue gas since virtually all the mercury introduced into the process exits "particulate bound" with the low carbon CBO™ product material.

Mass balance information in table 4 suggests that mercury volatization and a subsequent absorption/adsorption process is taking place within the CBO™ process. In order to develop an understanding of this mechanism speciation data was examined from several Carbon Burn-Out sampling points.

Table 5: <u>Mercury Particulate/Gas Data</u>

Sampling Point	Matrix	Sample Type	Particulate	-------Vapor Phase----- Oxidized	Elemental
Fly Ash Feed	Solid	Grab	100%		
Fluid Bed	Solid	Grab		>96%	
Hot Cyclone Inlet	Gas, Solid	Ontario Hydro		>96%	
Hot Cyclone Outlet	Gas, Solid	Ontario Hydro		>96%	
Baghouse Inlet	Gas, Solid	Ontario Hydro	99.7%	.2%	.1%
Fly Ash Product	Solid	Grab	100%		

Combining the results presented in Table 5 with the CBO™ process diagram (figure 1) the fate of mercury in the Carbon Burn-Out Process becomes clear. Mercury enters the CBO™ process in the high carbon feed material. Mercury contained with the feed is on the particles of the fly ash.

The fly ash is then metered into the fluid bed combustor and subject to temperatures in the 1300°F range and residence times approaching 45 minutes. In the fluid bed combustor, the mercury is volatized and exits the fluid bed in the vapor state, existing as either the oxidized or elemental form.

The mercury free, low carbon fly ash product exiting the fluid bed is combined with 1200°F to 1300°F flue gas from the hot cyclone. At this point in the process, the hot cyclone exhaust gas contains essentially all of the mercury.

The combined stream of mercury laden flue gas from the hot cyclone discharge and mercury free fly ash exiting the fluid bed enter the gas/product cooler. The combined stream is then cooled from 1100°F to 300°F and subsequently collected by the cold cyclone and baghouse for storage or shipment.

The speciation data shows that fly ash efficiently captures the mercury as the hot fly ash and gas stream pass through the gas product cooler and cold cyclone. By the time the gas stream enters the baghouse, the final particle collection device of the CBO™ process, mercury is particulate bound.

Fly ash enters the gas/product cooler virtually mercury free and by the time it exits the low temperature cyclone, the mercury that was entrained in the flue gas is efficiently transfered to the fly ash. The conditions associated with the G/P cooler and cold cyclone are ideal for the capture of mercury.

The conditions associated with the G/P cooler and cold cyclone are as follows:

Table 6: G/P Cooler & Cold Cyclone Conditions

	G/P Cooler Inlet	Cold Cyclone Discharge
Fly Ash Carbon Content	2%	2%
Fly Ash Mass Flow	60 TPH	60 TPH
Flow Rate	13,500 DSCFM	13,500 DSCFM
Temperature	1050°F	300°F
Residence Time	1 sec	3-4 sec

CONCLUSIONS

Mercury and ammonia are two environmental parameters of interest for the fly ash industry. Progress Materials has undertaken in-depth studies to determine the fate of ammonia and mercury in the Carbon Burn-Out system.

Results indicate that, under normal Carbon Burn-Out operating conditions, essentially all ammonia is eliminated from the fly ash feed material and decomposed. Fly ash having ammonia concentrations between 300 and 750 ppm were processed and in all cases the Carbon Burn-Out process successfully reduced ammonia concentrations below detectable levels. The Carbon Burn-Out process with operational temperatures at 1300°F and 45-minute solid residence times decomposes the ammonia associated with the fly ash. Thus ammonia air emissions tests found that all but 4% to 8% of the total ammonia from the feed ash was decomposed.

Mercury is inherent to coal combustion and, even without activated carbon injection for mercury capture, a substantial portion of mercury found in the coal remains with the high carbon fly ash used as feed for the Carbon Burn-Out system. Operating conditions of the Carbon Burn-Out process results in mercury being volatized and subsequently absorbed/adsorbed on the fly ash product. Process efficiency for the absorption/adsorption process approaches 100%. Therefore, essentially all of the mercury entering the CBO™ process exits the process attached to the product ash. The product ash is used in concrete so the mercury becomes sequestered in the concrete product.

Testing conditions presented in this paper were conducted on Carbon Burn-Out systems functioning in their normal operational modes. No additional equipment modifications or process changes were made .

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5. Schager, P., Hall, B. and Lindqvist, O. 1994. "The Retention of Gaseous Mercury on Flyashes" . Mercury Pollution: Integration and Synthesis: 621-628.

Table B-4E Unit 1 Actual 2000 Emissions Rates

Average 2000 Data:		
Heat Input	49,418,601	MMBtu/yr (HHV)
Operating Hours	8,007	hr/yr
Coal Sulfur Content	2.90	weight percent S
Petcoke Sulfur Content	6.19	weight percent S
Coal Consumption	1,758,963	tpy
Petcoke Consumption	28,953	tpy
Coal Consumption	98.38	blend weight percent
Petcoke Consumption	1.62	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.603	3,721.5	14,899
NO_x*	0.449	2,834.5	11,094
CO†	0.144	594.2	3,557
VOCs‡	0.002	13.5	54
PM†	0.024	133.3	589
PM_{10}**	0.024	133.3	589
H_2SO_4 mist†	0.020	111.8	494

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2000
Golder, 2005

Table B-4F Unit 1 Actual 2001 Emissions Rates

Average 2001 Data:

Heat Input	49,668,948	MMBtu/yr (HHV)
Operating Hours	7,704	hr/yr
Coal Sulfur Content	2.95	weight percent S
Petcoke Sulfur Content	5.88	weight percent S
Coal Consumption	1,665,401	tpy
Petcoke Consumption	66,037	tpy
Coal Consumption	96.19	blend weight percent
Petcoke Consumption	3.81	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.522	3,364.5	12,960
NO_x*	0.459	2,959.2	11,399
CO†	0.062	402.0	1,549
VOCs‡	0.002	13.6	52
PM†	0.012	75.3	290
PM_{10}**	0.012	75.3	290
H_2SO_4 mist†	0.029	187.7	723

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2001
Golder, 2005

Table B-4G Unit 1 Actual 2002 Emissions Rates

Average 2002 Data:

Heat Input	48,594,869	MMBtu/yr (HHV)
Operating Hours	7,517	hr/yr
Coal Sulfur Content	3.01	weight percent S
Petcoke Sulfur Content	6.23	weight percent S
Coal Consumption	1,462,320	tpy
Petcoke Consumption	175,428	tpy
Coal Consumption	89.29	blend weight percent
Petcoke Consumption	10.71	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.457	2,952.8	11,098
NO_x*	0.444	2,870.3	10,788
CO†	0.076	493.8	1,856
VOCs‡	0.002	13.1	49
PM†	0.012	75.1	282
PM_{10}**	0.012	75.1	282
H_2SO_4 mist†	0.051	332.5	1,250

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2002
Golder, 2005

Table B-4H Unit 1 Actual 2003 Emissions Rates

Average 2003 Data:		
Heat Input	45,734,834	MMBtu/yr (HHV)
Operating Hours	8,011	hr/yr
Coal Sulfur Content	3.03	weight percent S
Petcoke Sulfur Content	5.97	weight percent S
Coal Consumption	1,620,199	blend weight percent
Petcoke Consumption	271,815	blend weight percent
Coal Consumption	85.63	blend weight percent
Petcoke Consumption	14.37	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.592	3,382.1	13,547
NO_x*	0.478	2,728.9	10,931
CO†	0.088	500.5	2,005
VOCs‡	0.002	14.3	57
PM†	0.020	111.5	446
PM_{10}**	0.020	111.5	446
H_2SO_4 mist†	0.044	251.0	1,005

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2003
Golder, 2005

Table B-4I Unit 1 Actual 2004 Emissions Rates

Average 2004 Data:

Heat Input	45,312,403	MMBtu/yr (HHV)
Operating Hours	8,162	hr/yr
Coal Sulfur Content	3.07	weight percent S
Petcoke Sulfur Content	5.19	weight percent S
Coal Consumption	1,338,145	tpy
Petcoke Consumption	399,916	tpy
Coal Consumption	76.99	blend weight percent
Petcoke Consumption	23.01	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.630	3,499.1	14,280
NO_x*	0.476	2,642.6	10,784
CO†	0.083	458.5	1,871
VOCs‡	0.002	12.8	52
PM†	0.015	82.3	336
PM_{10}**	0.015	82.3	336
H_2SO_4 mist†	0.045	247.4	1,010

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2004
Golder, 2005

Table B-4J Unit 1 Actual 2005 Emissions Rates

Average 2000 Data:

Heat Input	47,228,429	MMBtu/yr (HHV)
Operating Hours	8,000	hr/yr
Coal Sulfur Content	3.07	weight percent S
Petcoke Sulfur Content	5.19	weight percent S
Coal Consumption	1,338,145	tpy
Petcoke Consumption	399,916	tpy
Coal Consumption	76.99	blend weight percent
Petcoke Consumption	23.01	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.646	3,816.0	15,264
NO_x*	0.474	2,798.3	11,193
CO†	0.083	458.5	1,950
VOCs‡	0.002	12.8	52
PM†	0.015	87.5	350
PM_{10}**	0.015	87.5	350
H_2SO_4 mist†	0.045	263.1	1,052

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2000
Golder, 2005

Table B-4K Unit 2 Actual 2000 Emissions Rates

Average 2000 Data:

Heat Input	51,954,131	MMBtu/yr (HHV)
Operating Hours	7,878	hr/yr
Coal Sulfur Content	2.90	weight percent S
Petcoke Sulfur Content	6.19	weight percent S
Coal Consumption	1,679,618	tpy
Petcoke Consumption	74,443	tpy
Coal Consumption	95.76	blend weight percent
Petcoke Consumption	4.24	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.688	4,536.7	17,870
NO_x*	0.390	2,627.1	10,131
CO†	0.432	1,122.9	11,223
VOCs‡	0.002	13.5	53
PM†	0.009	51.6	236
PM_{10}**	0.009	51.6	236
H_2SO_4 mist†	0.018	104.2	474

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2000
Golder, 2005

Table B-4L Unit 2 Actual 2001 Emissions Rates

Average 2001 Data:		
Heat Input	55,355,534	MMBtu/yr (HHV)
Operating Hours	8,244	hr/yr
Coal Sulfur Content	2.95	weight percent S
Petcoke Sulfur Content	5.88	weight percent S
Coal Consumption	1,762,839	tpy
Petcoke Consumption	107,738	tpy
Coal Consumption	94.24	blend weight percent
Petcoke Consumption	5.76	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.610	4,093.2	16,872
NO_x*	0.470	3,155.9	13,009
CO†	0.038	257.0	1,060
VOCs‡	0.002	13.7	56
PM†	0.008	50.5	208
PM_{10}**	0.008	50.5	208
H_2SO_4 mist†	0.018	123.3	508

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2001
Golder, 2005

0.039	0.027
0.0074	0.0094
0.0074	0.0094
0.018	0.024

Table B-4M Unit 2 Actual 2002 Emissions Rates

Average 2002 Data:

Heat Input	49,488,475	MMBtu/yr (HHV)
Operating Hours	8,033	hr/yr
Coal Sulfur Content	3.01	weight percent S
Petcoke Sulfur Content	6.23	weight percent S
Coal Consumption	1,514,054	tpy
Petcoke Consumption	169,260	tpy
Coal Consumption	89.94	blend weight percent
Petcoke Consumption	10.06	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.525	3,234.7	12,992
NO_x*	0.460	2,896.6	11,382
CO†	0.030	183.2	736
VOCs‡	0.002	12.6	50
PM†	0.018	109.2	439
PM_{10}**	0.018	109.2	439
H_2SO_4 mist†	0.052	318.5	1,279

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2002
Golder, 2005

Table B-4N Unit 2 Actual 2003 Emissions Rates

Average 2003 Data:

Heat Input	46,823,323	MMBtu/yr (HHV)
Operating Hours	8,243	hr/yr
Coal Sulfur Content	3.03	weight percent S
Petcoke Sulfur Content	5.97	weight percent S
Coal Consumption	1,628,641	tpy
Petcoke Consumption	311,406	tpy
Coal Consumption	83.95	blend weight percent
Petcoke Consumption	16.05	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.590	3,351.4	13,813
NO_x*	0.454	2,578.9	10,629
CO†	0.145	823.7	3,395
VOCs‡	0.003	14.2	59
PM†	0.020	115.5	476
PM_{10}**	0.020	115.5	476
H_2SO_4 mist†	0.031	175.5	723

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2003
Golder, 2005

0.1696	0.033
0.0176	0.0328
0.0176	0.0328
0.03	0.035

Table B-4O Unit 2 Actual 2004 Emissions Rates

Average 2004 Data:		
Heat Input	39,583,424	MMBtu/yr (HHV)
Operating Hours	7,033	hr/yr
Coal Sulfur Content	3.07	weight percent S
Petcoke Sulfur Content	5.19	weight percent S
Coal Consumption	1,128,531	tpy
Petcoke Consumption	324,146	tpy
Coal Consumption	77.69	blend weight percent
Petcoke Consumption	22.31	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.628	3,533.1	12,424
NO_x*	0.464	2,611.5	9,183
CO†	0.135	762.3	2,681
VOCs‡	0.002	12.5	44
PM†	0.013	74.6	262
PM_{10}**	0.013	74.6	262
H_2SO_4 mist†	0.031	175.9	618

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2004
Golder, 2005

Table B-4P Unit 2 Actual 2005 Emissions Rates

Average 2004 Data:		
Heat Input	50,573,650	MMBtu/yr (HHV)
Operating Hours	7,033	hr/yr
Coal Sulfur Content	3.07	weight percent S
Petcoke Sulfur Content	5.19	weight percent S
Coal Consumption	1,128,531	tpy
Petcoke Consumption	324,146	tpy
Coal Consumption	77.69	blend weight percent
Petcoke Consumption	22.31	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.640	4,601.2	16,180
NO_x*	0.476	3,422.9	12,037
CO†	0.135	974.0	3,425
VOCs‡	0.002	12.5	44
PM†	0.013	95.3	335
PM_{10}**	0.013	95.3	335
H_2SO_4 mist†	0.031	224.7	790

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2004
Golder, 2005

Table B-4Q Unit 1 Highest 2 Year Average

Pollutant	2000-2001 (tpy)	2001-2002 (tpy)	2002-2003 (tpy)	2003-2004 (tpy)	2004-2005 (tpy)	Highest 2 Year Average
SO_2	13,930	12,029	12,323	13,914	14,772	14,772
NO_x	11,247	11,094	10,859	10,857	10,989	11,247
CO	2,553	1,702	1,930	1,938	1,911	2,553
VOCs	53	51	53	55	52	55
PM	439	286	364	391	343	439
PM_{10}	439	286	364	391	343	439
H_2SO_4 mist	609	987	1,128	1,007	1,031	1,128
Heat Input	49,543,775	49,131,909	47,164,852	45,523,619	46,270,416	49,543,775

Table B-4R Unit 2 Highest 2 Year Average

Pollutant	2000-2001 (tpy)	2001-2002 (tpy)	2002-2003 (tpy)	2003-2004 (tpy)	2003-2004 (tpy)	Highest 2 Year Average
SO_2	17,371	14,932	13,403	13,119	14,302	17,371
NO_x	11,570	12,195	11,006	9,906	10,610	12,195
CO	6,141	898	2,065	3,038	3,053	6,141
VOCs	55	53	55	51	44	55
PM	222	323	457	369	299	457
PM_{10}	222	323	457	369	299	457
H_2SO_4 mist	491	894	1,001	671	704	1,001
Heat Input	53,654,833	52,422,005	48,155,899	43,203,374	45,078,537	53,654,833

Table B-4S Highest Baseline 2-Year Average

Pollutant	2000-2001 (tpy)	2001-2002 (tpy)	2002-2003 (tpy)	2003-2004 (tpy)	2004-2005 (tpy)	Highest 2 Year Average
SO_2	31,301	26,961	25,725	27,032	29,074	31,301
NO_x	22,817	23,289	21,865	20,764	21,599	23,289
CO	8,694	2,600	3,996	4,976	4,964	8,694
VOCs	108	104	108	106	96	108
PM	661	610	822	760	642	822
PM_{10}	661	610	822	760	642	822
H_2SO_4 mist	1,100	1,880	2,129	1,678	1,735	2,129
Heat Input	103,198,607	101,553,913	95,320,751	88,726,992	91,348,953	103,198,607

APPENDIX B-5

LIST OF EXEMPT ACTIVITIES

Exempt Activities

A urea-to-ammonia system will be used for the SCR's. A urea-to-ammonia system stores liquid urea (typically a 40-50 percent solution) and hydrolyzes or thermally decomposes the urea into NH_3, H_2O and CO_2. Urea is transported to the site via truck or rail as a dry solid in a prilled or granular form that will be mixed with demineralized water and stored as a 40-50 percent wet solution in storage tanks. The dry urea is fed from the supply truck or railcar, by use of a pneumatic unloader, to the dissolving tank with mounted agitators which mixes the urea with hot water. A recirculation pump sends the urea solution through a heat exchanger to maintain the urea in the dissolver at the desired mixing temperature. Within the dissolver tank, the concentration of the urea solution is controlled by level and density controls, with make up water being supplied from the demineralized water system. The recirculation pumps also act as transfer pumps to transfer the solution from the dissolving tank to the storage tanks. The urea solution from the storage tanks is then pumped through a pre-heater to increase the temperature to approximately 400°F. From the pre-heater, the heated solution goes to the hydrolyzer where steam is used to decompose the urea solution into ammonia and carbon dioxide. Any liquid phase leaving the hydrolyzer is sent to a flash separator that vaporizes the ammonia and combines it with the main hydrolyzer vapor flow. The ammonia gas is then mixed with air in the ammonia flow control units and sent to the ammonia injection grid.

Particulate emissions from material handling were estimated to be less than one pound per year. No other pollutant emissions from this proposed process were considered significant.

WAHLCO, INC.®

DRY UREA SPECIFICATION
for LIQUID UREA PREPARATION
FOR U2A™ UREA TO AMMONIA CONVERSION SYSTEM

Product: **UREA**

Grade:	Industrial
Physical Form:	Solid Prills or Granular
Other Names:	Carbamide
Chemical Formula:	$CO(NH_2)_2$

CHEMICAL ANALYSIS

SPECIFICATION	UNITS	VALUE
PURITY AS $CO(NH_2)_2$	%	>99.0
TOTAL NITROGEN	%	>46.0
MOISTURE (H_2O)	%	<0.3
CHLORIDE (Cl^-)	ppmw	<0.3
BROMIDE (Br^-)	ppmw	<0.01
PHOSPHATE ($PO_4^{\equiv}$)	ppmw	<0.1
SULFATE ($SO_4^{=}$)	ppmw	<0.1
THIOSULFATE ($S_2O_3^{=}$)	ppmw	<0.1
ADDITIVE	%	<1.5
COLOUR	A.P.H.A. UNITS	<10
TURBIDITY AS SiO_2	ppm	<20
HEAVY METALS	ppm	<0.4

PHYSICAL PROPERTIES:
(Approx.)

Nominal Bulk Density (prill)	750 kg/m^3 (46 lb/cu.ft.)
NominalBulk Density (granular, loose)	769 kg/m^3 (48 lb/cu.ft.)
NominalBulk Density (granular, tapped)	801 kg/m^3 (50 lb/cu.ft.)

LIQUID UREA SPECIFICATION
FOR U2A™ UREA TO AMMONIA CONVERSION SYSTEM
40% UREA SOLUTION

SPECIFICATION	UNITS	VALUE
UREA	wt%	39-41
ALKALINITY AS NaOH	Normality	<0.03
TOTAL DISSOLVED SOLIDS	ppmw	<10
TOTAL SUSPENDED SOLIDS	ppmw	<10
CHLORIDE (Cl^-)	ppmw	<0.3
SULFATE ($SO_4^=$)	ppmw	<0.1
THIOSULFATE ($S_2O_3^=$)	ppmw	<0.1
PHOSPHATE ($PO_4^{\equiv}$)	ppmw	<0.1
SPECIFIC GRAVITY		1.105-1.110
APPEARANCE		CLEAR LIQUID

3600 W. Segerstrom Avenue
Santa Ana, CA 92704

(714) 979-7300
FAX: (714) 979-0130

Urea dust emission from urea dissolver tanks during prill urea unloading calculation and estimate

The dissolver tank (10 ft in diameter by 26 ft high) is filled with urea from a 4" diameter fill line from the top of the tank (See Figure 1). The urea is pnuematically conveyed and is shot straight into the water. The air then exhausts from the top of the tank through a 12" vent. The tank is filled with water up to a height of 16 ft. There is a 10 ft high by 10 ft in diameter volume above the water that allows the air to recirculate and exhaust through the vent. The calculation will show that the exit velocity of the air in this 10 ft diameter section is less than the settling velocity of the smallest urea particulate, thus no urea will be exhausted with the air.

Urea typical screen analysis (by % weight)

Tyler Mesh	Granular % Weight	Prill % Weight
+6	6.0	–
+8	75.0	–
+10	98.0	–
+14	99.8	4.0
+20	99.9	36.0
+30	100.0	85.0
+40	–	99.3

Specific Gravity of Urea $SG := \frac{49}{62.4}$ $SG = 0.7853$

Urea inlet pipe diameter (in) $d_{pipe} := 4$

Area of pipe (in^2) $A_{pipe} := \frac{\pi}{4} \cdot d_{pipe}^{2}$ $A_{pipe} = 12.5664$

Urea typical unloading rate20 Tons/hr with 700 ACFM air.

Flowrate of air/particles in pipe (ft^3/min) $Q := 700$

Pipe Exit velocity (ft/min) $V_{pipe\_exit} := \frac{144 \cdot Q}{A_{pipe}}$ $V_{pipe\_exit} = 8021.4091$

Assuming smallest particle size of urea is greater than or equal to 0.833mm (0.0328 in) or 20 mesh, the terminal velocity of the settling particle is:

Diameter of settling particle (microns) $D_{part} := 833$

Gas pressure, air at atmospheric pressure (atm) $p := 1.00027566948$

Constant for irregular shapes $K_1 := 0.142$ (Ref. 2)

Terminal Velocity of settling particles (m/s) $V_t := K_1 \cdot \sqrt{SG \cdot p \cdot D_{part}}$ $V_t = 3.6323$ (Ref. 2)

Terminal Velocity of settling particle (ft/min) $V_{t1} := V_t \cdot 60 \cdot 3.2808$ $V_{t1} = 715.0023$

Tank diameter (ft) $D_{tank} := 10$

Area of Tank (ft^2) $A_{tank} := \frac{\pi}{4} \cdot D_{tank}^{\ 2}$ $A_{tank} = 78.5398$

Velocity of Air trying to exit tank in main body area (ft/min) $V_{air\_tankbody} := \frac{Q}{A_{tank}}$ $V_{air\_tankbody} = 8.9127$

Urea dust emissions is

$$Urea\_Emissions := \begin{cases} \text{"Okay"} & \text{if } V_{air\_tankbody} \le V_{t1} \\ \text{"Not Acceptable"} & \text{otherwise} \end{cases}$$

$$Urea\_Emissions = \text{"Okay"}$$

In the most conservative case, the smallest particle will have a greater settling terminal velocity than the velocity of the air escaping the vessel. Thus no urea particles of size 20 mesh and greater will exit the Dissolver tank.

Next step: Would the smallest particle size get trapped and not escape?

Diameter of settling particle, (microns)	$D_{partsmallest} := 295$	(40 mesh)	
Gas pressure, air at atmospheric pressure (atm)	$p := 1.00027566948$		
Constant for irregular shapes	$K_1 := 0.142$		
Terminal Velocity of settling particles (m/s)	$V_{tsmallest} := K_1 \cdot \sqrt{SG \cdot p \cdot D_{partsmallest}}$	$V_t = 3.6323$	(Ref. 2)
Terminal Velocity of settling particle (ft/min)	$V_{t1smallest} := V_{tsmallest} \cdot 60 \cdot 3.2808$	$V_{t1smallest} = 425.4965$	

Urea dust emissions is

$$Urea\_Emissions := \begin{cases} \text{"Okay"} & \text{if } V_{air\_tankbody} \le V_{t1smallest} \\ \text{"Not Acceptable"} & \text{otherwise} \end{cases}$$

$$Urea\_Emissions = \text{"Okay"}$$

References:

1) Mechanical Engineering Reference Manual, Micheal R. Lindeburg, 11th Edition, Pages 64-6

2) Marks' Standard Handbook for Mechnical Engineers, Avallone, Baumeister III, 10th Edition, Pages 18-10.

3) Terra Urea and Urea Solution Handbook, Page 10.

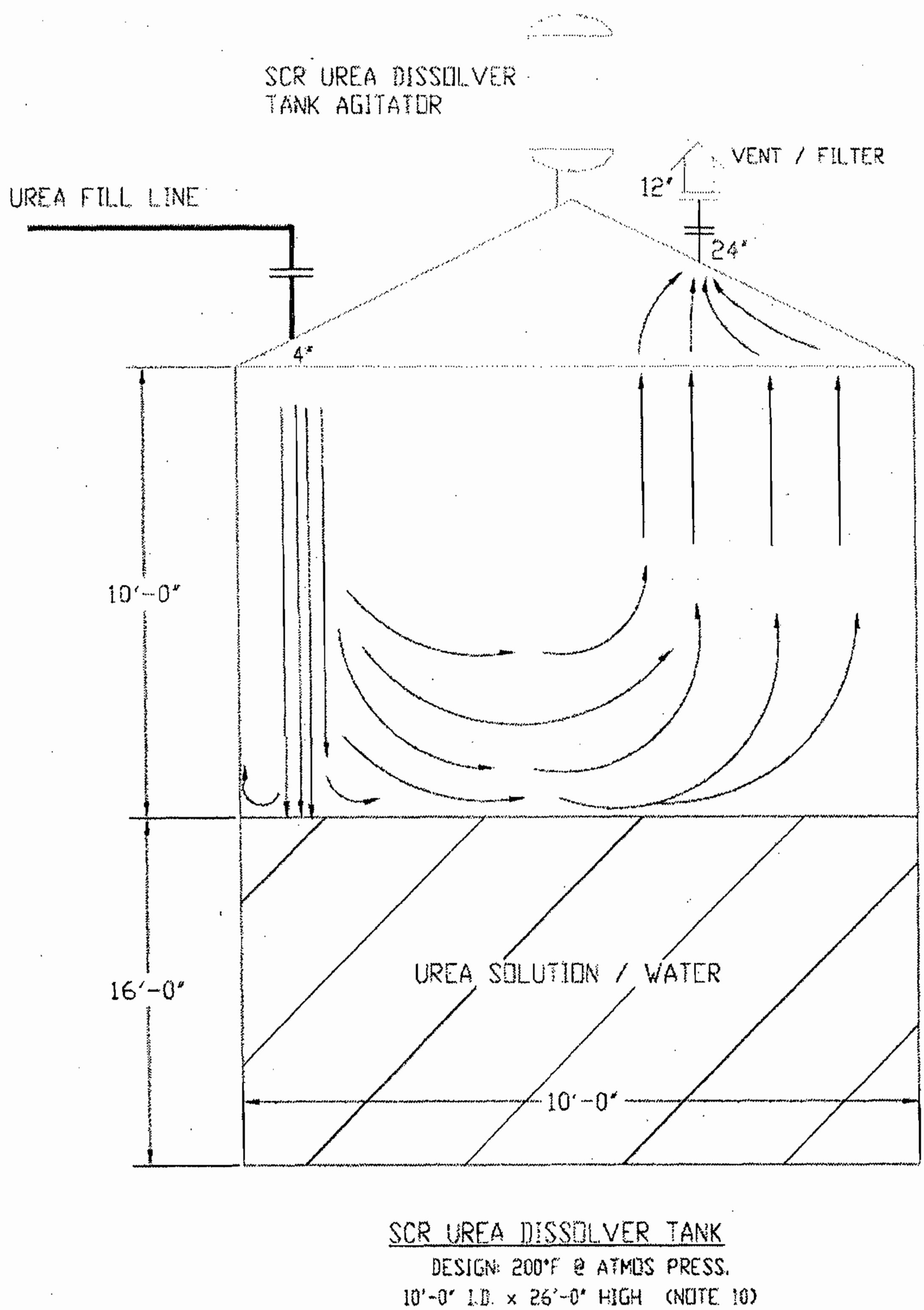
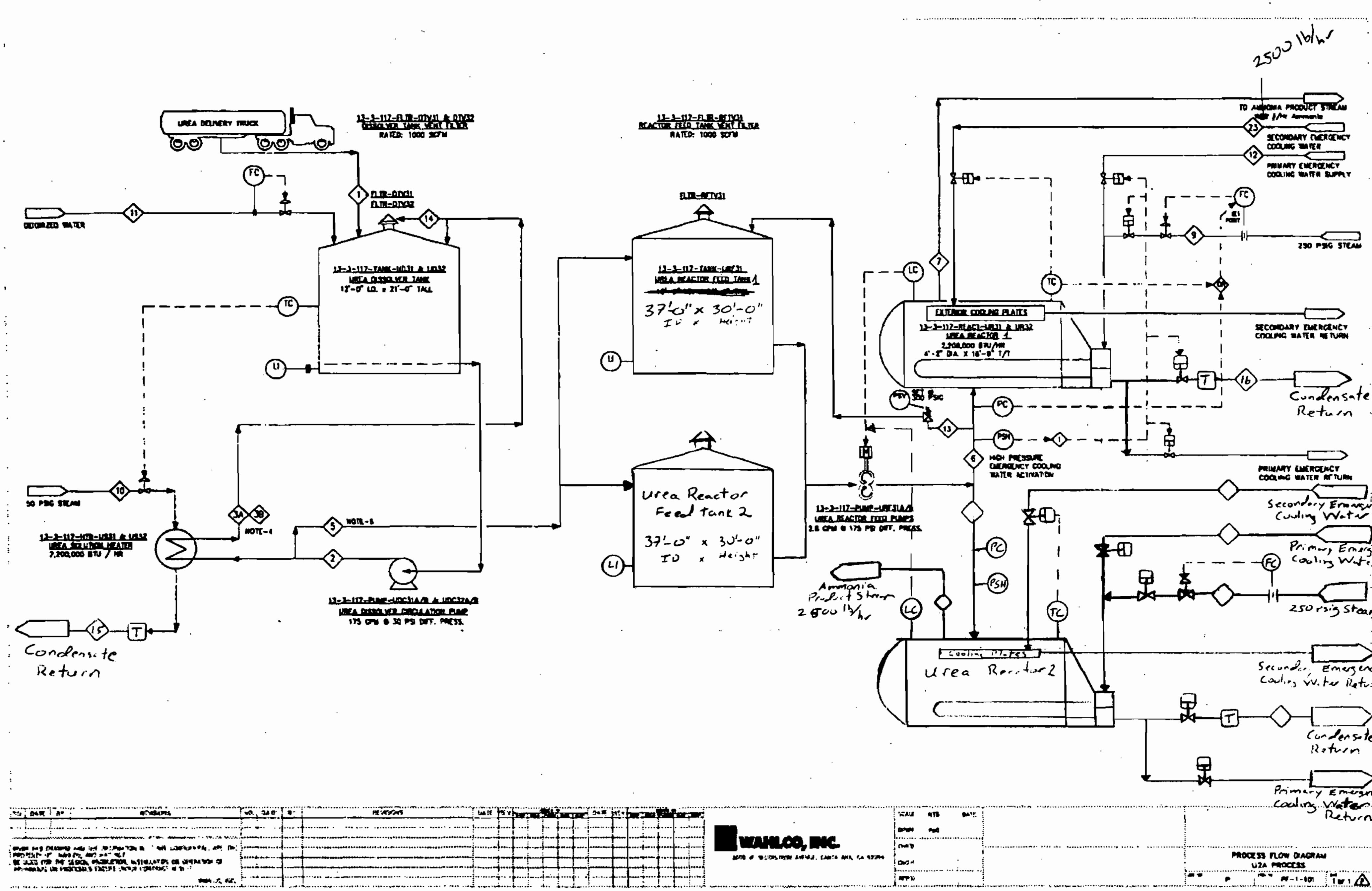


Figure 1 - Urea Dissolver Tank

Best Available Copy



APPENDIX B-6

FUEL ANALYSIS OR SPECIFICATION

COMMERCIAL TESTING & ENGINEERING CO.
GENERAL OFFICES: 1919 SOUTH HIGHLAND AVE., SUITE 210-B, LOMBARD, ILLINOIS 60148 • TEL: 708-953-9300 FAX: 708-953-9306
Member of the SGS Group (Société Générale de Surveillance)

April 4, 1995

PLEASE ADDRESS ALL CORRESPONDENCE T
P.O. BOX 752, HENDERSON, KY 424
TEL: (502) 827-1
FAX: (502) 826-07

SEMINOLE ELECTRIC CORPORATION
P. O. BOX 272000
TAMPA FL 33688

Sample identification by
Seminole Electric

January 1995 Composite
As Fired Coal
Date Sampled: 1/1-31/95
P.O. #B9308-02815

Kind of sample reported to us: Coal

Sample taken at: -----

Sample taken by: Seminole Electric

Date sampled: January 1-31, 1995

Date received: February 13, 1995

Analysis Report No. 63-73996

ULTIMATE ANALYSIS

	As Received	Dry Basis
% Moisture	10.68	xxxxx
% Carbon	66.04	73.94
% Hydrogen	4.63	5.18
% Nitrogen	1.23	1.38
% Sulfur	2.58	2.89
% Ash	7.95	8.90
% Oxygen(diff)	6.89	7.71
	100.00	100.00
% Chlorine	0.19	0.21

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO

Manager, Henderson Laboratory

OVER 40 BRANCH LABORATORIES STRATEGICALLY LOCATED IN PRINCIPAL COAL MINING AREAS, TIDEWATER AND GREAT LAKES PORTS, AND RIVER LOADING FACILITIES

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

COMMERCIAL TESTING & ENGINEERING CO.
GENERAL OFFICES: 1919 SOUTH HIGHLAND AVE., SUITE 210-B, LOMBARD, ILLINOIS 60148 • TEL: 708-953-9300 FAX: 708-953-9306
Member of the SGS Group (Société Générale de Surveillance)

April 4, 1995

PLEASE ADDRESS ALL CORRESPONDENCE TO:
P.O. BOX 752, HENDERSON, KY 42420
TEL: (502) 827-1187
FAX: (502) 826-0719

SEMINOLE ELECTRIC CORPORATION
P. O. BOX 272000
TAMPA FL 33688

Sample identification by
Seminole Electric

January 1995 Composite
As Fired Coal
Date Sampled: 1/1-31/95
P.O. #B9308-02815

Kind of sample reported to us: Coal

Sample taken at: -----

Sample taken by: Seminole Electric

Date sampled: January 1-31, 1995

Date received: February 13, 1995

Analysis Report No. 63-73996

ANALYSIS OF ASH	WEIGHT %, IGNITED BASIS
Silicon dioxide	49.04
Aluminum oxide	20.33
Titanium dioxide	1.05
Iron oxide	20.23
Calcium oxide	3.00
Magnesium oxide	0.80
Potassium oxide	2.25
Sodium oxide	0.96
Sulfur trioxide	1.75
Phosphorus pentoxide	0.18
Strontium oxide	0.04
Barium oxide	0.06
Manganese oxide	0.11
Undetermined	0.20
	100.00

Silica Value = 67.11
Base:Acid Ratio = 0.39
T_{250} Temperature = 2427 °F

Type of Ash = BITUMINOUS
Fouling Index = 0.37
Slagging Index = 1.13

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO

Manager, Henderson Laboratory

OVER 40 BRANCH LABORATORIES STRATEGICALLY LOCATED IN PRINCIPAL COAL MINING AREAS, TIDEWATER AND GREAT LAKES PORTS, AND RIVER LOADING FACILITIES

465

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

COMMERCIAL TESTING & ENGINEERING CO.

GENERAL OFFICES: 1919 SOUTH HIGHLAND AVE., SUITE 210-B, LOMBARD, ILLINOIS 60148 • TEL: 708-953-9300 FAX: 708-953-9306

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P.O. BOX 752, HENDERSON, KY 42420
TEL: (502) 827-1187
FAX: (502) 826-0719

April 4, 1995

SEMINOLE ELECTRIC CORPORATION
P. O. BOX 272000
TAMPA FL 33688

Sample identification by
Seminole Electric

January 1995 Composite
As Fired Coal
Date Sampled: 1/1-31/95
P.O. #B9308-02815

Kind of sample reported to us Coal

Sample taken at -----

Sample taken by Seminole Electric

Date sampled January 1-31, 1995

Date received February 13, 1995

Analysis report no. 63-73996

TRACE ANALYSIS

Parameter	ug/g, dry coal basis	Parameter	ug/g, dry coal basis
Antimony, Sb	<1	Molybdenum, Mo	<2
Arsenic, As	4	Nickel, Ni	8
Barium, Ba	39	Selenium, Se	3
Beryllium, Be	1.0	Silver, Ag	<0.2
Cadmium, Cd	<0.2	Strontium, Sr	28
Chloride, Cl	2500	Tin, Sn	<1
Chromium, Cr	15	Uranium, U	1.8
Cobalt, Co	3	Vanadium, V	44
Copper, Cu	7	Zinc, Zn	42
		Zirconium, Zr	15
Fluoride, Fl	70		
Lead, Pb	8		
Lithium, Li	8	Radium 226 pCi/g	0.5 +/- 0.2
Manganese, Mn	24	Radium 228 pCi/g	0.3 +/- 0.5
Mercury, Hg	0.08		

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

Manager Henderson Laboratory

OVER 40 BRANCH LABORATORIES STRATEGICALLY LOCATED IN PRINCIPAL COAL MINING AREAS, TIDEWATER AND GREAT LAKES PORTS, AND RIVER LOADING FACILITIES

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

	Petroleum Coke		
	Minimum	Average	Maximum
Ultimate Analysis			
Carbon	78.0	80.0	85.0
Sulfur	3.5	5.5	6.8
Oxygen	0.1	0.8	2.0
Hydrogen	2.5	2.8	3.5
Nitrogen	1.0	1.3	1.8
Ash	0.1	0.3	0.5
Moisture	5.0	7.0	12.0
Proximate Analysis			
Moisture	5.0	7.0	12.0
Volatile matter	9.0	10.0	12.0
Fixed Carbon	78.0	80.0	85.0
Ash	0.1	0.3	0.5
Gross (Higher) Heating Value	12,900	14,000	14,500

Seminole Power Plant
No. 2 Fuel Oil Description

No. 2 fuel oil will have the following approximate composition:

Parameter	Units	Value
Carbon	Weight %	87.0
Hydrogen	Weight %	12.4
Sulfur	Weight %	0.5
Nitrogen	Weight %	0.1
Heat Content	Btu/lb	19,400

PROGRESS MATERIALS INC
CARBON BURNOUT PLANT - MASS AND ENERGY BALANCE
Seminole Electric Palatka Station CBO PLANT
225,000 TPY Feed Base Case, 13.5% LOI

	FEED ASH
TEMPERATU (DEG F)	80
ASH INERTS (TON/HR)	25.83
ASH CARBOI (TON/HR)	4.05
ASH SULFUF (TON/HR)	0.12
TOTAL SOLII (TON/HR)	30.01
SOLIDS SPE (BTU/LB-F)	0.16
SOL HEAT C (MBTU/HR)	0.78
CARBON CO (% WT)	13.50
SULFUR COI (% WT)	0.41

APPENDIX B-7

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Unconfined particulate matter emissions that may result from operations include:

- Vehicular traffic on paved and unpaved roads.
- Wind-blown dust from plant grounds.
- Periodic abrasive blasting.

The following techniques will be used to control unconfined particulate matter emissions on an as needed basis:

- Chemical or water application to:
  - Unpaved roads
  - Unpaved yard areas
- Paving and maintenance of roads, parking areas and plant grounds.
- Landscaping or planting of vegetation.
- Confining abrasive blasting where possible.
- Other techniques, as necessary

APPENDIX B-8

STARTUP PROCEDURE

This procedure is to be followed for cold start-ups of the unit. If it is necessary to deviate from this procedure, OA-1 SHALL be followed.

CAUTION: U-2 has an ABB sliding pressure live steam pressure controller. This controller must have its set point adjusted prior to placing the unit on the line to avoid inadvertent trips from the live steam pressure controller coming into action.

_____ 1. Verify all necessary clearances released, confined space logs have been signed off, and jumper/lifted lead log has been reviewed and cleared of any inappropriate jumpers/lifted leads.

_____ 2. Verify from the condensate system checklist that the condensate system is lined up and ready for service with condensate polishers by-passed.

_____ 3. Verify circulating water system is in service with two pumps in operation.

_____ 4. Have condensate storage tank water quality checked by lab. Fill hotwell to normal level and drain to waste. If hotwell had not been drained, drain and refill to normal level. Restart condensate system.

_____ 4.1 Ensure there are adequate levels in the ammonia and carbohydrazide chemical addition tanks. If tanks are low, a normal charge of 7 bolts in the sight glass of the charge tank mixed with ½ tank of condensate in the chemical addition tank for ammonia, and 4 bolts in the sight glass of the charge tank mixed with 1/2 tank of condensate in the chemical addition tank for carbohydrazide should be added.

_____ 5. The dewatering system should be ready to receive waste slurry from the FGD and to send return supernate to the supernate tank in the FGD area.

_____ 5.1 Start the service water booster pump using the selector switch. If the required water pressure at the battery limit of the SW booster pump is available, and the manual suction and discharge valves are in the "open" position, the pump will start.

_____ 5.2 Place the waste slurry-supernate return loop in service.

_____ 5.2.1 Contact EPF to have their return pump placed in service.

_____ 5.2.2 Place the supernate pump selector switch in the "Start" position. If the low-level sensing switch (LSL 0702) is satisfied and the EPF return tank level is adequate, the pump will start.

_____ 5.3 Reagent Slurry Loop Start-Up

_____ 5.3.1 Place the reagent slurry transfer pump selector switch in the "Start" position. If the level of the reagent storage tank satisfies the low level condition, the pump will start.

_____ 5.3.2 Have the Support Systems Operator verify good return flow of reagent back to the reagent storage tank.

NOTE: **Step 6 below may be omitted if D.A. has not been drained.**

_____ 6. With polisher vessels by-passed, fill the D.A. to normal level with one condensate pump and the D.A. level control by-pass valve. Keep remaining condensate pumps in pull-to-lock. shut down the condensate pump (pull-to-lock) and drain the D.A. to waste through the hotwell. Drain hotwell and refill to normal level. Restart condensate system.

_____ 7. With polisher vessels by-passed, fill D.A. to high level as in Step 5 while maintaining hotwell level. Begin the condensate loop flow through D.A. high level dump to hotwell. It may be necessary to bleed condensate to waste (hotwell drain) and make-up from the condensate storage tank to lower iron oxide reading to <u>≤2000 ppb</u>. If condensate flow is stable, controls may be placed in automatic.

_____ 8. HD270 and LCV625 bypass should be opened to ensure adequate flow through D.A. flow loop. Also ensure the D.A. belly drain is open to drain any sediment. This line-up is to remain this way until unit is on bypass.

_____ 9. When condensate pump discharge iron oxide is less than 2000 ppb, specific conductivity is less than 20 mmho, the chloride is less than 1 mg/l, (verified by lab personnel) place one polisher vessel in service. Change to clean vessel as necessary.

_____ 10. With adequate chemistry bypass polishers prior to filling boiler. Place one carbohydrazide pump in service and adjust feed rate with manual loader (1-HK-4039) until #3 F.W. heater discharge carbohydrazide residue is 40-100 ppb. Place one ammonia pump in service and adjust feed rate with manual loader (1-CCC-4038) until #3 F.W. heater discharge specific conductivity is 2.5 to 5.0 mmho or pH 8.5 – 9.3.

_____ 11. If available, cross tie the auxiliary steam system in order to seal the turbine and pull vacuum on condenser. This will help remove dissolved oxygen from the condensate which helps prevent iron build-up in the preboiler piping and boiler. Ensure vacuum breakers have seal water.

_____ A. Place the gland steam function group <u>"on"</u>.

_____ B. Place lube oil and jacking oil function group <u>"on"</u> lube oil 70-100°F.

_____ C. Establish seal oil.

_____ D. Check turbine oil and EHC fluid tank levels.

_____ E. Put main turbine on turbine gear.

_____ F. Check valving for exhaust hood sprays.

_____ G. Ensure all charts/recorders are in service.

NOTE: If cross tied, this will add steam to the unit that is starting up, thus causing the hotwell level to increase. If start-up is delayed for an abnormal period, untie the units when pressure is adequate.

_____ 12. When condensate polisher effluent reading is down to 100 ppb iron oxide, the water quality is sufficient to be used in the boiler.

_____ 13. A. Check start <u>**ALL**</u> auxiliary lube oil pumps, I.D., F.D., P.A., ball mills, etc.

_____ B. Check for any problems.

_____ C. Leave either all "A": or all "B" pumps in service.

_____ D. Place B.F.P.s on T.G. and open HMV-1301 bypass valve.

_____ 14. Verify the "pre-fire" requirements are completed by the control room, unit and auxiliary operator checklists.

_____ 15. When adequate vacuum is achieved, reset main turbine and L.P. bypass. (To locate any problems)

_____ 16. Open bypass on polisher to allow more chemicals to boiler. Contact laboratory personnel prior to filling boiler. Have lab verify proper concentration of ammonia and carbohydrazide as boiler is filled. (pH 8.5 – 9.3, conductivity 2.5 – 5.0 umho carbohydrazide 40-100 ppg). Fill the boiler using the boiler fill line off of the condensate pump discharge header to 5 ports. Verify locally at drum and compare with control room indication. Drain drum level back down (3 ports) for firing and verify level locally at drum. Have lab check iron level, at water wall drains, should be (<2000 ppb).

_____ 17. Start air preheaters, and open secondary air inlet and outlet and gas inlet and outlet dampers.

_____ 18. Verify clear path for air flow from fans to stack utilizing the FGD system bypass.

_____ 19. Place one ID fan in service and one FD fan in service maintaining furnace draft at – ½". Place in service ID fan in "AUTO."

_____ 20. Place second ID fan in service and second FD fan in service maintaining furnace draft at – ½". Parallel in service ID fans and place the second ID fan in "AUTO."

NOTE: If problems are encountered in starting the second ID or FD, do not delay startup. Proceed with the startup sequence while attempting to start the second set of fans. One set of fans is adequate to initially fire boiler and

synchronize generator. Normally, #1 or #2 ID is started with #1 FD and #3 or #4 ID is started with #2 FD. This is for even flow through precipitators.

_____ 21. Parallel FD fans and raise air flow to 2.2 million LB/hr. Verify the air flow MFT signal and air flow <30% alarm clear as air flow is increased.

_____ A. Parallel running amps on FD Fans using BOMAR and 6.9kv breaker indications. As air flow increases throughout the start-up, maintain balanced fan amps. If amps are balanced, and there is an indicated discrepancy of >5% with blade pitch positions, contact Mech. Maint. and/or I&C for proper operation or correction. Compare and verify blade pitch position locally with the operator.

This step shall be followed and maintained throughout the unit start-up, as well as when the unit is on line. When the FD Fans are in "auto", and a bias of >5% is needed to balance the amps between fans, this could be an indication of APH pluggage, or other air flow restrictions. This is especially important between outages when there is a possibility of a potential APH wash needed. Early detection of APH pluggage is important so that some corrective action can be taken.

_____ 22. Start tertiary air fans and a scanner fan. Place redundant fans in standby.

NOTE: Contact lab personnel when ready to light off ignitors.

_____ 23. Start one ignition oil pump.

_____ 24. Select "BYPASS" mode on turbomat prior to boiler purge.

_____ 25. Depress the purge start button on the Forney panel. If all permissives are met, the 5 minute purge will begin. Purge permissives are:

_____ A. Air heaters in service.

_____ B. FD & ID fans in service.

_____ C. All mills and feeders stopped.

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Subject: **UNIT COLD START-UP/SUPERHEAT BOIL OUT**	Section: **EQUIPMENT OPERATION PROCEDURE**	

_____ D. All burner shut-off dampers closed.

_____ E. Ignitor trip valve closed.

_____ F. No primary air fan funning.

_____ G. No flame detected.

_____ H. 80% burner air registers to light off position.

_____ I. Both reheat and economizer pass dampers open.

_____ J. Full air flow path established.

_____ K. Tertiary air fans in service.

_____ L. All precipitators tripped.

_____ M. All ignition oil valves closed.

_____ N. All P.A.S.O. dampers closed.

_____ O. Furnace pressure in limits.

_____ P. All auxiliary air dampers closed.

_____ Q. All S.A.S.O. dampers closed.

_____ R. No boiler trip cond. present.

_____ S. Precipitator seal air fans running.

_____ T. Primary air dampers closed.

_____ U. Scanner cooling fan running.

_____ V. Air flow >25% <40%.

CAUTION: Station an operator on the lower burner decks to check for oil leaks before opening ignitor trip valve. The initial placing of ignitors in service will require an operator present to identify any oil leaks.

_____ 27. When purge is complete, open the ignitor trip valve. When oil pressure is stabilized, place ignitors in service associated with mills 5 and 6. This operation <u>**SHALL**</u> be observed locally so that visual observation of flames may occur. The local operator <u>**SHALL**</u> monitor ignitor fires and make adjustments as necessary to reduce smoke from oil guns and optimize opacity until 2 pulverizers are in service.

A. MFT and IFT relays reset when the ignitor trip valve opens.

B. Maintain drum level within limits and air flow above 25%.

_____ 28. Close R.H. damper to approximately 25%, since there is not flow yet in the R.H. section.

_____ 29. Open the continuous blowdown 100% and use the boiler fill line from the condensate discharge header to maintain drum level in limits. If proper firing rate is held and blowdown controlled, -5" in drum is enough water, due to swelling.

_____ 30. Line up dampers and auxiliary equipment and start the primary air fans. Do not load fans at this time. Load when placing ball mills in service.

_____ 31. Verify three air compressors in service. Start the air heater blowing sequence using steam as the blowing medium, if the aux steam is cross tied. If not, use compressed air.

_____ 32. Firing rate must be controlled so as not to exceed 200°F between top and bottom drum metal temperature and 1000°F gas temperature on thermoprobes. The pass dampers will allow some flexibility in controlling temperatures. Computer points for drum metal temps are: Unit 1 BT1007 through BT1016, AT[5] BC1003 through BC1007, Unit 2 BT20076 through BT2016, AT[5] BC2003 through BC2007.

_____ 33. Jog down #7 F.W. heater outlet valve to approximately 5% open, and open #7 heater extraction M.O.V. from cold reheat 100%. This is to help preheat feedwater and minimize L.P. bypass flow into the condenser (efficiency). If unable to jog down #7 R.W. heater, then jog down #8 F.W. heater outlet M.O.V. Jogging down is to assure S.H. sprays, when necessary. If #8 is jogged down, still

have #7 in service.

_____ 34. If units were not cross tied on auxiliary steam system, the open the auxiliary steam supply valve to allow the auxiliary steam line to warm up with the boiler and to prevent a drum level excursion if opened later.

_____ 35. Open the pegging steam valve to the D.A.

_____ 36. When 25 lbs. of drum pressure is attained, close the drum and superheater vents. Verify the "25 PSI drum pressure requirements" have been completed per the control room, unit and auxiliary operator boiler checklist. Add ignitors to increase firing rate up to the limit for T on steam drum, or 1000°F probe limit.

_____ 37. At approximately 150 PSI drum pressure, the drum level will start to rise (swell). It may be necessary to utilize the mass blowdown to maintain drum level within limits. Firing rate can also be manipulated to control this.

_____ 38. When 250 PSI drum pressure is attained, place the No. 3 boiler feed pump in service and close the condensate boiler fill valve. The mass blowdown should be opened to 50% at this time, and remain there, until turbine bypass operation for sufficient flow to control drum level. If adequate drum level control is attained, the No. 3 boiler feed pump may be placed on automatic. If a T.D.B.F.P. is used, operate with recirc. 100% open in manual until pump is working hard enough to keep turbine exhaust from overheating. Drum pressure might need to be higher if a T.D.B.F.P. is utilized.

_____ 39. If boiler drum blowdown pH (1-XR-4042) is between 8.3 and 9.2, iron oxide is less than 200 ppb, and specific conductivity (1-CJR-4044) is between 2.5 and 3.5 mmho, continue increasing drum pressure as required. Lab personnel should provide hourly readings.

_____ 40. Condensate flow should be sufficient to place the DA level control valve on automatic as well as hotwell make-up valves.

_____ 41. If boiler drum blowdown pH (1-XR-4042) is below 8.3, iron oxide is greater than 200 ppb, or specific conductivity (1-CJR-4041) is greater than 3.5 mmho due to ironic contamination, alternately open and close the boiler bottom drains for 30 seconds on each valve (not to exceed drum level limitations) between 400 PSI and 800 PSI drum pressure.

CAUTION: DO NOT BLOWDOWN USING BOILER BOTTOM DRAINS WHEN PRESSURE IS OVER 800 PSI.

_____ 42. Keep continuous boiler drum blowdown valve 100% open until water quality permits reduced blowdown rate. Mass blowdown is to be closed when unit is stable on bypass, unless water quality/lab deems it necessary to do otherwise.

_____43. If vacuum was not pulled earlier, place the turbine gland steam function group in the "ON" position. This will open the drain on the gland steam header and

start

the warm-up period. Gland steam function group can be placed in stop-manual, and open drain manually also.

_____ 44. As soon as the temperature is adequate for the gland steam function group (superheat >90°F and aux. steam >446°F) the supply valve will open.

_____ 45. Ensure vacuum breakers are closed and have seal water on them, then start two vacuum pumps to establish vacuum.

_____ 46. When vacuum is established, reset the LP bypass system. Verify the LP stop valves open (7" to 5" Hg). Check that LP bypass spray water is valved in.

Should

not reset without adequate spray water. Also reset the main turbine and verify the HP and IP stop valves open.

_____ 47. Initiate a pre-bypass checklist and rest H.P. bypass, if tripped.

_____ 48. At 400 psi start pressurizing and warming the electromatic power relief valves by slowly opening the bypass valves on both isolation valves. The relief valves must be warmed for at least 30 minutes prior to operating.

At 500 psi have the electromatics valved in. Then test them one at a time approximately 5 to 10 seconds. Be prepared for a sharp increase in drum level when this is done.

_____ 49. P.A. fans will need to be loaded at this time. Have the first mill in service when boiler pressure reaches 500 psig. Verify there is no coal laying out in burners. Start one of the lower ball mills.

_____ 50. Just prior to opening the Paso on the first mill, open the H.P. bypass 10% manually. Control HP bypass discharge temperature at 650°F. Open the Paso on the in-service mill and start the coal feeders. Establish and maintain normal mill level and temperature. Continue to monitor and control steam drum T. Fire mill lightly until 600 psi is achieved (M.S.). Ensure H.P. warm-up valves open 100%.

NOTE: Opening of HP bypass valves will cause drum level to go high if opened too much. Do not close the HP bypass valves while on manual control or a MFT will occur.

_____ 51. Notify Support Systems operators to place electrostatic precipitators in service when coal fire is visually verified in the furnace.

_____ 52. Increase firing rate (not to exceed limitations in step 31) and increase opening of HP bypass valves to increase steam flow while allowing pressure to slowly increase as well.

_____ 53. When coal fires are established, it is necessary to utilize the superheat sprays to control main steam temperature at or below 750°F.

_____ 54. When boiler pressure reaches 1200 PSI and HP bypass should be approximately 50% open (480,000 to 500,000 lb/hr).

_____ 55. Set the HP bypass setpoint at 1200 PSI and place the HP bypass valves on automatic.

_____ 56. Place the reheat and superheat pass dampers on automatic with R.H. setpoint at 700°F (115 psi @ 700°F = 361.92° Sh).

_____ 57. Verify the "10% steam flow" requirements have been completed per the control room, unit and auxiliary operators boiler checklists.

_____ 58. Place the second bottom elevation coal mill in service with 4 burners in service after purging coal conduits. If lower mill is unavailable, mills 2 or 4 can be utilized.

NOTE: This may cause drum level to swell rapidly. Use method as noted in Step 49. Have the absorber liquid side on three (3) modules in service.

_____ 59. Increase firing rate until thermal megawatts are approximately 130 as indicated on the L&N master panel.

NOTE: Steam flow should then be greater than 10% and the HP bypass approximately 90% open.

_____ 60. Increase firing rate until:

_____ A. Thermal megawatts approx. 130 MW.

_____ B. Throttle pressure approx. 1200.

_____ C. Main steam temperature 750°, R.H. temperature @ 700°F.

_____ D. HP bypass open approx. 90% to 100%.

_____ E. All conditions under control.

_____ F. Boiler/manual control mode.

_____ 61. All F.W. controls should/could be in auto at this time.

_____ 62. When the O_2 is below 10%, the scrubber modules should be put into service by notifying the Support Systems Control Room Operator.

_____ 63. Verify all turbine drains open, oil temperature 85 to 110°F, >40 PSI header pressure, and stator cooling system in service, and generator H_2 pressure at 65 lbs. minimum.

_____ 64. Select "IDLE" mode on the turbomat panel. (Turbine should have been on turning gear at least 4 hours prior to rolling.) Main steam temperature may have to be increased to provide permissive to roll turbine.

_____ 65. Roll the turbine up to 500 RPM and hold for approximately 20 minutes. Check the turbine/generator for rubbing, vibration, oil flow, etc.

_____ 66. Roll the turbine up to 1200 RPM and hold for approximately 20 minutes checking the turbine/generator conditions as above. (Check that turning gear motor has stopped >800 RPM.) Hold at 1200 RPM until HP probe shows a decreasing trend. Begin procedure for starting next (3rd) mill (2 or 4). 3rd mill should be available for service just before synchronization.

_____ 67. Roll the turbine up to 3600 RPM. The control system will roll the turbine up at a rate allowed by the HP and IP probes. 30/min. Check all turbine/generator supervisory instrumentation as well as local checks.

NOTE: Roll time will be approximately 2 hours from initial roll to rated speed. When 3600 RPMs is reached, notify dispatcher of intentions to synch. and tie.

_____ 68. When the turbine reaches 3600 RPM, select "LOAD" mode on turbomat, close the generator field breaker. Observe that generator terminal voltage increases,

and

is matched with grid voltage.

NOTE: If load mode is selected early, the synchronization mode times out (640 seconds) before the Unit can tie on in the auto mode. Load mode should be selected when ready to tie-on.

_____ 69. Set the target load at 100 MWS and the load gradient at 25 MWS/MIN.

_____ 70. Remove one of the switches for the generator OCBs (either 8W30 or 8W40) from the pull-to-lock position to the green flag position (normal after trip position).

_____ 71. Unlock the sync. switch for the corresponding breaker taken out of pull-to-lock in step #69. Turn the spring loaded sync. switch all the way to the "auto on" position and let it return to the "auto" position. The "auto" sync. circuit should automatically adjust the generator voltage to match the line voltage on the grid and the frequency. **<u>THIS IS TO BE VERIFIED</u>**. The selected OCB will not auto close in the "GREEN FLAG" position (normal after trip position). When frequency and voltage are matched, as the sync. scope is moving in the clockwise direction the selected OCB control switch is to be placed in the "RED FLAG" position **<u>only</u>** when the sync. scope is between the 10 o'clock and 12 o'clock position. If the OCB doesn't auto close between 10 o'clock and 12 o'clock it is to be placed back in the "GREEN FLAG" position until the sync. scope is moving clockwise and between 10 o'clock and 12 o'clock. Verify a breaker close signal is being sent by observing the synchronization red lamp illuminates in pulse fashion when the synchroscope pointer is between the 10 o'clock and 12 o'clock position. The OCB control switch should **<u>never</u>** be in the "RED FLAG" position unless these conditions exist or the OCB is close in. Upon synchronization, zero vars. (Do not totally depend on automatic mode!) If unable to sync. in auto, take the sync. switch for the corresponding breaker taken out of pull-to-lock in step 69, and turn the sync. switch to manual. Use the frequency controller to adjust cycles so that the sync. scope starts slowly turning in a clockwise direction. Re-verify that generator voltage and grid voltage are still matched. When the sync. scope indication is at 11 o'clock and approaching 12 o'clock, close the pre-selected OCB. Zero VARs.

_____ 72. Verify unit load comes up to the target load set value that was set in step #68.

_____ 73. Place F.W. heaters 1-6 and #8 in service. Place steam driven B.F.P. in service, if #3 B.F.P. is in service.

_____ 74. Turn the selected sync. switch off. Unlock the other sync. switch and close the corresponding generator breaker.

_____ 75. At this point the IP probe will probably be limiting. With this condition, most of the steam will be by-passing the IP and LP turbines. The firing rate will be higher than normal at this low load. The HP bypass must remain in "AUTO" and in service during this time.

_____ 76. If the bypass is closing to a point of closing off, it may be necessary to increase the firing rate. This is accomplished by manually raising the air flow and fuel flow.

When the IP probe is no longer limiting start picking up load using the target load set value on the turbotrol panel. Set the load gradient at 5 MWS/MIN. Load increases should be approximately 25 MW intervals.

_____ 77. Close boiler and turbine drains. Downstream valves first, then all root valves.

NOTE: Do not select turbine follow mode if the HP bypass is still open.

_____ 78. Continue increasing firing rate and load slowly, keeping H.P. bypass approximately 25% open for pressure control. Increase pressure as allowed by lab.

_____ 79. Transfer station service when load is >200 mw.

_____ 80. When unit is stable at 250 MW, increase the target load set value, slightly, which will cause the H.P. bypass to close slowly. (Note: The H.P. bypass setpoint will have to be increased to a higher setpoint than throttle pressure setpoint, to prevent H.P. bypass from opening unnecessarily.) Re-correct target load set value, or firing rate, to re-stabilize unit. Unit still in boiler manual/turbine base, TT42,@ 250 MW. Match throttle pressure control setpoint with actual pressure, and select turbine follow mode only. Boiler base should only be selectd after feedwater temperature is constant.

_____ 81. When unit is stabilized at 2200 PSI throttle pressure (HP bypass setpoint at 2425 PSI) raise unit load to 300 MWS while placing another mill in service to accommodate the needed firing rate.

NOTE: Throttle pressure kept down to 2200 to ensure the L.P. bypass will not come into service.

_____ 82. When unit is at 300 MWS it will be necessary to place the other boiler feed pump turbine in service. Once the second pump is in service the loading should be approximately equal and the second pump placed on automatic.

NOTE: The second pump should be brought into service slowly allowing the already in service pump to decrease automatically while maintaining drum level.

_____ 83. At 300 MWS all essential equipment should be in service to allow unit load capability throughout the entire load range. Equipment that is not required at this time should be in a "ready for service" type of condition. Also, throttle pressure can be increased to 2400 PSI if chemistry allows.

_____ 84. The generator hydrogen pressure should be at the 75 lb. maximum pressure.

_____ 85. Notify the dispatcher the unit is available for system load requirements within the 300 to 650 MW range.

NOTE: Any known restrictions that would prevent the unit from attaining full load (650 MWS) capability should be reported to the dispatcher at this time, or earlier, and logged on the derate information form.

APPENDIX B-9

SHUTDOWN PROCEDURE

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

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	Approved By: Ron L. Waugh	Number: EO-16 R3
Subject: UNIT SHUT DOWN	Section: EQUIPMENT OPERATING PROCEDURE	

1.0 PURPOSE

To provide an approved operating procedure for removing a unit from on-line status to off-line status for outage work.

2.0 SCOPE

This operating procedure will outline steps to be taken from full load operation to off-line/turning gear operation.

3.0 SKILL LEVEL

When performing this task, it will require no less than the proficiency of a Control Room Operator, Unit Operator and Auxiliary Operator.

4.0 RESPONSIBILITIES

It shall be the responsibility of the Control Room Operator to perform the following:

4.1 Ensure the Unit is maintained in a stable condition throughout all load drops to off-line status.

4.2 Ensure all equipment is removed from service and secured properly in a timely manner.

4.3 Ensure that all required permissive and logics are met as required when reducing load and removing Unit from the grid.

4.4 Ensure that the shutdown procedure is followed throughout its entirety. Should any deviation be required, authorization from the Shift Supervisor must be obtained first. Exception to this rule is (1) safety to personnel or equipment or (2) if stipulated in this procedure, authorizing deviation without prior approval.

4.5 Maintain an open communication with all departments involved at ALL times.

5.0 REMOVING THE UNIT FROM SERVICE

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NOTE 1: **Assume Unit is at 650 MWs, 5 and 2/3 mills in service, 2400 psi throttle pressure, 1000 degrees main steam temperature, 4 ID fans in service and associated modules for full load requirements.**

NOTE 2: **Upon notice of Unit being removed from service, clean the boiler of slag with the sootblowing system. It will require approximately 5 hours to complete the cleaning process using all blowers.**

5.1 Select DEB/LFC or DEB/TB mode at a 5 MW a minute ramp rate. Deviation to ramp rate is authorized to accommodate state load requirements. Deviation from Boiler/Turbine modes is also authorized if they are not available or stable.

5.1.1 Verify that the in-service ignition oil tank has a level greater than 15'.

5.2 Begin decreasing MWs (load) at the given ramp rate. As load is reduced, slide pressure to maintain turbine valve position at no less than 90% valve position. Large load drops may result in a valve position less than 90%. Continue sliding pressure after load drop until 90% or greater turbine valve position is achieved. This valve position is to maintain steam flow velocities to assist in cooling the turbine/boiler. This accelerated flow rate will aid in control of steam temperatures at lower loads.

5.3 Reduce the Main steam and Hot Reheat steam temperature set points to a degree not to exceed the minimum BBC requirements. BBC requires no less than 150 degrees of steam temperature above saturation pint being admitted to the turbines. (Reference Steam Tables)

5.4 Reducing thermal MWs for load reduction is done by removing fire power, i.e., mills from service. Dependent upon related outage repair requirements when removing a mill from service, stripping and/or emptying the silo may be required. If there is not any related outage work to be performed, the CRO will remove the mill from service by the normal accepted practice.

5.5 Repairs requiring the silo to be emptied will require at least twelve hours advanced notice. This will give adequate time for pre-planning to ensure that the silo is prepared properly allowing repairs to be performed during unit shut down.

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NOTE: **When and at what load to remove fire power is at the discretion of the Control Room Operator. Unit fire power configuration is dictated by the mills and burners available for use. Another determining factor is the need introduced by pre-planning as to which mill is removed from service first and in what desired order.**

6.0 LOAD REDUCTION

6.1 Reduce load by reducing fire power from the upper mills first. Remove the upper mills, if able: first, Mill #1 and then Mill #3.

6.2 When dropping load, constant monitoring of the HP/IP probes is required. There is an expected deflection to occur to the probes. The probes are expected to respond by indicating 50% towards the negative direction on the probe chart. This is acceptable. However, sharp increases in position (spikes) or an elevated percentage above 65% will require the immediate attention of the Control Room Operator.

6.3 Monitor throttle pressure and drum pressures frequently. These pressures must remain stable. Unstable throttle or drum pressures will not be conducive of a controlled shutdown.

6.4 Monitor main steam temperature vigilantly throughout all load reductions and constant conditions. Main steam temperature becomes increasingly difficult to maintain at a steady rate as low load and low flow conditions become realized.

6.5 <u>UNIT STATUS:</u>

6.5.1 LOAD AT 580 MWS.

6.5.2 THROTTLE PRESSURE 2300 PSI APPROXIMATELY.

6.5.3 FIVE MILLS IN SERVICE.

6.5.4 MAIN STEA TEMPERATURE 950 DEGREES AND APPROXIMATELY 300 DEGREES SUPERHEAT.

6.5.5 FOUR ID FANS IN SERVICE.

6.5.6 FOUR MODULES IN SERVICE.

6.6 Remove one of the four ID Fans from service as soon as load conditions permit. This will allow Supports to remove one module from service as long as logics are met.

6.7 Have the Unit Operator verify that the hood sprays are lined up for service.

6.8 Place the Start Up Boiler Feed Pump in ser5vice. Do not initiate any increases to the pump output at this time, i.e., feed pump discharge being placed into the feedwater header. Placing the Start Up Boiler Feed Pump in service is only to ensure pump operation. Placing the pump in service at this time will supply ample time for check out and field repairs if any are needed.

6.9 UNIT STATUS:

6.9.1 450 MWS.

6.9.2 FOUR MILLS IN SERVICE.

6.9.3 THROTTLE PRESSURE AT 1800 PSI.

6.9.4 MAIN STEAM TEMPERATURE 900 DEGREES, SUPERHEAT STEAM 270 DEGREES.

6.9.5 THREE ID FANS IN SERVICE.

6.9.6 THREE MODULES IN SERVICE.

NOTE: **To obtain 900 degrees main steam temperature, it will require the #7 FWH discharge valve to be throttled to 25%. This will produce sufficient spray flow to the sprays to control superheat temperature at the desired temperature. CAUTION: When 35% open on the #7**

FWH discharge valve has been obtained, reduce as needed, not to exceed the 25% mark. Closely monitor drum level chart. Should drum level become erratic at anytime, open the discharge valve to 50% and wait until load begins to drop below 450 MWs. Should temperature of 900 degrees still be a problem to obtain, blow the wall blowers as well as bull nose sootblowers. The economizer damper should already be 100% open at this time. If it is not, open the economizer to 100% now. Do not throttle the #7 FWH outlet valve below 5% at any time.

NOTE: **If the Unit is being shut down for short term repairs to something other than boiler internals or turbine/generator, there is no need to reduce temperatures to the degree outlined in this procedure.**

6.10 Check to ensure the auxiliary steam system is valved in and operational from the boiler source.

6.11 UNIT STATUS:

6.11.1 300 MWS.

6.11.2 THREE MILLS IN SERVICE.

6.11.3 THROTTLE PRESSURE 1400 PSI.

6.11.4 MAIN STEAM TEMPERATURE 800 DEGREES, SUPERHEAT APPROXIMATELY 212 DEGREES.

6.11.5 THREE ID FANS IN SERVICE.

6.11.6 INSTRUCT UNIT OPERATOR TO CONDUCT A THOROUGH INSPECTION OF THE BOILER FURNACE SECTION, ESPECIALLY THE BULL NOSE AND SUPERHEAT AREA, FOR A SLAGGING STATUS. REPORT THE STATUS TO THE CRO FOR DOCUMENTATION IN THE CRO LOG.

6.12 Test the HP bypass operation electronically and actually. Perform the electronic test procedure through the test mode located at the HP bypass panel. Actual test will be opening the HP bypass slightly to ensure all components work properly.

6.13 Remove one of the Steam Driven Boiler Feed Pumps from service under 300 MWs. CRO discretion. Ensure HMV-1301 OPEN, and HMV-1301 bypass OPEN 100%.

6.14 If unit is coming off line and fast cool down is not required, modules will be removed from service as needed.

6.15 Unit status reaches 450 MWs or less and only three ID Fans in service or less, remove fourth module from service.

6.16 Unit status reaches 300 MWs or less with three ID Fans still in service, leave the third module in service to accommodate air flow needed for force cooling.

NOTE: **Unit loads BELOW 300 MWs place the Unit Master Control in a manual mode to ensure stable unit operation.**

NOTE: **Swap station service at approximately 200 MWs.**

7.0 TURBINE SOAKING

Should repairs necessitate reduction of metal temperatures, soak time must be at least two to three hours consecutively in duration to remove the latent heat. Steam flow of approximately 2.5 million lbs. per hour should equate out to ~275 to 300 MWs. Ensure that the throttle pressure versus main steam temperatures are such that 150 degrees superheat steam temperature above saturation is maintained at all times. (REFERENCE STEAM TABLES)

8.0 LOAD REDUCTION CONTINUED

8.1 Remove the fourth mill at approximately 190 MWs. This MW value is flexible and fire power requirements should dictate at what time the mill is removed from service. However, when this mill is removed from service the fifth mill should be prepared for removal.

8.2 UNIT STATUS:

8.2.1 150 MWS.

8.2.2 TWO MILLS IN SERVICE.

8.2.3 THROTTLE PRESSURE 1000 PSI.

8.2.4 MAIN STEAM TEMPERATURE ~750 DEGREES AND APPROXIMATELY 250 DEGREES SUPERHEAT.

8.2.5 THREE ID FANS IN SERVICE.

8.3 When the Unit is stable and at 150 MWs, request authorization from the dispatcher to remove the Unit from operation. When authorization is obtained, prepare the Unit for final load reduction. Place HP bypass in service at 1000 psi set point. With the HP bypass in service boiler energy fro the boiler will be diverted through the HP bypass. This will reduce the impact to the boiler pressure and alleviate drum level excursions.

9.0 REMOVING UNIT FROM THE GRID

9.1 Reduce load by reducing valve position in the turbine manual mode. Be advised that when C valve closes, the probes will indicate a sharp change in position. C valve should be fully closed by 85% indication of the live steam valve position indication located on TT42. Actual valve position can be seen on the Bently Nevada panel.

9.2 When C valve indicates closed, Unit load should be such that one of the two remaining mills may be removed from service. Prepare the last mill for removal, i.e., cool the mill down.

9.3 Once load has been reduced to 50 MWs, place the turbine controls in the idle mode load gradient above 3 MWs a minute and the Unit will decrease rapidly to zero MWs. HP bypass.

9.4 UNIT STATUS:

9.4.1 TURBINE/GENERATOR OFF LINE.

9.4.2 THROTTLE PRESSURE 1000 PSI.

9.4.3 ONE MILL IN SERVICE.

9.4.4 ONE TURBINE DRIVEN BOILER FEED PUMP IN SERVICE.

9.4.5 THREE ID FANS IN SERVICE.

9.5 With no Tests/PMs required, remove the last mill from service, purging all coal conduits. Once the last coal fire is out and coal conduits are purged, remove and purge out all ignitors.

9.6 When boiler comes off line and MFT relay activates, T/R sets trip automatically.

9.7 Check to ensure main turbine turning gear comes into operation at 600 RPMs and that it maintains 25 RPMs on the rotor.

9.8 Isolate both electromatic power relief valves at 500 psi by closing the isolation gate valves and the isolation valve bypass valves.

9.9 Continue to depressurize the boiler through the HP/LP bypass loop down to the desired pressure ~200 to 300 psi.

9.10 When boiler depressurization is complete, fully break condenser vacuum. Vacuum may require being broken earlier if turbine steam seals are lost.

NOTE: **If the Main Turbine did not reach turning gear RPMs at "9.7" of this procedure, RPM deceleration will increase now that vacuum is broken. Monitor Turbine speed to ensure proper operation of the turning gear occurs.**

APPENDIX B-10

APPLICABLE REGULATIONS

Title V Core List

Effective: 03/01/02

[**Note:** The Title V Core List is meant to simplify the completion of the "List of Applicable Regulations" for DEP Form No. 62-210.900(1), Application for Air Permit - Long Form. The Title V Core List is a list of rules to which all Title V Sources are presumptively subject. The Title V Core List may be referenced in its entirety, or with specific exceptions. The Department may periodically update the Title V Core List.]

Federal: ***(description)***

40 CFR 60, Subparts Da and Db
40 CFR 61, Subpart M: NESHAP for Asbestos.

40 CFR 82: Protection of Stratospheric Ozone.
40 CFR 82, Subpart B: Servicing of Motor Vehicle Air Conditioners (MVAC).
40 CFR 82, Subpart F: Recycling and Emissions Reduction.

State: ***(description)***

CHAPTER 62-4, F.A.C.: PERMITS, effective 06-01-01

62-4.030, F.A.C.: General Prohibition.
62-4.040, F.A.C.: Exemptions.
62-4.050, F.A.C.: Procedure to Obtain Permits; Application.
62-4.060, F.A.C.: Consultation.
62-4.070, F.A.C.: Standards for Issuing or Denying Permits; Issuance; Denial.
62-4.080, F.A.C.: Modification of Permit Conditions.
62-4.090, F.A.C.: Renewals.
62-4.100, F.A.C.: Suspension and Revocation.
62-4.110, F.A.C.: Financial Responsibility.
62-4.120, F.A.C.: Transfer of Permits.
62-4.130, F.A.C.: Plant Operation - Problems.
62-4.150, F.A.C.: Review.
62-4.160, F.A.C.: Permit Conditions.
62-4.210, F.A.C.: Construction Permits.
62-4.220, F.A.C.: Operation Permit for New Sources.

CHAPTER 62-210, F.A.C.: STATIONARY SOURCES - GENERAL REQUIREMENTS, effective 06-21-01

62-210.300, F.A.C.: Permits Required.
62-210.300(1), F.A.C.: Air Construction Permits.
62-210.300(2), F.A.C.: Air Operation Permits.
62-210.300(3), F.A.C.: Exemptions.
62-210.300(5), F.A.C.: Notification of Startup.
62-210.300(6), F.A.C.: Emissions Unit Reclassification.
62-210.300(7), F.A.C.: Transfer of Air Permits.

62-210.350, F.A.C.: Public Notice and Comment.
62-210.350(1), F.A.C.: Public Notice of Proposed Agency Action.
62-210.350(2), F.A.C.: Additional Public Notice Requirements for Emissions Units Subject to Prevention of Significant Deterioration or Nonattainment-Area Preconstruction Review.
62-210.350(3), F.A.C.: Additional Public Notice Requirements for Sources Subject to Operation Permits for Title V Sources.

62-210.360, F.A.C.: Administrative Permit Corrections.
62-210.370(3), F.A.C.: Annual Operating Report for Air Pollutant Emitting Facility.
62-210.400, F.A.C.: Emission Estimates.
62-210.650, F.A.C.: Circumvention.
62-210.700, F.A.C.: Excess Emissions.

62-210.900, F.A.C.: Forms and Instructions.
62-210.900(1), F.A.C.: Application for Air Permit – Title V Source, Form and Instructions.
62-210.900(5), F.A.C.: Annual Operating Report for Air Pollutant Emitting Facility, Form and Instructions.
62-210.900(7), F.A.C.: Application for Transfer of Air Permit – Title V and Non-Title V Source.

CHAPTER 62-212, F.A.C.: STATIONARY SOURCES - PRECONSTRUCTION REVIEW, effective 08-17-00

CHAPTER 62-213, F.A.C.: OPERATION PERMITS FOR MAJOR SOURCES OF AIR POLLUTION, effective 04-16-01

62-213.205, F.A.C.: Annual Emissions Fee.
62-213.400, F.A.C.: Permits and Permit Revisions Required.
62-213.410, F.A.C.: Changes Without Permit Revision.
62-213.412, F.A.C.: Immediate Implementation Pending Revision Process.
62-213.415, F.A.C.: Trading of Emissions Within a Source.
62-213.420, F.A.C.: Permit Applications.
62-213.430, F.A.C.: Permit Issuance, Renewal, and Revision.
62-213.440, F.A.C.: Permit Content.
62-213.450, F.A.C.: Permit Review by EPA and Affected States
62-213.460, F.A.C.: Permit Shield.

62-213.900, F.A.C.: Forms and Instructions.
62-213.900(1), F.A.C.: Major Air Pollution Source Annual Emissions Fee Form.
62-213.900(7), F.A.C.: Statement of Compliance Form.

CHAPTER 62-296, F.A.C.: STATIONARY SOURCES - EMISSION STANDARDS, effective 03-02-99

62-296.320(4)(c), F.A.C.: Unconfined Emissions of Particulate Matter.

62-296.320(2), F.A.C.: Objectionable Odor Prohibited.

CHAPTER 62-297, F.A.C.: STATIONARY SOURCES - EMISSIONS MONITORING, effective 03-02-99

62-297.310, F.A.C.: General Test Requirements.
62-297.330, F.A.C.: Applicable Test Procedures.
62-297.340, F.A.C.: Frequency of Compliance Tests.
62-297.345, F.A.C.: Stack Sampling Facilities Provided by the Owner of an Emissions Unit.
62-297.350, F.A.C.: Determination of Process Variables.
62-297.570, F.A.C.: Test Report.
62-297.620, F.A.C.: Exceptions and Approval of Alternate Procedures and Requirements.

<u>**Miscellaneous**</u>:

CHAPTER 28-106, F.A.C.: Decisions Determining Substantial Interests
CHAPTER 62-110, F.A.C.: Exception to the Uniform Rules of Procedure, effective 07-01-98
CHAPTER 62-256, F.A.C.: Open Burning and Frost Protection Fires, effective 11-30-94
CHAPTER 62-257, F.A.C.: Asbestos Notification and Fee, effective 02-09-99
CHAPTER 62-281, F.A.C.: Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling, effective 09-10-96

APPENDIX B-11

PHASE II NO_X COMPLIANCE PLAN

Florida Department of Environmental Protection

Phase II NO_x Compliance Plan

For more information, see instructions and refer to 40 CFR 76.9

This submission is: ☐ New X Revised

STEP 1 Indicate plant name, state, and ORIS code from NADB, if applicable.	Seminole Generating Unit Plant Name	FL State	000136 ORIS Code
STEP 2	Identify each affected Group 1 and Group 2 boiler using the boiler ID# from NADB, if applicable. Indicate boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and"WB" for wet bottom. Indicate the compliance option selected for each unit.		

	ID# U01	ID# U02	ID#	ID#	ID#	ID#
	Type DBW	Type DBW	Type	Type	Type	Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)	X	X	☐	☐	☐	☐
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(c) EPA-approved early election plan under 40 CFR 76.8 through 12/31/07 (also indicate above emission limit specified in plan)	X	X	☐	☐	☐	☐
(d) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)	X	X	☐	☐	☐	☐
(e) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)	☐	☐	☐	☐	☐	☐
(f) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)	☐	☐	☐	☐	☐	☐
(g) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)	☐	☐	☐	☐	☐	☐
(h) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)	☐	☐	☐	☐	☐	☐
(i) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)	☐	☐	☐	☐	☐	☐
(j) NO_x Averaging Plan (include NO_x Averaging form)	☐	☐	☐	☐	☐	☐
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)	☐	☐	☐	☐	☐	☐

Seminole Generating Unit Plant Name (from Step 1)

STEP 2, cont'd.

	ID# U01	ID# U02	ID#	ID#	ID#	ID#
	Type DBW	Type DBW	Type	Type	Type	Type
(l) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_x Averaging (check the NO_x Averaging Plan box and include NO_x Averaging Form)	☐	☐	☐	☐	☐	☐
(m) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17 (a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)	☐	☐	☐	☐	☐	☐
(n) AEL (include Phase II AEL Demonstration Period, Final AEL Petition, or AEL Renewal form as appropriate)	☐	☐	☐	☐	☐	☐
(o) Petition for AEL demonstration period or final AEL under review by U.S. EPA or demonstration period ongoing	☐	☐	☐	☐	☐	☐
(p) Repowering extension plan approved or under review	☐	☐	☐	☐	☐	☐

STEP 3
Read the standard requirements and certification, enter the name of the designated representative, sign and date.

Standard Requirements

General. This source is subject to the standard requirements in 40 CFR 72.9 (consistent with 40 CFR 76.8(e)(1)(i)). These requirements are listed in this source's Acid Rain Part of its Title V permit.

Special Provisions for Early Election Units

Nitrogen Oxides. A unit that is governed by an approved early election plan shall be subject to an emissions limitation for NO_x as provided under 40 CFR 76.8(a)(2) except as provided under 40 CFR 76.8(e)(3)(iii).

Liability. The owners and operators of a unit governed by an approved early election plan shall be liable for any violation of the plan or 40 CFR 76.8 at that unit. The owners and operators shall be liable, beginning January 1, 2000, for fulfilling the obligations specified in 40 CFR Part 77.

Termination. An approved early election plan shall be in effect only until the earlier of January 1, 2008 or January 1 of the calendar year for which a termination of the plan takes effect. If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under 40 CFR 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year after the year for which there is a failure to demonstrate compliance, and the designated representative may not submit a new early election plan. The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated representative must submit a notice under 40 CFR 72.40(d) by January 1 of the year for which the termination is to take effect. If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7. If an early election plan is terminated on or after 2000, the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NO_x for Phase II units with Group 1 boilers under 40 CFR 76.7.

STEP 3, cont'd.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Michael P. Opalinski, D.R. or James R. Frauen, A.D.R	
Signature James R. Frauen	Date 2-13-06

APPENDIX C

AIR QUALITY MODELING ANALYSIS

SULFUR DIOXIDE
AMBIENT IMPACT ANALYSIS
FOR
SEMINOLE ELECTRIC COOPERATIVE, INC.
SEMINOLE GENERATING STATION
UNITS 1 AND 2

Prepared For:

SEMINOLE ELECTRIC COOPERATIVE, INC.
PALATKA, FLORIDA

Prepared By:

Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

February 2006

053-9540

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1.0 INTRODUCTION

Seminole Electric Cooperative, Inc. (Seminole) currently operates the Seminole Generating Station (SGS) in Palatka, Putnam County, Florida. The SGS consist of two solid fuel-fired steam boilers (Emission Units ID Nos. 001 and 002) and associated solid fuel (coal and petroleum coke), limestone, and flue gas desulfurization (FGD) sludge handling and storage activities.

Seminole is submitting this air construction permit application as part of a Regulatory Compliance Package for meeting the requirements of the Acid Rain regulations and Clean Air Interstate Rule (CAIR). In addition, Seminole will be submitting a second package to include the addition of the proposed Unit 3 as well as an emission netting package due to additional upgrades to Units 1 and 2. The specifics of the additional upgrades to Units 1 and 2 will be identified in the second package.

For the current air construction permit application, Units 1 and 2 will be installed with selective catalytic reduction (SCR) control systems and have upgrades to the existing low nitrogen oxides (NO_x) burners and flue gas desulfurization (FGD) systems. In addition, a carbon burn out (CBO) unit is proposed to be added to Units 1 and 2 to avoid the continued onsite landfilling of fly ash and to recover its available heating value. The CBO unit will also help to address the effects resulting from installation of the SCR systems and low NO_X burner upgrades. Finally, upgrades to the existing Units 1 and 2 steam turbines are proposed to take advantage of the waste heat generated by the CBO process. Details of the proposed modifications are presented in the application.

The permitting of the Project requires an Air Construction Permit and Prevention of Significant Deterioration (PSD) review. PSD review requires air quality assessments for determining the facility's compliance with state and federal new source review (NSR) regulations, including addressing applicable PSD and nonattainment review requirements. The critical aspects of these assessments include the air quality impact analyses performed using appropriate air dispersion models and the Best Available Control Technology (BACT) analyses performed to evaluate the selected emission control technology.

The proposed Project will be a modification to an existing major air pollution source that will result in net increases in air emissions. The U.S. Environmental Protection Agency (EPA) has implemented regulations requiring a PSD review for new or modified sources that increase air emissions above certain threshold amounts. Because the threshold amounts for a modification will be exceeded by the

Project, the Project is subject to PSD review. EPA's PSD regulations are promulgated under 40 Code of Federal Regulations (CFR) Part 51.166. Florida's PSD regulations are codified in Rules 62-212.400, Florida Administrative Code (F.A.C.) and have been approved by EPA to FDEP. These Florida PSD regulations incorporate the requirements of EPA's PSD regulations.

SGS is located in Putnam County, which has been designated as an attainment area for all criteria pollutants [i.e., attainment: (O_3), PM_{10}, SO_2, CO, and NO_2; unclassifiable: lead] and is a PSD Class II area for PM_{10}, SO_2, and NO_2; therefore, the PSD review will follow regulations pertaining to such designations.

Based on the emissions from the proposed modifications (see details in the application), PSD review is required only for carbon monoxide (CO). Consequently, modeling was conducted to address compliance of the Project with CO AAQS. However, previous air modeling analyses have shown that SGS, when emitting at its allowable limit for SO_2, caused predicted violations of the PSD Class II and Class I increments for the 3-hour and 24-hour averaging times. Several of these predicted violations were due solely to the operation of the SGS.

Therefore, the purpose of the present modeling analyses is also to present SO_2 AAQS and PSD increment consumption impacts based on the proposed revised SO_2 emission limits for the SGS. These analyses demonstrate that the SO_2 impacts for the SGS together with other sources would comply with the AAQS, PSD Class II increments and, in general, with the PSD Class I increments. The maximum SO_2 concentrations from the SGS alone do not exceed the allowable PSD Class I increment; however, there are only several periods during which the combined impacts from the SGS and background sources slightly exceed the 3-hour and 24-hour PSD Class I increments.

This report contains the technical information and analysis developed in accordance with PSD regulations as promulgated by the U.S. Environmental Protection Agency (EPA) and implemented through delegation to the Florida Department of Environmental Protection (FDEP). It presents an assessment of potential CO and SO_2 quality impacts associated with the SGS. The existing applicable national and Florida AAQS for SO_2 are presented in Table 1-1.

The EPA class designations and allowable PSD increments for SO_2 are also presented in Table 1-1. The nearest PSD Class I areas area 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. As indicated, these PSD Class I areas are within 200 km of the SGS. Air impact modeling analyses for SO_2 were performed for the PSD Class I areas of Okefenokee and Chassahowitzka NWA. Air impact analyses were not performed for the Wolf Island NWA since it is located in the same general direction as the Okefenokee NWA but at a much greater distance from the SGS. As a result, air impacts due to the SGS would be lower at the Wolf Island NWA than at the Okefenokee NWA. Air impacts were not predicted at other PSD Class I areas since they are located more than 200 km from the SGS.

This report is divided into three major sections, including this introduction:

- Section 2.0 presents the air modeling methodology, emissions inventories, and data used in the analysis; and
- Section 3.0 presents the results which demonstrate compliance of the SGS with AAQS and PSD increments.

TABLE 1-1.

NATIONAL AND STATE AAQS, ALLOWABLE PSD INCREMENTS, AND SIGNIFICANT IMPACT LEVELS

		AAQS (μg/m³)			PSD Increments (μg/m³)		Significant Impact Levels [d] (μg/m³)	
Pollutant	Averaging Time	National Primary Standard	National Secondary Standard	State of Florida	Class I	Class II	Class I (proposed)	Class II
Particulate Matter[a]	Annual Arithmetic Mean	50	50	50	4	17	0.2	1
Particulate Matter (PM_{10})	24-Hour Maximum[b]	150[b]	150[b]	150[b]	8	30	0.3	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	0.1	1
	24-Hour Maximum[e]	365[b]	NA	260[b]	5	91	0.2	5
	3-Hour Maximum[b]	NA	1,300[b]	1,300[b]	25	512	1.0	25
Carbon Monoxide	8-Hour Maximum[b]	10,000[b]	10,000[b]	10,000[b]	NA	NA	NA	500
	1-Hour Maximum[b]	40,000[b]	40,000[b]	40,000[b]	NA	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	0.1	1
Ozone[a]	1-Hour Maximum	235[c]	235[c]	235[c]	NA	NA	NA	NA
	1-Hour Maximum	235	235	NA	NA	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA	NA

Note: NA = Not applicable, i.e., no standard exists.
PM_{10} = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.

[a] On July 18, 1997, the EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, $PM_{2.5}$ standards were introduced with a 24-hour standard of 65 μg/m³ (3-year average of 98th percentile) and an annual standard of 15 μg/m³ (3-year average at community monitors). Implementation of these standards has not yet occurred. The ozone standard was modified to be 0.08 ppm for 8-hour average; achieved when 3-year average of 99th percentile is 0.08 ppm or less. The FDEP has not yet adopted these standards.

[b] Short-term maximum concentrations are not to be exceeded more than once per year except for the PM_{10} AAQS (these do not apply to significant impact levels). The PM_{10} 24-hour AAQS is attained when the expected number of days per year with a 24-hour concentration above 150 μg/m³ is equal to or less than 1. For modeling purposes, compliance is based on the sixth highest 24-hour average value over a 5-year period.

[c] Achieved when the expected number of days per year with concentrations above the standard is fewer than 1.

[d] Maximum concentrations.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978. 40 CFR 50. 40 CFR 52.21. Rule 62-204, F.A.C.

2.0 AIR QUALITY IMPACT ANALYSIS METHODOLOGY

The air quality impact analysis is provided to demonstrate that the SGS' emissions of CO and SO_2 associated with the regulatory compliance package will comply with the AAQS and allowable PSD Class I and II increments. This section presents descriptions of the modeling methodology, emissions inventory, meteorological data, and receptor grids used in the air impact analyses.

2.1 Significant Impact Analysis Approach

The general modeling approach followed EPA and FDEP modeling guidelines for determining compliance with AAQS and PSD increments. For all criteria pollutants that will be emitted in excess of the PSD significant emission rate due to a proposed project, a significant impact analysis is performed to determine whether the emission and/or stack configuration changes due to the project alone will result in predicted impacts that are in excess of the EPA significant impact levels at any location beyond the plant's restricted boundaries.

If the project-only impacts are above the significant impact levels in the vicinity of the facility, then two additional and more detailed air modeling analyses are required. The first analysis demonstrates compliance with federal and Florida ambient AAQS, and the second analysis demonstrates compliance with allowable PSD Class II increments.

2.2 AAQS and PSD Class II Increment Analyses

In general, current policies stipulate that the highest annual average and highest, second-highest (HSH) short-term (i.e., 24 hours or less) concentrations be compared to the applicable standard when 5 years of meteorological data are used. The HSH concentration is calculated for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

This approach is consistent with the air quality standards, which permit a short-term average concentration to be exceeded once per year at each receptor.

For the AAQS analysis, the future emissions of the facility are modeled together with background emission facilities. Additionally, a non-modeled background concentration is added to the maximum predicted air quality concentration to determine a total air quality concentration. The maximum annual total concentration is compared to the AAQS.

For the PSD Class II increment analysis, the PSD sources at the SGS are modeled with background PSD consuming or expanding sources. The maximum predicted PSD increment consumption concentrations are compared to the SO_2 PSD Class II increments.

2.3 PSD Class I Increment Analyses

Similar to the AAQS and PSD Class II increment analyses, when 5 years of meteorological data are used, the highest annual and HSH short-term SO_2 concentrations are compared to the allowable PSD Class I increments. The PSD increment consuming and expanding sources are modeled. The maximum predicted PSD increment consumption concentrations are compared to the SO_2 PSD Class I increments.

2.4 Model Selection

The selection of an air quality model to predict air quality impacts for the proposed projects was based on the ability of the model to simulate impacts in areas surrounding the projects as well as at the PSD Class I areas. Two air quality dispersion models were selected and used in these analyses to address air quality impacts for these projects. These models were:

- The American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model, and
- The California Puff model (CALPUFF).

The AERMOD dispersion model (Version 04300) is available on the EPA's Internet web site, Support Center for Regulatory Air Models (SCRAM), within the Technical Transfer Network (TTN). A listing of AERMOD model features is presented in Table 2-1.

On November 9, 2005, the EPA implemented AERMOD into its *Guideline of Air Quality Models (Appendix W to 40 CFR Part 51)* as the recommended model for regulatory modeling applications. The FDEP is allowing the use of AERMOD for air permitting projects as a replacement for the

Industrial Source Complex Short-Term Model (ISCST3), which will no longer be in effect as of December 2006.

The EPA and FDEP recommend that the AERMOD model be used to predict pollutant concentrations at receptors located within 50 km from a source. The AERMOD model calculates hourly concentrations based on hourly meteorological data. The AERMOD model is applicable for most applications since it is recognized as containing the latest scientific algorithms for simulating plume behavior in all types of terrain. For evaluating plume behavior within the building wake of structures, the AERMOD model incorporates the Plume Rise Model Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). AERMOD can predict pollutant concentrations for averaging times of annual and 24, 8, 3, and 1 hour.

The AERMOD model was used to predict the maximum pollutant concentrations due to the SGS Units 1 and 2 in nearby areas surrounding the SGS. The AERMOD model was also used to predict the maximum pollutant concentrations due to Units 1 and 2's emissions together with appropriate background sources. The predicted concentrations were then compared to the applicable AAQS and PSD Class II increments.

For this analysis, the EPA regulatory default options were used to predict all maximum impacts. These options include:

- Final plume rise at all receptor locations,
- Stack-tip downwash,
- Buoyancy-induced dispersion,
- Default wind speed profile coefficients,
- Default vertical potential temperature gradients, and
- Calm wind processing.

At distances beyond 50 km from a source, the CALPUFF model, Version 5.711a (EPA, 2004), is recommended for use by the EPA and FDEP. The CALPUFF model is a long-range transport Lagrangian puff model applicable for estimating the air quality impacts. The methods and assumptions used in the CALPUFF model were based on the latest recommendations for a refined analysis as presented in the IWAQM Phase 2 Summary Report and the FLAG document. This model is also maintained by the EPA on the SCRAM website. A listing of CALPUFF model features is presented in Table 2-2.

The CALPUFF model was used to assess impacts from the project at each of the PSD Class I areas located beyond 50 km from the SGS. The predicted concentrations were then compared to applicable PSD Class I significant impact levels. More detailed descriptions of the assumptions and methods used for the CALPUFF model are presented in Appendix A.

2.5 Meteorological Data

Meteorological data used in the AERMOD model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) offices located at the Jacksonville International Airport and in Waycross, Georgia, respectively. Concentrations were predicted using 5 years of hourly meteorological data from 1986 through 1990. The NWS office at Jacksonville is located approximately 92 km (55 miles) northeast of the site. The FDEP consider this station to have surface meteorological data representative of the project site.

The data for these stations were processed into a format that can be input to the AERMOD model using the meteorological preprocessor program AERMET. The data were processed using the Lakes Environmental graphical interface using the latest version of AERMET (04300). The hourly surface data were obtained from the Solar and Meteorological Observation Network (SAMSON) CD. Upper air sounding data were obtained in the required NCDC TD-6201 format from the Lakes website (www.webmet.com).

A unique feature of AERMOD is its incorporation of land use parameters for the processing of boundary layer parameters used for the dispersion. Based on the most recent regulatory guidance, the land use parameters should be representative of the data measurement site (i.e., NWS at Jacksonville). Land use data, representing the average surface roughness, albedo, and Bowen ratio that exist within a 3-km radius of the NWS station at Jacksonville were extracted from 1-degree land use files from the U.S. Geographical Survey (USGS) using the AERSURFACE program. AERSURFACE currently extracts land use data in 12 wind direction sectors covering 360 degrees. The land use values for each wind direction sector were input into Stage 3 of the AERMET preprocessor program to create the surface and profile meteorological files that AERMOD requires.

CALMET, the meteorological preprocessor to CALPUFF, was used to develop a 3-dimensional wind field necessary to perform the air modeling analysis to evaluate pollutant impacts at each PSD Class I area. The modeling domain consisted of a rectangular 3-dimensional grid that extended from approximately 79.0 to 83.5 degrees longitude and from 23.75 to 28.0 degrees latitude. The modeling domain includes the following meteorological and land use parameters:

- Surface weather data,
- Upper air data,
- A 1-degree land use data,
- A 1-degree Digital Elevation Model (DEM) terrain data,
- Mesoscale Model - Generations 4 and 5 (MM4 and MM5) data (for initializing the wind field), and
- Hourly precipitation data.

These data were obtained and processed for 1990, 1992, and 1996, the years for which MM4 and MM5 data are available. It should be noted that MM4 data are available for 1990 while MM5 data are available for 1992 and 1996. The CALMET wind field and the CALPUFF model options used were consistent with the suggestions of the FLMs. Meteorological data used with the CALPUFF model consist of a CALMET-developed wind field covering North-Central Florida. More detailed descriptions of the assumptions and methods used for processing the meteorological data and establishing the model domain are presented in Appendix A.

2.6 Emission Inventory

2.6.1 SGS Sources

The SGS is located in Palatka, Putnam County, Florida. A site map of the area is provided in Figure 2-1. The plant boundary is shown in Figure 2-2.

The proposed CO emissions from the CBO unit and revised SO_2 emissions and stack and operating data for Units 1 and 2 are presented in Table 2-3. The CBO emissions are exhausted through the stack for Units 1 and 2.

As indicated, the maximum SO_2 emission was based on 0.67 pound per million British thermal units (lb/MMBtu), which is lower than each unit's maximum allowable emission rate of 1.2 lb/MMBtu. The SO_2 emission rate was based on the air modeling analyses performed in Section 3.0 to ensure that the maximum SO_2 concentrations from the SGS alone do not exceed the allowable PSD Class I increments. The SO_2 emissions include emissions from Units 1 and 2 and the CBO unit.

It should be noted that the maximum actual SO_2 emissions from the SGS were approximately 0.86 and 0.69 lb/MMBtu for the 3- and 24-hour averaging periods, respectively (corresponding to approximately 12,400 and 9,850 lb/hr, respectively). These actual emissions were obtained from the continuous emission monitoring (CEM) data available from the EPA Acid Rain Program for 2001 to 2003. The highest SO_2 emissions in lb/hr were determined for the 3- and 24-hour averaging periods and excluded periods when the SO_2 scrubber was inoperative.

As indicated in Table 2-3, the stack for Units 1 and 2 was modeled with a height of 675 ft and diameter of 36 ft.. The stack for Units 1 and 2 is actually 695 ft in height and 23.4 ft in diameter. Based on the building dimensions associated with buildings and structures at the SGS, the stack for Units 1 and 2 complies with the good engineering practice (GEP) stack height regulations with a stack height of 675 ft. Therefore, for modeling purposes, the stack height of 675 ft and associated diameter of 36 ft was used in the analysis. Since the stack height of 675 ft is GEP height, the potential for building downwash to occur was not considered in the air modeling analysis for this stack.

2.6.2 AAQS and PSD class II Analyses

As discussed in Section 3.0, the maximum CO impacts from the Project were predicted to be less than the significant impact levels. As a result a cumulative source analysis is not required to demonstrate compliance with the CO AAQS. There are no PSD Class II increments for CO. Therefore, CO emission inventories for background sources were not developed.

For the SO_2 AAQS and PSD Class II increment analyses, only major sources located in Putnam County were included. Sources outside of Putnam County are accounted for in the SO_2 background concentrations. This approach is consistent with that used in the previous modeling analyses performed for the sources located in this area. A listing of these facilities was developed mainly from previous air modeling studies performed by Golder. A summary of these facilities is presented in Appendix B.

As shown, the GP Mill and the FP&L Putnam and Palatka facilities are the only other major SO_2 sources located in Putnam County. As a result, these facilities are included in the AAQS and PSD

Class II increment air modeling analyses. The individual source emission, stack, and operating parameters for the AAQS and PSD Class II modeling analysis are also presented in Appendix B.

For Florida Power & Light's (FPL) Palatka Plant, the SO_2 emissions for the AAQS were based on the maximum emissions on the combustion turbines (CTs) firing 0.7 percent sulfur content fuel oil and the duct burner (DB) firing 0.5 percent sulfur content fuel oil. Two of the four CT units (half of the total plant emissions) consume PSD increment and are included in the PSD increment analysis. Actual emissions for the units are based on the CTs firing 0.5 percent sulfur content fuel oil and the DB firing natural gas. The DB can fire oil but continuous opacity monitor must be installed before oil is used.

2.6.3 PSD Class I Analysis

There are no PSD Class I increments for CO and, therefore, no modeling was performed for CO at the PSD Class I areas. PSD Class I increment modeling analyses were performed for SO_2 at the Okefenokee and Chassahowitzka NWAs. The PSD sources modeled at the Okefenokee NWA are identified in Appendix B, along with detailed stack, operating, and emission data. These sources are also consistent with those used in the air modeling analyses performed for the previous analyses performed in the region. The inventory was updated based on information obtained from FDEP for the PCS, Suwannee American Cement, and Florida Rock facilities.

It should be noted that the St. Johns River Power Park (SJRPP) is located within 200 km of the Okefenokee PSD Class I area but more than 200 km from the Chassahowitzka PSD Class I area. As such, the SJRPP was included in the PSD Class I increment modeling at the Okefenokee PSD Class I area but not at the Chassahowitzka PSD Class I area.

Also, the maximum SO_2 emissions for the SJRPP were based on 0.76 lb SO_2/MMBtu which is allowed in the air operating permit as a 30-day rolling average when firing coal. This emission rate is more consistent with actual hourly emissions from the plant based on the 2001 to 2003 CEM data available from the EPA Acid Rain Program than the maximum permitted rate for coal-firing of 1.2 lb SO_2/MMBtu as a maximum two-hour average. From the CEM data, the highest SO_2 emissions in lb/hr were determined for the 3-hour and 24-hour averaging periods, and excluded periods when the SO_2 scrubber was inoperative, which were upset conditions, and during startup conditions. Based on this review, the maximum actual SO_2 emissions for the two units for the 3-hour and 24-hour averaging periods were approximately 7,441 and 6,238 lb/hr, respectively, which are equivalent to

0.55 and 0.47 lb SO_2/MMBtu, respectively. The modeled SO_2 emission rate of 0.76 lb SO_2/MMBtu is equivalent to 4,669.4 lb/hr for one unit, or 9,338.8 lb/hr for two units combined.

The PSD sources modeled at the Chassahowitzka NWA are presented in Appendix B with detailed stack, operating, and emission data. These data were obtained from recent PSD permit applications (CF Industries, PSD Application for the C and D Sulfuric Acid Plants, Plant City Phosphate Complex, January 2004).

2.7 Receptor Locations

2.7.1 Site Vicinity

For predicting maximum concentrations in the vicinity of the SGS, more than 2,000 receptors were located in a general Cartesian grid that extended out to a distance of 10 km from the SGS. The locations of these receptors are shown in Appendix C.

The modeling analysis used Universal Transverse Mercator (UTM) coordinates from zone 17, North American Datum 1927 (NAD27). Nested Cartesian receptor grids were used in addition to discrete Cartesian receptors along the SGS fenceline. The air impact analysis used the following receptor spacing from the SGS stack:

- 50-m intervals along the fenceline;
- 100-m intervals beyond the fenceline to 2 km;
- 250-m intervals from 2 to 3.5 km;
- 500-m intervals from 3.5 to 5 km; and
- 1,000-m intervals from 5 to 10 km.

Receptor elevations and hill scale heights for all receptors were obtained from 7.5 minute USGS Digital Elevation Model (DEM) data using the AERMOD terrain preprocessor program AERMAP, Version 03107.

2.7.2 Class I Areas

SO_2 concentrations were also predicted at 180 discrete receptors located in the Okefenokee NWA Class I area and 58 discrete receptors located in the Chassahowitzka NWA Class I area.

2.8 Background Concentrations

Background concentrations are necessary to determine total ambient air quality impacts to demonstrate compliance with the AAQS. "Background concentrations" are defined as concentrations due to sources other than those specifically included in the modeling analysis. For all pollutants, background would include other point sources not included in the modeling (i.e., distant sources or small sources), fugitive emission sources, and natural background sources. In general, monitoring data collected near the area in which the air quality impact is performed is used.

A summary of existing continuous ambient SO_2 concentrations measured for the only SO_2 monitor located in Putnam County is presented in Table 2-4. Data are presented for the monitor located in Palatka for the last three years of record, 2002 through 2004. The second-highest 3-hour and 24-hour average concentrations reported in those years were 110 and 37 micrograms per cubic meter ($\mu g/m^3$). The annual average concentration was 5 $\mu g/m^3$. The monitoring data for SO_2 show that ambient SO_2 concentrations are well below the 3-hour, 24-hour, and annual average AAQS of 1,300, 260, and 60 $\mu g/m^3$, respectively.

For purposes of determining an ambient SO_2 background concentration for use in the modeling analysis, the second-highest short-term and annual average values were selected to represent background concentrations:

Pollutant	Averaging Period	Background Concentration ($\mu g/m^3$)
SO_2	3-hour	110
	24-hour	37
	Annual	5

These concentrations are very conservative since the SGS and other sources impact this monitor. Other major point sources of SO_2 in the area, such as the GP Mill and the Florida Power & Light Company Putnam plant, are also included explicitly in the modeling analysis.

TABLE 2-1.
MAJOR FEATURES OF THE AERMOD MODEL, VERSION 04300

AERMOD Model Features
• Plume dispersion/growth rates are determined by the profile of vertical and horizontal turbulence, vary with height, and use a continuous growth function.
• In a convective atmosphere, uses three separate algorithms to describe plume behavior as it comes in contact with the mixed layer lid; in a stable atmosphere uses a mechanically mixed layer near the surface.
• Polar or Cartesian coordinate systems for receptor locations can be included directly or by an external file reference.
• Urban model dispersion is input as a function of city size and population density; sources can also be modeled individually as urban sources.
• Stable plume rise: uses Briggs equations with winds and temperature gradients at stack top up to half-way up to plume rise. Convective plume rise: plume superimposed on random convective velocities.
• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash.
• Has capability of simulating point, volume, area, and multi-sized area sources.
• Accounts for the effects of vertical variations in wind and turbulence (Brower *et al.*, 1998).
• Uses measured and computed boundary layer parameters and similarity relationships to develop vertical profiles of wind, temperature, and turbulence (Brower *et al.*, 1998).
• Concentration estimates for 1-hour to annual average times.
• Creates vertical profiles of wind, temperature, and turbulence using all available measurement levels.
• Terrain features are depicted by use of a controlling hill elevation and a receptor point elevation.
• Modeling domain surface characteristics are determined by selected direction and month/season values of surface roughness length, Albedo, and Bowen ratio.
• Contains both a mechanical and convective mixed layer height, the latter based on the hourly accumulation of sensible heat flux.
• The method of Pasquill (1976) to account for buoyancy-induced dispersion.
• A default regulatory option to set various model options and parameters to EPA-recommended values.
• Contains procedures for calm-wind and missing data for the processing of short term averages.

Note: AERMOD = The American Meteorological Society and Environmental Protection Agency Regulatory Model.

Source: Paine *et al.*, 2004.

TABLE 2-2
MAJOR FEATURES OF THE CALPUFF MODEL, VERSION 5.711A

CALPUFF Model Features
• Source types: Point, line (including buoyancy effects), volume, area (buoyant, non-buoyant)
• Non-steady-state emissions and meteorological conditions (time-dependent source and emission data; gridded 3-dimensional wind and temperature fields; spatially-variable fields of mixing heights, friction velocity, precipitation, Monin-Obukhov length; vertically and horizontally-varying turbulence and dispersion rates; time-dependent source and emission data for point, area, and volume sources; temporal or wind-dependent scaling factors for emission rates)
• Efficient sampling function (integrated puff formulation; elongated puff (slug) formation)
• Dispersion coefficient options (Pasquill-Gifford (PG) values for rural areas; McElroy-Pooler values (MP) for urban areas; CTDM values for neutral/stable; direct measurements or estimated values)
• Vertical wind shear (puff splitting; differential advection and dispersion)
• Plume rise (buoyant and momentum rise; stack-tip effects; building downwash effects; partial plume penetration above mixing layer)
• Building downwash effects (Huber-Snyder method; Schulman-Scire method)
• Complex terrain effects (steering effects in CALMET wind field; puff height adjustments using ISC model method or plume path coefficient; enhanced vertical dispersion used in CTDMPLUS)
• Subgrid scale complex terrain (CTSG option) (CTDM flow module; dividing streamline as in CTDMPLUS)
• Dry deposition (gases and particles; options for diurnal cycle per pollutant, space and time variations with a resistance model, or none)
• Overwater and coastal interaction effects (overwater boundary layer parameters; abrupt change in meteorological conditions, plume dispersion at coastal boundary; fumigation; option to use Thermal Internal Boundary Layers (TIBL) into coastal grid cells)
• Chemical transformation options (Pseudo-first-order chemical mechanisms for SO_2, SO_4, HNO_3, and NO_3; Pseudo-first-order chemical mechanisms for SO_2, SO_4, NO, NO_2, HNO_3, and NO_3 (RIVAD/ARM3 method); user-specified diurnal cycles of transformation rates; no chemical conversions)
• Wet removal (scavenging coefficient approach; removal rate as a function of precipitation intensity and type)
• Graphical user interface
• Interface utilities (scan ISC-PRIME and AUSPLUME meteorological data files for problems; translate ISC-PRIME and AUSPLUME input files to CALPUFF input files)

Note: CALPUFF = California Puff Model

Source: EPA, 2004.

TABLE 2-3
STACK, OPERATING AND SO_2 EMISSION DATA
FOR THE SEMINOLE GENERATING STATION - UNITS 1 AND 2, CBO UNIT

Parameter	Values for Unit 1	Values for Unit 2	Values for CBO
	Each Unit		
General Data			
Operating Load	100%	100%	100%
Maximum Heat Input, MMBtu/hr	7,172	7,172	114.68
SO_2 Emissions			
Emission Rate, lb/MMBtu	0.67	0.67	[a]
lb/hr	4,805	4,805	[a]
CO Emissions			
Emission Rate, lb/MMBtu	NA	NA	0.244
lb/hr	NA	NA	28.0
	Combined [b]		
Coordinates (km) - UTM East	438.8		
UTM North	3289.2		
Stack Parameters [c]			
Height, ft (m)	675 (205.8)		
Exit Diameter, ft (m)	36.0 (11.0)		
Operating Parameters			
Gas Flow Rate, acfm	1,598,905		
Gas Exit Temperature, °F (K)	128 (326)		
Gas Exit Velocity, ft/sec (m/s)	26.2 (7.98)		
SO_2 Emissions			
Emission Rate, lb/hr (g/s)	9,610 (1211)		
CO Emissions [d]			
Emission Rate, lb/hr (g/s)	28.0 (3.53)		

[a] SO_2 emissions from the carbon burn out (CBO) unit included in Unit Nos.1 and 2's emissions.

[b] Single stack for exhausts from all emission units.

[c] Actual stack height and diameter are 695 ft and 23.4 ft, respectively.
Stack height of 675 ft is the Good Engineering Practice (GEP) stack height. Therefore, modeling was performed using a stack height of 675 ft and associated diameter of 36 ft.

[d] Due to CBO emissions only.

TABLE 2-4

SUMMARY OF MAXIMUM MEASURED SO_2 CONCENTRATIONS USED TO REPRESENT AIR QUALITY, 2002 THROUGH 2004

			Measurement Period		Concentration [ppm (ug/m^3)]				
					3-Hour		24-Hour		Annual
AIRS No.	County	Location	Year	Months	Highest	2nd Highest	Highest	2nd Highest	Average
Sulfur dioxide		Florida AAQS			NA	0.5 ppm	NA	0.1 ppm	0.02 ppm
12-107-1008	Putnam	Palatka, Comfort and Port Rd	2004	Jan-Dec	0.038 (99.6)	0.036 (94.3)	0.013 (34.1)	0.010 (26.2)	0.0018 (4.7)
			2003	Jan-Dec	0.066 (173)	0.042 (110)	0.016 (41.9)	0.014 (36.7)	0.0018 (4.7)
			2002	Jan-Dec	0.038 (99.6)	0.033 (86.5)	0.018 (47.2)	0.009 (23.6)	0.0018 (4.7)

Note: NA = not applicable.
AAQS = ambient air quality standard.

Source:EPA Aerametric Information Retrieval System, Air Quality Subsystem, Quick Look Reports, Florida: 2002, 2003, 2004.

3.0 AIR MODEL RESULTS

3.1 Maximum SGS Impact Analysis

The maximum CO concentrations predicted for the SGS are presented in Table 3-1. From these results, the SGS' impacts were predicted to be less significant impact levels. As a result, the Project's impacts comply with the CO AAQS and no additional analyses are required to demonstrate compliance with the CO AAQS.

The maximum SO_2 concentrations were also predicted for the SGS and are presented in Table 3-2. From these results, the SGS' impacts were predicted to occur within 2,000 m of the site and below the PSD Class II increments. Additional modeling was performed to address compliance with AAQS and PSD increments.

3.2 AAQS Impact Analysis

The maximum 3-hour, 24-hour and annual SO_2 concentrations predicted for the modeled AAQS sources are presented in Table 3-3 As shown in this table, the maximum SO_2 concentrations are predicted to be below the 3-hour, 24-hour, and annual average AAQS of 1,300; 260, and 60 $\mu g/m^3$, respectively.

The maximum impacts predicted in the SGS vicinity occurred at about 10 km from the SGS.

The summaries of the AERMOD results and example input files are presented in Appendix D.

3.3 PSD Class II Increment Analysis

The maximum 3-hour, 24-hour and annual SO_2 concentrations predicted for the modeled PSD Class II-increment affecting sources are presented in Table 3-4 As shown in this table, the maximum SO_2 concentrations are predicted within 2,000 m of the SGS. The maximum SO_2 concentrations are predicted to be below the 3-hour, 24-hour, and annual average PSD Class II allowable increments of 512, 91, and 20 $\mu g/m^3$, respectively. The highest concentrations were mainly due to the SGS.

The summaries of the AERMOD results and example input files are presented in Appendix D.

3.4 PSD Class I Increment Analysis

The maximum 3-hour, 24-hour, and annual average SO_2 concentrations predicted for the modeled PSD Class I sources at the Okefenokee and Chassahowitzka NWAs are presented in Table 3-5. As shown in this table, the maximum total SO_2 concentrations are predicted to be less than the PSD Class I increments, except for one year for the 3-hour and 24-hour averaging period at the Okefenokee NWA and for two years for the 24-hour averaging period at the Chassahowitzka NWA.

A summary of the predicted violations of the PSD Class I increments at the Okefenokee and Chassahowitzka NWA is presented in Table 3-6 As shown, there were a limited number of violations predicted at both NWA. The SGS' contributions to the predicted violations are also shown in Table 3-5. Based on these analyses, the SGS' impacts were predicted to be at or below the PSD Class I increment. As a result, the SO_2 impacts from the SGS' sources will comply with the PSD Class I increments.

TABLE 3-1
MAXIMUM CO IMPACTS PREDICTED FOR THE CBO UNIT ONLY
COMPARED TO THE SIGNIFICANT IMPACT LEVELS

Averaging Time and Rank	Concentration [a] ($\mu g/m^3$) Modeled Sources	Receptor Location UTM Coordinates (m) East	North	Local Coordinates (m) [b] x	y	Time Period (YYMMDDHH)	Significant Impact Levels ($\mu g/m^3$)
<u>8-Hour</u>							
Highest	0.58	437,685	3,289,907	-1,115	707	86070716	500
	0.53	437,600	3,289,726	-1,200	526	87072116	
	0.49	439,700	3,290,200	900	1,000	88123116	
	0.55	437,649	3,288,581	-1,151	-619	89090316	
	0.48	437,728	3,289,997	-1,072	797	90050816	
<u>1-Hour</u>							
Highest	1.03	440,200	3,287,500	1,400	-1,700	86012516	2,000
	0.92	436,800	3,285,200	-2,000	-4,000	87022710	
	0.83	437,642	3,289,215	-1,158	15	88062511	
	0.82	439,657	3,289,309	857	109	89080515	
	0.84	439,635	3,289,405	835	205	90072411	

Note: YYMMDDHH = Year, Month, Day, Hour Ending.

[a] Concentrations are based on highest concentrations predicted using AERMOD with five years of meteorological data from 1986 to 1990 of surface and upper air data from the National Weather Service stations at Jacksonville and Waycross, Georgia, respectively.

[b] Relative to Boiler Unit Nos. 1 and 2's stack which is located at the model origin with x and y coordinates of 0.0 and 0.0 m, respectively.

TABLE 3-2
MAXIMUM SO_2 IMPACTS PREDICTED FOR THE SGS UNITS 1 AND 2 ONLY

Averaging Time and Rank	Concentration [a] (μg/m³) Modeled Sources	Receptor Location UTM Coordinates (m) East	North	Local Coordinates (m) [b] x	y	Time Period (YYMMDDHH)
Annual						
Highest	11.3	437,600	3,290,000	-1,200	800	86123124
	10.7	440,462	3,288,276	1,662	-924	87123124
	11.8	437,600	3,290,100	-1,200	900	88123124
	10.2	440,100	3,289,900	1,300	700	89123124
	11.6	437,400	3,288,600	-1,400	-600	90123124
24-Hour						
Highest	92.5	437,706	3,289,952	-1,094	752	86070724
	94.2	437,600	3,289,800	-1,200	600	87072124
	89.3	437,749	3,290,042	-1,051	842	88072024
	89.1	437,200	3,288,000	-1,600	-1,200	89092724
	85.7	437,700	3,290,100	-1,100	900	90050824
Highest, second-highest	85.8	437,643	3,289,817	-1,157	617	86070724
	78.8	437,400	3,289,900	-1,400	700	87051424
	84.9	437,706	3,289,952	-1,094	752	88062924
	76.1	437,647	3,288,776	-1,153	-424	89091024
	77.0	437,400	3,289,000	-1,400	-200	90053124
3-Hour						
Highest	242	439,900	3,289,300	1100	100	86060812
	241	439,917	3,289,249	1117	49	87090912
	224	437,749	3,290,042	-1051	842	88081712
	251	439,867	3,289,252	1067	52	89060315
	235	439,900	3,289,900	1100	700	90062118
Highest, second-highest	231	439,917	3,289,249	1,117	49	86060812
	215	439,900	3,289,700	1,100	500	87080712
	217	437,728	3,289,997	-1,072	797	88073018
	233	439,966	3,289,247	1,166	47	89080612
	215	437,500	3,288,700	-1,300	-500	90070318

Note: YYMMDDHH = Year, Month, Day, Hour Ending.

[a] Concentrations are based on highest concentrations predicted using AERMOD with five years of meteorological data from 1986 to 1990 of surface and upper air data from the National Weather Service stations at Jacksonville and Waycross, Georgia, respectively.

SO_2 emissions for Units 1 and 2: 0.67 lb/MMBtu

[b] Relative to Boiler Unit Nos. 1 and 2's stack which is located at the model origin with x and y coordinates of 0.0 and 0.0 m, respectively.

TABLE 3-3
MAXIMUM SO_2 IMPACTS PREDICTED FOR COMPARISON TO THE SO_2 AAQS-
SCREENING AND REFINED ANALYSES

Averaging Time and Rank	Analysis	Concentration (µg/m³)[a] Total	Modeled Sources	Background	Receptor Location UTM Coordinates (m) East	North	Local Coordinates (m)[b] x	y	Time Period (YYMMDDHH)	AAQS (µg/m³)
Annual										
Highest	Screening	21.7	16.7	5	434,800	3,283,200	-4,000	-6,000	86123124	60
		24.5	19.5	5	434,800	3,283,200	-4,000	-6,000	87123124	
		20.6	15.6	5	434,800	3,283,200	-4,000	-6,000	88123124	
		21.6	16.6	5	434,800	3,283,200	-4,000	-6,000	89123124	
		19.5	14.5	5	434,800	3,284,200	-4,000	-5,000	90123124	
	Refined	28.5	23.5	5	434,514	3,283,109	-4286.0	-6091.0	87123124	
24-Hour										
Highest, second-highest	Screening	137.1	100.1	37	433800	3282200	-5,000	-7,000	86101224	260
		145.8	108.8	37	434800	3283200	-4,000	-6,000	87040424	
		127.8	90.8	37	434800	3283200	-4,000	-6,000	88021224	
		139.5	102.5	37	433800	3282200	-5,000	-7,000	89021824	
		116.9	79.9	37	434800	3284200	-4,000	-5,000	90062324	
	Refined	192.6	155.6	37	433400	3282800	-5,400	-6,400	87022024	
3-Hour										
Highest, second-highest	Screening	341	231	110	439,917	3,289,249	1,117	49	86060812	1,300
		330	220	110	433,800	3,284,200	-5,000	-5,000	87012915	
		330	220	110	434,800	3,283,200	-4,000	-6,000	88021603	
		343	233	110	439,966	3,289,247	1,166	47	89080612	
		336	226	110	442,800	3,279,200	4,000	-10,000	90032421	
	Refined	343	233	110	439,966	3,289,247	1,166	47	89080612	

Note: YYMMDDHH = Year, Month, Day, Hour Ending.

[a] Concentrations are based on highest concentrations predicted using AERMOD with five years of meteorological data from 1986 to 1990 of surface and upper air data from the National Weather Service stations at Jacksonville and Waycross, Georgia, respectively.

SO2 emissions for Units 1 and 2: 0.67 lb/MMBtu

[b] Relative to Boiler Unit Nos. 1 and 2's stack which is located at the model origin with x and y coordinates of 0.0 and 0.0 m, respectively.

TABLE 3-4

MAXIMUM SO_2 IMPACTS PREDICTED FOR COMPARISON TO THE SO_2 PSD CLASS II INCREMENTS-
SCREENING AND REFINED ANALYSES

Averaging Time and Rank	Analysis	Concentration [a] ($\mu g/m^3$) Modeled Sources	Receptor Location UTM Coordinates (m) East	North	Local Coordinates (m) [b] x	y	Time Period (YYMMDDHH)	PSD Class II Increment ($\mu g/m^3$)
Annual								
Highest	Screening	10.2	437,600	3,290,000	-1,200	800	86123124	20
		9.7	440,462	3,288,276	1,662	-924	87123124	
		10.9	437,700	3,290,100	-1,100	900	88123124	
		9.0	440,100	3,289,900	1,300	700	89123124	
		10.4	437,400	3,288,700	-1,400	-500	90123124	
	Refined	10.9	437,700	3,290,100	-1,100	900	88123124	
24-Hour								
Highest, second-highest	Screening	85.0	437,664	3,289,862	-1,136	662	86040524	91
		76.7	437,400	3,289,900	-1,400	700	87051424	
		83.7	437,706	3,289,952	-1,094	752	88062924	
		76.0	437,647	3,288,776	-1,153	-424	89091024	
		76.9	437,400	3,289,000	-1,400	-200	90053124	
	Refined	85.0	437,664	3,289,862	-1,400	-200	90053124	
3-Hour								
Highest, second-highest	Screening	231	439,917	3,289,249	1,117	49	86060812	512
		215	439,900	3,289,700	1,100	500	87080712	
		217	437,728	3,289,997	-1,072	797	88073018	
		233	439,966	3,289,247	1,166	47	89080612	
		215	437,500	3,288,700	-1,300	-500	90070318	
	Refined	233	439,966	3,289,247	1,166	47	89080612	

Note: YYMMDDHH = Year, Month, Day, Hour Ending.

[a] Concentrations are based on highest concentrations predicted using AERMOD with five years of meteorological data from 1986 to 1990 of surface and upper air data from the National Weather Service stations at Jacksonville and Waycross, Georgia, respectively.

SO2 emissions for Units 1 and 2: 0.67 lb/MMBtu

[b] Relative to Boiler Unit Nos. 1 and 2's stack which is located at the model origin with x and y coordinates of 0.0 and 0.0 m, respectively.

TABLE 3-5
MAXIMUM SO_2 IMPACTS PREDICTED FOR COMPARISON TO THE
SO_2 PSD CLASS I INCREMENTS AT THE OKEFENOKEE AND CHASSAHOWITZKA NWA

Pollutant / Averaging Time	Maximum Concentration (µg/m³)	Receptor Location UTM Coordinates (km) East	North	Time Period (YYMMDDHH)	PSD Class I Increment (µg/m³)
Okefenokee NWA					
Annual					
Highest	0.00 [b]	NA	NA	90123124	2
	0.00	NA	NA	92123124	
	0.00	NA	NA	96123124	
24-Hour					
Highest, second-highest	3.18	390.32	3,401.81	90011524	5
	3.07	390.49	3,418.44	92072224	
	5.17	388.53	3,383.36	96032724	
3-Hour					
Highest, second-highest	25.3	390.34	3,403.66	90010712	25
	13.9	390.24	3,394.42	92101512	
	22.1	388.53	3,383.36	96011703	
Chassahowitzka NWA					
Annual					
Highest	0.00 [b]	NA	NA	90123124	2
	0.00	NA	NA	92123124	
	0.10	338.52	3183.54	96123124	
24-Hour					
Highest, second-highest	5.18	339.91	3,166.90	90081324	5
	4.85	338.27	3,166.00	92012724	
	5.86	335.87	3,168.80	96011724	
3-Hour					
Highest, second-highest	18.6	338.46	3,179.85	90082715	25
	13.0	339.93	3,167.82	92072406	
	14.2	342.47	3,175.18	96041206	

Note: YYMMDDHH = Year, Month, Day, Hour Ending
UTM = Universal Transverse Mercator: Zone 16.

[a] Based on the CALPUFF model using 3 years of CALMET meteorological data for 1990, 1992, and 1996 for North Central Florida.

[b] A "0.00" impact means that the predicted concentration was zero or less. The CALPUFF model does not printout a negative concentration

TABLE 3-6
SOURCE CONTRIBUTION FROM THE SGS TO THE MAXIMUM SO_2 IMPACTS
PREDICTED AT THE OKEFENOKEE AND CHASSAHOWITZKA NWA

Pollutant / Averaging Time	Concentration (µg/m³) Total	SGS	Receptor Location UTM Coordinates (km) East	North	Time Period (YYMMDDHH)	PSD Class I Increment (µg/m³)
Okefenokee NWA						
24-Hour						
Highest, second-highest	5.08	4.93	386.91	3381.53	96032724	5
	5.17	4.99	388.53	3383.36	96032724	
	5.12	4.96	386.93	3383.37	96032724	
3-Hour						
Highest, second-highest	25.3	9.52	390.34	3403.66	90010712	25
Chassahowitzka NWA						
24-Hour						
Highest, second-highest	5.09	0	339.90	3165.98	90081224	5
	5.18	0	339.91	3166.90	90081224	
	5.02	0.07	339.91	3166.90	90051424	
	5.14	0	337.46	3166.01	96100324	5
	5.24	0	338.27	3166	96100324	
	5.29	0	339.09	3165.99	96100324	
	5.36	0	339.9	3165.98	96100324	
	5.47	0	336.66	3166.95	96100324	
	5.36	0	339.91	3166.9	96100324	
	5.48	0	335.85	3167.88	96011824	
	5.39	0			96100324	
	5.04	0	339.93	3167.82	96011824	
	5.86	0	335.87	3168.8	96011824	
	5.01	0.27	339.95	3169.67	96060824	
	5.46	0	339.97	3170.59	96092624	
	5.45	0	336.72	3171.56	96092624	
	5.59	0	339.98	3171.52	96092624	
	5.61	0	336.73	3172.49	96061524	
	5.58	0	337.55	3172.47	96061524	
	5.23	0	338.36	3172.46	96092624	
	5.14	0	339.18	3172.45	96092624	
	5.05	0.29	339.18	3172.45	96060824	
	5.10	0.29	339.99	3172.44	96060824	
	5.01	0	339.99	3172.44	96092624	
	5.15	0	335.14	3175.28	96061524	

Note: YYMMDDHH = Year, Month, Day, Hour Ending
UTM = Universal Transverse Mercator: Zone 16.

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APPENDIX A

CALPUFF MODEL DESCRIPTION AND METHODOLOGY

CALPUFF MODEL DESCRIPTION AND METHODOLOGY

A.1 INTRODUCTION

As part of the new source review requirements under Prevention of Significant Deterioration (PSD) regulations, new major sources or major modifications to those sources are required to address air quality impacts at PSD Class I areas. As part of the air construction permit revision application submitted to the Florida Department of Environmental Protection (FDEP) for the proposed modification to Seminole Electric Cooperative, Inc.'s (Seminole) Seminole Generating Station (SGS) in Palatka, Putnam County, Florida, the air quality impacts due to the potential changes for this project are required to be addressed at the PSD Class I areas within 200 kilometers (km) of the SGS. The nearest PSD Class I areas 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 were performed for the PSD Class I areas of Okefenokee and Chassahowitzka NWA. Air impact analyses were not performed for the Wolf Island NWA since it is located in the same general direction as the Okefenokee NWA but at a much greater distance from the SGS. As a result, air impacts due to the SGS would be lower at the Wolf Island NWA than at the Okefenokee NWA. Air impacts were not predicted at other PSD Class I areas since they are located more than 200 km from the SGS.

The evaluation of air quality impacts are only concerned with determining compliance with PSD Class I increments and not assessing a source's impact on Air Quality Related Values (AQRVs), such as regional haze. Further, compliance with PSD Class I increments can be evaluated by determining if the source's impacts are less than the proposed Environmental Protection Agency (EPA) Class I significant impact levels. The significant impact levels are threshold levels that are used to determine the type of air impact analyses needed for the facility. If the new or modified source's impacts are predicted to be less than significant, then the source's impacts are assumed not to have a significant adverse affect on air quality and additional modeling with other sources is not required. However, if the source's impacts are predicted to be greater than the significant impact levels, additional modeling with other sources is required to demonstrate compliance with Class I increments.

Currently, there are several air quality modeling approaches recommended by the Interagency Workgroup on Air Quality Models (IWAQM) to perform these analyses. The IWAQM consists of EPA and Federal Land Managers (FLM) of Class I areas who are responsible for ensuring that

AQRVs are not adversely impacted by new and existing sources. These recommendations have been summarized in two documents:

- *Interagency Workgroup on Air Quality Models (IWAQM), Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998), referred to as the IWAQM Phase 2 report.

- *Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report, USFS, NPS, USFWS* (12/00), referred to as the FLAG document.

For the SGS, air quality analyses were performed that assess the facility's impacts in the PSD Class I areas using the refined modeling approach from the IWAQM Phase 2 report for SO_2 PSD Class I increment analyses.

The refined analysis approach was used instead of the screening analysis approach since the air quality impacts are based on generally more realistic assumptions, include more detailed meteorological data, and are estimated at locations at the Class I areas.

A.2 GENERAL AIR MODELING APPROACH

The general modeling approach was based on using the long-range transport model, California Puff model Version 5.711a (CALPUFF). The CALPUFF model is the recommended model to use by the FDEP and EPA for addressing impacts at locations located more than 50 km from a source (40 CFR 51, Appendix W).

The methods and assumptions used in the CALPUFF model were based on the latest recommendations for a refined analysis as presented in the IWAQM Phase 2 Summary Report and the FLAG documents.

The following sections present the methods and assumptions used to assess the refined significant impact analyses performed for the proposed project. The results of these analyses are presented in Section 5.0 of the Air Impact Analyses Report for the air dispersion modeling analysis.

A.3 MODEL SELECTION AND SETTINGS

The CALPUFF air modeling system was used to assess the SGS' impacts at the PSD Class I area for comparison to the PSD Class I significant impact levels. CALPUFF is a non-steady state Lagrangian

Gaussian puff long-range transport model that includes algorithms for building downwash effects as well as chemical transformations (important for visibility controlling pollutants), and wet/dry deposition. The CALPUFF meteorological and geophysical data preprocessor (CALMET, Version 5.53a), a preprocessor to CALPUFF, is a diagnostic meteorological model that produces a three-dimensional field of wind and temperature and a two-dimensional field of other meteorological parameters. CALMET was designed to process raw meteorological, terrain and land-use databases to be used in the air modeling analysis. The CALPUFF modeling system uses a number of FORTRAN preprocessor programs that extract data from large databases and converts the data into formats suitable for input to CALMET. The processed data produced from CALMET was input to CALPUFF to assess the pollutant specific impact. Both CALMET and CALPUFF were used in a manner that is recommended by the IWAQM Phase 2 report and FLAG document.

A.3.1 CALPUFF MODEL APPROACHES AND SETTINGS

The IWAQM recommended approaches for performing refined air modeling analysis are summarized in Table B-1. These approaches involve the use of meteorological data, hourly ozone data, selection of receptors, dispersion conditions, and the post-processing of model output. The specific settings used in the CALPUFF model are presented in Table B-2.

A.3.2 EMISSION INVENTORY AND BUILDING WAKE EFFECTS

The CALPUFF model included the SGS' emission, stack, and operating data as well as building dimensions to account for the effects of building-induced downwash on the emission sources. Dimensions for all significant building structures were processed with the Building Profile Input Program (BPIP), Version 95086, and were included in the CALPUFF model input. The Air Impact Analyses Report presents a listing of the facility's emissions and structures included in the analysis.

A.4 <u>RECEPTOR LOCATIONS</u>

Pollutant concentrations were predicted at the PSD Class I areas using receptor locations developed by the NPS. For the analyses, the number of receptors modeled at each PSD Class I area is as follows:

- Okefenokee NWA, 180 receptors; and
- Chassahowitzka NWA, 58 receptors; and

Elevations for all receptor locations were included in the analysis.

A.5 METEOROLOGICAL DATA

A.5.1 REFINED ANALYSIS

The CALPUFF meteorological and geophysical data preprocessor (CALMET, Version 5.53a), a preprocessor to CALPUFF, is a diagnostic meteorological model that produces a 3-dimensional field of wind and temperature and a 2-dimensional field of other meteorological parameters. CALMET was designed to process raw meteorological, terrain, and land-use databases to be used in the air modeling analysis.

The CALPUFF modeling system uses a number of FORTRAN preprocessor programs that extract data from large databases and convert the data into formats suitable for input to CALMET. The processed data produced from CALMET was input to CALPUFF to assess the pollutant-specific impact. Both CALMET and CALPUFF were used in a manner that is recommended by the IWAQM Phase 2 report and FLAG document.

The wind domain used for air modeling analysis is shown in Figure B-1. The domain covers the SGS site and the two evaluated PSD Class I areas.

A.5.2 MODELING DOMAIN

A CALMET-developed rectangular modeling domain extending 448 km in the east-west (x) direction and 684 km in the north-south (y) direction was used for the air modeling analysis. The southwest corner of the domain is the origin and is located at 26.25 degrees north latitude and 85.0 degrees west longitude [East and North Universal Transverse Mercator (UTM) coordinates of 77 km and 2,966.0 km, respectively, Zone 17 equivalent]. This location is in the Gulf of Mexico, approximately 250 km west of Naples, Florida. For the processing of meteorological and geophysical data, the domain contains 112 grid cells in the x-direction and 171 grid cells in the y-direction. The domain grid resolution is 4 km. The air modeling analysis was developed in the UTM coordinate system, Zone 17.

A summary of the model domain description is presented Table B-3.

A.5.3 MESOSCALE MODEL – GENERATION 4 AND 5 (MM4/MM5) DATA

Pennsylvania State University, in conjunction with the National Center for Atmospheric Research (NCAR) Assessment Laboratory developed the MM4 and MM5 data set, a prognostic wind field or "guess" field, for the United States. The hourly meteorological variables used to create this data set (wind, temperature, dew point depression, and geopotential height for 8 standard levels and up to

15 significant levels) are extensive and are available for 1990, 1992, and 1996. The analysis used the MM4 and MM5 data to initialize the CALMET wind field. The MM4 and MM5 data available for 1990 and 1992, respectively, have a horizontal spacing of 80 km and are used to simulate atmospheric variables within the modeling domain. The MM5 data are also available for 1996 and have a horizontal spacing of 36 km.

The MM4 and MM5 data used in the CALMET, although advanced, lacks the fine detail of specific temporal and spatial meteorological variables and geophysical data. These variables were processed into the appropriate format and introduced into the CALMET model through the additional data files obtained from the following sources.

A.5.4 SURFACE DATA STATIONS AND PROCESSING

The surface station data processed for the CALPUFF analyses consisted of data from up to 16 National Weather Service (NWS) stations or Federal Aviation Administration (FAA) Flight Service stations for Charleston in South Carolina; Columbus, Macon, Savannah, Augusta, Athens, and Atlanta in Georgia; and Tampa, Jacksonville, Daytona Beach, Tallahassee, Vero Beach, Fort Myers, Orlando, Pensacola and Gainesville in Florida. The surface station parameters include wind speed, wind direction, cloud ceiling height, opaque cloud cover, dry bulb temperature, relative humidity, station pressure, and a precipitation code that is based on current weather conditions. The surface station data were processed into a SURF.DAT file format for CALMET input.

Because the modeling domain extends over water, up to 10 sea surface stations were incorporated in the analysis. Data were obtained from C-Man stations and National Oceanic and Atmospheric Administration (NOAA) buoys. These data were processed into an over-water surface station format (i.e., SEA*.DAT) for input to CALMET. The over-water station data include wind direction, wind speed and air temperature.

A summary of the surface, over water, and upper air station information and locations is presented in Table B-4.

A.5.5 UPPER AIR DATA STATIONS AND PROCESSING

Upper air data from the following NWS stations, based on the availability of the upper air data, were used in the modeling analysis:

- Waycross, Georgia (1990, 1992);
- Athens, Georgia (1990, 1992);

- Charleston, South Carolina (1990, 1992, 1996);
- Cape Canaveral, Florida (1996)
- Miami, Florida (1996)
- Apalachicola, Florida (1990);
- Ruskin, Florida (1990, 1992, 1996);
- Tallahassee, Florida (1992, 1996);
- West Palm Beach, Florida (1990, 1992)
- Jacksonville, Florida (1996); and
- Peachtree City, Georgia (1996).

A.5.6 PRECIPITATION DATA STATIONS AND PROCESSING

Precipitation data were processed from a network of hourly precipitation data files collected from primary and secondary NWS precipitation-recording stations located within the latitude and longitudinal limits of the modeling domain. Data for 82 stations in Alabama, Georgia, and Florida were obtained in NCDC TD-3240 variable format and converted into a fixed-length format. The utility programs PXTRACT and PMERGE were then used to process the data into the format for the PRECIP.DAT file that is used by CALMET

A.5.7 GEOPHYSICAL DATA PROCESSING

Terrain elevations for each grid cell of the modeling domain were obtained from 1-degree Digital Elevation Model (DEM) files obtained from the U.S. Geographical Survey (USGS) Internet website. The DEM data was extracted for the modeling domain grid using the utility program TERREL. Land-use data were also extracted from 1-degree USGS files and processed using utility programs CTGCOMP and CTGPROC. Both the terrain and land use files were combined into a GEO.DAT file for input to CALMET with the MAKEGEO utility program.

TABLE A-2
CALPUFF MODEL SETTINGS

Parameter	Setting
Pollutant Species	SO_2, SO_4, NO_x, PM_{10}
Chemical Transformation	MESOPUFF II scheme including hourly ozone data.
Deposition	Include both dry and wet deposition, plume depletion.
Meteorological/Land Use Input	CALMET
Plume Rise	Transitional, stack-tip downwash, partial plume penetration.
Dispersion	Puff plume element, PG/MP coefficients, rural mode, ISC building downwash scheme.
Terrain Effects	Partial plume path adjustment.
Output	Create binary concentration file including output species for SO_4, NO_3, PM_{10}, SO_2, and NO_x; process for visibility change using Method 2 and FLAG background extinctions.
Visiblity Model Processing for BART Rule	98 percentile (8th-highest) 24-hour extinction change (%) for a year.
Background Values	Ozone: 50 ppb; Ammonia: 1 ppb.

Notes:

ISC = Industrial Source Complex.
PG/MP = Pasquill-Gifford/McAlroy-Pooler
ppb = parts per billion.

TABLE A-3
CALMET SETTINGS AND MODEL DOMAIN

Parameter	Setting
Horizontal Grid Dimensions	448 by 684 km, 4 km grid resolution
Vertical Grid	10 layers
Weather Station Data Inputs	16 surface, 11 upper air, 82 precipitation stations
Wind model options	Diagnostic wind model, no kinematic effects
Prognostic wind field model	1990 MM4 data and 1992 MM5 data, 80 km resolution; 1996 MM5 data, 36 km resolution; used for wind field initialization
Output	Binary hourly gridded meteorological data file for CALPUFF input

TABLE A-4
SURFACE AND UPPER AIR STATIONS USED IN THE NORTH CENTRAL FLORIDA AND SOUTH GEORGIA CALMET DOMAIN

Station Name	Station Symbol	WBAN Number	UTM Coordinates Easting (km)	Northing (km)	UTM Zone	Anemometer Height (m)
Surface Stations						
Tampa, FL	TPA	12842	349.195	3094.289	17	10
Jacksonville, FL	JAX	13889	432.809	3374.192	17	10
Daytona Beach, FL	DAB	12834	495.118	3228.056	17	10
Tallahassee, FL	TLH	93805	176.408[a]	3365.835	16	10
Fort Myers. F L	FMY	12835	413.644	2940.405	17	10
Orlando, FL	MCO	12815	468.942	3146.889	17	10
Pensacola, FL	PNS	13899	-95.74	3386.714	16	10
Vero Beach, FL	VRB	12843	557.487	3058.363	17	10
Columbus, GA	CSG	93842	128.871[a]	3604.422	16	10
Charleston, SC	CHS	13880	590.422	3640.405	17	10
Macon, GA	MCN	3813	251.562	3620.929	17	10
Savannah, GA	SAV	3822	481.12	3554.985	17	10
Gainesville, FL	GNV	12816	377.39	3284.126	17	10
Augusta, GA	AGS	3820	410.024	3692.184	17	10
Athens, GA	AHN	13873	285.867	3758.824	17	10
Atlanta, GA	ATL	13874	181.588[a]	3728.434	16	10
Sea Surface Stations						
Venice, FL	VENF1	-	356.24	2995.05	17	--
Cape Canaveral, FL	41009	-	380.25	3152.87	17	--
Tampa West, FL	42036	-	156.41	3158.73	16	--
Cedar Key, FL	CDRF1	-	302.52	3225.2	17	--
Cape San Blas, FL	CSBF1	-	77.89	3290.18	16	--
Folly Island, SC	FBIS1	-	604.09	3616.38	17	--
Keaton Beach, FL	KTNF1	-	249.71	3301.66	17	--
Lake Worth, FL	LKWF1	-	596.57	2943.61	17	--
Savannah, GA	SVLS1	-	530.24	3534.94	17	--
St. Augustine, FL	SAUF1	-	474.89	3303.3	17	--
Upper Air Stations						
Ruskin, FL	TPA	12842	361.961	3064.616	17	NA
Waycross, GA	AYS	13861	366.674	3457.945	17	NA
Athens, GA	AHN	13873	285.866	3758.824	17	NA
Charleston, SC	CHS	13880	590.421	3640.405	17	NA
Cape Canaveral	XMR	12868	544.048	3150.459	17	NA
Miami -FIU	MFL	92803	562.181	2847.983	17	NA
Apalachicola, FL	AQQ	12832	109.807[a]	3295.816	16	NA
Tallahassee, FL	TLH	93805	176.4072	3365.835	16	NA
Jacksonville, FL	JAX	13889	432.808	3374.192	17	NA
Peachtree, GA	FFC	53819	155.6372	3696.207	16	NA

[a] Equivalent coordinate for Zone 17.

APPENDIX B

SO_2 EMISSION INVENTORIES FOR AAQS AND PSD SOURCES

TABLE B-1
INVENTORY OF SO_2 SOURCES INCLUDED IN THE AAQS AND PSD CLASS II AIR MODELING ANALYSES

Facility ID	Facility Units	Model ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to SGS [a] X (km)	Relative to SGS [a] Y (km)	Stack Parameters Height (ft)	Height (m)	Diameter (ft)	Diameter (m)	Temperature (°F)	Temperature (K)	Velocity (ft/s)	Velocity (m/s)	Emission Rate (lb/hr)	Emission Rate (g/s)	PSD [b] Source (C/E)	Modeled in AAQS	Modeled in Class II
1070014	Florida Power & Light (FPL)- Putnam Plant																		
	4x70Mw CT/HRSG + DB	FPLPUTNM	443.3	3277.6	4.50	-11.60	73.1	22.3	10.3	3.15	328	437.4	192.2	58.60	3,098.4	390.4 [c]	C	Yes	Yes
															1,850.8	233.2 [d]			
1070016	Florida Power & Light (FPL)- Palatka Plant																		
	Unit 2	FPLPALAT	442.8	3277.6	4.00	-11.60	149.9	45.7	13.0	3.96	275	408.1	31.2	9.50	-2,039.9	-257.03	E	No	Yes
	Georgia Pacific, Palatka Mill	Current																	
	Recovery Boiler No. 4	RB4	433.8823	3283.44	-4.92	-5.76	230	70.1	12.0	3.66	424	491	65.9	20.08	109.8	13.84	C	Yes	Yes
	Smelt Dissolving Tank No. 4	SDT4	433.9347	3283.48	-4.87	-5.72	206	62.8	5.0	1.52	179	355	33.9	10.35	7.7	0.97	C	Yes	Yes
	Power Boiler No. 5	PB5	433.9773	3283.45	-4.82	-5.75	237	72.2	8.0	2.44	413	485	85.9	26.19	1,461.9	184.2	C	Yes	Yes
	Combination Boiler No. 4	CB4	433.9824	3283.45	-4.82	-5.75	236.8	72.2	8.0	2.44	466	514	92.3	28.14	961.1	121.1	C	Yes	Yes
	Package Boiler No. 5	PB7	433.9862	3283.47	-4.81	-5.73	60.0	18.3	7.0	2.13	750	672	43.5	13.25	0.2	0.0189	C	Yes	Yes
	Lime Kiln No. 4	LK4	434.1067	3283.25	-4.69	-5.95	130.9	39.9	4.4	1.35	164	346.5	70.6	21.51	34.5	4.35	C	Yes	Yes
		TM5P	434.2864	3283.44	-4.51	-5.76	94.0	28.65	4.2	1.29	450	505.4	77.1	23.5	0.030	0.00378	C	Yes	Yes
		Baseline																	
	Recovery Boiler No. 1	RB1B	434.0536	3283.41	-4.75	-5.79	250	76.2	12.0	3.66	188	360	28.9	8.8	-49.3	-6.21	E	No	Yes
	Recovery Boiler No. 2	RB2B	434.0536	3283.41	-4.75	-5.79	250	76.2	12.0	3.66	210	372	28.9	8.8	-70.5	-8.88	E	No	Yes
	Recovery Boiler No. 3	RB3B	434.0195	3283.38	-4.78	-5.82	133	40.5	11.2	3.41	210	372	23.9	7.28	-68.1	-8.58	E	No	Yes
	Recovery Boiler No. 4	RB4B	433.8823	3283.44	-4.92	-5.76	230	70.1	12.0	3.66	394	474	55.3	16.86	-277.5	-34.97	E	No	Yes
	Smelt Dissolving Tank No. 1	SDT1B	434.0593	3283.41	-4.74	-5.79	100	30.5	2.5	0.76	199	366	24.7	7.53	-1.0	-0.13	E	No	Yes
	Smelt Dissolving Tank No. 2	SDT2B	434.0593	3283.41	-4.74	-5.79	100	30.5	3.0	0.91	215	375	31.2	9.51	-1.4	-0.18	E	No	Yes
	Smelt Dissolving Tank No. 3	SDT3B	434.0253	3283.39	-4.77	-5.81	109	33.2	2.5	0.76	205	369	11.7	3.57	-1.4	-0.18	E	No	Yes
	Smelt Dissolving Tank No. 4	SDT4B	433.9347	3283.48	-4.87	-5.72	206	62.8	5.0	1.52	163	346	27.1	8.26	-5.6	-0.71	E	No	Yes
	Lime Kiln No. 1	LK1B	434.1219	3283.3	-4.68	-5.90	49.9	15.2	4.2	1.28	262	401	17.2	5.24	-1.9	-0.24	E	No	Yes
	Lime Kiln No. 2	LK2B	434.1174	3283.3	-4.68	-5.90	52.2	15.9	5.6	1.71	154	341	35.0	10.67	-1.9	-0.24	E	No	Yes
	Lime Kiln No. 3	LK3B	434.1193	3283.27	-4.68	-5.93	52.2	15.9	5.6	1.71	156	342	27.8	8.47	-3.8	-0.48	E	No	Yes
	Lime Kiln No. 4	LK4B	434.1067	3283.25	-4.69	-5.95	149	45.4	4.3	1.31	172	351	54.0	16.46	-11.1	-1.4	E	No	Yes
	Power Boiler No. 4	PB4B	433.998	3283.48	-4.80	-5.72	122	37.2	4.0	1.22	399	477	47.7	14.54	-358.9	-45.22	E	No	Yes
	Power Boiler No. 5	PB5B	433.9773	3283.45	-4.82	-5.75	239	72.9	9.0	2.74	476	520	52.4	15.97	-1,279.0	-161.15	E	No	Yes
	Combination Boiler No. 4	CB4B	433.9825	3283.45	-4.82	-5.75	239	72.9	10.0	3.05	399	477	34.5	10.52	-962.5	-121.28	E		

[a] Seminole SGS UTM East and North coordinates are: 438.8 and 3289.2 km, respectively.
[b] Comsuming (C) sources are sources that were constructed or modified after the PSD baseline date.
Expanding (E) sources are sources that have shutdown or have been modified since the baseline date.
[c] Two of the four CT units (half of the total plant emissions) consume PSD increment and are included in the PSD increment analysis.
[d] Actual emissions for the units are based on the combustion turbines (CTs) firing 0.5% sulfur content fuel oil (permits allow 0.7% sulfur content) and duct burner (DB) firing natural gas (DB can fire oil but continuous opacity monitor must be installed before oil is used).

TABLE B-2
SUMMARY OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES
AT THE OKEFENOKEE NWA

Facility	UTM Coordinates East (km)	UTM Coordinates North (km)	Emission Rate [a] (TPY)	PSD [b] Source (C/E)
Florida Power & Light (FPL)- Putnam Plant	443.3	3277.6	4,053.2	C
Florida Power & Light (FPL)- Palatka Plant	442.8	3277.6	-8,934.9	E
Georgia Pacific, Palatka Mill	433.9	3283.5	11,416.6	C
			13,537.3	E
Gerdau Ameristeel	405.7	3350.0	141.1	C
			49.6	E
JEA Brandy Branch	408.8	3354.5	429.8	C
Millenium Specialty Products	436.8	3360.7	2,782.3	C
			295.1	E
JEA - Northside Power Plant	447.0	3,365.2	4,847.7	C
			-44,356.2	E
JEA - St. Johns River Power Park	447.1	3,366.7	64,642.5	C
Anheiser Busch, Inc	440.6	3,366.8	74.4	C
Cedar Bay Cogeneration	441.6	3,365.5	3,357.0	C
Gilman Paper Co. St. Mary's, GA	448.2	3,401.3	7,276.4	C
			-12,931.4	E
Jefferson Smurfit Corp. (Jacksonville)	439.9	3,359.3	2,215.7	C
			-1,886.9	E
Jefferson Smurfit Corp. (Fernandina Beach)	456.2	3,394.2	15,087.7	C
			-12,656.5	E
Rayonier, Inc.	454.7	3,392.2	5,536.9	C
			-1,383.5	E
Stone Container Corp. (Seminole Kraft)	443.0	3,365.4	75.1	C
			-19,261.9	E
JEA - Kennedy Power Plant	440.0	3,359.2	-11,648.7	E
JEA- Southside Power Plant	437.7	3,353.9	-11,054.3	E
PCS	328.3	3,368.8	10,000.0	C
			-13,213.0	E
Suwannee American Cement	321.4	3,315.9	124.4	C
Florida Rock Thompson S. Baker Cement Plant	348.4	3,287.0	77.5	C

[a] Based on 24-hour average emission rate.
[b] Comsuming (C) sources are sources that were constructed or modified after the PSD baseline date.
Expanding (E) sources are sources that have shutdown or have been modified since the baseline date.

TABLE B-3
SUMMARY OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES
AT THE CHASSAHOWITZKA NWA

Facility	UTM Coordinates East (km)	UTM Coordinates North (km)	Emission Rate [a] (TPY)	PSD [b] Source (C/E)
Florida Power & Light (FPL)- Putnam Plant	443.3	3277.6	4,053.2	C
Florida Power & Light (FPL)- Palatka Plant	442.8	3277.6	-8,934.9	E
Georgia Pacific, Palatka Mill b	433.9	3283.5	11,416.6	C
			13,537.3	E
Gerdau Ameristeel	405.7	3350.0	141.1	C
			49.6	E
JEA Brandy Branch	408.8	3354.5	429.8	C
Gainesville Regional Utilities- Deerhaven	365.7	3292.6001	12,995.4	C
CF Industries, Plant City	388.0	3,116.0	6,740.6	C
			-6,265.0	E
Cargill Fertilizer, Inc.--Riverview	362.9	3,082.5	6,552.8	C
			-21,312.7	E
Natonal Gypsum - Apollo Beach	363.3	3,075.6	238.0	C
Big Bend Transfer Co. L.L.C.	361.1	3,076.2	15.7	C
TECO - Big Bend	361.9	3,075.0	15,662.9	C
			-127,020.0	E
Tampa Bay Shipbuiding & Repair Co.	358.0	3,089.0	12.0	C
McKay Bay Refuse-to-Energy Facility	360.2	3,092.2	716.0	C
Hillsborough Cty. Resource Recovery Fac.	368.2	3,092.7	770.9	C
Yuengling Brewing Co.	362.0	3,103.2	39.4	C
Pinellas Co. Resource Recovery Facility	335.2	3,084.1	3,044.1	C
IMC PhosphateS Company - New Wales	396.7	3,079.4	14,624.9	C
			-6,266.5	E
TECO - Polk Power Station	402.5	3,067.4	2,925.8	C
Cargill Mulberry (Formerly Mulberry Phosphates, Inc.)	406.8	3,085.1	1,241.0	C
			-8,954.5	E
CF Industries, Inc. - Bartow	408.3	3,082.5	1,825.6	C
			-29,546.6	E
IMC Phosphates Company - South Pierce	407.5	3,071.4	3,942.0	C
			-2,628.0	E
Cargill Green Bay (Formerly Farmland Hydro, L.P. - Green Bay)	409.5	3,080.1	6,895.0	C
			-9,726.5	E
Cargill Fertilizer - Bartow	409.8	3,086.6	6,753.8	C
Hardee Power Station	404.8	3,057.4	9,673.2	C
Lakeland Electric, Larsen Power Plant	408.9	3,102.5	925.9	C
Lakeland Electric, McIntosh Power Plant	409.0	3,106.2	19,686.8	C

TABLE B-3
SUMMARY OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES
AT THE CHASSAHOWITZKA NWA

Facility	UTM Coordinates East (km)	UTM Coordinates North (km)	Emission Rate [a] (TPY)	PSD [b] Source (C/E)
U.S. Agri-Chemicals - Ft. Meade	416.0	3,069.0	4,383.2	C
			-3,374.3	E
Cutrale Citrus Juices USA, Inc.	421.6	3,103.7	1,676.7	C
Auburndale Power Partners, LP	420.8	3,103.3	598.3	C
Florida Distillers - Auburndale	421.4	3,102.9	0.3	C
FPC - Intercession City Plant	446.3	3,126.0	17,025.9	C
IPS - Shady Hills	347.2	3,138.8	1,333.7	C
Estech/Swift Polk	411.5	3,074.2	-4,853.1	E
FL Crushed Stone Kiln 1	360.0	3,162.5	3,531.8	C
FPC Polk County Site	414.3	3,073.9	858.6	C
General Portland Cement #4	358.0	3,090.6	-2,189.7	E
General Portland Cement #5	358.0	3,090.6	-2,409.0	E
IMC-Agrico Pierce	404.1	3,079.0	-1,644.9	E
Imperial Phosphates (Brewer)	404.8	3,069.5	-669.5	E
Mobil Electrophos Division	405.6	3,079.4	-3,334.4	E
Stauffer (Shutdown)	325.6	3,116.7	-2,263.0	E
US Agri-Chem Bartow	413.2	3,086.3	-1,578.5	E
Asphalt Pavers 3	359.9	3,162.4	78.2	C
Asphalt Pavers 4	361.4	3,168.4	78.2	C
Borden Hillsborough	394.6	3,069.6	-225.3	E
Borden Polk	414.5	3,109.0	-183.9	E
Couch Const-Zephyrhills (Asphalt)	390.3	3,129.4	123.1	C
Couch Const-Odessa (Asphalt)	340.7	3,119.5	252.0	C
Dris Paving (Asphalt)	340.6	3,119.2	8.0	C
Dolime	404.8	3,069.5	-354.6	E
Evans Packing	383.3	3,135.8	7.0	C
E R Jahna (Lime Dryer)	386.7	3,155.8	28.5	C
FDOC Boiler #3	382.2	3,166.1	103.9	C
FL Mining and Materials Kiln	356.2	3,169.9	50.4	C
FPC - Crystal River	334.2	3,204.5	-75,537.6	E
			70,135.6	C
FPC Debary	467.5	3,197.2	16,213.0	C
Hospital Corp of America	333.4	3,141.0	5.6	C
Kissimmee Utilities	447.7	3,127.9	1,022.0	C
Kissimmee Utilites Exist	460.1	3,129.3	1,115.9	C
Lake Cogen	434.0	3,198.8	175.2	C
Mulberry Cogeneration	413.6	3,080.6	464.1	C
New Pt Richey Hospital	331.2	3,124.5	3.1	C
Oman Construction	359.8	3,164.9	72.7	C
Orlando Utilities Commission - Stanton	483.5	3,150.6	24,083.0	C
Overstreet Paving	355.9	3,143.7	127.6	C
Pasco Cty RRF	347.1	3,139.2	490.1	C

TABLE B-3
SUMMARY OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES
AT THE CHASSAHOWITZKA NWA

Facility	UTM Coordinates East (km)	UTM Coordinates North (km)	Emission Rate [a] (TPY)	PSD [b] Source (C/E)
Pasco Cogen	385.6	3,139.0	175.2	C
Reedy Creek Energy Services- EPCOT	442.0	3,139.0	127.2	C
Reedy Creek Energy Services	443.1	3,144.3	5.2	C
Ridge Cogeneration	416.7	3,100.4	479.7	C
PCS	328.3	3,368.8	10,000.0	C
			-13,213.0	E
Suwannee American Cement	321:4	3,315.9	124.4	C
Florida Rock Thompson S. Baker Cement Plant	348.4	3,287.0	77.5	C

Note: Detailed inventory presented in Appendix C.

[a] Based on 24-hour average emission rate.

[b] Comsuming (C) sources are sources that were constructed or modified after the PSD baseline date.
Expanding (E) sources are sources that have shutdown or have been modified since the baseline date.

TABLE B-4
STACK, OPERATING, AND SO_2 EMISSIONS OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES AT THE OKEFENOKEE NWA

Facility	Model ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Height (ft)	Height (m)	Diameter (ft)	Diameter (m)	Temperature (°F)	Temperature (K)	Velocity (ft/s)	Velocity (m/s)	Emission Rate (lb/hr)	Emission Rate (g/s)	PSD [a] Source (C/E)
Florida Power & Light (FPL)- Putnam Plant	CFPLPUTM	443.3	3277.6	73.1	22.3	10.3	3.2	328	437	192.2	58.6	1,549.2	195.2 [b]	C
												925.4	116.6 [b]	C
Florida Power & Light (FPL)- Palatka Plant	FPLPALAT	442.8	3277.6	149.9	45.7	13.0	4.0	275	408	31.2	9.5	-2,039.9	-257.0	E
Georgia Pacific, Palatka Mill	SDT4	433.935	3283.478	206.0	62.8	5.0	1.52	179	355.0	33.9	10.35	7.7	0.97	C
	PB524	433.977	3283.447	236.8	72.2	8.0	2.44	413	485.0	85.9	26.19	1,461.9	184.20	C
	CB4	433.983	3283.45	236.8	72.2	8.0	2.44	466	514.0	92.3	28.14	961.1	121.10	C
	PB7	433.986	3283.466	60.0	18.3	7.0	2.13	750	672.0	43.5	13.25	0.2	0.02	C
	LK4	434.107	3283.247	130.9	39.9	4.4	1.35	164	346.5	70.6	21.51	34.5	4.35	C
	TM5P	434.286	3283.44	94.0	28.7	4.2	1.29	450	505.4	77.1	23.50	0.030	0.00378	C
	RB4_24HR	433.882	3283.438	229.9	70.1	12.0	3.66	424	491.0	65.9	20.08	109.8	13.84	C
	TOX	433.982	3283.38	249.9	76.2	3.6	1.10	160	344.0	18.0	5.49	31.3	3.94	C
	RB1B	434.054	3283.407	249.9	76.2	12.0	3.66	188	360.0	28.9	8.80	49.3	6.21	E
	RB2B	434.054	3283.407	249.9	76.2	12.0	3.66	210	372.0	28.9	8.80	70.5	8.88	E
	RB3B	434.02	3283.385	132.8	40.5	11.2	3.41	210	372.0	23.9	7.28	68.1	8.58	E
	RB4B	433.882	3283.438	229.9	70.1	12.0	3.66	394	474.0	55.3	16.86	277.8	35.00	E
	SDT1B	434.059	3283.411	100.0	30.5	2.5	0.76	199	366.0	24.7	7.53	1.0	0.13	E
	SDT2B	434.059	3283.411	100.0	30.5	3.0	0.91	215	375.0	31.2	9.51	1.4	0.18	E
	SDT3B	434.025	3283.388	108.9	33.2	2.5	0.76	205	369.0	11.7	3.57	1.4	0.18	E
	SDT4B	433.935	3283.478	206.0	62.8	5.0	1.52	163	346.0	27.1	8.26	5.6	0.71	E
	LK1B	434.122	3283.301	49.9	15.2	4.2	1.28	262	401.0	17.2	5.24	1.9	0.24	E
	LK2B	434.117	3283.299	52.2	15.9	5.6	1.71	154	341.0	35.0	10.67	1.9	0.24	E
	LK3B	434.119	3283.271	52.2	15.9	5.6	1.71	156	342.0	27.8	8.47	3.8	0.48	E
	LK4B	434.107	3283.247	148.9	45.4	4.3	1.31	172	351.0	54.0	16.46	11.1	1.40	E
	PB4B	433.998	3283.481	122.0	37.2	4.0	1.22	399	477.0	47.7	14.54	358.7	45.2	E
	PB5B	433.977	3283.447	239.1	72.9	9.0	2.74	476	520.0	52.4	15.97	1,277.8	161.0	E
	CB4B	433.983	3283.45	239.1	72.9	10.0	3.05	399	477.0	34.5	10.52	960.3	121.0	E
Gerdau Ameristeel	EAFBH1	405.708	3350.006	110.0	33.5	12.0	3.66	230	383.2	55.2	16.84	16.0	2.02	C
	EAFBH2	405.715	3349.992	110.0	33.5	12.0	3.66	230	383.2	55.2	16.84	16.0	2.02	C
	REHEATN	405.811	3350.324	66.0	20.1	5.8	1.77	480	522.0	45.0	13.72	0.2	0.02	C
	ST12	405.699	3350.109	115.0	35.1	10.0	3.05	230	383.2	64.8	19.76	10.2	1.28	E
	ST34	405.732	3350.117	115.0	35.1	10.0	3.05	230	383.2	67.9	20.70	1.1	0.14	E
	REHEAT	405.758	3350.358	160.0	48.8	6.9	2.10	900	755.4	19.5	5.93	0.1	0.01	E
JEA Brandy Branch	S1NG	408.835	3354.491	189.9	57.9	18.0	5.49	266	403.0	69.8	21.28	32.7	4.12	C
	S2NG	408.713	3354.53	189.9	57.9	18.0	5.49	266	403.0	69.8	21.28	32.7	4.12	C
	S3FO	408.774	3354.53	189.9	57.9	18.0	5.49	266	403.0	69.8	21.28	32.7	4.12	C
	SFP	408.893	3354.536	24.0	7.3	0.5	0.15	649	616.0	196.9	60.02	0.032	0.0040	C
Millenium Specialty Products	BOILER4	436.79	3360.74	40.0	12.2	3.6	1.10	269	405.0	46.0	14.02	200.0	25.2	C
	BOILER5	436.79	3360.74	125.0	38.1	3.8	1.16	350	450.0	76.4	23.29	193.0	24.3	C
	BOILER6	436.79	3360.74	125.0	38.1	5.1	1.55	350	450.0	74.5	22.71	242.2	30.5	C
	BOILER7	436.79	3360.74	125.0	38.1	5.1	1.55	350	450.0	74.5	22.71	82.0	10.3	C
	EBOILER3	436.79	3360.74	40.0	12.2	3.6	1.10	725	658.0	33.1	10.10	67.4	8.5	E
JEA - Northside Power Plant	CJEAN1	447.0	3365.2	495	151.0	15.0	4.57	136	331	63	19.20	553.3	69.7	C
	CJEAN2			495	151.0	15.0	4.57	136	331	63	19.20	553.3	69.7	C
	CJEAN3			75.1	22.9	3.4	1.04	165	347	50.0	15.24	0.28	0.04	C
	EJEAN1			250	76.2	16.0	4.87	266	403	76	23.10	-5,484.1	-691.0	E
	EJEAN2			290	88.4	16.4	5.00	250	394	43	13.10	-4,642.9	-585.0	E

TABLE B-4

STACK, OPERATING, AND SO_2 EMISSIONS OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES AT THE OKEFENOKEE NWA

Facility	Model ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Stack Parameters Height (ft)	Height (m)	Diameter (ft)	Diameter (m)	Temperature (°F)	Temperature (K)	Velocity (ft/s)	Velocity (m/s)	Emission Rate (lb/hr)	Emission Rate (g/s)	PSD [a] Source (C/E)
JEA - St. Johns River Power Park	CRIVER1	447.1	3366.7	640	195.1	22.3	6.79	156	342	90	27.40	7,379.3	929.8 [c]	NA
	CRIVER2			640	195.1	22.3	6.79	156	342	90	27.40	7,379.3	929.8 [c]	NA
	CRIVER1			640	195.1	22.3	6.79	156	342	90	27.40	4,669.4	588.3 [d]	C
	CRIVER2			640	195.1	22.3	6.79	156	342	90	27.40	4,669.4	588.3 [d]	C
Anheiser Busch, Inc	CBUSH1	440.6	3366.8	20.0	6.1	1.97	0.60	1000	811	413.6	126.10	8.49	1.1	C
	CBUSH2			20.0	6.1	1.97	0.60	1000	811	413.6	126.10	8.49	1.1	C
Cedar Bay Cogeneration	CCBAY1	441.6	3365.5	403.1	122.9	13.4	4.10	129	327	120.0	36.60	255.3	32.2	C
	CCBAY2			403.1	122.9	13.4	4.10	129	327	120.0	36.60	255.3	32.2	C
	CCBAY3			403.1	122.9	13.4	4.10	129	327	120.0	36.60	255.3	32.2	C
	CCBAY4			63.0	19.2	4.3	1.30	82	301	93.2	28.40	0.24	0.030	C
	CCBAY5			63.0	19.2	4.3	1.30	82	301	93.2	28.40	0.24	0.030	C
Gilman Paper Co. St. Mary's, GA	CPAPER1	448.2	3401.3	275	83.8	14.1	4.30	350	450	9	2.80	693.3	87.4	C
	CPAPER2			150	45.7	10.2	3.10	127	326	26	7.80	704.9	88.8	C
	CPAPER3			180	54.9	6.9	2.10	305	425	55	16.80	120.6	15.2	C
	CPAPER4			250	76.2	8.5	2.60	280	411	40	12.20	125.5	15.8	C
	CPAPER5			100	30.5	4.9	1.50	170	350	38	11.60	16.9	2.1	C
	EPAPER1			275	83.8	14.1	4.30	350	450	24	7.30	-2,230.2	-281.0	E
	EPAPER2			120	36.6	5.9	1.80	800	700	66	20.00	-476.2	-60.0	E
	EPAPER3			155	47.2	7.5	2.30	307	426	43	13.10	-60.3	-7.6	E
	EPAPER4			175	53.3	5.2	1.60	250	394	83	25.20	-60.3	-7.6	E
	EPAPER5			250	76.2	8.5	2.60	309	427	72	22.10	-125.4	-15.8	E
Jefferson Smurfit Corp. (Jacksonville)	CMILL1	439.9	3359.3	175.2	53.4	10.5	3.20	278	410	75.1	22.90	291.9	36.8	C
	CMILL2			200.1	61.0	9.8	3.00	143	335	35.1	10.70	203.6	25.7	C
	CMILL3			209.9	64.0	4.6	1.40	163	346	36.1	11.00	10.4	1.3	C
	EMILL1			175.2	53.4	10.5	3.20	278	410	75.1	22.90	-133.3	-16.8	E
	EMILL2			51.8	15.8	4.9	1.50	165	347	22.0	6.70	-7.8	-1.0	E
	EMILL3			249.9	76.2	12.5	3.80	359	455	26.2	8.00	-289.7	-36.5	E
Jefferson Smurfit Corp. (Fernandina Beach)	CBMILL1	456.2	3394.2	257	78.4	11.2	3.40	358	454	50	15.20	1,512.5	190.6	C
	CBMILL2			265	80.8	11.5	3.50	428	493	61	18.60	321.1	40.5	C
	CBMILL3			289	88.1	12.8	3.90	412	484	62	18.90	358.1	45.1	C
	CBMILL4			340	103.7	14.8	4.50	334	441	42	12.80	1,226.3	154.5	C
	CBMILL5			75	22.9	5.6	1.70	325	436	55	16.80	26.7	3.4	C
	EBMILL1			227	69.2	7.9	2.40	410	483	55	16.90	-1,150.8	-145.0	E
	EBMILL2			227	69.2	11.2	3.40	404	480	53	16.30	-1,349.2	-170.0	E
	EBMILL3			249	75.9	11.5	3.50	428	493	62	18.80	-278.6	-35.1	E
	EBMILL4			134	40.8	8.9	2.70	242	390	44	13.30	-83.3	-10.5	E
	EBMILL5			44	13.4	3.6	1.10	190	361	40	12.30	-10.3	-1.3	E
	EBMILL6			44	13.4	4.6	1.40	188	360	58	17.60	-10.3	-1.3	E
	EBMILL7			228	69.5	5.9	1.80	170	350	17	5.20	-1.6	-0.2	E
	EBMILL8			109	33.2	2.0	0.60	188	360	19	5.80	-5.5	-0.7	E
Rayonier, Inc.	CRAY1	454.7	3392.2	180	54.9	9.8	3.00	145	336	32	9.80	422.3	53.2	C
	CRAY2			180	54.9	9.8	3.00	145	336	32	9.80	401.3	50.6	C
	CRAY3			180	54.9	9.8	3.00	133	329	32	9.80	440.6	55.5	C
	ERAY			180	54.9	9.8	3.00	133	329	32	9.80	-315.9	-39.8	E
Stone Container Corp. (Seminole Kraft)	CS1	443.0	3365.4	200.1	61.0	7.9	2.40	331	439	17.1	5.20	5.7	0.7	C
	CS2			200.1	61.0	7.9	2.40	331	439	17.1	5.20	5.7	0.7	C
	CS3			200.1	61.0	7.9	2.40	331	439	17.1	5.20	5.7	0.7	C

TABLE B-4

STACK, OPERATING, AND SO_2 EMISSIONS OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES AT THE OKEFENOKEE NWA

Facility	Model ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Height (ft)	Height (m)	Diameter (ft)	Diameter (m)	Temperature (°F)	Temperature (K)	Velocity (ft/s)	Velocity (m/s)	Emission Rate (lb/hr)	Emission Rate (g/s)	PSD [a] Source (C/E)
	ES1			136.0	41.5	8.1	2.46	138	332	42.7	13.01	-458.7	-57.8	E
	ES2			136.0	41.5	8.1	2.46	138	332	42.7	13.01	-458.7	-57.8	E
	ES3			106.0	32.3	6.0	1.83	359	455	46.0	14.02	-334.1	-42.1	E
	ES4			106.0	32.3	7.0	2.13	331	439	47.6	14.51	-488.9	-61.6	E
	ES5			106.0	32.3	7.0	2.13	331	439	47.6	14.51	-485.7	-61.2	E
	ES6			126.0	38.4	8.5	2.59	154	341	52.4	15.97	-102.4	-12.9	E
	ES7			126.0	38.4	9.0	2.74	161	345	51.2	15.61	-131.0	-16.5	E
	ES8			126.0	38.4	9.0	2.74	160	344	47.9	14.60	-131.0	-16.5	E
	ES9			120.0	36.6	3.5	1.07	160	344	13.0	3.96	-2.9	-0.4	E
	ES10			124.0	37.8	4.0	1.22	160	344	14.0	4.27	-3.7	-0.5	E
	ES11			124.0	37.8	4.0	1.22	160	344	14.0	4.27	-3.7	-0.5	E
	ES12			69.0	21.0	5.8	1.77	158	343	10.2	3.11	-6.5	-0.8	E
	ES13			75.0	22.9	4.7	1.42	145	336	21.4	6.52	-6.5	-0.8	E
	ES14			75.0	22.9	3.7	1.12	145	336	26.8	8.17	-6.5	-0.8	E
	ES15			136.0	41.5	8.1	2.46	138	332	42.7	13.01	-62.3	-7.9	E
	ES16			136.0	41.5	8.1	2.46	138	332	42.7	13.01	-74.2	-9.4	E
	ES17			106.0	32.3	6.0	1.83	359	455	46.0	14.02	-323.0	-40.7	E
	ES18			106.0	32.3	7.0	2.13	331	439	47.6	14.51	-473.0	-59.6	E
	ES19			106.0	32.3	7.0	2.13	331	439	47.6	14.51	-471.4	-59.4	E
	ES20			126.0	38.4	8.5	2.59	154	341	52.4	15.97	-97.6	-12.3	E
	ES21			126.0	38.4	9.0	2.74	161	345	51.2	15.61	-124.6	-15.7	E
	ES22			126.0	38.4	9.0	2.74	160	344	47.9	14.60	-126.2	-15.9	E
	ES23			120.0	36.6	3.5	1.07	160	344	13.0	3.96	-2.8	-0.4	E
	ES24			124.0	37.8	4.0	1.22	160	344	14.0	4.27	-3.6	-0.5	E
	ES25			124.0	37.8	4.0	1.22	160	344	14.0	4.27	-3.6	-0.5	E
	ES26			69.0	21.0	5.8	1.77	158	343	10.2	3.11	-4.4	-0.6	E
	ES27			75.0	22.9	4.7	1.42	145	336	21.4	6.52	-5.3	-0.7	E
	ES28			75.0	22.9	3.7	1.12	145	336	26.8	8.17	-5.2	-0.7	E
JEA - Kennedy Power Plant	EKEN	440.0	3359.2	149.9	45.7	10.5	3.2	250	394	34.1	10.4	-596.0	-75.1	E
	KNDY10A			136.1	41.5	9.0	2.74	309	427	79.7	24.3	-734.1	-92.5	E
	KNDY10B			136.1	41.5	9.0	2.74	309	427	79.7	24.3	-734.1	-92.5	E
	KNDY9			149.9	45.7	10.5	3.2	289	416	40.0	12.2	-595.2	-75.0	E
JEA- Southside Power Plant	JEASS1			133.5	40.7	8.0	2.44	343	446	50.8	15.5	-418.3	-52.7	E
	JEASS2			133.5	40.7	8.0	2.44	343	446	50.8	15.5	-418.3	-52.7	E
	JEASS3			133.5	40.7	10.0	3.05	304	424	44.0	13.4	-633.3	-79.8	E
	JEASS4	437.7	3353.9	143.3	43.7	10.7	3.25	275	408	60.7	18.5	-873.0	-110.0	E
	JEASS5A			145.0	44.2	9.7	2.96	287	415	69.9	21.3	-825.4	-104.0	E
	JEASS5B			145.0	44.2	9.7	2.96	287	415	69.9	21.3	-825.4	-104.0	E
Gainesville Regional Utilities- Deerhaven	GRUDH2	365.7	3292.6	349.9	106.68	18.5	5.64	275	408.1	50.0	15.24	2,914.0	367.2	C
	GRUDHCC	365.5	3292.6	52.0	15.85	14.1	4.3	1100	866.5	168.0	51.21	53.0	6.7	C
PCS	SULACC&D	328.3	3368.8	149.9	45.7	5.2	1.59	181	356.0	94.1	28.7	766.7	96.6	C
	SULACE&F			200.1	61.0	9.5	2.90	181	356.0	30.5	9.3	833.3	105.0	C
	AUXBLRE			50.2	15.3	5.2	1.60	311	428.0	52.2	15.9	170.6	21.5	C
	AUXBLRB			35.1	10.7	4.8	1.46	383	468.0	31.2	9.5	174.6	22.0	C
	AUXBLRC&			104.0	31.7	6.5	1.98	383	468.0	49.9	15.2	332.4	41.9	C
	DAP2ZTR			140.1	42.7	8.0	2.44	125	325.0	43.0	13.1	5.5	0.7	C
	SULACA&B			200.1	61.0	5.9	1.80	170	350.0	50.8	15.5	-2,416.7	-304.5	E
	SULACC&D			149.9	45.7	5.2	1.59	181	356.0	94.1	28.7	-600.0	-75.6	E
Suwannee American Cement	AMSUWCEM	321.4	3315.9	315	96.0	9.42	2.87	205	369	46.4	14.1	28.4	3.6	C
Florida Rock Thompson S. Baker Cement Plant	FLROCCEM	348.4	3287.0	250	76.2	9.42	2.87	356	453	47.8	14.6	17.7	2.2	C

NA= not applicable

[a] Comsuming (C) sources are sources that were constructed or modified after the PSD baseline date.
Expanding (E) sources are sources that have shutdown or have been modified since the baseline date.

[b] Two of the four CT units (half of the total plant emissions) consume PSD increment and are included in the PSD increment analysis.
Higher emissions based on maximum allowable emissions. Lower emissions are based on maximum actual emissions for the two units. See Table 3-3 for details.

[c] Maximum allowable emissions for each unit based on 1.2 lb/MMBtu and maximum heat input rate of 6144 MMBtu/hr. For one unit, SO2 emissions are 7,372.8 lb/hr.

TABLE B-4

STACK, OPERATING, AND SO_2 EMISSIONS OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES AT THE OKEFENOKEE NWA

Facility	Model ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Height (ft)	Height (m)	Diameter (ft)	Diameter (m)	Temperature (°F)	Temperature (K)	Velocity (ft/s)	Velocity (m/s)	Emission Rate (lb/hr)	Emission Rate (g/s)	PSD[a] Source (C/E)

[d] Actual emissions for each unit were obtained from the EPA Acid Rain Program using the 2001 to 2003 CEM data:
4,669.4 lb/hr (equivalent to approximately 0.76 lb/MMBtu for each unit operating at maximum heat input rate)

Source: FDEP, File 7_3_12_99.DAT (1/11/02)
SECI 2003

STACK, OPERATING AND SO_2 EMISSIONS OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES AT THE CHASSAHOWITZKA NWA

Facility	Model ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Stack Parameters Height (ft)	Height (m)	Diameter (ft)	Diameter (m)	Temperature (°F)	Temperature (K)	Velocity (ft/s)	Velocity (m/s)	Emission Rate (lb/hr)	Emission Rate (g/s)	PSD [a] Source (C/E)
Florida Power & Light (FPL)- Putnam Plant	CFPLPUTM	443.3	3277.6	73.144	22.3	10.33	3.15	327.65	437.4	192.21	58.6	1,549.2	195.2 [c]	NA
												925.4	116.6 [c]	C
Florida Power & Light (FPL)- Palatka Plant	FPLPALAT	442.8	3277.6	149.896	45.7	12.99	3.96	274.91	408.1	31.16	9.5	-2,039.9	-257.0	E
Georgia Pacific, Palatka Mill [b]	SDT4	433.9347	3283.478	206.0	62.8	5.0	1.52	179	355	33.9	10.35	7.7	0.97	C
	PB524	433.9773	3283.447	236.8	72.2	8.0	2.44	413	485	85.9	26.19	1,461.9	184.2	C
	CB4	433.9825	3283.45	236.8	72.2	8.0	2.44	466	514	92.3	28.14	961.1	121.1	C
	PB7	433.9862	3283.466	60.0	18.3	7.0	2.13	750	672	43.5	13.25	0.2	0.0189	C
	LK4	434.1067	3283.247	130.9	39.9	4.4	1.35	164	346.5	70.6	21.51	34.5	4.35	C
	TM5P	434.2864	3283.44	94.0	28.65	4.2	1.29	450	505.4	77.1	23.5	0.030	0.00378	C
	RB4_24HR	433.8823	3283.438	229.9	70.1	12.0	3.66	424	491	65.9	20.08	109.8	13.84	C
	TOX	433.9816	3283.38	249.9	76.2	3.6	1.1	160	344	18.0	5.49	31.3	3.94	C
	RB1B	434.0536	3283.407	249.9	76.2	12.0	3.66	188	360	28.9	8.8	49.3	6.21	E
	RB2B	434.0536	3283.407	249.9	76.2	12.0	3.66	210	372	28.9	8.8	70.5	8.88	E
	RB3B	434.0195	3283.385	132.8	40.5	11.2	3.41	210	372	23.9	7.28	68.1	8.58	E
	RB4B	433.8823	3283.438	229.9	70.1	12.0	3.66	394	474	55.3	16.86	277.8	35	E
	SDT1B	434.0593	3283.411	100.0	30.5	2.5	0.76	199	366	24.7	7.53	1.0	0.13	E
	SDT2B	434.0593	3283.411	100.0	30.5	3.0	0.91	215	375	31.2	9.51	1.4	0.18	E
	SDT3B	434.0253	3283.388	108.9	33.2	2.5	0.76	205	369	11.7	3.57	1.4	0.18	E
	SDT4B	433.9347	3283.478	206.0	62.8	5.0	1.52	163	346	27.1	8.26	5.6	0.71	E
	LK1B	434.1219	3283.301	49.9	15.2	4.2	1.28	262	401	17.2	5.24	1.9	0.24	E
	LK2B	434.1174	3283.299	52.2	15.9	5.6	1.71	154	341	35.0	10.67	1.9	0.24	E
	LK3B	434.1193	3283.271	52.2	15.9	5.6	1.71	156	342	27.8	8.47	3.8	0.48	E
	LK4B	434.1067	3283.247	148.9	45.4	4.3	1.31	172	351	54.0	16.46	11.1	1.4	E
	PB4B	433.998	3283.481	122.0	37.2	4.0	1.22	399	477	47.7	14.54	358.7	45.2	E
	PB5B	433.9773	3283.447	239.1	72.9	9.0	2.74	476	520	52.4	15.97	1,277.8	161	E
	CB4B	433.9825	3283.45	239.1	72.9	10.0	3.05	399	477	34.5	10.52	960.3	121	E
Gerdau Ameristeel	EAFBH1	405.708	3350.0	110.0	33.53	12.0	3.66	230	383.2	55.2	16.84	16.0	2.02	C
	EAFBH2	405.715	3350.0	110.0	33.53	12.0	3.66	230	383.2	55.2	16.84	16.0	2.02	C
	REHEATN	405.811	3350.3	66.0	20.12	5.8	1.77	480	522	45.0	13.72	0.16	0.02	C
	ST12	405.699	3350.1	115.0	35.05	10.0	3.05	230	383.2	64.8	19.76	10.16	1.28	E
	ST34	405.732	3350.1	115.0	35.05	10.0	3.05	230	383.2	67.9	20.7	1.11	0.14	E
	REHEAT	405.758	3350.4	160.0	48.77	6.9	2.1	900	755.4	19.5	5.93	0.054	0.0068	E
JEA Brandy Branch	S1NG	408.835	3354.5	189.9	57.91	18.0	5.49	266	403	69.8	21.28	32.70	4.12	C
	S2NG	408.713	3354.5	189.9	57.91	18.0	5.49	266	403	69.8	21.28	32.70	4.12	C
	S3FO	408.774	3354.5	189.9	57.91	18.0	5.49	266	403	69.8	21.28	32.70	4.12	C
	SFP	408.893	3354.5	24.0	7.32	0.5	0.15	649	616	196.9	60.02	0.032	0.0040	C
Gainesville Regional Utilities- Deerhaven	GRUDH2	365.7	3292.6	349.9	106.68	18.5	5.64	275	408.1	50.0	15.24	2,913.97	367.16	C
	GRUDHCC	365.5	3292.6	52.0	15.85	14.1	4.3	1100	866.5	168.0	51.21	53.02	6.68	C
CF Industries, Plant City														

STACK, OPERATING AND SO_2 EMISSIONS OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES AT THE CHASSAHOWITZKA NWA

	Facility	Model ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Stack Parameters Height (ft)	Height (m)	Diameter (ft)	Diameter (m)	Temperature (°F)	Temperature (K)	Velocity (ft/s)	Velocity (m/s)	Emission Rate (lb/hr)	Emission Rate (g/s)	PSD [a] Source (C/E)
001	Johnson Scotch Boiler	JOHNSTON	388.0	3116.0	25.0	7.6	3.5	1.1	550	561	61.6	18.8	46.86	5.90	C
002	"A" SAP	SAPA			110.0	33.5	5.0	1.5	85	303	72.6	22.1	303.30	38.22	C
003	"B" SAP	SAPB			110.0	33.5	5.0	1.5	84	302	80.1	24.4	303.30	38.22	C
007	"C" SAP	SAPC			199.0	60.7	8.0	2.4	0	0	46.7	14.2	401.04	55.58	C
008	"D" SAP	SAPD			199.0	60.7	8.0	2.4	0	0	48.3	14.7	401.04	55.58	C
010	"A" DAP/MAP Plant	ADMP			80.0	24.4	10.0	3.0	137	331	36.8	11.2	13.86	1.75	C
011	"Z" DAP/MAP Plant	ZDMP			136.0	41.5	9.0	2.7	140	333	44.5	13.6	20.79	2.62	C
012	"X" DAP/MAP/GTSP Plant	XDMGP			136.0	41.5	9.0	2.7	134	330	50.7	15.5	24.17	3.05	C
013	"Y" DAP/MAP/GTSP Plant	YDMGP			136.0	41.5	9.0	2.7	135	330	53.3	16.2	24.07	3.03	C
022	--Storage Tank (022)b	MSTK22			38.0	11.6	2.0	0.6	212	373.2	-	0.0	0.13	0.02	C
033	--Storage Tank (033)c	MSTK33			41.0	12.5	-	-	-	-	-	-	0.13	0.02	C
023	--Truck Pit Ab	MSTPTA			12.0	3.7	0.7	0.2	212	373.2	-	0.0	0.13	0.02	C
024	--Truck Pit Bb	MSTPTB			12.0	3.7	0.7	0.2	212	373.2	-	0.0	0.13	0.02	C
010	"A" DAP Plant	ADMPB			100	30.5	10.0	3.0	128	326.483	26.8	8.2	-18.42	-2.32	E
012	"X" DAP/MAP/GTSP Plant	XDMGPB			125	38.1	7.3	2.2	110	316.483	69.7	21.2	-27.43	-3.46	E
013	"Y" GTSP Plant	YDMGPB			125	38.1	7.3	2.2	110	316.483	44.8	13.6	-18.34	-2.31	E
011	"Z" DAP/GTSP Plant	ZDMPB			125	38.1	7.3	2.2	110	316.483	69.7	21.2	-18.34	-2.31	E
002	"A" Sulfuric Acid Plant with Ammonia Scrubber	SAPAB			80	24.4	5.0	1.5	98	309.817	62.2	19.0	-416.70	-52.50	E
003	"B" Sulfuric Acid Plant with Ammonia Scrubber	SAPBB			80	24.4	5.0	1.5	96	308.706	68.4	20.9	-416.70	-52.50	E
007	"C" Sulfuric Acid Plant Double Absorption	SAPCB			199	60.7	8.0	2.4	150	338.706	34.5	10.5	-250.00	-31.50	E
008	"D" Sulfuric Acid Plant Double Absorption	SAPDB			199	60.7	8.0	2.4	150	338.706	27.7	8.4	-250.00	-31.50	E
--	Sulfur Storage and Handling (b)				--	--	--	--	--	--	--	--	-0.33	-0.04	E
--	ROP/MGTSP Manufacturing	RMMANB			135	41.1	6.5	2.0	87	303.706	33.9	10.3	-14.11	-1.78	E
Cargill Fertilizer, Inc.--Riverview															
	MOLTEN SULFUR PITS 7, 8, AND 9	CRPITS	363	3083	d	d	d	d	d	d	d	d	0.13	0.016	C
	MOLTEN SULFUR TANKS 1, 2, AND 3/TRUCK LO/	CRTKTL			33	10.1	0.8	0.25	110	316	20.5	6.24	3.34	0.42	C
4	NO. 7 SULFURIC ACID PLANT	CR7SAP			150	45.7	7.5	2.29	152	340	41.5	12.64	466.70	58.8	C
5	NO. 8 SULFURIC ACID PLANT	CR8SAP			150	45.7	8.0	2.44	165	347	42.9	13.08	393.75	49.6	C
6	NO. 9 SULFURIC ACID PLANT	CR9SAP			150	45.7	9.0	2.74	155	341	44.8	13.66	495.83	62.5	C
100	NO. 5 ROCK MILL	CR5RKML			91	27.7	2.5	0.76	166	348	122.6	37.36	6.59	0.83	C
106	NO. 7 ROCK MILL	CR7RKML			91	27.7	3.0	0.91	165	347	47.2	14.37	6.59	0.83	C
101	NO. 9 ROCK MILL	CR9RKML			91	27.7	2.5	0.76	162	345	106.5	32.46	6.59	0.83	C
7	NO. 6 GRANULATION PLANT DRYER STACK	CR6GRAN			162	49.4	8.5	2.59	164	346	58.7	17.89	40.57	5.1	C
	AFI PLANT NO. 1	CRAFI1			136	41.5	6.0	1.83	150	339	64.5	19.66	25.36	3.2	C
	AFI PLANT NO. 2	CRAFI2			155	47.2	6.0	1.83	150	339	64.5	19.66	38.04	4.8	C
55	NO. 5 GRANULATION PLANT-DRYER/COOLER S1	CR5GRAN			133	40.5	7.0	2.13	110	316	67.6	20.59	12.58	1.585	C
22,23,24	NOS. 3 AND 4 MAP PLANTS, SOUTH COOLER	CR34MAP			133	40.5	7.0	2.13	142	334	71.5	21.78	0.0030	0.00038	C
	Ammonia Plant (Expanding Source)	AMMPLTB			60	18.3	8.3	2.5	600	589	22.7	6.93	-32.80	-4.13	E

STACK, OPERATING AND SO_2 EMISSIONS OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES AT THE CHASSAHOWITZKA NWA

Facility	Model ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Height (ft)	Height (m)	Diameter (ft)	Diameter (m)	Temperature (°F)	Temperature (K)	Velocity (ft/s)	Velocity (m/s)	Emission Rate (lb/hr)	Emission Rate (g/s)	PSD [a] Source (C/E)
Sodium Silicofluoride/Sodium Fluoride Plant (Expandin	SSFSFPB			28	8.5	2.5	0.76	95	308	11.6	3.55	-0.20	-0.03	E
No. 10 KVS Mill (Expanding Source)	10KVSMB			87	26.5	1.7	0.52	118	321	59.8	18.24	-0.020	-0.0025	E
No. 12 KVS Mill (Expanding Source)	12KVSMB			71	21.6	1.6	0.49	135	330	68.5	20.87	-0.040	-0.0050	E
No. 7 Oil-Fired Concentrator (Expanding Source)	7OFCONB			78	23.8	6.0	1.83	165	347	17.2	5.24	-41.40	-5.22	E
No. 8 Oil-Fired Concentrator (Expanding Source)	8OFCONB			78	23.8	6.0	1.83	159	344	16.7	5.10	-39.70	-5.00	E
GTSP Plant (Expanding Source)	GTSPAPB			126	38.4	8.0	2.44	129	327	34.9	10.65	-71.40	-9.00	E
No. 5 and No. 9 Mills Bag Filter (Expanding Source)	RKML59B			66	20.1	2.0	0.61	115	319	58.3	17.75	-0.010	-0.0013	E
No. 3 Continuous Triple Dryer (Expanding Source)	3CONTDB			68	20.7	3.5	1.07	115	319	45.8	13.96	-22.80	-2.87	E
No. 4 Continuous Triple Dryer (Expanding Source)	4CONTDB			68	20.7	3.5	1.07	134	330	61.8	18.85	-23.20	-2.92	E
Molten Sulfur Handling- Pits 7 & 8 (Expanding Source)	MSPTSB			[e]	[e]	[e]	[e]	[e]	[e]	[e]	[e]	-0.080	-0.010	E
Molten Sulfur Handling- Pits 4,5, & 6 (Expanding Sour	PTS456B			[f]	[f]	[f]	[f]	[f]	[f]	[f]	[f]	-0.13	-0.02	E
Molten Sulfur Handling- Tanks (Expanding Source)	MSTKTLB			[g]	[g]	[g]	[g]	[g]	[g]	[g]	[g]	-2.12	-0.27	E
No. 4 Sulfuric Acid Plant (Expanding Source)	NO4SAPB			80	24.4	4.7	1.43	194	363	20.4	6.23	-282.00	-35.53	E
No. 5 Sulfuric Acid Plant (Expanding Source)	NO5SAPB			74	22.6	5.3	1.62	189	360	25.3	7.72	-480.00	-60.48	E
No. 6 Sulfuric Acid Plant (Expanding Source)	NO6SAPB			72	21.9	5.9	1.80	189	360	31.3	9.53	-688.00	-86.69	E
No. 7 Sulfuric Acid Plant (Expanding Source)	NO7SAPB			92	28.0	9.4	2.87	183	357	22.3	6.80	-1,503.00	-189.38	E
No. 8 Sulfuric Acid Plant (Expanding Source)	NO8SAPB			96	29.3	10.7	3.26	174	352	24.2	7.37	-1,679.00	-211.55	E
Natonal Gypsum - Apollo Beach														
1 Imp Mill #1	NATGYP1	363.3	3075.6	98	29.9	3.8	1.14	350	450	28.2	8.6	5.28	0.67	C
Imp Mill #2	NATGYP2			98	29.9	3.8	1.14	350	450	28.2	8.6	5.28	0.67	C
Imp Mill #3	NATGYP3			98	29.9	3.8	1.14	350	450	28.2	8.6	5.28	0.67	C
Imp Mill #4	NATGYP4			98	29.9	3.8	1.14	350	450	28.2	8.6	5.28	0.67	C
Kiln	NATGYP5			54	16.5	13.4	4.08	384	469	58.2	17.7	33.22	4.19	C
Big Bend Transfer Co. L.L.C.														
Melter/ Molten Scrubber stack	BBTCCMBO	361.1	3076.2	95	29.0	2.2	0.66	97	309	57.0	17.4	0.014	0.002	C
Package Boiler	BBTCPKBL			106	32.3	4.0	1.22	350	450	29.7	9.1	3.56	0.45	C
TECO - Big Bend														
4 UNIT #4 BOILER W/ESP	TECOBB4	361.9	3075.0	490	149.4	24.0	7.32	127	326	78.3	23.9	3,576	451	C
1,2 Steam Generators 1 & 2 Baseline	TCBB12B			490	149.4	24.0	7.32	300	422	94.0	28.7	-19333	-2436	E
3 Steam Generator 3 Baseline	TCBB3B			490	149.4	24.0	7.32	293	418	47.0	14.3	-9667	-1218	E
Tampa Bay Shipbuiding & Repair Co.														
5 DIESEL COMPRESSORS	TBSHIP5	358.0	3089.0	10	3.0	0.5	0.15	350	450	148.5	45.3	2.74	0.35	C
McKay Bay Refuse-to-Energy Facility														
103 MWC & Aux Burner No. 1	MCKY103	360.2	3092.2	201	61.3	4.2	1.28	289	416	73.3	22.3	40.87	5.15	C
104 MWC & Aux Burner No. 2	MCKY104			201	61.3	4.2	1.28	289	416	73.3	22.3	40.87	5.15	C
105 MWC & Aux Burner No. 3	MCKY105			201	61.3	4.2	1.28	289	416	73.3	22.3	40.87	5.15	C

STACK, OPERATING AND SO_2 EMISSIONS OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES AT THE CHASSAHOWITZKA NWA

Facility	Model ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Stack Parameters Height (ft)	Height (m)	Diameter (ft)	Diameter (m)	Temperature (°F)	Temperature (K)	Velocity (ft/s)	Velocity (m/s)	Emission Rate (lb/hr)	Emission Rate (g/s)	PSD * Source (C/E)
106 MWC & Aux Burner No. 4	MCKY106			201	61.3	4.2	1.28	289	416	73.3	22.3	40.87	5.15	C
Hillsborough Cty. Resource Recovery Fac.														
1 MWC & Aux Burner #1	HILLSRC1	368.2	3092.7	220	67.1	5.1	1.55	290	416	72.5	22.1	58.67	7.39	C
2 MWC & Aux Burner #2	HILLSRC2			220	67.1	5.1	1.55	290	416	72.5	22.1	58.67	7.39	C
3 MWC & Aux Burner #3	HILLSRC3			220	67.1	5.1	1.55	290	416	72.5	22.1	58.67	7.39	C
Yuengling Brewing Co.														
1 2 Natural gas boilers	YNGBREW1	362.0	3103.2	90	27.4	6.5	1.98	275	408	7.0	2.1	9.00	1.13	C
Pinellas Co. Resource Recovery Facility														
1 Waste Combustor & Aux burners-Unit #1	PINRCY1	335.2	3084.1	161	49.1	7.8	2.38	449	505	88.0	26.8	170.00	21.4	C
3 Waste Combustor & Aux burners-Unit #2	PINRCY3			165	50.3	9.0	2.74	450	505	90.0	27.4	525.00	66.2	C
IMC PhosphateS Company - New Wales														
2 SAP No. 1	IMCWAL2	396.7	3079.4	200	61.0	8.5	2.59	170	350	50.0	15.2	483.30	60.90	C
3 SAP No. 2	IMCWAL3			200	61.0	8.5	2.59	170	350	50.0	15.2	483.30	60.90	C
4 SAP No. 3	IMCWAL4			200	61.0	8.5	2.59	170	350	50.0	15.2	483.30	60.90	C
9 DAP Plant No. 1	IMCWAL9			133	40.5	7.0	2.13	105	314	49.0	14.9	74.60	9.40	C
13 Auxiliary Boiler	IMCWAL13			85	25.9	3.0	0.91	555	564	193.3	58.9	569.00	71.69	C
27 AFI Plant	IMCWAL27			172	52.4	8.0	2.44	130	328	66.3	20.2	18.30	2.31	C
36 Kilns, Dryer, Blending Op.	IMCWAL36			172	52.4	4.5	1.37	105	314	52.0	15.8	192.00	24.19	C
42 SAP No. 4	IMCWAL42			199	60.7	8.5	2.59	170	350	50.0	15.2	483.30	60.90	C
44 SAP No. 5	IMCWAL44			199	60.7	8.5	2.59	170	350	50.0	15.2	483.30	60.90	C
45 DAP Plant No 2 - East Train	IMCWAL45			171	52.1	6.0	1.83	110	316	58.0	17.7	22.00	2.77	C
46 DAP Plant No 2 - West Train	IMCWAL46			171	52.1	6.0	1.83	110	316	58.0	17.7	22.00	2.77	C
60 Molten Storage Tank	IMCWAL60			40	12.2	2.0	0.61	240	389	0.4	0.1	0.50	0.06	C
62 Molten Storage Tank	IMCWAL62			40	12.2	2.0	0.61	240	389	0.4	0.1	0.50	0.06	C
63 Unloading Sulfur Pit	IMCWAL63			40	12.2	2.0	0.61	240	389	0.4	0.1	0.30	0.04	C
64 Unloading Sulfur Pit	IMCWAL64			40	12.2	2.0	0.61	240	389	0.4	0.1	0.10	0.01	C
65 Unloading Sulfur Pit	IMCWAL65			40	12.2	2.0	0.61	240	389	0.4	0.1	0.30	0.04	C
66 Sulfur Transfer Pit	IMCWAL66			40	12.2	2.0	0.61	240	389	0.4	0.1	0.10	0.01	C
68 Unloading Sulfur Pit	IMCWAL68			25	7.6	0.1	0.03	90	305	0.1	0.03	0.30	0.04	C
69 Unloading Sulfur Pit	IMCWAL69			25	7.6	0.1	0.03	90	305	0.1	0.03	0.10	0.01	C
74 Multifos C Kiln	IMCWAL74			172	52.4	4.5	1.37	105	314	70.2	21.4	8.70	1.10	C
78 GRANULAR MAP PLANT	IMCWAL78			133	40.5	6.0	1.83	145	336	109.6	33.4	13.72	1.73	C
Expanding Source	IMCWAL0			69	21.0	7.0	2.13	165	347	61.0	18.6	-272.0	-34.27	E
Expanding Source	IMCWAL1			200	61.0	8.5	2.59	170	350	42.9	13.1	-1158.7	-146.00	E
Agrifos, L.L.C. - Nichols	(formerly Mobil Mining & Minerals Nichols)													

STACK, OPERATING AND SO_2 EMISSIONS OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES AT THE CHASSAHOWITZKA NWA

Facility	Model ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Stack Parameters: Height (ft)	Height (m)	Diameter (ft)	Diameter (m)	Temperature (°F)	Temperature (K)	Velocity (ft/s)	Velocity (m/s)	Emission Rate (lb/hr)	Emission Rate (g/s)	PSD [a] Source (C/E)
Expanding Source	AGRINK3	398.7	3085.3	93	28.4	3.6	1.10	152	340	63.1	19.2	-110.32	-13.90	E
Expanding Source	AGRINK4			13	4.0	2.6	0.79	480	522	5.9	1.8	-6.90	-0.87	E
IMC Phosphates Company - Nichols	(formerly IMC Agrico/Conserve)													
5 SAP NO. 1 PSD	AGRNK5	398.4	3084.2	150	45.7	7.5	2.29	170	350	33.0	10.1	416.80	52.52	C
Expanding Source	AGRNK1			100	30.5	5.9	1.80	95	308	62.0	18.9	-120.5	-15.2	E
Expanding Source	AGRNK2			80	24.4	5.0	1.52	151	339	42.3	12.9	-30.8	-3.88	E
TECO - Polk Power Station														
1 Combined cycle CT	TECOPK1	402.5	3067.4	150	45.7	19.0	5.79	340	444	75.8	23.1	518.00	65.27	C
3 120 MMBtu/HR AuxBlr	TECOPK3			75	22.9	3.7	1.13	375	464	50.0	15.2	96.00	12.10	C
4 Sulfuric Acid Plant	TECOPK4			199	60.7	2.5	0.76	180	355	60.0	18.3	35.60	4.49	C
9 Simple Cycle CT	TECOPK9			114	34.7	29.0	8.84	1117	876	60.2	18.3	9.20	1.16	C
10 Simple Cycle CT	TECOPK10			114	34.7	29.0	8.84	1117	876	60.2	18.3	9.20	1.16	C
Cargill Mulberry (Formerly Mulberry Phosphates, Inc.)														
2 SAP 2	MULPHS2	406.8	3085.1	200	61.0	7.0	2.13	200	366	32.0	9.8	283.33	35.70	C
1 Expanding Source	MULPHSX			168	51.2	7.0	2.13	181	356	37.5	11.4	-2,044.40	-258	E
CF Industries, Inc. - Bartow	(Bonnie Mine Road)													
6 SAP NO.6	CFIBAR6	408.3	3082.5	206	62.8	7.0	2.13	140	333	21.0	6.4	400.00	50.40	C
21 BOILER NO. 1	CFIBAR21			36	11.0	2.5	0.76	600	589	44.0	13.4	16.80	2.12	C
1 Expanding Source	CFIBARX1			100	30.5	4.5	1.37	170	350	40.0	12.2	-483	-61	E
2 Expanding Source	CFIBARX2			100	30.5	5.5	1.68	170	350	34.0	10.4	-875	-110	E
3 Expanding Source	CFIBARX3			100	30.5	9.0	2.74	196	364	14.0	4.3	-850	-107	E
4 Expanding Source	CFIBARX4			100	30.5	7.0	2.13	185	358	26.0	7.9	-1,388	-175	E
5 Expanding Source	CFIBARX5			206	62.8	7.0	2.13	185	358	35.0	10.7	-1,800	-227	E
6 Expanding Source	CFIBARX6			206	62.8	7.0	2.13	187	359	34.0	10.4	-1,350	-170	E
IMC Phosphates Company - South Pierce														
4 SAP No. 10	IMCSPR4	407.5	3071.4	144	43.9	9.0	2.74	170	350	41.1	12.5	450.0	56.70	C
5 SAP No. 11	IMCSPR5			144	43.9	9.0	2.74	170	350	41.1	12.5	450.0	56.70	C
Combined Expanding Sources	IMCPIER6			144	43.9	5.2	1.58	170	350	86.6	26.4	-600.0	-75.6	E
Cargill Green Bay (Formerly Farmland Hydro, L.P. - Green Bay)														
3 SAP #3	FARM3	409.5	3080.1	100	30.5	7.5	2.29	170	350	28.0	8.5	350.00	44.10	C
4 SAP #4	FARM4			100	30.5	7.5	2.29	180	355	39.6	12.1	350.00	44.10	C
5 SAP #5	FARM5			150	45.7	8.0	2.44	180	355	44.1	13.4	466.70	58.80	C
7 South AP Plant--Stack A	FARM7			130	39.5	8.0	2.44	97	309	49.7	15.2	3.16	0.40	C
29 NORTH MAP/DAP PLANT--MAIN STACK	FARM29			128	39.0	8.0	2.44	113	318	50.7	15.5	2.63	0.33	C
34 MOLTEN SULFUR PIT	FARM34			10	3.0	0.8	0.24	200	366	54.0	16.5	0.70	0.09	C

STACK, OPERATING AND SO_2 EMISSIONS OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES AT THE CHASSAHOWITZKA NWA

Facility	Model ID Name	UTM Coordinates East (km)	North (km)	Stack Parameters Height (ft)	(m)	Diameter (ft)	(m)	Temperature (°F)	(K)	Velocity (ft/s)	(m/s)	Emission Rate (lb/hr)	(g/s)	PSD [a] Source (C/E)
38 No. 6 SAP	FARM38			150	45.7	9.0	2.74	180	355	34.8	10.6	401.00	50.53	C
SAP # 1 (Expanding Source)	FRMSAP1			100	30.5	7.0	2.13	169	349	18.9	5.8	-493	-62.10	E
SAP # 2 (Expanding Source)	FRMSAP2			100	30.5	7.0	2.13	171	350	18.8	5.7	-533	-67.13	E
SAP # 3 (Expanding Source)	FRMSAP3			100	30.5	7.5	2.29	162	345	30.3	9.2	-653	-82.23	E
SAP # 4 (Expanding Source)	FRMSAP4			100	30.5	7.5	2.29	124	324	22.7	6.9	-542	-68.34	E
Cargill Fertilizer - Bartow														
1 NO.3 FERTILIZER PLANT	CARBAR1	409.8	3086.6	141	43.0	7.5	2.29	160	344	79.0	24.1	76.90	9.69	C
12 No. 4 SAP	CARBAR12			200	61.0	6.8	2.07	180	355	61.0	18.6	433.30	54.60	C
32 No. 6 SAP	CARBAR32			200	61.0	6.8	2.07	180	355	61.0	18.6	433.30	54.60	C
33 No. 5 SAP	CARBAR33			200	61.0	6.8	2.07	180	355	61.0	18.6	433.30	54.60	C
51 Boiler	CARBAR51			31	9.4	3.5	1.07	410	483	20.0	6.1	165.17	20.81	C
Hardee Power Station														
1 CT 1A W\HRSG	HARDE1	404.8	3057.4	90	27.4	14.5	4.42	236	386	77.5	23.6	734.40	92.53	C
2 CT 2A W\HRSG	HARDE2			90	27.4	14.5	4.42	245	391	75.8	23.1	734.40	92.53	C
3 Simple cycle CT 2A	HARDE3			75	22.9	17.9	5.46	986	803	94.3	28.7	734.40	92.53	C
5 Unit 2B - 75 MW gas turbine	HARDE5			85	25.9	14.8	4.51	999	810	142.0	43.3	5.30	0.67	C
Lakeland Electric, Larsen Power Plant														
8 Combined Cycle CT	LARS8	408.9	3102.5	155	47.2	16.0	4.88	481	523	85.7	26.1	211.40	26.64	C
Lakeland Electric, McIntosh Power Plant														
6 McIntosh Unit 3	MCINT6	409.0	3106.2	250	76.2	18.0	5.49	167	348	82.6	25.2	4,368.00	550.37	C
28 CT UNIT 5	MCINT28			85	25.9	28.0	8.53	1095	864	82.7	25.2	126.70	15.96	C
U.S. Agri-Chemicals - Ft. Meade														
16 SAP #1	USAGFM16	416.0	3069.0	175	53.3	8.5	2.59	180	355	32	9.8	500.00	63.00	C
17 SAP #2	USAGFM17			175	53.3	8.5	2.59	180	355	32	9.8	500.00	63.00	C
28 MOLTEN SULFUR TANK	USAGFM28			6	1.8	0.3	0.09	270	405	344	104.9	0.49	0.06	C
29 MOLTEN SULFUR TANK	USAGFM29			6	1.8	0.3	0.09	260	400	157	47.9	0.23	0.03	C
Expanding Source	USAGFM0			95	29	9.9	3.02	106	314	23	6.9	-625.4	-78.80	E
Expanding Source	USAGFM1			93	28	5.0	1.52	134	330	58	17.6	-145.0	-18.27	E
Cutrale Citrus Juices USA, Inc.														
3 PEEL DRYER	CUTR3	421.6	3103.7	100	30.5	3.2	0.98	161	345	49.0	14.9	186.00	23.44	C
8 COGEN #1	CUTR8			40	12.2	4.0	1.22	323	435	60.0	18.3	170.80	21.52	C
9 COGEN #2	CUTR9			40	12.2	4.0	1.22	330	439	66.0	20.1	26.00	3.28	C

STACK, OPERATING AND SO_2 EMISSIONS OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES AT THE CHASSAHOWITZKA NWA

Facility	Model ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Stack Parameters Height (ft)	Height (m)	Diameter (ft)	Diameter (m)	Temperature (°F)	Temperature (K)	Velocity (ft/s)	Velocity (m/s)	Emission Rate (lb/hr)	Emission Rate (g/s)	PSD [a] Source (C/E)
Auburndale Power Partners, LP														
Proposed CT	LD7595A	420.8	3103.3	50	15	22.0	6.71	1,040	833	68	20.8	53.60	6.75	C
1 Existing CT	CALEXT1			160	49	18.0	5.49	280	411	58	17.7	70.00	8.82	C
Proposed CT, Osprey	CALOSP1			135	41	19.0	5.79	200	366	60	18.3	6.50	0.82	C
Proposed CT, Osprey	CALOSP2			135	41	19.0	5.79	200	366	60	18.3	6.50	0.82	C
Florida Distillers - Auburndale														
3 Boiler	FDIST31	421.4	3102.9	45	14	4.0	1.22	350	450	5	1.5	0.060	0.008	C
FPC - Intercession City Plant														
1-6 Combined CT Units 1-6	INTCP16	446.3	3126.0	20	6	14.6	4.46	760	678	175	53.3	2,185.20	275.34	C
7-10 Combined CTs 7-10	INTCP710			75	23	19.0	5.79	1034	830	139	42.5	1,295.00	163.17	C
11 CT 11	INTCP11			75	23	19.0	5.79	1034	830	139	42.5	407.00	51.28	C
IPS - Shady Hills														
CT No. 1-3	IPSPASCO	347.2	3138.8	60	18.3	22	6.71	1076	853	122.4	37.3	304.50	38.37	C
Estech/Swift Polk														
	ESTDRY1	411.5	3,074.2	60.0	18.3	9.7	2.95	151	339	27.8	8.47	-190.00	-23.94	E
	ESTDRY2			61.5	18.8	9.7	2.95	152	340	16.6	5.06	-180.95	-22.80	E
	ESTSAP			101	30.8	7.0	2.13	185	358	12.8	3.90	-737.06	-92.87	E
FL Crushed Stone Kiln 1														
	FCS1	360.0	3,162.5	320	97.5	21.3	6.48	323	435	54.6	16.6	806.35	101.60	C
FPC Polk County Site														
				113	34.4	13.5	4.115	260	400	133.0	40.5	98.02	12.35	C
				113	34.4	13.5	4.1	260	400	133.0	40.5	98.02	12.35	C
	FPCPKC2	414.3	3,073.9	113	34.4	13.5	4.1	260	400	133.0	40.5	196.03	24.7	C
General Portland Cement #4														
	GPCEM4B	358.0	3,090.6	118	36.0	9.0	2.74	450	505	57.8	17.6	-499.92	-62.99	E
General Portland Cement #5														
	GPCEM5B	358.0	3,090.6	149	45.4	12.5	3.81	430	494	19.0	5.80	-550.00	-69.3	E
IMC-Agrico Pierce														
	IAPRC12	404.1	3,079.0	80.0	24.4	5.0	1.52	151	339	42.5	12.9	-193.02	-24.3	E
	IAPRC34	404.1	3,079.0	80.0	24.4	8.0	2.43	151	339	61.7	18.8	-182.54	-23.0	E
Imperial Phosphates (Brewer)														

STACK, OPERATING AND SO_2 EMISSIONS OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES AT THE CHASSAHOWITZKA NWA

Facility	Model ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Height (ft)	Height (m)	Diameter (ft)	Diameter (m)	Temperature (°F)	Temperature (K)	Velocity (ft/s)	Velocity (m/s)	Emission Rate (lb/hr)	Emission Rate (g/s)	PSD [a] Source (C/E)
	IMPRLX	404.8	3,069.5	90	27.4	7.5	2.29	151	339	50.0	15.3	-152.86	-19.3	E
Mobil Electrophos Division														
	MOBELE1	405.6	3,079.4	24.0	7.3	3.0	0.91	376	464	10.6	3.2	-51.83	-6.53	E
	MOBELE2			20.0	6.1	3.0	0.91	376	464	25.3	7.7	-79.76	-10.05	E
	MOBELE3			60.0	18.3	6.0	1.83	170	350	22.3	6.8	-173.10	-21.81	E
	MOBELE4			84.0	25.6	7.0	2.13	91	306	22.9	7.0	-56.43	-7.11	E
	MOBELE5			60.0	18.3	2.3	0.7	120	322	75.0	22.9	-25.16	-3.17	E
	MOBELE6			96.0	29.3	7.0	2.13	106	314	28.0	8.5	-375.00	-47.25	E
Stauffer (Shutdown)														
	STAUFR1	325.6	3,116.7	24.0	7.3	3.0	0.91	376	464	10.6	3.2	-38.57	-4.86	E
	STAUFR2			60.0	18.3	2.3	0.7	120	322	75.0	22.9	-11.90	-1.50	E
	STAUFR3			161	49.0	3.9	1.2	143	335	11.8	3.6	-404.21	-50.93	E
	STAUFR4			84.0	25.6	7.0	2.13	91	306	22.9	7.0	-58.41	-7.36	E
	STAUFR5			84.0	25.6	3.0	0.91	120	322	22.9	7.0	-3.57	-0.45	E
US Agri-Chem Bartow														
	UAGBAR1	413.2	3,086.3	51.8	15.8	6.0	1.83	138	332	32.8	10.0	-27.06	-3.41	E
	UAGBAR2			95.0	29.0	7.0	2.12	89	305	24.6	7.5	-333.33	-42.00	E
Asphalt Pavers 3														
	ASPHALT3	359.9	3,162.4	40.0	12.2	4.5	1.37	219	377	34.7	10.6	17.86	2.25	C
Asphalt Pavers 4														
	ASPHALT4	361.4	3,168.4	28.0	8.5	3.5	1.08	184	357	35.9	11.0	17.86	2.25	C
Borden Hillsborough														
	BORDHIL	394.6	3,069.6	100	30.5	6.0	1.82	160	344	48.5	14.8	-51.43	-6.48	E
Borden Polk														
	BORDPLK	414.5	3,109.0	56.0	17.1	7.7	2.34	140	333	27.1	8.3	-41.98	-5.29	E
Couch Const-Zephyrhills (Asphalt)														
	COUCHZEP	390.3	3,129.4	20.0	6.1	4.5	1.38	300	422	68.9	21.0	28.10	3.54	C
Couch Const-Odessa (Asphalt)														
	COUCHODE	340.7	3,119.5	30.0	9.1	4.6	1.4	325	436	73.2	22.3	57.54	7.25	C
Dris Paving (Asphalt)														
	DRIS	340.6	3,119.2	40.0	12.2	10.0	3.05	151	339	21.2	6.5	1.83	0.23	C

STACK, OPERATING AND SO_2 EMISSIONS OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES AT THE CHASSAHOWITZKA NWA

Facility	Model ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Stack Parameters Height (ft)	Height (m)	Diameter (ft)	Diameter (m)	Temperature (°F)	Temperature (K)	Velocity (ft/s)	Velocity (m/s)	Emission Rate (lb/hr)	Emission Rate (g/s)	PSD [a] Source (C/E)
Dolime														
Dryers	DOLIMEDR	404.8	3,069.5	90.0	27.4	5.0	1.52	140	333	67.8	20.7	-45.08	-5.68	E
Boilers	DOLIMEBL			90.0	27.4	2.0	0.61	430	494	23.8	7.3	-35.87	-4.52	E
Evans Packing														
	EVANS	383.3	3,135.8	40.4	12.3	1.3	0.4	379	466	30.2	9.2	1.59	0.20	C
E R Jahna (Lime Dryer)														
	ERJAHNA	386.7	3,155.8	35.0	10.7	6.0	1.83	129	327	29.5	9.0	6.51	0.82	C
FDOC Boiler #3														
	FDOC	382.2	3,166.1	30.0	9.1	2.0	0.61	401	478	15.0	4.6	23.73	2.99	C
FL Mining and Materials Kiln														
	FMM	356.2	3,169.9	105	32.0	14.0	4.27	250	394	32.5	9.9	11.51	1.45	C
FPC - Crystal River														
Crystal River 1	CRYRIV1B	334.2	3,204.5	499	152.0	15.0	4.57	300	422	138.1	42.1	-2,492.06	-314.00	E
Crystal River 2	CRYRIV2B			502	153.0	16.0	4.88	300	422	138.1	42.1	-14,753.97	-1,859.00	E
Crystal River 4				585	178.2	25.5	7.77	253	396	68.9	21.0	8,006.35	1,008.80	C
Crystal River 5				585	178.2	25.5	7.77	253	396	68.9	21.0	8,006.35	1,008.80	C
	CRYRIV45			585	178.2	25.5	7.77	253	396	68.9	21.0	16,012.70	2,017.60	C
FPC Debary														
	DEBARY	467.5	3,197.2	50.0	15.2	13.8	4.21	1016	820	184.4	56.2	3,701.59	466.40	C
Hospital Corp of America														
Boiler #1				36.0	11.0	1.0	0.31	500	533	13.1	4.0	0.63	0.08	C
Boiler #2				36.0	11.0	1.0	0.31	500	533	13.1	4.0	0.63	0.08	C
	HCOA12	333.4	3,141.0	36.0	11.0	1.0	0.31	500	533	13.1	4.0	1.27	0.16	C
Kissimmee Utilities														
	KISSUT	447.7	3,127.9	40.0	12.2	10.0	3.05	718	654	95.5	29.1	233.33	29.40	C
Kissimmee Utilites Exist														
	KISSEX	460.1	3,129.3	60.0	18.3	12.0	3.66	300	422	124.7	38.0	254.76	32.10	C
Lake Cogen														

STACK, OPERATING AND SO_2 EMISSIONS OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES AT THE CHASSAHOWITZKA NWA

Facility	Model ID Name	UTM Coordinates East (km)	UTM Coordinates North (km)	Height (ft)	Height (m)	Diameter (ft)	Diameter (m)	Temperature (°F)	Temperature (K)	Velocity (ft/s)	Velocity (m/s)	Emission Rate (lb/hr)	Emission Rate (g/s)	PSD [a] Source (C/E)
	LAKECOGN	434.0	3,198.8	100	30.5	11.0	3.35	232	384	56.2	17.1	40.00	5.04	C
Mulberry Cogeneration														
CT	MULCNAA	413.6	3,080.6	125	38.1	15.0	4.57	219	377	61.9	18.9	100.79	12.70	C
Duct Burner	MULCNAB			125	38.1	6.5	1.98	300	422	30.5	9.3	5.16	0.65	C
New Pt Richey Hospital														
Boiler #1				36.0	11.0	1.0	0.31	520	544	12.7	3.9	0.48	0.06	C
Boiler #2				36.0	11.0	1.0	0.31	520	544	12.7	3.9	0.24	0.03	C
	NEWPTR12	331.2	3,124.5	36.0	11.0	1.0	0.31	520	544	12.7	3.9	0.71	0.09	C
Oman Construction														
	OMAN	359.8	3,164.9	25.0	7.6	6.0	1.83	165	347	20.6	6.3	16.59	2.09	C
Orlando Utilities Commission - Stanton														
Unit 1	OUC1	483.5	3,150.6	550	167.6	19.0	5.8	127	326	70.9	21.6	4,769.84	601.00	C
Unit 2 (24-hour)	OUC2			550	167.6	19.0	5.8	124	324	77.1	23.5	728.57	91.80	C
Overstreet Paving														
	OVERST	355.9	3,143.7	30	9.1	4.3	1.3	275	408	52.5	16.0	29.13	3.67	C
Pasco Cty RRF														
	PASCORRF	347.1	3,139.2	275	83.8	10.0	3.05	250	394	51.0	15.5	111.90	14.10	C
Pasco Cogen														
	PASCOGN	385.6	3,139.0	100	30.5	11.0	3.35	232	384	56.2	17.1	40.00	5.04	C
Reedy Creek Energy Services- EPCOT														
Generator 1				17.0	5.2	1.8	0.55	650	617	144.8	44.1	14.52	1.83	C
Generator 2				17.0	5.2	1.8	0.55	650	617	144.8	44.1	14.52	1.83	C
	EPCOT12	442.0	3,139.0	17.0	5.2	1.8	0.55	650	617	144.8	44.1	29.05	3.66	C
Reedy Creek Energy Services														
	REEDY	443.1	3,144.3	65.0	19.8	11.2	3.41	285	414	51.0	15.6	1.19	0.15	C
Ridge Cogeneration														
	RIDGE	416.7	3,100.4	325	99.1	10.0	3.05	170	350	47.6	14.5	109.52	13.80	C
PCS	SULACC&D	328.3	3368.8	149.896	45.7	5.215	1.59	181.13	356	94.136	28.7	766.7	96.6	C
	SULACE&F			200.08	61	9.512	2.9	181.13	356	30.504	9.3	833.3	105.0	C
	AUXBLRE			50.184	15.3	5.248	1.6	310.73	428	52.152	15.9	170.6	21.5	C

STACK, OPERATING AND SO_2 EMISSIONS OF SO_2 SOURCES INCLUDED IN THE PSD CLASS I AIR MODELING ANALYSES AT THE CHASSAHOWITZKA NWA

		UTM Coordinates		Stack Parameters										PSD [a]
	Model	East	North	Height		Diameter		Temperature		Velocity		Emission Rate		Source
Facility	ID Name	(km)	(km)	(ft)	(m)	(ft)	(m)	(°F)	(K)	(ft/s)	(m/s)	(lb/hr)	(g/s)	(C/E)
	AUXBLRB			35.096	10.7	4.789	1.46	382.73	468	31.16	9.5	174.6	22.0	C
	AUXBLRC&			103.976	31.7	6.494	1.98	382.73	468	49.856	15.2	332.4	41.9	C
	DAP2ZTR			140.056	42.7	8.003	2.44	125.33	325	42.968	13.1	5.5	0.7	C
	SULACA&B			200.08	61	5.904	1.8	170.33	350	50.84	15.5	-2416.7	-304.5	E
	SULACC&D			149.896	45.7	5.215	1.59	181.13	356	94.136	28.7	-600.0	-75.6	E
Suwannee American Cement	AMSUWCEM	321.4	3315.9	315	96.0366	9.42	2.872	205	369.261	46.4	14.146	28.4	3.6	C
Florida Rock Thompson S. Baker Cement Plant	FLROCCEM	348.4	3287.0	250	76.2195	9.42	2.872	356	453.15	47.8	14.573	17.7	2.2	C
JEA Southside	JEASS1	437.67	3353.89	133.5	40.7	8.0	2.44	343	446	50.8	15.5	418.3	52.7	E
	JEASS2	437.67	3353.91	133.5	40.7	8.0	2.44	343	446	50.8	15.5	418.3	52.7	E
	JEASS5B	437.682	3353.841	145.0	44.2	9.7	2.96	287	415	69.9	21.3	825.4	104.0	E
	JEASS5A	437.682	3353.849	145.0	44.2	9.7	2.96	287	415	69.9	21.3	825.4	104.0	E
	JEASS4	437.67	3353.962	143.3	43.7	10.7	3.25	275	408	60.7	18.5	873.0	110.0	E
	JEASS3	437.678	3353.933	133.5	40.7	10.0	3.05	304	424	44.0	13.4	633.3	79.8	E

[a] Comsuming (C) sources are sources that were constructed or modified after the PSD baseline date.
Expanding (E) sources are sources that have shutdown or have been modified since the baseline date.

[b] Higher emissions based on maximum allowable emissions. Lower emissions are based on maximum actual 3-hour and 24-hour average emissions for the two units from CEM data.

[c] Two of the four CT units (half of the total plant emissions) consume PSD increment and are included in the PSD increment analysis.
Higher emissions based on maximum allowable emissions. Lower emissions are based on maximum actual emissions for the two units.

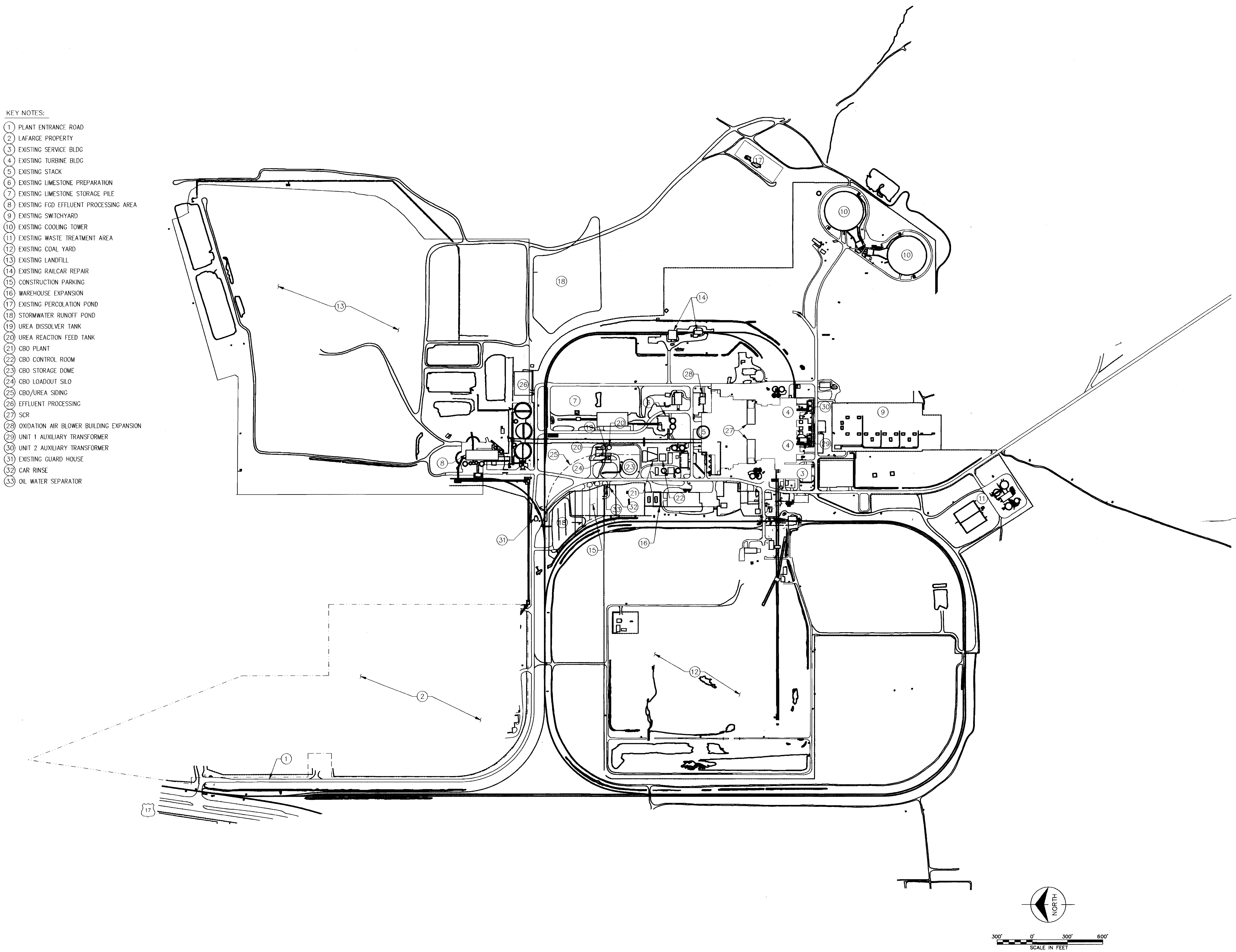
[d, e, f, g] Modeled as volume sources. Dimensions are based on methods presented in accordance with ISCST3 User's Manual, and are as follows:

	Physical Dimensions (ft)		Model Dimensions (ft)		
	Height (H)	Width (W)	Height (H or H/2)	Sigma Y (W/4.3)	Sigma Z (H/2.15)
d	8.0	210.0	8.0	48.8	3.72
e	8.0	210.0	8.0	48.8	3.72
f	8.0	210.0	8.0	48.8	3.72
g	36.0	125.0	36.0	29	16.7

APPENDIX C

SITE AND MODELING RECEPTORS AND BUILDING DATA USED IN THE MODELING

1070025-004 (1)



KEY NOTES:

1. PLANT ENTRANCE ROAD
2. LAFARGE PROPERTY
3. EXISTING SERVICE BLDG
4. EXISTING TURBINE BLDG
5. EXISTING STACK
6. EXISTING LIMESTONE PREPARATION
7. EXISTING LIMESTONE STORAGE PILE
8. EXISTING FGD EFFLUENT PROCESSING AREA
9. EXISTING SWITCHYARD
10. EXISTING COOLING TOWER
11. EXISTING WASTE TREATMENT AREA
12. EXISTING COAL YARD
13. EXISTING LANDFILL
14. EXISTING RAILCAR REPAIR
15. CONSTRUCTION PARKING
16. WAREHOUSE EXPANSION
17. EXISTING PERCOLATION POND
18. STORMWATER RUNOFF POND
19. UREA DISSOLVER TANK
20. UREA REACTION FEED TANK
21. CBO PLANT
22. CBO CONTROL ROOM
23. CBO STORAGE DOME
24. CBO LOADOUT SILO
25. CBO/UREA SIDING
26. EFFLUENT PROCESSING
27. SCR
28. OXIDATION AIR BLOWER BUILDING EXPANSION
29. UNIT 1 AUXILIARY TRANSFORMER
30. UNIT 2 AUXILIARY TRANSFORMER
31. EXISTING GUARD HOUSE
32. CAR RINSE
33. OIL WATER SEPARATOR

Burns & McDonnell

date JANUARY 31, 2006	detailed
designed R. SEDLACEK	checked

Seminole Electric COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

SEMINOLE GENERATING STATION
UNITS 1 AND 2

SITE PLAN

project 41262	contract
drawing GS1 — 1	rev.
sheet	of sheets

file $FILE$

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Jim Frauen
Seminole Electric Cooperative, Inc.
Payne Creek Generating Station
16313 North Dale Mabry Highway
Tampa, Florida 33618

2. Article
(Trans

PS Form

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Mr. Jim Frauen
Seminole Electric Cooperative, Inc.
Payne Creek Generating Station
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Tampa, Florida 33618

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1. Article Addressed to:

Mr. James Frauen
Manager, Environmental Affairs
Seminole Electric Cooperative, Inc.
P.O. Box 272000
Tampa, Florida 33688-2000

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Mr. James Frauen, Manager, Environ. Affairs

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Sent To Mr. James Frauen, Manager, Environ. Affairs
Street, Apt. No.; or PO Box No. P. O. Box 272000
City, State, ZIP+4 Tampa, Flroida 33688-2000

PS Form 3800, June 2002 See Reverse for Instructions

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

RECEIVED
APR 18 2006
BUREAU OF AIR REGULATION

CERTIFIED MAIL – RETURN RECEIPT REQUESTED

April 14, 2006

Mr. Michael P. Halpin, P.E.
Florida Department of Environmental Protection
Division of Air Resource Management
North Permitting Section
2600 Blair Stone Rd.
Tallahassee, FL 32399-2400

Re: Request for Additional Information
Pollution Controls Upgrade Project
Seminole Generating Station, Unit 1 and 2
DEP File 1070025-004-AC

Dear Mr. Halpin:

Seminole Electric Cooperative, Inc. (SECI) is in receipt of your letter dated March 1, 2006, which offers comments and requests additional information on the air permit application submitted for the above-referenced project. Specifically, the air application addresses several pollution control upgrades planned for Units 1 and 2 at the Seminole Generating Station (SGS) in Palatka, Florida. The Department's comments and questions are addressed below.

Department's Comment

1. The Department notes that on Table B-4 entitled "PSD Netting Analysis", one PSD Pollutant (CO) is expected to cause a BACT Review and every other PSD pollutant shows an increase. Please address the following issues relative to Table B-4:

   A. It is unclear which part of the project is responsible for the increase in CO emissions. Please provide specific information on where this increase originates. For example, if the applicant has deemed that the replacement burners will generate the additional CO, the Department will require support for this increase in the way of supplying detailed manufacturer burner specifications for the new as well as the existing burners. Upon receipt of such information, the Department will be better positioned to evaluate whether the selected burners meet the Department's BACT Standard for CO emissions.

SECI's Response

The original baseline data for CO contained in the application was based on an average of individual CO test data taken when co-firing petroleum coke with coal. While these tests reflect the operating conditions at the time, establishing an emissions limit for CO is problematic due to the inherent hour-to-hour variability of CO emissions. Indeed, CO emissions are influenced by many factors including fuel moisture content, excess air, pulverizer operation and fuel grindability, to name only a few.

The Department's recent adoption of Rule 62-210.370 Emissions Computation and Reporting, prescribes the approach for determining annual emissions through a hierarchy of technical methods. In summary, the presumptive hierarchy in Rule 62-210.370 is:

- continuous emission monitoring systems (CEMS) including continuous parameter monitoring systems (CPMS) and predictive emissions monitoring systems (PEMS),
- mass-balance, and
- emission factors (e.g., developed based on stack tests).

In 2001, CO monitors were added for operational purposes due to the NOx emissions requirements of the EPA acid rain program. These CO monitors were used to evaluate the combustion process and not specifically required for compliance or any other applicable requirement. The CO monitors are TECO Model 48C, which would meet the technical requirements for the instrument in 40 CFR Part 60 Appendix B, Performance Specification 4. Specification sheets regarding the instruments are included as Attachment 1 to this letter. The CO monitors were connected to existing probes and umbilicals for each unit. The calibration gases used are a dual-blend certified calibration gas for both SO_2 and CO, as supplied by Scott Specialty Gases.

In light of the known variability in individual CO stack test data and based on the provisions of Rule 62-210.370 F.A.C., the use of the existing continuous CO monitors for reporting historical emissions would be the most appropriate method for estimating baseline actual emissions for each unit.

The available CO CEMs data was recorded and is available as daily averages. In order to calculate the estimated annual CO emission rates in lb/MMBtu, data on generation (MWs), heat rate and gas flow were used. The gas flow data was used to determine the mass emissions of CO, while the generation and heat rate data were used to calculate heat input. The estimated CO emission rates in lb/MMBtu were then validated by comparing the data taken during the days stack testing was done to the daily averages from the estimated CO emission rates. The comparison of this data is summarized in the following table.

Comparison of Calculated CO Emission Rates

Date	Stack Test Average (lb/MMBtu)	CO CEMS Average (lb/MMBtu)
	Unit #1	
25-Jul-01	0.064	0.053
27-Jul-01	0.023	0.023
16-Jul-02	0.077	0.129

18-Jul-02	0.069	0.225
	Unit #2	
26-Jul-01	0.039	0.054
28-Jul-01	0.027	0.063
15-Jul-02	0.030	0.051
17-Jul-02	0.030	0.032

The stack test data obtained for 3 hourly test runs compares favorably with the CO CEMs data obtained over a 24-hour period and estimated using the procedure outlined above. Differences between the data are likely a result in differences in averaging times (3-hour runs compared to 24-hours) and calculation procedures (F-factor versus unit operating parameters). Accordingly, this comparison further supports the accuracy of the CEMs data.

The estimated baseline CO emission rates using CEMs data is summarized in the following table. The data availability is shown since for some certain periods of each year data was not available from the records.

	Unit 1			
Year	**Data (%)**	**Min (lb/MMBtu)**	**Max (lb/MMBtu)**	**Average (lb/MMBtu)**
2001	45.4	0.002	0.764	**0.189**
2002	70.5	0.002	1.060	**0.250**
2003	78.4	0.033	0.955	**0.408**
2004	78.1	0.012	1.006	**0.402**
2005	17.2	0.052	0.709	**0.350**
	Unit 2			
2001	49.5	0.004	0.798	**0.105**
2002	76.0	0.002	0.438	**0.116**
2003	79.0	0.006	0.712	**0.193**
2004	71.3	0.013	0.898	**0.199**
2005	83.1	0.002	0.767	**0.296**

The data availability is not related to monitor accuracy or operation. The gaps are simply due to the retrieval of the data. As the monitors were not installed for compliance, the data was not compiled in a typical data acquisition and handling system (DAHS) and was filed on PCs and discs. Seminole also recently upgraded the boiler controls for both units to a new DCS system and that has compounded the problem of retrieving old data. The Unit 1 upgrade occurred in 2005 and is one reason the recovery of data for that year was 17 percent. The monitors were operating properly; the problem was with the retrieval of all data records.

Calibrations are performed weekly, as opposed to daily for NOx and SO_2 compliance monitors. QA/QC is performed using the requirements of 40 CFR Part 75 on the probes, umbilicals, and calibration gas lines/connections. No major problems have ever existed with the monitors and calibrations are always minor. Seminole's onsite technicians did not keep calibration records, however they said that they did not recall ever having a major calibration issue, only minor adjustments. They indicated that the most frequent CEMS problems are with probe pluggage and problems with umbilical connections.

Relative accuracy tests audits (RATAs) have not been performed on the CO monitors and monitor operation has not consistently met the precise technical requirements of 40 CFR Part 60. The CO monitors were also not integrated into the compliance CEMs database where data collected from the CO CEMs could be used with data from the NOx CEMs (i.e., using O_2 concentrations and F-factors to calculate lb/MMBtu emission rates). However, since the CO CEMS are connected to the plant's existing compliance probes and umbilicals, this component of the system is operated according to EPA QA/QC requirements. The fact that RATAs are conducted on compliance monitors connected to these same lines confirms the integrity of this portion of the system.

The table above shows the minimum, maximum and average daily CO emission rates in lb/MMBtu. At your request, the calculation spreadsheet, containing the raw data, was sent to your attention via e-mail on April 11, 2006. The data support the highly variable nature of the CO emissions during operation. For the proposed upgrades Project, SECI is proposing to use the average estimated CO emission rates for 2003 and 2004 to calculate baseline actual emissions. For Units 1 and 2, the average emission rates for 2003-2004 are 0.405 lb/MMBtu and 0.196 lb/MMBtu, respectively. Using the heat input values for the 2003-2004 period (45,523,619 MMBtu/yr and 43,203,374 MMBtu/yr for Units 1 and 2, respectively) results in 9,219 TPY for Unit 1 and 4,229 TPY for Unit 2, or a total of 13,448 TPY for the CO emissions baseline.

Projected emissions after the upgrade Project would be based on a short-term emission rate of 0.2 lb/MMBtu for Units 1 and 2. This would result in an estimated 12,565 TPY, with a 100 percent capacity factor. Even when factoring in the relatively small contribution from the CBO unit of 123 TPY, Seminole should not exceed the baseline CO emission estimates. There is sufficient margin in the difference between the assumed worst-case capacity factor of 100 percent and the anticipated actual capacity factor of 85 percent that, even if short-term emissions were to exceed the anticipated 0.2 lb/MMBtu, emissions would be well below the estimated baseline on an annual basis. Vendor-supplied data indicates that CO emissions will consistently meet 200 ppm, which is roughly equivalent to 0.2 lb/MMBtu. Relevant excerpts from the vendor's response to the Request for Proposal are included as Attachment 2 to this letter. Please note that these data show a balancing of the CO and NOx emissions, and that further reductions of CO would result in a corresponding increase in NOx emissions.

This change in the method of calculating CO emissions requires that the emission tables in Appendix B of the application be updated. Accordingly, attached to this letter are revised Tables B-4 through B-4S (Attachment 3). In addition, the sections of the air application long form, relative to CO emissions, have been revised and attached, including Section H of the form which provides additional information on the CO CEMS (Attachment 4).

In the initial application, SECI had proposed a CO BACT level of 0.15 lb/MMBtu (or 1,076 pounds per hour) for CO emissions from Units 1 and 2, based on previous estimates of these units' CO baseline emissions. The additional CO baseline data discussed above, as well as projected actual CO emissions data (based on information supplied by the low NOx burner vendor), now lead to the conclusion that CO emissions will not increase as a result of this project and therefore PSD review, including a BACT determination for CO, is no longer necessary.

Future CO emissions will be monitored using the existing CO CEMs, to ensure the accuracy of SECI's projections that future emissions (for 10 years) following the changes do not result in a significant net increase on an annual basis. These CEMs will be integrated into the same database as the NO_x and SO_2 monitors such that emission rates in lb/MMBtu can be calculated using the F-Factor method in 40 CFR Part 60 Appendix A-7, Method 19. The monitor operation will be upgraded to meet the requirements of Appendix B, Performance Specification 4, including applicable RATA requirements.

Department's Comment

B. Contemporaneous Emissions Changes are defined in Rule 62-212.500(l)(e)3 as follows:

3. Contemporaneous Emissions Changes. An increase or decrease in the actual emissions, or in the quantifiable fugitive emissions, of a facility is contemporaneous with a particular modification if it occurs <u>within the period beginning five years prior to the date on which the owner or operator of the facility submits a complete application for a permit to modify the facility,</u> and ending on the date on which the owner or operator of the modified facility projects the new or modified facility to begin operation.

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

(34) "Baseline Actual Emissions" and "Baseline Actual Emissions for PAL" – The rate of emission, 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 <u>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.</u>

The Department notes that based upon the above definitions, the Baseline Actual Emissions which are allowable for forming the basis of a netting analysis, cannot precede February 13, 2001; however, emissions for calendar year 2000 have been included within your application. The Department requests that the applicant indicate which 24-month period(s) following January 2001 is to be utilized for the baseline emission calculations of the project.

SECI's Response

Calendar year 2000 data were included in the tables for informational purposes, but were not used in the baseline determination for any of the subject pollutants. As indicated in Tables B-4E through B-4S, SECI selected baseline years for each pollutant as follows (on a calendar-year basis):

Pollutant	*Baseline Years*	*Annual Emissions (TPY)*
SO_2	2004-2005	29,074
NOx	2001-2002	23,289
CO	2003-2004	4,976*
VOC	2002-2003	108
PM	2002-2003	822
PM_{10}	2002-2003	822
SAM	2002-2003	2,129

* *Note that, based on the previous response regarding the CO emissions baseline, the above figure (4,976 TPY) has now been revised to 13,448 TPY. The baseline years, however, are unchanged.*

SECI requests that calendar year data be utilized and, for the proposed NOx baseline period of 2001 - 2003, acknowledges that this approach results in two months (i.e., January and February of 2001) falling outside of the 5-year (60 month) contemporaneous window, based on the date of application filing. The Department has the authority to allow the use of this proposed NOx baseline, and it is appropriate to do so in this circumstance. Emissions data are routinely calculated and reported on a calendar-year basis and the calendar years chosen are representative of normal SECI operations. Further, Rule 62-212.300(1) (e) requires that post-project tracking of annual emissions be performed on a calendar-year basis. As further support, using the 24-month period from March 2001 to February 2003 (the 48th – 60th months immediately preceding the application submittal), would result in a NOx baseline of 22,670 TPY, a difference of only 619 TPY from the proposed calendar-year period of 23,289.

Finally, Seminole has further updated Table B-4 with respect to projected actual emissions for NOx, SO_2 and sulfuric acid mist. The initial application had provided projections that included an additional emissions increase in TPY, allowed under the rules while not triggering PSD review. Seminole has maintained that there will be no increase in these pollutants as a result of this project; therefore, this allowable emission increase, albeit small, is no longer included in the projections. In addition, the revised table corrects an inadvertent entry for the NOx projection that was the result of a glitch in the calculation spreadsheet. The revised value is 23,289 TPY, versus the previous estimate of 21,638 TPY.

Department's Comment

C. The following tables compare Departmental AOR records (TPY) of Unit 1 plus Unit 2 emissions to your TPY submittals:

   [See Department's Letter for Tabular Summaries]

   In summary, after SECI has elected the baseline period(s) from the table above, any TPY values which are shaded, represent areas where the applicant is required to provide further supporting data for the higher than AOR values. If stack test data is

> utilized (e.g. CO, PM, or H_2SO_4), the Department requires that certified summaries of all stack tests conducted during the subject calendar years be submitted; where AP-42 emissions factors are utilized, the Department requires calculations along with the supporting data (i.e. annual heat input by fuel type, etc). Where CEMS data is utilized, the Department requires that the applicant provide supporting documentation from EPA's Acid Rain database demonstrating the data matches. For the year 2005, the DARM/BAR is not in receipt of a copy of the AOR; hence no comparison can be made. Should SECI determine that 2004/2005 represents the baseline period, supporting data shall be required for all 2005 TPY emission data.

SECI's Response

As an initial matter, SECI utilized Part 75 CEMs data where available to develop its baseline emissions in accordance with the recently revised Rule 62-210.370, and this is the same data reported in the Acid Rain database.

The baseline data used for SO2 is the average of calendar years 2004 plus 2005. The 2005 AOR was submitted to the Department on February 27, 2006 with SO2 emissions of 31,444 tons which is the same value used in the Units 1 and 2 permit package. We are attaching a copy of SECI's 2005 AOR (Attachment 5) for your convenience.

As explained in the response above, the NOx baseline emissions are the average of calendar years 2001 plus 2002, based on CEMs (as required by Rule 62-210.370) and as reported in the Acid Rain database. The difference in the 2001/2002 AOR value (19,618 tons) and the SECI Application value (23,289 tons) is due to the different approaches, purposes and prescribed methodologies for the two requirements. The Department's AOR rules require annual emissions data to be calculated per fuel type, and this is best performed using fuel analysis data for the heat input and the CEMs annual emission rate in lb/MMBtu. The Acid Rain program, and the Department's baseline-emissions-calculation rules, are only looking for a facility-wide annual emission value in tons per year, and require the use of CEMs data for both the emission rate and heat input. The primary difference in the values used in the AOR and those reported in the application are related to the calculation of heat input, based on fuel weight/rate/heating value measurements and based on CEMS reported heat input, respectively.

The baseline data used for CO is the average of calendar years 2003 plus 2004. The difference in the AOR value (3230 tons) and the SECI Application value (4976 tons) is due to the same difference described above for NOx. The emission rates in lb/mmBtu were taken from stack test data submitted to the Department's Northeast District. However, as described earlier, Seminole's revised CO emissions estimates will now be based on the use of CEMS.

The baseline data used for VOC is the average of calendar years 2002 plus 2003. The values were based on fuel use quantities and the AP-42 emission factor of 0.06 lbs/ton of coal. The difference between the AOR value (107 tons) and the SECI Application value (108 tons) appears to be due to rounding.

Department's Comment

2. Please confirm the Department's understanding of the permit limits you are seeking for Units 1 & 2. The Department notes that in order to "carve out" emission reductions so as to make room for Unit 3, federally enforceable permit limits will need to be established for those pollutants where netting is desired.

Pollutant	Current Limit	Proposed Limit
SO_2	1.20 lb/MMBtu – 30 day rolling	0.67 lb/MMBtu – 30 day rolling
NOx	0.60 lb/MMBtu – 30 day rolling	0.46 lb/MMBtu – 30 day rolling
PM/PM_{10}	0.30 lb/MMBtu stack test	Same
CO	NA	0.146 lb/MMBtu
VOC	NA	0.06 lb/ton coal
SAM	NA	0.096 lb/MMBtu

SECI's Response

The Department's understanding of SECI's proposed emission limits for SO_2, NOx and PM/PM_{10}, as summarized in the above table, is correct. However, SECI had proposed a BACT level of 0.15 lb/MMBtu (or 1,076 pounds per hour) for CO emissions from Units 1 and 2, based on previous estimates of these units' CO baseline emissions. Additional data regarding the baseline estimates, as well as projected actual emissions data supplied by the low NOx burner vendor, now lead to the conclusion that PSD review, as well as a BACT determination, are no longer necessary. Finally, no limits were proposed for emissions of VOC and SAM. SECI does not anticipate short-term emissions of these two pollutants, as well as CO, to increase as a result of this project and, in accordance with Rule 62-212.300(1) (e), propose to track and submit to the Department, on an calendar-year basis for a period of ten years from the date the project is completed, information demonstrating that the modification did not result in significant emissions increases of these pollutants. The emissions computation and reporting will be based on the requirements of Rule 62-210.370 F.A.C. The basis for evaluating an emission increase is on a tons-per-calendar-year basis.

Department's Comment

Please note that EPA and NPS have been copied on your application, and should FDEP receive questions or comments from them, we will forward you a copy.

SECI's Response

SECI notes the Department's comment.

Department's Comment

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the state of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): "The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department........... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."

SECI's Response

As some of the above responses to the Department's request for additional information are of an engineering nature, Seminole has provided for both professional engineering and Responsible Official certifications that accompany this response package.

If you have any questions regarding any of the above responses, please don't hesitate to contact me at (813) 739-1213.

Sincerely,

Mike Roddy for

James R. Frauen
Manager of Environmental Affairs

Hamilton Oven, DEP-SCO
Chris Kirts, DEP-NED
Scott Osbourn, P.E., Golder Associates Inc.

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Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : **Michael P. Opalinski**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Seminole Electric Cooperative, Inc.** Street Address: **16313 North Dale Mabry Highway** City: **Tampa** State: **FL** Zip Code: **33618**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(813) 963-994** ext. Fax: **(813) 264-7906**
4.	Owner/Authorized Representative Email Address: **MOpalinski@seminole-electric.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.* M.P. Opalinski 4/14/06 Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **Scott H. Osbourn** Registration Number: **57557**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **5100 West Lemon St., Suite 114** City: **Tampa** State: **FL** Zip Code: **33609**
3.	Professional Engineer Telephone Numbers... Telephone: **(813) 287-1717** ext.**211** Fax: **(813) 287-1716**
4.	Professional Engineer Email Address: **sosbourn@golder.com**
5.	Professional Engineer Statement: *I, the undersigned, hereby certify, except as particularly noted herein*, that:* *(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and* *(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.* *(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.* *(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.* *(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.* Signature Date 4/14/06 (seal) SCOTT OSBOURN LICENSE NO. 57557 STATE OF FLORIDA PROFESSIONAL ENGINEER

* Attach any exception to certification statement.
**** Board of Professional Engineers Certificate of Authorization #00001670**

ATTACHMENT 1

CO CEMS SPEC SHEET

Product Specifications

Model 48C CO Analyzer

Gas Filter Correlation analyzer for ambient air monitoring and source emissions monitoring

For High Sensitivity Air Monitoring

The Model 48C Gas Filter Correlation (GFC) CO Analyzer measure low CO concentrations. It combines proven detection technology, easy-to-use menu-driven software and advanced diagnostics to offer unsurpassed flexibility and reliability.

The Model 48C is based on the principle that carbon monoxide (CO) absorbs infrared radiation at a wavelength of 4.6 microns. Because infrared absorption is a nonlinear measurement technique, it is necessary for the instrument electronics to transform the basic analyzer signal into a linear output. The Model 48C uses an exact calibration curve to accurately linearize the instrument output over any range up to a concentration of 10,000ppm.

The sample is drawn into the analyzer through the SAMPLE bulkhead. The sample flows through the optical bench. Radiation from an infrared source is chopped and then passed through a gas filter alternating between CO and N_2. The radiation then passes through a narrow bandpass interference and enters the optical bench where absorption by the sample gas occurs. The infrared radiation then exits the optical bench and falls on an infrared detector.

Key Features

- U.S. EPA Designated Method (RFCA-0981-054)
- Gas filter correlation selectivity
- Highly specific to CO
- Electronic diagnostic transducers
- Multi-line alpha numeric display
- Dedicated communications processor
- Remote performance diagnostics
- Self aligning optics

Preset Ranges	0-1, 2, 5, 10, 20, 50, 100, 200, 500, 1000, 2000, 5000 and 10000 ppm 0-1, 2, 5, 10, 20, 50, 100, 200, 500, 1000, 2000, 5000 and 10000mg/m³
Custom Ranges	0-1 to 10000 ppm 0-1 to 10000 mg/m³
Zero Noise	0.02 ppm RMS (30 second time setting)
Lower Detectable Limit	0.04 ppm
Zero Drift (24 hour)	<0.1 ppm
Span Drift (24 hour)	+/-1% full scale
Response Time	60 seconds (30 second time setting)
Precision	+/-0.1 ppm
Linearity	+/-1% full scale ≤ 1000 ppm +/-2.5% full scale > 1000 ppm
Sample Flow Rate	0.5-2 liters/min.
Operating Temperature	20°C - 30°C
Power Requirements	105-125 VAC @ 50/60Hz 220-240 VAC @ 50/60Hz 100 Watts
Size and Weight	16.75" (W) x 8.62' (H) x 23" (D), 45 lbs.
Outputs	Selectable voltages and RS-232 (standard) 4-20 mA isolated current RS-485 (optional)

Analyze • Detect • Measure • Control™

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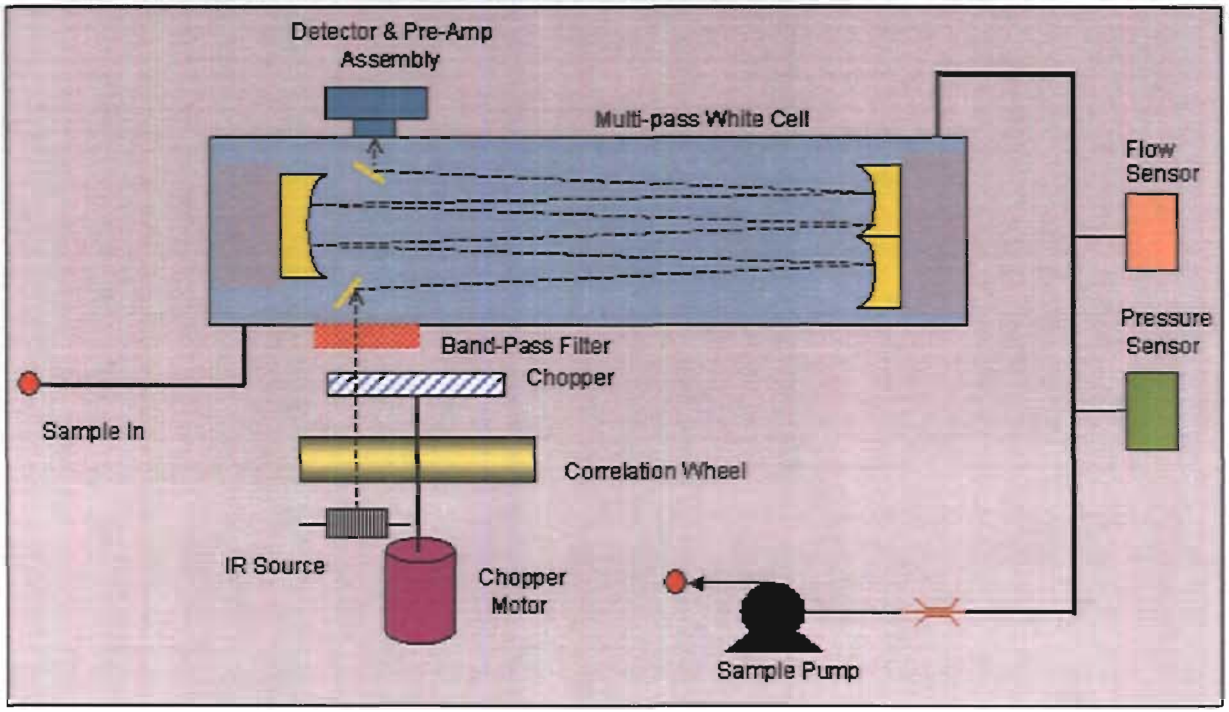
Comprehensive Service Solutions

To maintain optimal product performance, you need immediate access to experts worldwide, as well as priority status when your air quality equipment needs repair or replacement. Thermo Electron offers comprehensive, flexible support solutions for all phases of the product lifecycle. Through predictable, fixed-cost pricing, Thermo services help protect the return on investment (ROI) and total cost of ownership of your Thermo Electron air quality products.

Model 48C Flow Diagram



The CO gas filter acts to produce a reference beam which cannot be further attenuated by CO in the sample cell. The N_2 side of the filter wheel transparent to the infrared radiation and therefore produces a measure beam which can be absorbed by CO in the cell.

The chopped detector signal is modulated by the alternation between the two gas filters with an amplitude related to the concentration of CO in the sample cell. Other gases do not cause modulated by the detector signal since they absorb the reference and measure beams equally. Thus the GFC system responds specifically to CO.

ISO 9001

Lit_48CEID_8/05

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ATTACHMENT 2

LOW NOX BURNER VENDOR DATA

2A.6.0.2.3. Burner to Burner Coal Flow Differential Control Capability

Foster Wheeler guarantees that coal flow distribution control can be demonstrated to be controlled within +/- 15% from average on an individual mill basis based on the calibrated ECT system relative coal flow reading over a one (1) hour demonstration test, when firing the specified blend fuel at a maintained rate at a turbine inlet steam flow of 4,706,000 lbs/hr.

The predicted performance shall be furnished across the full operating range.

ITEM	VALUE
Main Steam Capacity	***4,706,621*** lb/hr at ***1000° F, see Note 2.***
NO_x, lb/MBtu (at economizer outlet, ***corrected to 3% O2)***	0.35
CO, ppmvd ***(corrected to 3% O2) by volume dry basis*** (at economizer outlet)	200
Fly Ash LOI	As indicated in Contract Section IV – Price, 1.1.
Combustion air pressure drop	As indicated in Contract Section IV – Price, 1.1.
Coal fineness	97.55% passing 50 mesh, 87.55% passing 100 mesh, 67.4% passing 200 mesh
Burner to burner air flow differential	No burner greater than 5% from average
Sec. Air front/rear windbox differential	Less than 5%
Burner to burner coal flow differential	No burner greater than 10% from average

The Contractor shall modify the system or pay the specified Liquidated Damages in accordance with Section I, Provision 49 until all Guarantees are met simultaneously at no less than 2.5% excess O2 (dry volume basis) as measured at economizer exit.

NOTE 1: Failure to meet the Guarantees at the stated excess air level following Combustion System Modifications shall result in liquidated damages and/ or draw upon the Letter of Credit to the extent of Contractor's inability to pay said liquidated damages per Section I – General Terms and Conditions

NOTE 2: The guaranteed steam capacity shall be determined by reading the 1st stage shell pressure. A 1st stage shell pressure of 2045 psi (top heater o/s), corresponds to a steam capacity (at the turbine) of 4,706,621 lb/hr.

2A.6.0.3 Performance Condition Requirements during Performance Testing

To ensure a technically proper evaluation of the Combustion System Modifications performance, it is necessary to have normal, non-transient unit and system operating conditions. The following requirements are the basis for the Performance Test.

4 DESCRIPTION OF PROPOSED COMBUSTION SYSTEM MODIFICATIONS

Based on SECI's requirements and Foster Wheeler's evaluation of the current unit operation, Foster Wheeler is proposing a NOx reduction system consisting of the following components.

Base Scope:

- Foster Wheeler Vortex Series Low NOx Burners
- Vortex Series OFA Registers (Omitted in Approach 2)
- System of "Jumper Ducts" to supplement OFA Air (Omitted in Approach 2)
- CFD Modeling of Air Flow and Combustion Process
- Redesigned Secondary Air and Hot Primary Flow Measurement Systems
- ~~*Fuel Injection* System, consisting of Electric Charge Transfer Coal Flow Measurement System (ECT) and Register Air Distribution Measurement (RADM)~~
- Coal Distribution Aids (three way coal distributors, Omitted if Optional RC Style Dymanic Classifiers are selected)
- Installation of All Above

Optional Scope:

- ~~Foster Wheeler RC Style Dynamic Classifiers~~
- ~~Plugging of the existing OFA ports with straight tube panels (Provided for Approach 2)~~
- Coal Piping Support Study
- ~~Supply New Forney Type IV/IR Inflame Flame Scanners for Main and Igniter service.~~
- ~~Installation of Selected Options Above~~

The new Foster Wheeler Low NOx burners, Overfire Air, and Fuel Injection Systems are described and shown in the following section. .The proposed modifications to Seminole Units 1 and 2 OFA System are described here, and also shown on Foster Wheeler proposal drawings presented in Appendix E. For the complete scope of supply, please refer to Section 5.0

4.1. Foster Wheeler Low NOx Burners

Foster Wheeler proposes installation of our latest burner design, the Vortex Series/Split Flame (VS/SF) burner. The changes described in this section are primarily for performance reasons but have the added benefit of improved burner adjustability and maintenance, as well as flow measurement capabilities. Figure 4-1 shows a sketch of the proposed Foster Wheeler VS/SF burner. Design details of the VS/SF burner are discussed in subsequent sections. The register will include new electric motor drives for the sleeve dampers. The burner cone damper and swirlers will be operated by manual screw drives, and only need to be set once during unit optimization.

Burner performance is closely related to the throat geometry and the velocities of air and coal. Under Approach 1 in which the new and improved OFA System will be provided, we have investigated the relationship of the existing burner throat size of 44" diameter with the proposed OFA System, and have determined that the existing tube panels do not need to be resized. All 36 burners per unit will be provided with new seal refurbishment, and will feature a ~~Nitride Silicon Carbide replacement~~ refractory design.

In the current modularized Foster Wheeler burner design, a rigid truss-like structure distributes the burner weight between the watertube wall and the front panel of the windbox.

The new burners will be designed with an elbow inlet, a more cost-effective approach, and current standard for Foster Wheeler. This modification eliminates coal layout problems common to scrolls, reduces future maintenance costs, and significantly reduces burner deck crowding. In addition, the elbow design results in lower primary air pressure drop, allowing for additional primary air flow margin.

Further, coal roping is essentially eliminated by design as compared with the scroll inlet, with added precautions provided in the form of a rope breaker bar. Finally, the internals of the coal elbow are coated with a high hardness refractory surfacing to minimize the effects of coal particle erosion.

The elbow inlet conversion necessitates some changes of the coal pipe immediately upstream of the burners to accommodate the simpler axial burner inlet. The current coal pipes approach the burner axes tangentially from a location close to the windbox. Typically, an elbow burner retrofit makes coal pipe changes necessary to meet the burner inlet that is away from the windbox and on the burner axis.

Foster Wheeler has developed a modification to the windbox to accommodate an axial elbow that minimizes the coal pipe changes and eliminates interference with platforms and steel. This greatly reduces retrofit costs. Our innovative design only requires changing the angle in the final bend of the coal pipes towards the burners. The fuel injector will use the Split Flame Tip fuel nozzle with inner adjustable tip to allow easy changes to the primary air exit velocity for optimized combustion. A schematic view of the proposed recessed Type VS/SF burner appears in Figure 4-1.

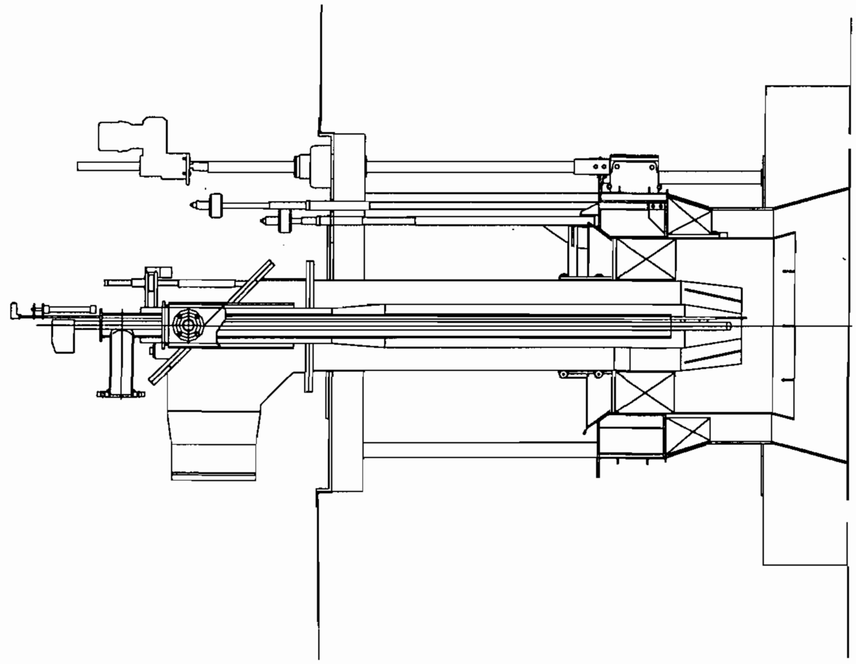


Figure 4-1: Vortex Series Burner

4.2 Vortex Register Description.

In 1971 Foster Wheeler began development of Low NOx burners for coal-fired boilers with the introduction of new NOx emission legislation in the US. The first generation Controlled Flow (CF) design burner was demonstrated in 1976. Three (3) years later, the second generation Controlled Flow/Split Flame Burner (CF/SF) was commercially operational. The latest burner design, the Vortex Series Low NOx Burner, is a result of a rigorous design review of the CF/SF design. The burner was radically simplified and the performance improved. The design goals for this burner were defined as follows:

- Combustion air flow and swirl must be independently controllable.
- Primary air/coal velocity must be adjustable to control staging between primary and secondary air streams.
- Primary and secondary air pressure drop must be within the range for existing burners, eliminating the need for additional fan head capacity.
- The design must have plug-in retrofitability, i.e., minimal pressure part changes, conduit rearrangement or major windbox modifications.
- The design must have the capability to fire a wide range of coals under high efficiency combustion <u>AND</u> low NOx conditions.
- The design must have low maintenance qualities including superior oxidation and wear resistance.

- The design must have reliable individual air flow measurement capability

Much of the above was achieved with the design of the now standard register, the Vortex Series Register. This unique register minimizes retrofit costs and provides exceptional performance with low maintenance. A sketch of a typical Vortex Series Burner shown in a split view is presented in Figure 4-2.

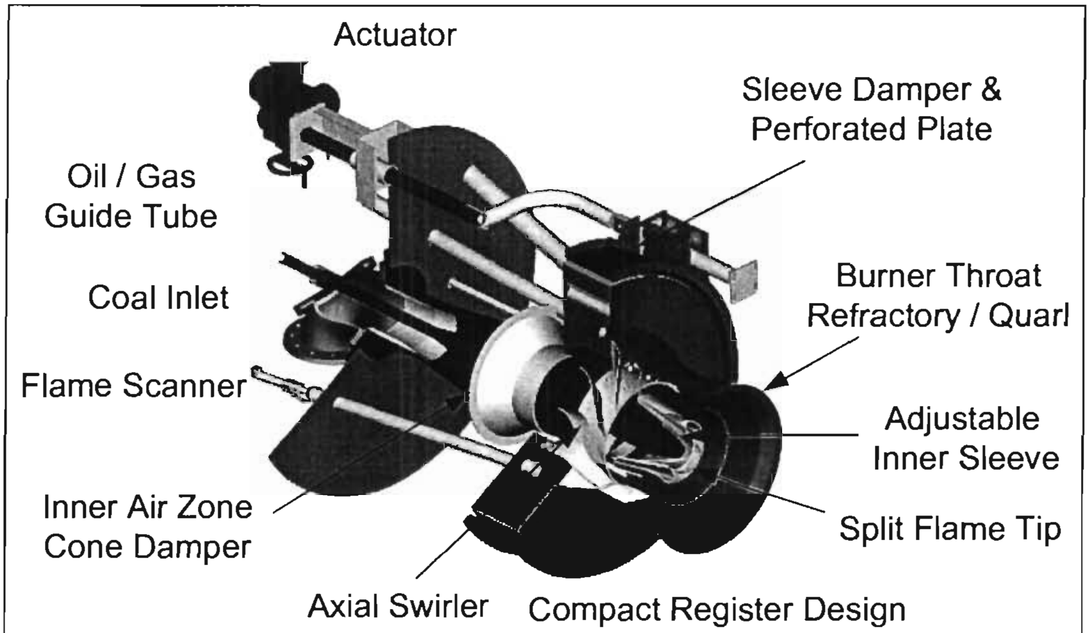
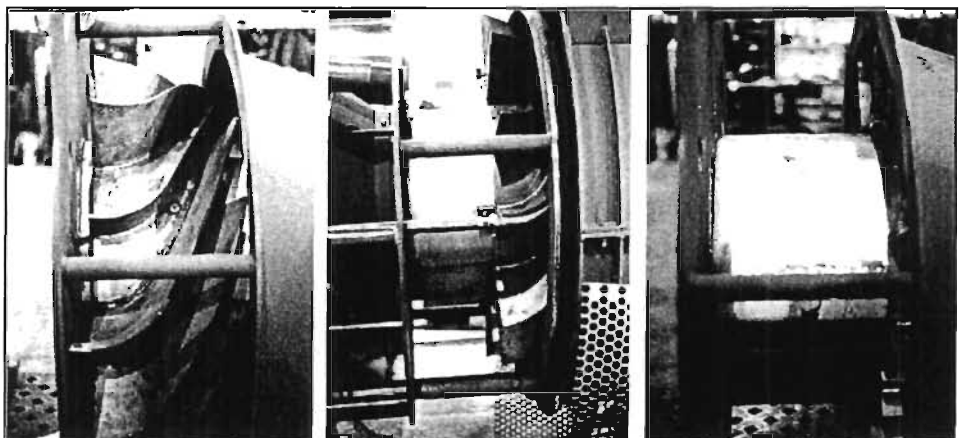


Figure 4-2: Vortex Series Burner Split View

The existing burner register generates swirl with a set of moving blades installed in the burner air paths. The radial blades are attached to linkages for synchronous movement. However, the multiple linkages and blades have the tendency to bind and break which results in deteriorating flame stability and NOx performance. The Vortex Series Register uses an axially movable swirl generator to produce air and fuel mixing. This ensures superior combustion, emission control, as well as reliable operation and flame stability over the entire boiler load range. All register components exposed to furnace radiation are fabricated from stainless steel to provide years of reliable longevity.

The Vortex Series Register has only three moving parts:

- The Vortex Series design eliminates the complexities associated with most burner air registers. Swirl is generated by a set of aerodynamically shaped fixed vanes that are mounted on a hub. The outer periphery of the swirler is conical and fits into a conical section of the register housing. When the swirler is inserted fully into the cone full swirl capability is achieved. By retracting the swirler partly, unswirled air bypasses the swirler and mixes downstream with the swirled air. The movable swirler results in a high degree of swirl adjustability, which provides significant flame-shape control. A high nickel-chrome alloy assures superior durability under all operating conditions. Once its position is established, no further adjustment should be necessary unless dictated by major fuel changes. The photographs below show the adjustment of the swirl generation with just one moving part; please refer to Figure 4-3.



Fully Retracted Axial Vanes - Minimum Swirl	Partially Inserted Axial Vanes - Moderate Swirl	Inserted Axial Vanes - Maximum Swirl

Figure 4-3: Vortex Series Register Principle

- Within the inner air register, a conical damper regulates the flow of secondary air around the perimeter of the coal jet to optimize combustion efficiency and flame position. The damper is moving in the axial direction.

- The sliding sleeve damper provides the air flow control to each burner. This circular sleeve damper also serves as the means to provide burner to burner balancing and the necessary cooling when burners are out of service. An electric drive is used for sleeve damper control.

4.2.1. Split Flame Nozzle and Fuel Injector

Foster Wheeler burners have a coal nozzle that uses the *split flame nozzle* technology. The Split Flame Coal Nozzle has for many years been a central component of Foster Wheeler's burner technology. This design segregates the coal into multiple concentrated streams producing a fuel staging effect, which inhibits NOx formation throughout the combustion process in a furnace, while at the same time promoting complete combustion of the fuel. The nozzle tip design forces the finer coal particles to devolatize early and ignites the fuel under oxygen-lean conditions reducing fuel nitrogen conversion. The unique configuration also causes controlled mixing of coal with secondary air further from the burner as the coal jets begin to dissipate into the secondary air, ensuring high combustion efficiency with the added benefit of NOx emissions reduction. Each nozzle tip is designed specifically for each application. The material used is a high nickel chromium alloy casting which has demonstrated over the years to provide superior oxidation and erosion resistance. Figure 4-4 shows the current generation of fuel staged four port split flame nozzle tip design.

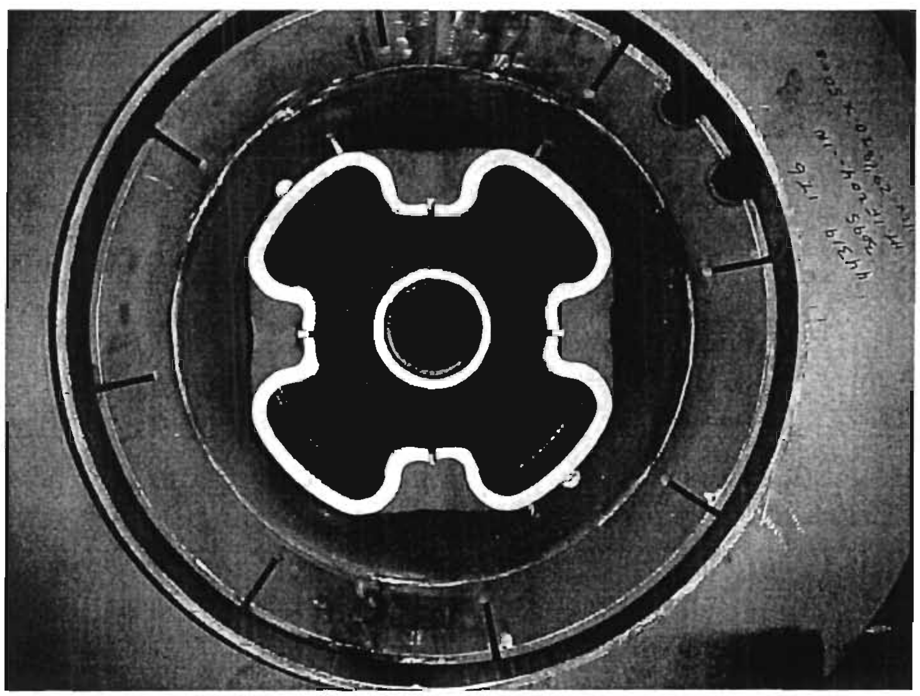


Figure 4-4: Split Flame Coal Nozzle Tip

The design features of the split flame tip are intended for coal with high slagging potentials, as are high sulfur, high iron containing coals such as Patiki, and petroleum coke in general.

One of the other unique features of the split flame coal nozzle is the ability to change the exit velocity of the primary air and coal jet. It should be noted that no other burner design offers this degree of flexibility. This adjustability is key for achieving optimized emissions; low NOx, low CO, and low LOI. It provides the flexibility to optimize individual burner exit velocities based their associated primary air flow differences. As a result, this feature also allows for firing a wider range of coals with a single burner design. The simple design of the adjustable tip allows for optimization of the primary air/coal velocity without changing primary air flow. The proper relationship between primary and secondary air is important for both NOx control and fly ash LOI management. Foster Wheeler's experience has shown that there is a NOx performance relationship between coal jet velocity and fly ash LOI.

Foster Wheeler includes special burner thermocouples for temperature monitoring. In current designs, three thermocouples are installed on the nozzle tip and inner barrel.

~~4.2.2. Foster Wheeler's Individual Burner Register Air Flow Measurement~~

The registers were designed to be equipped with a non-pitot tube based measurement of the secondary air flow. The system uses the pressure drop generated by the axial swirler to measure the air flow. We have applied for a patent for this novel approach. This system was developed in our air flow laboratory using full size registers. An example of a test set up is shown in Figure 4-5, in which are seen the various pressure tap and temporary sensing lines used to calibrate the system in preparation for installation at a jobsite.

4.3 Improved OFA System – Approach 1

The proposed OFA (Overfire Air System) system under Approach 1 will achieve lowest consistent NOx reductions as well as lowest CO and fly ash LOI, beyond the capabilities of the current design. Foster Wheeler will add two additional OFA registers to the front wall, and two to the rear wall for better overfire air flow distribution in the furnace. The new OFA registers will be located over the outer burner columns, in order to complement the Vortex Series Low NOx burner operation by providing more optimum penetration of overfire air above the entire burner zone. The existing original OFA registers will be replaced with Vortex Series OFA Registers. Additional OFA air will be supplied to the existing OFA windboxes from the tops of their respective main windboxes by means of six supplemental OFA Air *jumper ducts*. These ducts are shown in Figure 4-7 in green.

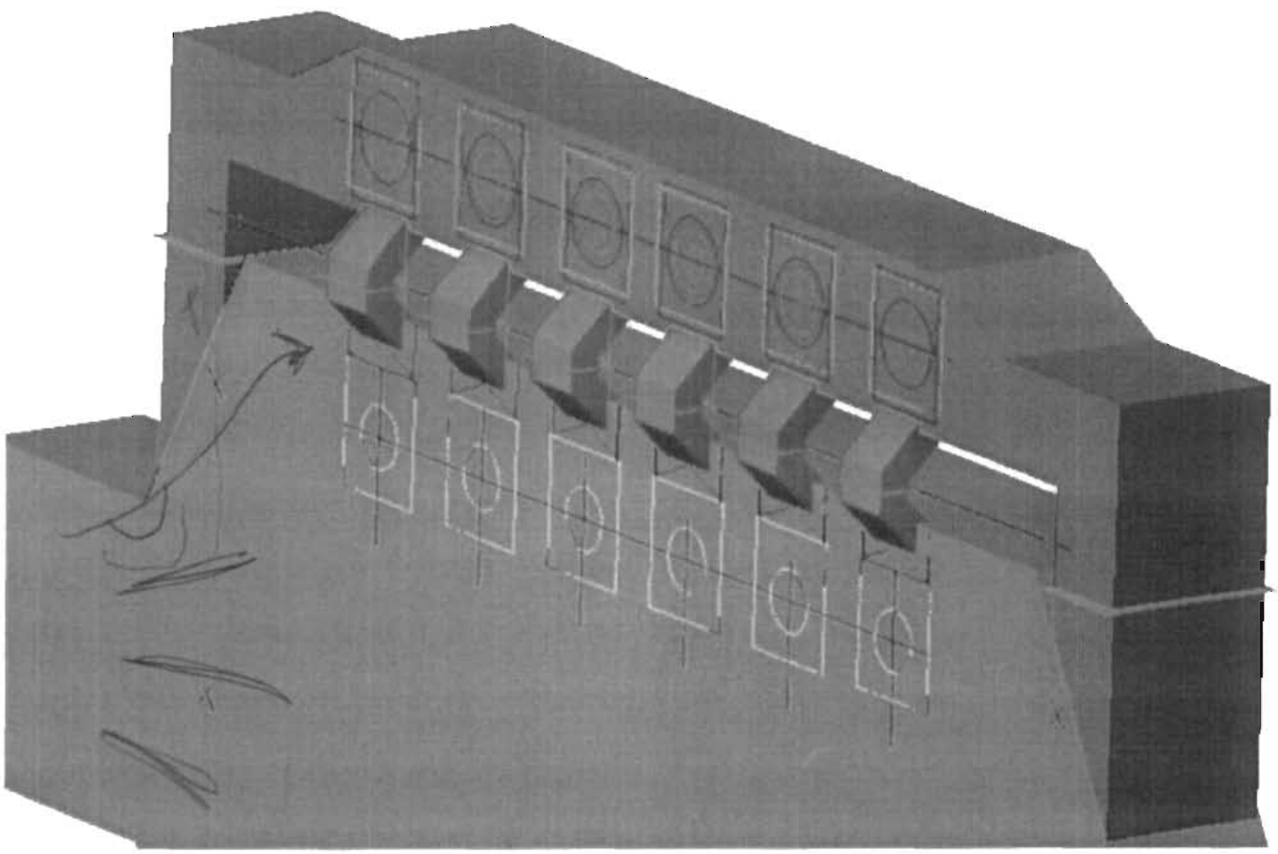


Figure 4-7: Concept Isometric View of OFA Jumper Ducts used to Supplement OFA from top of Main Windbox

Based on Foster Wheeler's review of the alternative flow-enhancement improvements described in the referenced EPRI CFD study, the level of improvements are not adequate to provide the additional OFA air required to achieve the low NOx levels target of 0.35 lb/M Btu, thus more flow area is required. The sizing and location of the OFA jumper ducts will be such that the additional OFA air required to achieve the lower target NOx is provided to the OFA registers.

Careful consideration for potential air starving of the top elevation of burners will be given in the CFD modeling, and appropriate deflection baffles will be incorporated into the design to mitigate these effects. Foster Wheeler has taken a similar approach on a very successful recent OFA project, where deflector baffles were introduced to *protect* the top outer burners in a conceptually similar OFA air duct extraction project.

The Vortex Series OFA registers are based on the same air flow principles as is the Vortex Series burner. An example of a Vortex Series OFA register is shown in Figure 4-8.

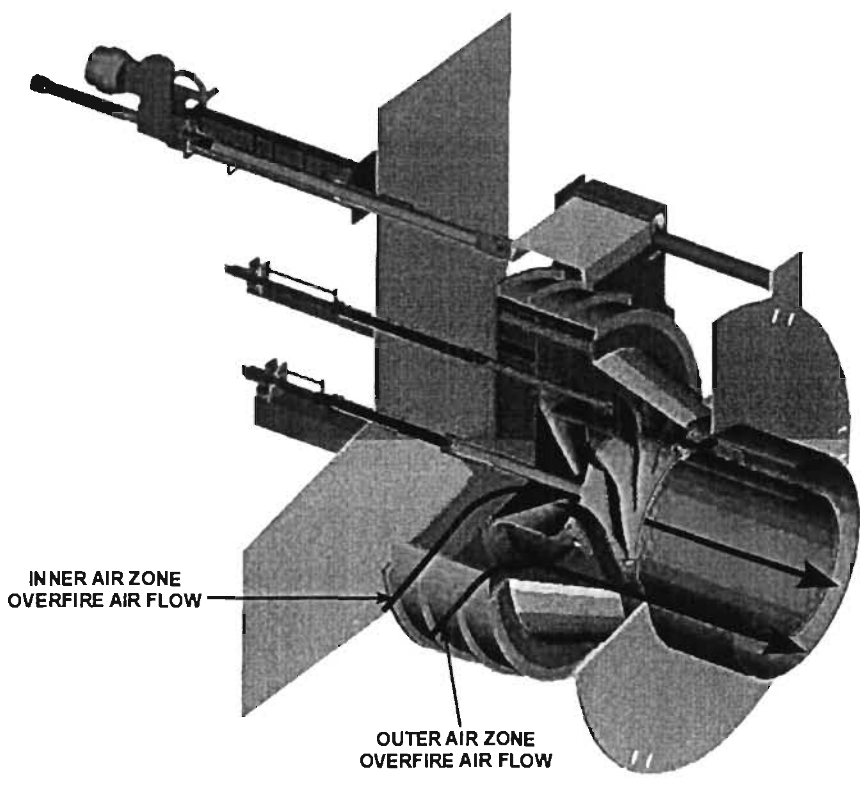


Figure 4-8: Vortex Series OFA Register Split View

The Vortex Series OFA Register also consists of a dual zone opening. The outer annulus can be swirled to increase mixing in the vicinity of the OFA register. By retracting the movable swirler from the conical housing, the degree of swirl can be reduced to produce a jet with high momentum and penetration. The inner zone can be closed with a conical damper to force more air through the outer zone. The swirler and the inner cone settings are manual adjustments that are set during optimization. The airflow through the register is modulated with the sleeve damper around the circumference of the register. This sleeve damper is motor operated to allow OFA bias across the boiler width and as well as reduce airflow at low load points.

With all of these features, the Foster Wheeler OFA System Vortex Register provides a high degree of adjustability creating effective mixing of air and flue gas at the right location within the furnace.

Included in each OFA Register will be a set of static pressure taps and sensor tubing leading to pressure taps at the front of the windbox. The purpose of these taps is to provide relative flow readings to assist in balancing the OFA flows during operation. As with the burner registers, this flow measurement feature forms the basis of the RADM (Register Air Distribution Monitoring) System, which along with the coal flow measurement (ECT) system forms the "Fuel Injection" air/fuel balancing system.

The complete set of proposal drawings appears in Appendix E.

4.4 Computational Fluid Dynamics (CFD) Study – Air Flow Model

Foster Wheeler will either begin with the existing EPRI model, or develop its own CFD model to examine the flow distribution throughout the combustion air system from the air heater outlet through the furnace exit. The model will be used to confirm the suitability of the ductwork and damper control modifications proposed as part of the project. The final detailed design of the OFA duct system improvements will be configured based on our experience in conjunction with the air flow CFD analysis to ensure that each OFA register receives the necessary amount of air, without negatively effecting the top elevation of burners. We propose some means of guide vanes as a means to help isolate these top burners, as well as provide appropriate *channels* for the additional OFA air to flow through. A complete report will be prepared and submitted for SECI review.

OFA or other ducts & dampers?

A sample of a previous duct air flow modeling study slide is presented in Figure 4-9.

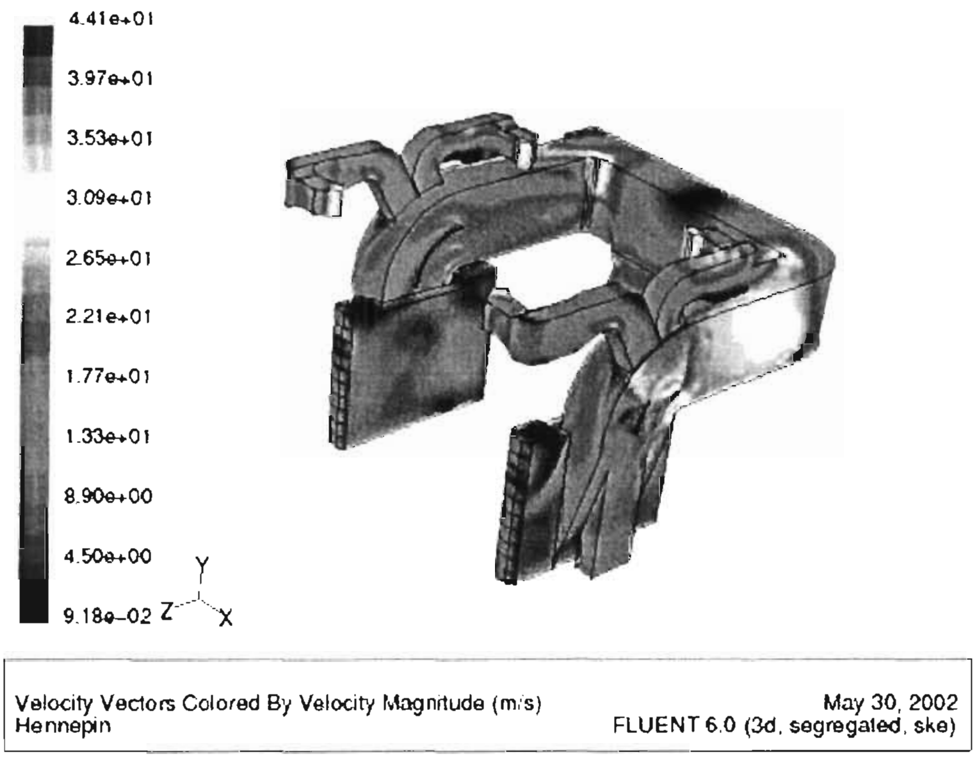


Figure 4-9: Sample CFD Modeling result for Air Flow in Secondary Air Ducts

4.5 Computational Fluid Dynamics (CFD) Study – Combustion Model

As requested, Foster Wheeler is offering a Computational Fluid Dynamics only (CFD) study of the furnace using the proposed Approach 1 OFA arrangement. The Combustion CFD model will extend from the burner fronts up through the leading edge of the first bank of the finishing superheater. Experienced engineers at Foster Wheeler Development Corporation will perform this work.

Vital to any OFA design is the penetration of the air jets into the furnace flue gas to promote mixing with the bulk of the rising flue gases. This is accomplished by choosing appropriate nozzle velocities and sizes. Foster Wheeler studied the jet penetration through physical modeling and with CFD analysis as part of our engineering standard development. This work yielded that our arrangement of OFA nozzles is in fact achieving a very good lateral air distribution and that empirical correlations for jet penetration depth are describing the model results very well.

A three-dimensional computational fluid dynamics model representing both of Seminole Units 1 & 2 furnaces will be set-up using the Foster Wheeler computer code, FW-FIRE. FW-FIRE contains comprehensive CFD furnace modeling capability that has been well validated for several furnace types including front wall-fired, opposed-wall fired, and tangentially fired units.

Two models will be constructed: 1) existing (present burners and OFA arrangement) and 2) proposed Approach 1 configuration (with FW VS/SF Burners and new "optimized" OFA). Output from the program will predict three-dimensional distributions of O2, CO, NOx, temperature, heat flux distribution and identify potential corrosion areas of the furnace walls flue gas temperature, mixing, and velocity. The second CFD model will also address different modes of the burner register settings which vary the burner's and OFA port's inner/outer air zones.

The number of "runs" will also address Approach 1 configuration at low, medium, and full loads.

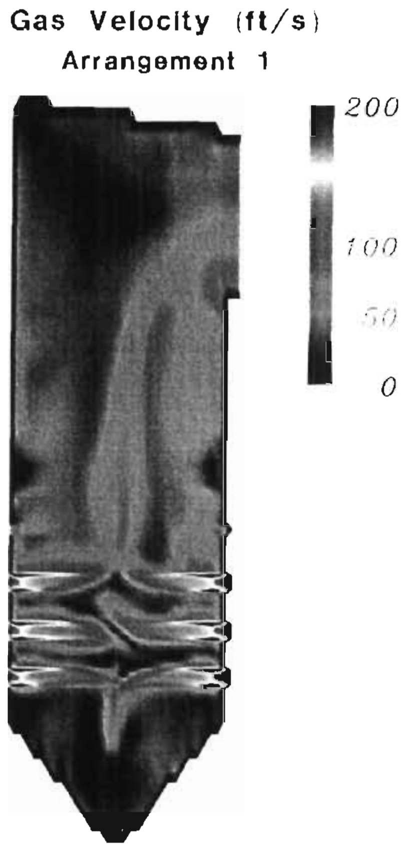


Figure 4-10: Sample CFD Model of an opposed wall fired unit with OFA System

Baseline operating boundary conditions will be applied to the FW-FIRE model of the existing furnace. Burner outlet conditions such as temperatures, velocities and air/coal loading will be input as boundary conditions at the furnace wall. The effects of the over-fired air (OFA) system will be identified by modifying the existing furnace model to include the OFA ports. A set of boundary conditions will be applied to simulate the OFA operation. The effective surface emissivity will be kept at the same value as that determined for the existing baseline case. The program output will be post-processed to determine the OFA penetration and mixing by analyzing the three dimensional distributions of O2, velocity, and char oxidation. FW-FIRE can also predict the effect of the OFA system on FEGT, surface heat absorption, and unburned carbon (UBC).

A report will be issued which will summarize the model boundary conditions and results for the existing configuration and the proposed Approach 1 OFA cases.

ATTACHMENT 3

UPDATED APPENDIX B EMISSION TABLES

Table B-4 PSD Netting Analysis

Pollutant	Units 1 and 2 Baseline Actual Emissions (tpy)	Projected Actual Emissions with Project (tpy)	Net Emissions Increase with Project (tpy)	Significant Emission Rates (tpy)	PSD Review Required?
SO_2	29,074	29,074	0.0	40	No
NOx	23,289	23,289	0.0	40	No
PM	822	846	24.4	25	No
PM_{10}	822	836	14.4	15	No
H_2SO_4	2,129	2,129	0.0	7	No
VOC	108	147	39.0	40	No
CO	13,448	12,565	0.0	100	No
Hg	0.065	0.065	<0.1	<0.1	No

* Units 1 and 2 baseline actual emissions are based on Tables B-4E through B-4S, as well as a Supplemental Submittal, dated April 14, 2006.

Table B-4A CBO Project - Fluidized Bed Emission Estimates

Pollutant	Emission Rate (lb/MMBtu)	CBO Emission Rate (lb/hr)	CBO Emission Rate (TPY) to Units 1 and 2	Material Handling Emissions (TPY)	Net Emissions Increase with Units 1 and 2 (TPY)	PSD Significant Emission Rates (TPY)	PSD Review Required?
SO_2	5.200	596.3	2,611.8		0*	40	No
NO_x	0.782	89.7	392.9		0*	40	No
CO	0.244	28.0	122.6		0*	100	No
VOCs	0.018	2.1	9.0		9.0	40	No
PM	0.024	2.8	12.1**	5.8	6.4**	25	No
PM_{10}	0.024	2.8	12.1**	5.8	6.4**	15	No

* See Table B-4. Projected actual emissions will be limited to baseline actual emissions.

** CBO emissions before Units 1 and 2 ESPs. Based on a conservative 95% removal, PM/PM10 emissions from the CBO FBC will be 0.6 TPY.

Table B-4B CBO Material Handling Emissions

Emission Source	Control Device	Exhaust Flow Rate (dscfm)	PM Emission Rate (gr/dscf)	PM Emission Rate (lb/hr)	PM Emission Rate (TPY)
Feed Fly Ash Silo	Baghouse	3,000	0.01	0.3	1.1
Product Fly Ash Storage Dome	Baghouse	6,000	0.01	0.5	2.3
Product Fly Ash Loadout Silo & Truck Loading	Baghouse	6,000	0.01	0.5	2.3
Fly Ash Fugitives (Truck Traffic)	Paved Roads; Watering	NA		0.1	0.2
Totals				1.4	5.8

Table B-4E Unit 1 Actual 2000 Emissions Rates

Average 2000 Data:		
Heat Input	49,418,601	MMBtu/yr (HHV)
Operating Hours	8,007	hr/yr
Coal Sulfur Content	2.90	weight percent S
Petcoke Sulfur Content	6.19	weight percent S
Coal Consumption	1,758,963	tpy
Petcoke Consumption	28,953	tpy
Coal Consumption	98.38	blend weight percent
Petcoke Consumption	1.62	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.603	3,721.5	14,899
NO_x*	0.449	2,834.5	11,094
CO†	0.144	594.2	3,557
VOCs‡	0.002	13.5	54
PM†	0.024	133.3	589
PM_{10}**	0.024	133.3	589
H_2SO_4 mist†	0.020	111.8	494

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2000
Golder, 2005

Table B-4F Unit 1 Actual 2001 Emissions Rates

Average 2001 Data:		
Heat Input	49,668,948	MMBtu/yr (HHV)
Operating Hours	7,704	hr/yr
Coal Sulfur Content	2.95	weight percent S
Petcoke Sulfur Content	5.88	weight percent S
Coal Consumption	1,665,401	tpy
Petcoke Consumption	66,037	tpy
Coal Consumption	96.19	blend weight percent
Petcoke Consumption	3.81	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.522	3,364.5	12,960
NO_x*	0.459	2,959.2	11,399
CO*	0.189	1,218.5	4,694
VOCs‡	0.002	13.6	52
PM†	0.012	75.3	290
PM_{10}**	0.012	75.3	290
H_2SO_4 mist†	0.029	187.7	723

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2001
Golder, 2005

Table B-4G Unit 1 Actual 2002 Emissions Rates

Average 2002 Data:		
Heat Input	48,594,869	MMBtu/yr (HHV)
Operating Hours	7,517	hr/yr
Coal Sulfur Content	3.01	weight percent S
Petcoke Sulfur Content	6.23	weight percent S
Coal Consumption	1,462,320	tpy
Petcoke Consumption	175,428	tpy
Coal Consumption	89.29	blend weight percent
Petcoke Consumption	10.71	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.457	2,952.8	11,098
NO_x*	0.444	2,870.3	10,788
CO*	0.250	1,616.2	6,074
VOCs‡	0.002	13.1	49
PM†	0.012	75.1	282
PM_{10}**	0.012	75.1	282
H_2SO_4 mist†	0.051	332.5	1,250

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2002
Golder, 2005

Table B-4H Unit 1 Actual 2003 Emissions Rates

Average 2003 Data:		
Heat Input	45,734,834	MMBtu/yr (HHV)
Operating Hours	8,011	hr/yr
Coal Sulfur Content	3.03	weight percent S
Petcoke Sulfur Content	5.97	weight percent S
Coal Consumption	1,620,199	blend weight percent
Petcoke Consumption	271,815	blend weight percent
Coal Consumption	85.63	blend weight percent
Petcoke Consumption	14.37	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.592	3,382.1	13,547
NO_x*	0.478	2,728.9	10,931
CO*	0.408	2,329.3	9,330
VOCs‡	0.002	14.3	57
PM†	0.020	111.5	446
PM_{10}**	0.020	111.5	446
H_2SO_4 mist†	0.044	251.0	1,005

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2003
Golder, 2005

Table B-4I Unit 1 Actual 2004 Emissions Rates

Average 2004 Data:		
Heat Input	45,312,403	MMBtu/yr (HHV)
Operating Hours	8,162	hr/yr
Coal Sulfur Content	3.07	weight percent S
Petcoke Sulfur Content	5.19	weight percent S
Coal Consumption	1,338,145	tpy
Petcoke Consumption	399,916	tpy
Coal Consumption	76.99	blend weight percent
Petcoke Consumption	23.01	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.630	3,499.1	14,280
NO_x*	0.476	2,642.6	10,784
CO*	0.402	2,231.8	9,108
VOCs‡	0.002	12.8	52
PM†	0.015	82.3	336
PM_{10}**	0.015	82.3	336
H_2SO_4 mist†	0.045	247.4	1,010

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2004
Golder, 2005

Table B-4J Unit 1 Actual 2005 Emissions Rates

Average 2000 Data:

Heat Input	47,228,429	MMBtu/yr (HHV)
Operating Hours	8,000	hr/yr
Coal Sulfur Content	3.07	weight percent S
Petcoke Sulfur Content	5.19	weight percent S
Coal Consumption	1,338,145	tpy
Petcoke Consumption	399,916	tpy
Coal Consumption	76.99	blend weight percent
Petcoke Consumption	23.01	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.646	3,816.0	15,264
NO_x*	0.474	2,798.3	11,193
CO*	0.350	2,066.2	8,265
VOCs‡	0.002	12.8	52
PM†	0.015	87.5	350
PM_{10}**	0.015	87.5	350
H_2SO_4 mist†	0.045	263.1	1,052

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2000
Golder, 2005

Table B-4K Unit 2 Actual 2000 Emissions Rates

Average 2000 Data:		
Heat Input	51,954,131	MMBtu/yr (HHV)
Operating Hours	7,878	hr/yr
Coal Sulfur Content	2.90	weight percent S
Petcoke Sulfur Content	6.19	weight percent S
Coal Consumption	1,679,618	tpy
Petcoke Consumption	74,443	tpy
Coal Consumption	95.76	blend weight percent
Petcoke Consumption	4.24	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.688	4,536.7	17,870
NO_x*	0.390	2,627.1	10,131
CO†	0.432	1,122.9	11,223
VOCs‡	0.002	13.5	53
PM†	0.009	51.6	236
PM_{10}**	0.009	51.6	236
H_2SO_4 mist†	0.018	104.2	474

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2000
Golder, 2005

Table B-4L Unit 2 Actual 2001 Emissions Rates

Average 2001 Data:		
Heat Input	55,355,534	MMBtu/yr (HHV)
Operating Hours	8,244	hr/yr
Coal Sulfur Content	2.95	weight percent S
Petcoke Sulfur Content	5.88	weight percent S
Coal Consumption	1,762,839	tpy
Petcoke Consumption	107,738	tpy
Coal Consumption	94.24	blend weight percent
Petcoke Consumption	5.76	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.610	4,093.2	16,872
NO_x*	0.470	3,155.9	13,009
CO*	0.105	705.0	2,906
VOCs‡	0.002	13.7	56
PM†	0.008	50.5	208
PM_{10}**	0.008	50.5	208
H_2SO_4 mist†	0.018	123.3	508

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2001
Golder, 2005

Table B-4M Unit 2 Actual 2002 Emissions Rates

Average 2002 Data:		
Heat Input	49,488,475	MMBtu/yr (HHV)
Operating Hours	8,033	hr/yr
Coal Sulfur Content	3.01	weight percent S
Petcoke Sulfur Content	6.23	weight percent S
Coal Consumption	1,514,054	tpy
Petcoke Consumption	169,260	tpy
Coal Consumption	89.94	blend weight percent
Petcoke Consumption	10.06	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.525	3,234.7	12,992
NO_x*	0.460	2,896.6	11,382
CO*	0.116	714.6	2,870
VOCs‡	0.002	12.6	50
PM†	0.018	109.2	439
PM_{10}**	0.018	109.2	439
H_2SO_4 mist†	0.052	318.5	1,279

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2002
Golder, 2005

Table B-4N Unit 2 Actual 2003 Emissions Rates

Average 2003 Data:		
Heat Input	46,823,323	MMBtu/yr (HHV)
Operating Hours	8,243	hr/yr
Coal Sulfur Content	3.03	weight percent S
Petcoke Sulfur Content	5.97	weight percent S
Coal Consumption	1,628,641	tpy
Petcoke Consumption	311,406	tpy
Coal Consumption	83.95	blend weight percent
Petcoke Consumption	16.05	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.590	3,351.4	13,813
NO_x*	0.454	2,578.9	10,629
CO*	0.193	1,096.3	4,518
VOCs‡	0.003	14.2	59
PM†	0.020	115.5	476
PM_{10}**	0.020	115.5	476
H_2SO_4 mist†	0.031	175.5	723

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2003
Golder, 2005

Table B-4O Unit 2 Actual 2004 Emissions Rates

Average 2004 Data:		
Heat Input	39,583,424	MMBtu/yr (HHV)
Operating Hours	7,033	hr/yr
Coal Sulfur Content	3.07	weight percent S
Petcoke Sulfur Content	5.19	weight percent S
Coal Consumption	1,128,531	tpy
Petcoke Consumption	324,146	tpy
Coal Consumption	77.69	blend weight percent
Petcoke Consumption	22.31	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.628	3,533.1	12,424
NO_x*	0.464	2,611.5	9,183
CO*	0.199	1,120.0	3,939
VOCs‡	0.002	12.5	44
PM†	0.013	74.6	262
PM_{10}**	0.013	74.6	262
H_2SO_4 mist†	0.031	175.9	618

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2004
Golder, 2005

Table B-4P Unit 2 Actual 2005 Emissions Rates

Average 2004 Data:		
Heat Input	50,573,650	MMBtu/yr (HHV)
Operating Hours	7,033	hr/yr
Coal Sulfur Content	3.07	weight percent S
Petcoke Sulfur Content	5.19	weight percent S
Coal Consumption	1,128,531	tpy
Petcoke Consumption	324,146	tpy
Coal Consumption	77.69	blend weight percent
Petcoke Consumption	22.31	blend weight percent

Pollutant	Emissions Rate		
	lb/MMBtu	lb/hr	tpy
SO_2*	0.640	4,601.2	16,180
NO_x*	0.476	3,422.9	12,037
CO*	0.296	2,128.5	7,485
VOCs‡	0.002	12.5	44
PM†	0.013	95.3	335
PM_{10}**	0.013	95.3	335
H_2SO_4 mist†	0.031	224.7	790

*CEMS Data.
†Stack test data.
‡AP-42 emission factor.
**PM_{10} assumed equal to PM.

Sources: AOR, 2004
Golder, 2005

Table B-4Q Unit 1 Highest 2 Year Average

Pollutant	2000-2001 (tpy)	2001-2002 (tpy)	2002-2003 (tpy)	2003-2004 (tpy)	2004-2005 (tpy)	Highest 2 Year Average
SO_2	13,930	12,029	12,323	13,914	14,772	14,772
NO_x	11,247	11,094	10,859	10,857	10,989	11,247
CO	4,125	5,384	7,702	9,219	8,686	9,219
VOCs	53	51	53	55	52	55
PM	439	286	364	391	343	439
PM_{10}	439	286	364	391	343	439
H_2SO_4 mist	609	987	1,128	1,007	1,031	1,128
Heat Input	49,543,775	49,131,909	47,164,852	45,523,619	46,270,416	49,543,775

Table B-4R Unit 2 Highest 2 Year Average

Pollutant	2000-2001 (tpy)	2001-2002 (tpy)	2002-2003 (tpy)	2003-2004 (tpy)	2003-2004 (tpy)	Highest 2 Year Average
SO_2	17,371	14,932	13,403	13,119	14,302	17,371
NO_x	11,570	12,195	11,006	9,906	10,610	12,195
CO	7,065	2,888	3,694	4,229	5,712	7,065
VOCs	55	53	55	51	44	55
PM	222	323	457	369	299	457
PM_{10}	222	323	457	369	299	457
H_2SO_4 mist	491	894	1,001	671	704	1,001
Heat Input	53,654,833	52,422,005	48,155,899	43,203,374	45,078,537	53,654,833

Table B-4S Highest Baseline 2-Year Average

Pollutant	2000-2001 (tpy)	2001-2002 (tpy)	2002-2003 (tpy)	2003-2004 (tpy)	2004-2005 (tpy)	Highest 2 Year Average
SO_2	31,301	26,961	25,725	27,032	29,074	31,301
NO_x	22,817	23,289	21,865	20,764	21,599	23,289
CO	11,190	8,272	11,397	13,447	14,398	14,398
VOCs	108	104	108	106	96	108
PM	661	610	822	760	642	822
PM_{10}	661	610	822	760	642	822
H_2SO_4 mist	1,100	1,880	2,129	1,678	1,735	2,129
Heat Input	103,198,607	101,553,913	95,320,751	88,726,992	91,348,953	103,198,607

ATTACHMENT 4

AIR APPLICATION LONG FORM- REVISED PAGES

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2,904.7** lb/hour **9,219** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.405 lb/MMBtu** Reference: **CEMS Data**	7. Emissions Method Code:
8. Calculation of Emissions: **See Supplemental Submittal, dated April 14, 2006, and Appendix B-4** **The emission factor (0.405 lb/MMBtu) is based on 2003-2004 data. The TPY value is based on an annual heat input value of 45,523,619 MMBtu/yr (2003-2004 two-year average). Total baseline emissions from Units 1 and 2 combined are 13,448 TPY.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **There is no allowable CO emissions limitation.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **12,565** tons/yr	4. Equivalent Allowable Emissions: lb/hour **12,565** tons/year
5. Method of Compliance: **See Supplemental Submittal, dated April 14, 2006 and Appendix B-4.**	
6. Allowable Emissions Comment (Description of Operating Method): **The TPY estimate reflects an assumed short-term rate of 0.2 lb/MMBtu for Units 1 and 2 and a 100 percent capacity factor for both units (i.e., 7,172 MMBtu/hr from each unit; 8,760 hr/yr).**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 5

1. Parameter Code: **SO2**	2. Pollutant(s): **SO2**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Thermo-Environmental Instruments, inc.** Model Number: **43B** Serial Number: **43B-46935-277**	
5. Installation Date: **05/31/1994**	6. Performance Specification Test Date: **10/19/1994**
7. Continuous Monitor Comment: **40 CFR 60, Subpart Da and 40 CFR Part 75.**	

Continuous Monitoring System: Continuous Monitor 2 of 5

1. Parameter Code: **NOX**	2. Pollutant(s): **NOX**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Thermo-Environmental, Inc.** Model Number: **42D** Serial Number: **42D-46961-277**	
5. Installation Date: **05/31/1994**	6. Performance Specification Test Date: **10/19/1994**
7. Continuous Monitor Comment: **40 CFR 60, Subpart Da and 40 CFR Part 75.**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 3 of 5

1. Parameter Code: **VE**	2. Pollutant(s): **VE**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **KVB/MIP** Model Number: **LM3086EPA3**	Serial Number: **730097**
5. Installation Date: **05/31/1994**	6. Performance Specification Test Date: **11/07/1995**
7. Continuous Monitor Comment: **40 CFR 60, Subpart Da and 40 CFR Part 75.**	

Continuous Monitoring System: Continuous Monitor 4 of 5

1. Parameter Code:	2. Pollutant(s): **CO2**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo-Environmental Instruments, Inc.** Model Number: **41H**	Serial Number: **41H-42927-268**
5. Installation Date: **05/31/1994**	6. Performance Specification Test Date: **10/19/1994**
7. Continuous Monitor Comment: **40 CFR Part 75.**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 5 of 5

1. Parameter Code: **CO**	2. Pollutant(s): **CO**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **Thermo Electron Corp** Model Number: **48C**	Serial Number: **48C-67478-356**
5. Installation Date: **01/01/2001**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Installed for diagnostic purposes. Future operation will be in accordance with 40 CFR Part 60.**	

Continuous Monitoring System: Continuous Monitor of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1,405.7** lb/hour **4,229** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.196 lb/MMBtu** Reference: **CEMS Data**	7. Emissions Method Code:

8. Calculation of Emissions:
See Supplemental Submittal, dated April 14, 2006, and Appendix B-4

The emission factor (0.196 lb/MMBtu) is based on 2003-2004 data. The TPY value is based on an annual heat input value of 43,203,374 MMBtu/yr (2003-2004 two-year average). Total baseline emissions from Units 1 and 2 combined are 13,448 TPY.

9. Pollutant Potential/Estimated Fugitive Emissions Comment:
There is no allowable CO emissions limitation.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **12,565** tons/yr	4. Equivalent Allowable Emissions: lb/hour **12,565** tons/year
5. Method of Compliance: **See Supplemental Submittal, dated April 14, 2006 and Appendix B-4.**	
6. Allowable Emissions Comment (Description of Operating Method): **The TPY estimate reflects an assumed short-term rate of 0.2 lb/MMBtu for Units 1 and 2 and a 100 percent capacity factor for both units (i.e., 7,172 MMBtu/hr from each unit; 8,760 hr/yr).**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 5

1. Parameter Code: **SO2**	2. Pollutant(s): **SO2**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo-Environmental Instruments, inc.** Model Number: **43B**	Serial Number: **43B-46935-277**
5. Installation Date: **05/31/1994**	6. Performance Specification Test Date: **10/19/1994**
7. Continuous Monitor Comment: **40 CFR 60, Subpart Da and 40 CFR Part 75.**	

Continuous Monitoring System: Continuous Monitor 2 of 5

1. Parameter Code: **NOX**	2. Pollutant(s): **NOX**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo-Environmental, Inc.** Model Number: **42D**	Serial Number: **42D-46961-277**
5. Installation Date: **05/31/1994**	6. Performance Specification Test Date: **10/19/1994**
7. Continuous Monitor Comment: **40 CFR 60, Subpart Da and 40 CFR Part 75.**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 3 of 5

1. Parameter Code: **VE**	2. Pollutant(s): **VE**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **KVB/MIP** Model Number: **LM3086EPA3**	Serial Number: **730097**
5. Installation Date: **05/31/1994**	6. Performance Specification Test Date: **11/07/1995**
7. Continuous Monitor Comment: **40 CFR 60, Subpart Da and 40 CFR Part 75.**	

Continuous Monitoring System: Continuous Monitor 4 of 5

1. Parameter Code:	2. Pollutant(s): **CO2**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo-Environmental Instruments, Inc.** Model Number: **41H**	Serial Number: **41H-42927-268**
5. Installation Date: **05/31/1994**	6. Performance Specification Test Date: **10/19/1994**
7. Continuous Monitor Comment: **40 CFR Part 75.**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 5 of 5

1. Parameter Code: **CO**	2. Pollutant(s): **CO**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **Thermo Electron Corp** Model Number: **48C**	Serial Number: **48C-67477-356**
5. Installation Date: **01/01/2001**	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Installed for diagnostic purposes. Future operation will be in accordance with 40 CFR Part 60.**	

Continuous Monitoring System: Continuous Monitor of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

ATTACHMENT 5

SEMINOLE 2005 AOR

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

February 27, 2006

SENT BY OVERNIGHT MAIL

Florida Department of Environmental Protection
Division of Air Resources Management, MS5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: Seminole Electric Cooperative, Inc.
Seminole Generating Station - Facility ID 1070025
Payne Creek Generating Station - Facility ID 0490340
2005 Annual Operating Report Forms

Dear Sir or Madam:

Pursuant to the requirements of Chapter 62-210.370(3), Florida Administrative Code (F.A.C.) and in accordance with Department guidance regarding submittal of the 2005 Annual Operating Report (AOR), please find enclosed the first two pages of the 2005 AOR Forms for the Seminole Electric Cooperative, Inc. (SECI) Seminole Generating Station (Facility ID No. 1070025) and the Payne Creek Generating Station (Facility ID No. 0490340). The second page of each report has been signed and dated by the owner or authorized representative. The Electronic AOR files have been transferred electronically to the Department via the Internet.

Please contact me at (813) 739-1224 if there are any questions regarding the SECI 2005 AORs.

Sincerely,

Mike Roddy
Senior Environmental Engineer

Enclosures

Department of Environmental Protection

Division of Air Resources Management

ANNUAL OPERATING REPORT FOR AIR POLLUTANT EMITTING FACILITY

See Instructions for Form No. 62-210.900(5).

I. FACILITY REPORT

A. REPORT INFORMATION

1. Year of Report **2005**	2. Number of Emissions Units in Report **8**

B. FACILITY INFORMATION

1. Facility ID **1070025**	2. Facility Status **ACTIVE**	3. Date of Permanent Facility Shutdown
4. Facility Owner/Company Name **SEMINOLE ELECTRIC COOPERATIVE, INC.**		
5. Site Name **SEMINOLE GENERATING STATION**		
6. Facility Location Street Address or Other Locator: **890 NORTH U.S. HIGHWAY 17** City: **PALATKA** County: **PUTNAM** Zip Code: **32177-8647**		
7. Facility Compliance Tracking Code **A**	8. Governmental Facility Code **0**	9. Facility SIC(s) **4911**
10. Facility Comment **TITLE V (MAJOR & NSPS)**		

C. FACILITY HISTORY INFORMATION

1. Change in Facility Owner/ Company Name During Year?	Previous Name	2. Date of Change

DEP Form No. 62-210.900(5) - Form
Effective: 2/11/99

Facility ID : 1070025

D. OWNER/CONTACT INFORMATION

1. Owner or Authorized Representative			
Name and Title **MICHAEL P. OPALINSKI** **VICE PRESIDENT OF TECHNICAL SERVICES**			
Mailing Address			
Organization/Firm:	**SEMINOLE ELECTRIC COOPERATIVE, INC.**		
Street Address:	**POST OFFICE BOX 272000**		
City:	**TAMPA**		
State:	**FL**	Zip Code:	**33688-2000**
Telephone:	**(813) 963-0994 1233**	Fax:	**(813) 264-7906**

2. Facility Contact			
Name and Title **BRENDA SHIVER** **ENVIRONMENTAL COMPLIANCE SPECIALIST**			
Mailing Address			
Organization/Firm:	**SEMINOLE ELECTRIC COOPERATIVE, INC.**		
Street Address:	**890 NORTH U.S. HIGHWAY 17**		
City:	**PALATKA**		
State:	**FL**	Zip Code:	**32177-8647**
Telephone:	**(386) 328-9255 2174**	Fax:	**(386) 328-5571**

E. OWNER OR AUTHORIZED REPRESENTATIVE STATEMENT

I hereby certify that the information given in this report is correct to the best of my knowledge.

M.P. [signature] 2/27/06

Signature Date

DEP Form No. 62-210.900(5) - Form
Effective: 2/11/99

Department of
Environmental Protection

Division of Air Resources Management

ANNUAL OPERATING REPORT
FOR AIR POLLUTANT EMITTING FACILITY

See Instructions for Form No. 62-210.900(5).

I. FACILITY REPORT

A. REPORT INFORMATION

1. Year of Report **2005**	2. Number of Emissions Units in Report **8**

B. FACILITY INFORMATION

1. Facility ID **1070025**	2. Facility Status **ACTIVE**	3. Date of Permanent Facility Shutdown
4. Facility Owner/Company Name **SEMINOLE ELECTRIC COOPERATIVE, INC.**		
5. Site Name **SEMINOLE GENERATING STATION**		
6. Facility Location Street Address or Other Locator: **890 NORTH U.S. HIGHWAY 17** City: **PALATKA** County: **PUTNAM** Zip Code: **32177-8647**		
7. Facility Compliance Tracking Code **A**	8. Governmental Facility Code **0**	9. Facility SIC(s) **4911**
10. Facility Comment **TITLE V (MAJOR & NSPS)**		

C. FACILITY HISTORY INFORMATION

1. Change in Facility Owner/ Company Name During Year?	Previous Name	2. Date of Change

Facility ID : 1070025

D. OWNER/CONTACT INFORMATION

1. Owner or Authorized Representative			
Name and Title **MICHAEL P. OPALINSKI** **VICE PRESIDENT OF TECHNICAL SERVICES**			
Mailing Address			
Organization/Firm:	**SEMINOLE ELECTRIC COOPERATIVE, INC.**		
Street Address:	**POST OFFICE BOX 272000**		
City:	**TAMPA**		
State:	**FL**	Zip Code:	**33688-2000**
Telephone:	**(813) 963-0994 1233**	Fax:	**(813) 264-7906**
2. Facility Contact			
Name and Title **BRENDA SHIVER** **ENVIRONMENTAL COMPLIANCE SPECIALIST**			
Mailing Address			
Organization/Firm:	**SEMINOLE ELECTRIC COOPERATIVE, INC.**		
Street Address:	**890 NORTH HIGHWAY 17**		
City:	**PALATKA**		
State:	**FL**	Zip Code:	**32177-8647**
Telephone:	**(386) 328-9255 2174**	Fax:	**(386) 328-5571**

E. OWNER OR AUTHORIZED REPRESENTATIVE STATEMENT

I hereby certify that the information given in this report is correct to the best of my knowledge.

Signature ______________________ Date ______________________

Facility ID : 1070025 **Emissions Unit ID : 001**

II. EMISSIONS UNIT REPORT

A. EMISSIONS UNIT INFORMATION

1. Emissions Unit Description **Steam Electric Generator No. 1**		
2. Emissions Unit ID **001**	3. Emissions Unit Classification **Regulated Emissions Unit**	4. Operated During Year? **Y**
5. DEP Permit or PPS Number **1070025002AV** **PPS PA7810**	6. Emissions Unit Status **ACTIVE**	7. Ozone SIP Base Year Emissions Unit?
8. Emissions Unit Startup Date **01-Jan-1985**	9. Long-term Reserve Shutdown Date	10. Permanent Shutdown Date

B. EMISSION POINT/CONTROL INFORMATION

1. Emissions Point Type **SINGLE POINT SERVING A SINGLE EMISSIONS UNIT**
2a. Description of Control Equipment 'a' **ELECTROSTATIC PRECIPITATOR HIGH EFFICIENCY (95.0-99.9%)**
2b. Description of Control Equipment 'b' **MODIFIED FURNACE/BURNER DESIGN**

C. EMISSIONS UNIT OPERATING SCHEDULE INFORMATION

1. Average Annual Operation hours/day **21** days/week **7**	2. Total Operation During Year (hours/year) **7648**
3. Percent Hours of Operation by Season DJF : **25** MAM : **25** JJA : **25** SON : **25**	
4. Average Ozone Season Operation (June 1 to August 31) hours/day days/week	5. Total Operation During Ozone Season (days/season)

Facility ID : 1070025 **Emissions Unit ID : 001**

D. EMISSIONS UNIT COMMENT

Facility ID : 1070025 **Emissions Unit ID : 001** **SCC : 1-01-002-02**

E. EMISSIONS INFORMATION BY PROCESS/FUEL

(1) PROCESS/FUEL INFORMATION

1. SCC **1-01-002-02**	2. Description of Process or Type of Fuel **External Combustion Boilers Electric Generation**	**Bituminous/Subbituminous Coal Pulverized Coal: Dry Bottom (Biti**
3. Annual Process or Fuel Usage Rate **1390374**	4. Ozone Season Daily Process or Fuel Usage Rate	5. SCC Unit **Tons Bituminous Coal Burned**
6. Fuel Average % Sulfur **3**	7. Fuel Average % Ash **7.67**	8. Fuel Heat Content (mmBtu/SCC Unit) **24**

(2) EMISSIONS INFORMATION

1. Pollutant **CO** **Carbon Monoxide**	CAS No. **630-08-0**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **457.686272**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 457.686272 = 1998-2002 Average CO Test Results, 100% Coal (lb/mmBtu) 0.0958 * 100% Coal Annual Heat Input (mmBtu/year) 9555037 * (1 / 2000)**		

1. Pollutant **H015** **Arsenic Compounds (inorganic including arsine)**	CAS No.	[**X**] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 001** **SCC : 1-01-002-02**

1. Pollutant **H027** **Cadmium Compounds**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H046** **Chromium Compounds**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H106** **Hydrogen chloride (Hydrochloric acid)**	CAS No. **7647-01-0**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **79.251318**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **5**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 79.251318 = HCl Emission Factor (lb/ton) 1.9 * Annual Process or Fuel Usage Rate (Tons Bituminous Coal Burned) 1390374 * (1 - (FGD HCl Removal Efficiency (%) 94 / 100)) * (1 / 2000)** **HCl emission factor from Table 3-10, EPCRA Section 313 Industry Guidance, Electricity Generating Facilities, February 2000.**		

*: Pollutant subject to emissions limiting standard or emissions cap

1. Pollutant **H107** **Hydrogen fluoride (Hydrofluoric acid)**	CAS No. **7664-39-3**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **105.529387**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **5**

5. Emissions Calculation (Show separately both annual and daily emissions calculations)

Annual Emissions (Ton/Year) 105.529387 = HF Emission Factor (lb/ton) 0.23 * Annual Process or Fuel Usage Rate (Tons Bituminous Coal Burned) 1390374 * (1 - (FGD HF Removal Efficiency (%) 34 / 100)) * (1 / 2000)

HF emission factor from Table 3-10, EPCRA Section 313 Industry Guidance, Electricity Generating Facilities, February 2000.

1. Pollutant **H150** **Polychlorinated biphenyls (Aroclors)**	CAS No. **1336-36-3**	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code

5. Emissions Calculation (Show separately both annual and daily emissions calculations)

1. Pollutant * **NOX** **Nitrogen Oxides**	CAS No. **10102-44-0**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **8063.738955**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**

5. Emissions Calculation (Show separately both annual and daily emissions calculations)

Annual Emissions (Ton/Year) 8063.738955 = Total Coal Heat Input (mmBtu/yr) 34024215 * NOx CEMS Emission Factor for All Fuels (lbs/mmBtu) 0.474 * (1 / 2000)

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 001** **SCC : 1-01-002-02**

1. Pollutant **PB** **Lead - Total (elemental lead and lead compounds)**	CAS No.	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **0.291979**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **3**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 0.291979 = Annual Process or Fuel Usage Rate (Tons Bituminous Coal Burned) 1390374 * Emission Factor (Lbs/Tons Bituminous Coal Burned) 0.00042 * (1 / 2000)**		

1. Pollutant * **PM** **Particulate Matter - Total**	CAS No.	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **95.55037**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 95.55037 = 100% Coal Heat Input (mmBtu/yr) 9555037 * 100% Coal PM Stack Test Results (lbs/mmBtu) 0.02 * (1 / 2000)**		

1. Pollutant **PM10** **Particulate Matter - PM10**	CAS No.	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **95.55037**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 95.55037 = 100% Coal Heat Input (mmBtu/yr) 9555037 * 100% Coal PM Stack Test Results (lbs/MMBtu) 0.02 * (1 / 2000)**		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 001** **SCC : 1-01-002-02**

1. Pollutant * **SO2** **Sulfur Dioxide**	CAS No. **7446-09-5**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **11250.334827**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**

5. Emissions Calculation (Show separately both annual and daily emissions calculations)
Annual Emissions (Ton/Year) 11250.334827 = Total Coal Heat Input (mmBtu/yr) 34024215 * Emission Factor (lbs/MMBtu) 0.661313410284814 * (1 / 2000)

1. Pollutant **VOC** **Volatile Organic Compounds**	CAS No.	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **41.71122**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **3**

5. Emissions Calculation (Show separately both annual and daily emissions calculations)
Annual Emissions (Ton/Year) 41.71122 = Annual Process or Fuel Usage Rate (Tons Bituminous Coal Burned) 1390374 * Emission Factor (Lbs/Tons Bituminous Coal Burned) 0.06 * (1 / 2000)

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 001** **SCC : 1-01-005-01**

E. EMISSIONS INFORMATION BY PROCESS/FUEL

(1) PROCESS/FUEL INFORMATION

1. SCC **1-01-005-01**	2. Description of Process or Type of Fuel **External Combustion Boilers Distillate Oil** **Electric Generation Grades 1 and 2 Oil**	
3. Annual Process or Fuel Usage Rate **1059**	4. Ozone Season Daily Process or Fuel Usage Rate	5. SCC Unit **1000 Gallons Distillate Oil (No.**
6. Fuel Average % Sulfur **0.34**	7. Fuel Average % Ash **0.1**	8. Fuel Heat Content (mmBtu/SCC Unit) **140**

(2) EMISSIONS INFORMATION

1. Pollutant **CO** **Carbon Monoxide**	CAS No. **630-08-0**	[**X**] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H015** **Arsenic Compounds (inorganic including arsine)**	CAS No.	[**X**] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 001** **SCC : 1-01-005-01**

1. Pollutant **H027** **Cadmium Compounds**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H046** **Chromium Compounds**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H106** **Hydrogen chloride (Hydrochloric acid)**	CAS No. **7647-01-0**	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H107** **Hydrogen fluoride (Hydrofluoric acid)**	CAS No. **7664-39-3**	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 001** **SCC : 1-01-005-01**

1. Pollutant **H150** **Polychlorinated biphenyls (Aroclors)**	CAS No. **1336-36-3**	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant * **NOX** **Nitrogen Oxides**	CAS No. **10102-44-0**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **34.896354**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 34.896354 = NOx CEMS Emission Factor for All Fuels (lbs/MMBtu) 0.474 * (Heat Input From No. 2 Oil (MMBtu/yr) 147242) * (1 / 2000)**		

1. Pollutant **PB** **Lead - Total (elemental lead and lead compounds)**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant * **PM** **Particulate Matter - Total**	CAS No.	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **0.005295**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **3**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 0.005295 = Controlled AP-42 Emission Factor (lb/1,000 gal) 0.01 * Annual Process or Fuel Usage Rate (1000 Gallons Distillate Oil (No. 1 & 2) Burned) 1059 * (1 / 2000)**		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 001** **SCC : 1-01-005-01**

1. Pollutant **PM10** **Particulate Matter - PM10**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **3**
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant * **SO2** **Sulfur Dioxide**	CAS No. **7446-09-5**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **48.686555**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 48.686555 = Heat Input From No. 2 Oil (MMBtu/yr) 147242 * CEMS SO2 Emission Factor for All Fuels (lbs/MMBtu) 0.661313410284814 * (1 / 2000)**		

1. Pollutant **VOC** **Volatile Organic Compounds**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **3**
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 001** **SCC : 1-01-008-01**

E. EMISSIONS INFORMATION BY PROCESS/FUEL

(1) PROCESS/FUEL INFORMATION

1. SCC **1-01-008-01**	2. Description of Process or Type of Fuel **External Combustion Boilers Coke** **Electric Generation All Boiler Sizes** **Maximum weight of petroleum coke burned shall not exceed 180,000**	
3. Annual Process or Fuel Usage Rate **428188**	4. Ozone Season Daily Process or Fuel Usage Rate	5. SCC Unit **Tons Coke Burned**
6. Fuel Average % Sulfur **5.66**	7. Fuel Average % Ash **0.9**	8. Fuel Heat Content (mmBtu/SCC Unit) **28**

(2) EMISSIONS INFORMATION

1. Pollutant **CO** **Carbon Monoxide**	CAS No. **630-08-0**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **820.359045**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 820.359045 = 1998 - 2002 Average CO Test Results for 70% Coal / 30% Petcoke Blend (lb/mmBtu) 0.045 * Heat Input for 70% Coal / 30% Petcoke Blend (mmBtu/year) 36460402 * (1 / 2000)**		

1. Pollutant **H015** **Arsenic Compounds (inorganic including arsine)**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 001** **SCC : 1-01-008-01**

1. Pollutant **H027** **Cadmium Compounds**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H046** **Chromium Compounds**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H106** **Hydrogen chloride (Hydrochloric acid)**	CAS No. **7647-01-0**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **24.406716**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **5**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 24.406716 = HCl Emission Factor (lb/ton) 1.9 * Annual Process or Fuel Usage Rate (Tons Coke Burned) 428188 * (1 - (FGD HCl Removal Efficiency (%) 94 / 100)) * (1 / 2000)** **HCl emission factor from Table 3-10, EPCRA Section 313 Industry Guidance, Electricity Generating Facilities, February 2000.**		

*: Pollutant subject to emissions limiting standard or emissions cap

1. Pollutant **H107** **Hydrogen fluoride (Hydrofluoric acid)**	CAS No. **7664-39-3**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **32.499469**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **5**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 32.499469 = HF Emission Factor (lb/ton) 0.23 * Annual Process or Fuel Usage Rate (Tons Coke Burned) 428188 * (1 - (FGD HF Removal Efficiency (%) 34 / 100)) * (1 / 2000)** **HF emission factor from Table 3-10, EPCRA Section 313 Industry Guidance, Electricity Generating Facilities, February 2000.**		

1. Pollutant **H150** **Polychlorinated biphenyls (Aroclors)**	CAS No. **1336-36-3**	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant * **NOX** **Nitrogen Oxides**	CAS No. **10102-44-0**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **2841.920088**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 2841.920088 = Heat Input From Petcoke (mmBtu/year) 11991224 * NOx CEMS Emission Factor for All Fuels (lbs/mmBtu) 0.474 * (1 / 2000)**		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 | Emissions Unit ID : 001 | SCC : 1-01-008-01

1. Pollutant **PB** **Lead - Total (elemental lead and lead compounds)**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant * **PM** **Particulate Matter - Total**	CAS No.	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **382.834221**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 382.834221 = Heat Input From 70% Coal / 30% Petcoke Blend (mmBtu/yr) 36460402 * PM Test Results for 70% Coal / 30% Petcoke Blend (lb/mmBtu) 0.021 * (1 / 2000)**		

1. Pollutant **PM10** **Particulate Matter - PM10**	CAS No.	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **382.834221**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 382.834221 = Heat Input From 70% Coal / 30% Petcoke Blend (mmBtu/yr) 36460402 * PM Test Results for 70% Coal / 30% Petcoke Blend (lb/mmBtu) 0.021 * (1 / 2000)**		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 001** **SCC : 1-01-008-01**

1. Pollutant * **SO2** **Sulfur Dioxide**	CAS No. **7446-09-5**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **3964.978618**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 3964.978618 = Heat Input From Petcoke (mmBtu/yr) 11991224 * CEMS SO2 Emission Factor for All Fuels (lbs/mmBtu) 0.661313410284814 * (1 / 2000)**		

1. Pollutant **VOC** **Volatile Organic Compounds**	CAS No.	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **12.84564**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **3**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 12.84564 = Annual Process or Fuel Usage Rate (Tons Coke Burned) 428188 * Emission Factor (Lbs/Tons Coke Burned) 0.06 * (1 / 2000)**		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 001** **SCC : 1-01-013-02**

E. EMISSIONS INFORMATION BY PROCESS/FUEL

(1) PROCESS/FUEL INFORMATION

1. SCC **1-01-013-02**	2. Description of Process or Type of Fuel **External Combustion Boilers Liquid Waste** **Electric Generation Waste Oil** **On-Specification: Arsenic 5ppm, Cadium 2ppm, Chromium 10ppm,**	
3. Annual Process or Fuel Usage Rate **0**	4. Ozone Season Daily Process or Fuel Usage Rate	5. SCC Unit **1000 Gallons Waste Oil Burned**
6. Fuel Average % Sulfur	7. Fuel Average % Ash	8. Fuel Heat Content (mmBtu/SCC Unit)

(2) EMISSIONS INFORMATION

1. Pollutant **CO** **Carbon Monoxide**	CAS No. **630-08-0**	[ ] Below Threshold [**X**] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H015** **Arsenic Compounds (inorganic including arsine)**	CAS No.	[ ] Below Threshold [**X**] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 001** **SCC : 1-01-013-02**

1. Pollutant **H027** **Cadmium Compounds**	CAS No.	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H046** **Chromium Compounds**	CAS No.	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H106** **Hydrogen chloride (Hydrochloric acid)**	CAS No. **7647-01-0**	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H107** **Hydrogen fluoride (Hydrofluoric acid)**	CAS No. **7664-39-3**	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 Emissions Unit ID : 001 SCC : 1-01-013-02

1. Pollutant **H150** **Polychlorinated biphenyls (Aroclors)**	CAS No. **1336-36-3**	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant * **NOX** **Nitrogen Oxides**	CAS No. **10102-44-0**	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **PB** **Lead - Total (elemental lead and lead compounds)**	CAS No.	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant * **PM** **Particulate Matter - Total**	CAS No.	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 001** **SCC : 1-01-013-02**

1. Pollutant **PM10** **Particulate Matter - PM10**	CAS No.	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant * **SO2** **Sulfur Dioxide**	CAS No. **7446-09-5**	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **VOC** **Volatile Organic Compounds**	CAS No.	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

II. EMISSIONS UNIT REPORT

A. EMISSIONS UNIT INFORMATION

1. Emissions Unit Description **Steam Electric Generator No. 2**		
2. Emissions Unit ID **002**	3. Emissions Unit Classification **Regulated Emissions Unit**	4. Operated During Year? **Y**
5. DEP Permit or PPS Number **1070025002AV** **PPS PA7810**	6. Emissions Unit Status **ACTIVE**	7. Ozone SIP Base Year Emissions Unit?
8. Emissions Unit Startup Date **01-Jan-1985**	9. Long-term Reserve Shutdown Date	10. Permanent Shutdown Date

B. EMISSION POINT/CONTROL INFORMATION

1. Emissions Point Type **SINGLE POINT SERVING A SINGLE EMISSIONS UNIT**
2a. Description of Control Equipment 'a' **WET SCRUBBER HIGH EFFICIENCY (95.0-99.9%)**
2b. Description of Control Equipment 'b' **MODIFIED FURNACE/BURNER DESIGN**

C. EMISSIONS UNIT OPERATING SCHEDULE INFORMATION

1. Average Annual Operation hours/day **23** days/week **7**	2. Total Operation During Year (hours/year) **8415**
3. Percent Hours of Operation by Season DJF : **25** MAM : **25** JJA : **25** SON : **25**	
4. Average Ozone Season Operation (June 1 to August 31) hours/day days/week	5. Total Operation During Ozone Season (days/season)

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 002**

D. EMISSIONS UNIT COMMENT

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 002** **SCC : 1-01-002-02**

E. EMISSIONS INFORMATION BY PROCESS/FUEL

(1) PROCESS/FUEL INFORMATION

1. SCC **1-01-002-02**	2. Description of Process or Type of Fuel **External Combustion Boilers Electric Generation** **Bituminous/Subbituminous Coal Pulverized Coal: Dry Bottom (Bit**	
3. Annual Process or Fuel Usage Rate **1546131**	4. Ozone Season Daily Process or Fuel Usage Rate	5. SCC Unit **Tons Bituminous Coal Burned**
6. Fuel Average % Sulfur **3**	7. Fuel Average % Ash **7.67**	8. Fuel Heat Content (mmBtu/SCC Unit) **24**

(2) EMISSIONS INFORMATION

1. Pollutant **CO** **Carbon Monoxide**	CAS No. **630-08-0**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **1039.837019**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 1039.837019 = 1998-2002 Average CO Test Results, 100% Coal (lb/mmBtu) 0.1696 * 100% Coal Annual Heat Input (mmBtu/year) 12262229 * (1 / 2000)**		

1. Pollutant **H015** **Arsenic Compounds (inorganic including arsine)**	CAS No.	[**X**] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

1. Pollutant **H027** **Cadmium Compounds**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H046** **Chromium Compounds**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H106** **Hydrogen chloride (Hydrochloric acid)**	CAS No. **7647-01-0**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **88.129467**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **5**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 88.129467 = HCl Emission Factor (lb/ton) 1.9 * Annual Process or Fuel Usage Rate (Tons Bituminous Coal Burned) 1546131 * (1 - (FGD HCl Removal Efficiency (%) 94 / 100)) * (1 / 2000)** **HCl emission factor from Table 3-10, EPCRA Section 313 Industry Guidance, Electricity Generating Facilities, February 2000.**		

*: Pollutant subject to emissions limiting standard or emissions cap

1. Pollutant **H107** **Hydrogen fluoride (Hydrofluoric acid)**	CAS No. **7664-39-3**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **117.351343**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **5**

5. Emissions Calculation (Show separately both annual and daily emissions calculations)

Annual Emissions (Ton/Year) 117.351343 = HF Emission Factor (lb/ton) 0.23 * Annual Process or Fuel Usage Rate (Tons Bituminous Coal Burned) 1546131 * (1 - (FGD HF Removal Efficiency (%) 34 / 100)) * (1 / 2000)

HF emission factor from Table 3-10, EPCRA Section 313 Industry Guidance, Electricity Generating Facilities, February 2000.

1. Pollutant **H150** **Polychlorinated biphenyls (Aroclors)**	CAS No. **1336-36-3**	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code

5. Emissions Calculation (Show separately both annual and daily emissions calculations)

1. Pollutant *** NOX** **Nitrogen Oxides**	CAS No. **10102-44-0**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **9014.254284**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**

5. Emissions Calculation (Show separately both annual and daily emissions calculations)

Annual Emissions (Ton/Year) 9014.254284 = Total Coal Heat Input (mmBtu/yr) 37875018 * NOx CEMS Emission Factor for All Fuels (lbs/mmBtu) 0.476 * (1 / 2000)

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 002** **SCC : 1-01-002-02**

1. Pollutant **PB** **Lead - Total (elemental lead and lead compounds)**	CAS No.	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **0.324688**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **3**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 0.324688 = Emission Factor (Lbs/Tons Bituminous Coal Burned) 0.00042 * Annual Process or Fuel Usage Rate (Tons Bituminous Coal Burned) 1546131 * (1 / 2000)**		

1. Pollutant *** PM** **Particulate Matter - Total**	CAS No.	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **85.835603**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 85.835603 = 100% Coal Heat Input (mmBtu/yr) 12262229 * 100% Coal PM Stack Test Results (lbs/mmBtu) 0.014 * (1 / 2000)**		

1. Pollutant **PM10** **Particulate Matter - PM10**	CAS No.	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **85.835603**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 85.835603 = 100% Coal Heat Input (mmBtu/yr) 12262229 * 100% Coal PM Stack Test Results (lbs/MMBtu) 0.014 * (1 / 2000)**		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 002** **SCC : 1-01-002-02**

1. Pollutant * **SO2** **Sulfur Dioxide**	CAS No. **7446-09-5**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **12132.503348**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**

5. Emissions Calculation (Show separately both annual and daily emissions calculations)
Annual Emissions (Ton/Year) 12132.503348 = Total Coal Heat Input (mmBtu/yr) 37875018 * Emission Factor (lbs/MMBtu) 0.640659938338263 * (1 / 2000)

1. Pollutant **VOC** **Volatile Organic Compounds**	CAS No.	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **46.38393**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **3**

5. Emissions Calculation (Show separately both annual and daily emissions calculations)
Annual Emissions (Ton/Year) 46.38393 = Annual Process or Fuel Usage Rate (Tons Bituminous Coal Burned) 1546131 * Emission Factor (Lbs/Tons Bituminous Coal Burned) 0.06 * (1 / 2000)

*: Pollutant subject to emissions limiting standard or emissions cap

E. EMISSIONS INFORMATION BY PROCESS/FUEL

(1) PROCESS/FUEL INFORMATION

1. SCC **1-01-005-01**	2. Description of Process or Type of Fuel **External Combustion Boilers Distillate Oil** **Electric Generation Grades 1 and 2 Oil**	
3. Annual Process or Fuel Usage Rate **770**	4. Ozone Season Daily Process or Fuel Usage Rate	5. SCC Unit **1000 Gallons Distillate Oil (No.**
6. Fuel Average % Sulfur **0.34**	7. Fuel Average % Ash **0.1**	8. Fuel Heat Content (mmBtu/SCC Unit) **140**

(2) EMISSIONS INFORMATION

1. Pollutant **CO** **Carbon Monoxide**	CAS No. **630-08-0**	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H015** **Arsenic Compounds (inorganic including arsine)**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 002** **SCC : 1-01-005-01**

1. Pollutant **H027** **Cadmium Compounds**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H046** **Chromium Compounds**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H106** **Hydrogen chloride (Hydrochloric acid)**	CAS No. **7647-01-0**	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H107** **Hydrogen fluoride (Hydrofluoric acid)**	CAS No. **7664-39-3**	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 | Emissions Unit ID : 002 | SCC : 1-01-005-01

1. Pollutant **H150** **Polychlorinated biphenyls (Aroclors)**	CAS No. **1336-36-3**	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant * **NOX** **Nitrogen Oxides**	CAS No. **10102-44-0**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **25.484564**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 25.484564 = NOx CEMS Emission Factor for All Fuels (lbs/MMBtu) 0.476 * (Heat Input From No. 2 Oil (MMBtu/yr) 107078) * (1 / 2000)**		

1. Pollutant **PB** **Lead - Total (elemental lead and lead compounds)**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant * **PM** **Particulate Matter - Total**	CAS No.	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **0.00385**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **3**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 0.00385 = Controlled AP-42 Emission Factor (lb/1,000 gal) 0.01 * Annual Process or Fuel Usage Rate (1000 Gallons Distillate Oil (No. 1 & 2) Burned) 770 * (1 / 2000)**		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 002** **SCC : 1-01-005-01**

1. Pollutant **PM10** **Particulate Matter - PM10**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **3**
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant *** SO2** **Sulfur Dioxide**	CAS No. **7446-09-5**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **34.300292**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 34.300292 = Heat Input From No. 2 Oil (MMBtu/yr) 107078 * CEMS SO2 Emission Factor for All Fuels (lbs/MMBtu) 0.640659938338263 * (1 / 2000)**		

1. Pollutant **VOC** **Volatile Organic Compounds**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **3**
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

E. EMISSIONS INFORMATION BY PROCESS/FUEL

(1) PROCESS/FUEL INFORMATION

1. SCC **1-01-008-01**	2. Description of Process or Type of Fuel **External Combustion Boilers Coke** **Electric Generation All Boiler Sizes** **Maximun petroleum coke burned shall not exceed 180,000lbs per hou**	
3. Annual Process or Fuel Usage Rate **447431**	4. Ozone Season Daily Process or Fuel Usage Rate	5. SCC Unit **Tons Coke Burned**
6. Fuel Average % Sulfur **5.66**	7. Fuel Average % Ash **0.85**	8. Fuel Heat Content (mmBtu/SCC Unit) **28**

(2) EMISSIONS INFORMATION

1. Pollutant **CO** **Carbon Monoxide**	CAS No. **630-08-0**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **629.328299**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 629.328299 = 1998 - 2002 Average CO Test Results for 70% Coal / 30% Petcoke Blend (lb/mmBtu) 0.033 * Heat Input for 70% Coal / 30% Petcoke Blend (mmBtu/year) 38141109 * (1 / 2000)**		

1. Pollutant **H015** **Arsenic Compounds (inorganic including arsine)**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 002** **SCC : 1-01-008-01**

1. Pollutant **H027** **Cadmium Compounds**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H046** **Chromium Compounds**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H106** **Hydrogen chloride (Hydrochloric acid)**	CAS No. **7647-01-0**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **25.503567**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **5**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 25.503567 = HCl Emission Factor (lb/ton) 1.9 * Annual Process or Fuel Usage Rate (Tons Coke Burned) 447431 * (1 - (FGD HCl Removal Efficiency (%) 94 / 100)) * (1 / 2000)** **HCl emission factor from Table 3-10, EPCRA Section 313 Industry Guidance, Electricity Generating Facilities, February 2000.**		

*: Pollutant subject to emissions limiting standard or emissions cap

1. Pollutant **H107** **Hydrogen fluoride (Hydrofluoric acid)**	CAS No. **7664-39-3**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **33.960013**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **5**

5. Emissions Calculation (Show separately both annual and daily emissions calculations)

Annual Emissions (Ton/Year) 33.960013 = HF Emission Factor (lb/ton) 0.23 * Annual Process or Fuel Usage Rate (Tons Coke Burned) 447431 * (1 - (FGD HF Removal Efficiency (%) 34 / 100)) * (1 / 2000)

HF emission factor from Table 3-10, EPCRA Section 313 Industry Guidance, Electricity Generating Facilities, February 2000.

1. Pollutant **H150** **Polychlorinated biphenyls (Aroclors)**	CAS No. **1336-36-3**	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code

5. Emissions Calculation (Show separately both annual and daily emissions calculations)

1. Pollutant * **NOX** **Nitrogen Oxides**	CAS No. **10102-44-0**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **2981.74016**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**

5. Emissions Calculation (Show separately both annual and daily emissions calculations)

Annual Emissions (Ton/Year) 2981.74016 = Heat Input From Petcoke (mmBtu/year) 12528320 * NOx CEMS Emission Factor for All Fuels (lbs/mmBtu) 0.476 * (1 / 2000)

*: Pollutant subject to emissions limiting standard or emissions cap

1. Pollutant **PB** **Lead - Total (elemental lead and lead compounds)**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant * **PM** **Particulate Matter - Total**	CAS No.	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **305.128872**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 305.128872 = Heat Input From 70% Coal / 30% Petcoke Blend (mmBtu/yr) 38141109 * PM Test Results for 70% Coal / 30% Petcoke Blend (lb/mmBtu) 0.016 * (1 / 2000)**		

1. Pollutant **PM10** **Particulate Matter - PM10**	CAS No.	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **305.128872**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 305.128872 = Heat Input From 70% Coal / 30% Petcoke Blend (mmBtu/yr) 38141109 * PM Test Results for 70% Coal / 30% Petcoke Blend (lb/mmBtu) 0.016 * (1 / 2000)**		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 002** **SCC : 1-01-008-01**

1. Pollutant * **SO2** **Sulfur Dioxide**	CAS No. **7446-09-5**	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **4013.196359**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **1**

5. Emissions Calculation (Show separately both annual and daily emissions calculations)
Annual Emissions (Ton/Year) 4013.196359 = Heat Input From Petcoke (mmBtu/yr) 12528320 * CEMS SO2 Emission Factor for All Fuels (lbs/mmBtu) 0.640659938338263 * (1 / 2000)

1. Pollutant **VOC** **Volatile Organic Compounds**	CAS No.	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **13.42293**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **3**

5. Emissions Calculation (Show separately both annual and daily emissions calculations)
Annual Emissions (Ton/Year) 13.42293 = Annual Process or Fuel Usage Rate (Tons Coke Burned) 447431 * Emission Factor (Lbs/Tons Coke Burned) 0.06 * (1 / 2000)

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 002** **SCC : 1-01-013-02**

E. EMISSIONS INFORMATION BY PROCESS/FUEL

(1) PROCESS/FUEL INFORMATION

1. SCC **1-01-013-02**	2. Description of Process or Type of Fuel **External Combustion Boilers Liquid Waste** **Electric Generation Waste Oil** **On-Specification:Arsenic 5ppm, Cadmium 2ppm, Chromium 10ppm**	
3. Annual Process or Fuel Usage Rate **0**	4. Ozone Season Daily Process or Fuel Usage Rate	5. SCC Unit **1000 Gallons Waste Oil Burned**
6. Fuel Average % Sulfur	7. Fuel Average % Ash	8. Fuel Heat Content (mmBtu/SCC Unit)

(2) EMISSIONS INFORMATION

1. Pollutant **CO** **Carbon Monoxide**	CAS No. **630-08-0**	[ ] Below Threshold [**X**] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H015** **Arsenic Compounds (inorganic including arsine)**	CAS No.	[ ] Below Threshold [**X**] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

1. Pollutant **H027** **Cadmium Compounds**	CAS No.	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H046** **Chromium Compounds**	CAS No.	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H106** **Hydrogen chloride (Hydrochloric acid)**	CAS No. **7647-01-0**	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **H107** **Hydrogen fluoride (Hydrofluoric acid)**	CAS No. **7664-39-3**	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

1. Pollutant **H150** **Polychlorinated biphenyls (Aroclors)**	CAS No. **1336-36-3**	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant * **NOX** **Nitrogen Oxides**	CAS No. **10102-44-0**	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **PB** **Lead - Total (elemental lead and lead compounds)**	CAS No.	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant * **PM** **Particulate Matter - Total**	CAS No.	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 002** **SCC : 1-01-013-02**

1. Pollutant **PM10** **Particulate Matter - PM10**	CAS No.	[ ] Below Threshold [**X**] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant * **SO2** **Sulfur Dioxide**	CAS No. **7446-09-5**	[ ] Below Threshold [**X**] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **VOC** **Volatile Organic Compounds**	CAS No.	[ ] Below Threshold [**X**] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 003**

II. EMISSIONS UNIT REPORT

A. EMISSIONS UNIT INFORMATION

1. Emissions Unit Description **Rail Car Maintenance**		
2. Emissions Unit ID **003**	3. Emissions Unit Classification **Regulated Emissions Unit**	4. Operated During Year? **N**
5. DEP Permit or PPS Number **PPS PA7810**	6. Emissions Unit Status **ACTIVE**	7. Ozone SIP Base Year Emissions Unit?
8. Emissions Unit Startup Date	9. Long-term Reserve Shutdown Date	10. Permanent Shutdown Date

B. EMISSION POINT/CONTROL INFORMATION

1. Emissions Point Type **MULTIPLE EMISSION POINTS SERVING 1 EMISSIONS UNIT**
2a. Description of Control Equipment 'a' **PROCESS ENCLOSED**
2b. Description of Control Equipment 'b'

C. EMISSIONS UNIT OPERATING SCHEDULE INFORMATION

1. Average Annual Operation hours/day days/week			2. Total Operation During Year (hours/year)
3. Percent Hours of Operation by Season DJF :	MAM :	JJA :	SON :
4. Average Ozone Season Operation (June 1 to August 31) hours/day days/week			5. Total Operation During Ozone Season (days/season)

*: Pollutant subject to emissions limiting standard or emissions cap

D. EMISSIONS UNIT COMMENT

*: Pollutant subject to emissions limiting standard or emissions cap

II. EMISSIONS UNIT REPORT

A. EMISSIONS UNIT INFORMATION

1. Emissions Unit Description **Coal Storage Yard**		
2. Emissions Unit ID **004**	3. Emissions Unit Classification **Regulated Emissions Unit**	4. Operated During Year? **Y**
5. DEP Permit or PPS Number **1070025002AV** **PPS PA7810**	6. Emissions Unit Status **ACTIVE**	7. Ozone SIP Base Year Emissions Unit?
8. Emissions Unit Startup Date **01-Jan-1985**	9. Long-term Reserve Shutdown Date	10. Permanent Shutdown Date

B. EMISSION POINT/CONTROL INFORMATION

1. Emissions Point Type **NO TRUE EMISSION POINT (FUGITIVE EMISSION)**
2a. Description of Control Equipment 'a' **DUST SUPPRESSION BY WATER SPRAYS**
2b. Description of Control Equipment 'b' **PROCESS ENCLOSED**

C. EMISSIONS UNIT OPERATING SCHEDULE INFORMATION

1. Average Annual Operation hours/day **24** days/week **7**	2. Total Operation During Year (hours/year) **8760**
3. Percent Hours of Operation by Season DJF : **25** MAM : **25** JJA : **25** SON : **25**	
4. Average Ozone Season Operation (June 1 to August 31) hours/day days/week	5. Total Operation During Ozone Season (days/season)

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 004**

D. EMISSIONS UNIT COMMENT

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 004** **SCC : 3-05-101-03**

E. EMISSIONS INFORMATION BY PROCESS/FUEL

(1) PROCESS/FUEL INFORMATION

1. SCC **3-05-101-03**	2. Description of Process or Type of Fuel **Industrial Processes** **Bulk Materials Conveyors** **Mineral Products** **Coal** **Maximum hourly rate based on conveyor belt capacity.**	
3. Annual Process or Fuel Usage Rate **3812124**	4. Ozone Season Daily Process or Fuel Usage Rate	5. SCC Unit **Tons Material Processed**
6. Fuel Average % Sulfur	7. Fuel Average % Ash	8. Fuel Heat Content (mmBtu/SCC Unit)

(2) EMISSIONS INFORMATION

1. Pollutant **PM** **Particulate Matter - Total**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **PM10** **Particulate Matter - PM10**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 004** **SCC : 3-05-103-03**

E. EMISSIONS INFORMATION BY PROCESS/FUEL

(1) PROCESS/FUEL INFORMATION

1. SCC **3-05-103-03**	2. Description of Process or Type of Fuel **Industrial Processes** **Bulk Materials Open Stockpiles** **Mineral Products** **Coal**	
3. Annual Process or Fuel Usage Rate **3812124**	4. Ozone Season Daily Process or Fuel Usage Rate	5. SCC Unit **Tons Material Processed**
6. Fuel Average % Sulfur	7. Fuel Average % Ash	8. Fuel Heat Content (mmBtu/SCC Unit)

(2) EMISSIONS INFORMATION

1. Pollutant **PM** **Particulate Matter - Total**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **3**
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **PM10** **Particulate Matter - PM10**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **3**
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

II. EMISSIONS UNIT REPORT

A. EMISSIONS UNIT INFORMATION

1. Emissions Unit Description **Limestone and FGD Sludge Handling and Storage**		
2. Emissions Unit ID **005**	3. Emissions Unit Classification **Regulated Emissions Unit**	4. Operated During Year? **Y**
5. DEP Permit or PPS Number **1070025002AV**	6. Emissions Unit Status **ACTIVE**	7. Ozone SIP Base Year Emissions Unit?
8. Emissions Unit Startup Date	9. Long-term Reserve Shutdown Date	10. Permanent Shutdown Date

B. EMISSION POINT/CONTROL INFORMATION

1. Emissions Point Type **SINGLE POINT SERVING A SINGLE EMISSIONS UNIT**
2a. Description of Control Equipment 'a' **MAT OR PANEL FILTER**
2b. Description of Control Equipment 'b' **PROCESS ENCLOSED**

C. EMISSIONS UNIT OPERATING SCHEDULE INFORMATION

1. Average Annual Operation hours/day **8** days/week **5**			2. Total Operation During Year (hours/year) **2080**
3. Percent Hours of Operation by Season			
DJF : **25**	MAM : **25**	JJA : **25**	SON : **25**
4. Average Ozone Season Operation (June 1 to August 31) hours/day days/week			5. Total Operation During Ozone Season (days/season)

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 005**

D. EMISSIONS UNIT COMMENT

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 Emissions Unit ID : 005 SCC : 3-05-101-05

E. EMISSIONS INFORMATION BY PROCESS/FUEL

(1) PROCESS/FUEL INFORMATION

1. SCC **3-05-101-05**	2. Description of Process or Type of Fuel **Industrial Processes / Mineral Products / Limestone conveyor. / Bulk Materials Conveyors / Limestone**	
3. Annual Process or Fuel Usage Rate **447831**	4. Ozone Season Daily Process or Fuel Usage Rate	5. SCC Unit **Tons Material Processed**
6. Fuel Average % Sulfur	7. Fuel Average % Ash	8. Fuel Heat Content (mmBtu/SCC Unit)

(2) EMISSIONS INFORMATION

1. Pollutant **PM** **Particulate Matter - Total**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **PM10** **Particulate Matter - PM10**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 005** **SCC : 3-05-104-05**

E. EMISSIONS INFORMATION BY PROCESS/FUEL

(1) PROCESS/FUEL INFORMATION

1. SCC **3-05-104-05**	2. Description of Process or Type of Fuel **Industrial Processes** **Mineral Products** **Limestone unloading.**	**Bulk Materials Unloading Operat** **Limestone**
3. Annual Process or Fuel Usage Rate **447831**	4. Ozone Season Daily Process or Fuel Usage Rate	5. SCC Unit **Tons Material Processed**
6. Fuel Average % Sulfur	7. Fuel Average % Ash	8. Fuel Heat Content (mmBtu/SCC Unit)

(2) EMISSIONS INFORMATION

1. Pollutant **PM** **Particulate Matter - Total**	CAS No.	[**X**] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **PM10** **Particulate Matter - PM10**	CAS No.	[**X**] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 005** **SCC : 3-05-104-99**

E. EMISSIONS INFORMATION BY PROCESS/FUEL

(1) PROCESS/FUEL INFORMATION

1. SCC **3-05-104-99**	2. Description of Process or Type of Fuel **Industrial Processes** **Bulk Materials Unloading Operat** **Mineral Products** **Other Not Classified** **FGD sludge and materials used to stabilize FGD sludge.**	
3. Annual Process or Fuel Usage Rate **632996**	4. Ozone Season Daily Process or Fuel Usage Rate	5. SCC Unit **Tons Material Processed**
6. Fuel Average % Sulfur	7. Fuel Average % Ash	8. Fuel Heat Content (mmBtu/SCC Unit)

(2) EMISSIONS INFORMATION

1. Pollutant **PM** **Particulate Matter - Total**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **PM10** **Particulate Matter - PM10**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

II. EMISSIONS UNIT REPORT

A. EMISSIONS UNIT INFORMATION

1. Emissions Unit Description **One or More Emergency Generators**		
2. Emissions Unit ID **006**	3. Emissions Unit Classification **Unregulated Emissions Unit**	4. Operated During Year? **Y**
5. DEP Permit or PPS Number **1070025002AV**	6. Emissions Unit Status **ACTIVE**	7. Ozone SIP Base Year Emissions Unit?
8. Emissions Unit Startup Date	9. Long-term Reserve Shutdown Date	10. Permanent Shutdown Date

B. EMISSION POINT/CONTROL INFORMATION

1. Emissions Point Type **SINGLE POINT SERVING A SINGLE EMISSIONS UNIT**
2a. Description of Control Equipment 'a' **NO CONTROL EQUIPMENT**
2b. Description of Control Equipment 'b'

C. EMISSIONS UNIT OPERATING SCHEDULE INFORMATION

1. Average Annual Operation hours/day **1** days/week **1**	2. Total Operation During Year (hours/year) **52**
3. Percent Hours of Operation by Season DJF : **25** MAM : **25** JJA : **25** SON : **25**	
4. Average Ozone Season Operation (June 1 to August 31) hours/day days/week	5. Total Operation During Ozone Season (days/season)

*: Pollutant subject to emissions limiting standard or emissions cap

D. EMISSIONS UNIT COMMENT

Emergency generator engine is operated only for testing purposes.

*: Pollutant subject to emissions limiting standard or emissions cap

E. EMISSIONS INFORMATION BY PROCESS/FUEL

(1) PROCESS/FUEL INFORMATION

1. SCC **2-02-001-02**	2. Description of Process or Type of Fuel **Internal Combustion Engines Industrial** **Distillate Oil (Diesel) Reciprocating**	
3. Annual Process or Fuel Usage Rate **3.5**	4. Ozone Season Daily Process or Fuel Usage Rate	5. SCC Unit **1000 Gallons Distillate Oil (Die:**
6. Fuel Average % Sulfur **0.34**	7. Fuel Average % Ash **0.1**	8. Fuel Heat Content (mmBtu/SCC Unit) **140**

(2) EMISSIONS INFORMATION

1. Pollutant **CO** **Carbon Monoxide**	CAS No. **630-08-0**	[**X**] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **NOX** **Nitrogen Oxides**	CAS No. **10102-44-0**	[**X**] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 006** **SCC : 2-02-001-02**

1. Pollutant **PM** **Particulate Matter - Total**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **PM10** **Particulate Matter - PM10**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **SO2** **Sulfur Dioxide**	CAS No. **7446-09-5**	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **VOC** **Volatile Organic Compounds**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 Emissions Unit ID : 007

II. EMISSIONS UNIT REPORT

A. EMISSIONS UNIT INFORMATION

1. Emissions Unit Description **One or More Heating Units and General Purpose Engines**		
2. Emissions Unit ID **007**	3. Emissions Unit Classification **Unregulated Emissions Unit**	4. Operated During Year? **Y**
5. DEP Permit or PPS Number **1070025002AV**	6. Emissions Unit Status **ACTIVE**	7. Ozone SIP Base Year Emissions Unit?
8. Emissions Unit Startup Date	9. Long-term Reserve Shutdown Date	10. Permanent Shutdown Date

B. EMISSION POINT/CONTROL INFORMATION

1. Emissions Point Type **SINGLE POINT SERVING A SINGLE EMISSIONS UNIT**
2a. Description of Control Equipment 'a' **NO CONTROL EQUIPMENT**
2b. Description of Control Equipment 'b'

C. EMISSIONS UNIT OPERATING SCHEDULE INFORMATION

1. Average Annual Operation hours/day **1** days/week **1**				2. Total Operation During Year (hours/year) **52**
3. Percent Hours of Operation by Season				
DJF : **25**	MAM : **25**	JJA : **25**	SON : **25**	
4. Average Ozone Season Operation (June 1 to August 31) hours/day days/week				5. Total Operation During Ozone Season (days/season)

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 007**

D. EMISSIONS UNIT COMMENT

Fire water pump engine only operates for testing purposes.

*: Pollutant subject to emissions limiting standard or emissions cap

E. EMISSIONS INFORMATION BY PROCESS/FUEL

(1) PROCESS/FUEL INFORMATION

1. SCC **2-02-001-02**	2. Description of Process or Type of Fuel **Internal Combustion Engines Industrial** **Distillate Oil (Diesel) Reciprocating**	
3. Annual Process or Fuel Usage Rate **0.17**	4. Ozone Season Daily Process or Fuel Usage Rate	5. SCC Unit **1000 Gallons Distillate Oil (Die**
6. Fuel Average % Sulfur	7. Fuel Average % Ash	8. Fuel Heat Content (mmBtu/SCC Unit)

(2) EMISSIONS INFORMATION

1. Pollutant **CO** **Carbon Monoxide**	CAS No. **630-08-0**	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **NOX** **Nitrogen Oxides**	CAS No. **10102-44-0**	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 007** **SCC : 2-02-001-02**

1. Pollutant **PM** **Particulate Matter - Total**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **PM10** **Particulate Matter - PM10**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **SO2** **Sulfur Dioxide**	CAS No. **7446-09-5**	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **VOC** **Volatile Organic Compounds**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 008**

II. EMISSIONS UNIT REPORT

A. EMISSIONS UNIT INFORMATION

1. Emissions Unit Description **General Plant Fugitives Emissions**		
2. Emissions Unit ID **008**	3. Emissions Unit Classification **Unregulated Emissions Unit**	4. Operated During Year? **Y**
5. DEP Permit or PPS Number **1070025002AV**	6. Emissions Unit Status **ACTIVE**	7. Ozone SIP Base Year Emissions Unit?
8. Emissions Unit Startup Date	9. Long-term Reserve Shutdown Date	10. Permanent Shutdown Date

B. EMISSION POINT/CONTROL INFORMATION

1. Emissions Point Type **NO TRUE EMISSION POINT (FUGITIVE EMISSION)**
2a. Description of Control Equipment 'a' **NO CONTROL EQUIPMENT**
2b. Description of Control Equipment 'b'

C. EMISSIONS UNIT OPERATING SCHEDULE INFORMATION

1. Average Annual Operation hours/day **8** days/week **5**	2. Total Operation During Year (hours/year) **2080**
3. Percent Hours of Operation by Season DJF : **25** MAM : **25** JJA : **25** SON : **25**	
4. Average Ozone Season Operation (June 1 to August 31) hours/day days/week	5. Total Operation During Ozone Season (days/season)

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 008**

D. EMISSIONS UNIT COMMENT

*: Pollutant subiect to emissions limiting standard or emissions cap

E. EMISSIONS INFORMATION BY PROCESS/FUEL

(1) PROCESS/FUEL INFORMATION

1. SCC **3-05-320-09**	2. Description of Process or Type of Fuel **Industrial Processes** **Stone Quarrying - Processing (See** **Mineral Products** **Blasting: General** **Abrasive blasting and abrasive blast material bin.**	
3. Annual Process or Fuel Usage Rate **0.09**	4. Ozone Season Daily Process or Fuel Usage Rate	5. SCC Unit **1000 Tons Raw Material Proces**
6. Fuel Average % Sulfur	7. Fuel Average % Ash	8. Fuel Heat Content (mmBtu/SCC Unit)

(2) EMISSIONS INFORMATION

1. Pollutant **PM** **Particulate Matter - Total**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **PM10** **Particulate Matter - PM10**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 008** **SCC : 3-05-320-09**

1. Pollutant **VOC** **Volatile Organic Compounds**	CAS No.	[ ] Below Threshold [X] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 008** **SCC : 4-02-001-10**

E. EMISSIONS INFORMATION BY PROCESS/FUEL

(1) PROCESS/FUEL INFORMATION

1. SCC **4-02-001-10**	2. Description of Process or Type of Fuel **Petroleum and Solvent Evaporati Surface Coating Operations**	**Surface Coating Application - Gei Paint: Solvent-base**
3. Annual Process or Fuel Usage Rate **2036**	4. Ozone Season Daily Process or Fuel Usage Rate	5. SCC Unit **Gallons Coating Processed**
6. Fuel Average % Sulfur	7. Fuel Average % Ash	8. Fuel Heat Content (mmBtu/SCC Unit)

(2) EMISSIONS INFORMATION

1. Pollutant **PM** **Particulate Matter - Total**	CAS No.	[**X**] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **PM10** **Particulate Matter - PM10**	CAS No.	[**X**] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 008** **SCC : 4-02-001-10**

1. Pollutant **VOC** **Volatile Organic Compounds**	CAS No.	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **4.731664**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **2**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 4.731664 = Average coating density (lb/gal) 8.3 * (Average coating VOC content (weight %) 56 / 100) * Annual Process or Fuel Usage Rate (Gallons Coating Processed) 2036 * (1 / 2000)**		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 008** **SCC : 4-02-999-95**

E. EMISSIONS INFORMATION BY PROCESS/FUEL

(1) PROCESS/FUEL INFORMATION

1. SCC **4-02-999-95**	2. Description of Process or Type of Fuel **Petroleum and Solvent Evaporati Miscellaneous** **Surface Coating Operations Specify in Comments Field** **Painting operations.**	
3. Annual Process or Fuel Usage Rate **4.7**	4. Ozone Season Daily Process or Fuel Usage Rate	5. SCC Unit **Tons Solvent in Coating Used**
6. Fuel Average % Sulfur	7. Fuel Average % Ash	8. Fuel Heat Content (mmBtu/SCC Unit)

(2) EMISSIONS INFORMATION

1. Pollutant **PM** **Particulate Matter - Total**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

1. Pollutant **PM10** **Particulate Matter - PM10**	CAS No.	[X] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year)	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code
5. Emissions Calculation (Show separately both annual and daily emissions calculations)		

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 **Emissions Unit ID : 008** **SCC : 4-02-999-95**

1. Pollutant **VOC** **Volatile Organic Compounds**	CAS No.	[ ] Below Threshold [ ] Not Emitted
2. Annual Emissions (ton/year) **0**	3. Ozone Season Daily Emissions (lb/day)	4. Emissions Method Code **2**
5. Emissions Calculation (Show separately both annual and daily emissions calculations) **Annual Emissions (Ton/Year) 0.0** **VOC emissions included in SCC 4-02-001-10.**		

*: Pollutant subject to emissions limiting standard or emissions cap

Memorandum Florida Department of Environmental Protection

TO:	Joe Kahn, Acting Director – DARM
THRU:	Trina Vielhauer, Chief - BAR Jeff Koerner, Air Permitting North
FROM:	Michael P. Halpin, Air Permitting North
DATE:	June 14, 2006
SUBJECT:	Seminole Electric Generating Station DEP File No. 1070025-004-AC Units 1 - 2 Pollution Control Upgrades

Attached is the final air construction permit for Seminole Electric Cooperative's Seminole Generating Station. This is an existing facility which is currently in the process of adding pollution controls to its two existing steam generating units in Palatka. The modification incorporates a proposal to meet the CAIR and CAMR requirements, as well as provide for emission reductions adequate to provide some PSD netting for a planned Unit 3 (covered in a separate application).

The Public Notice of Intent to Issue concerning the Draft Permit was published in the Palatka Daily News on May 13, 2006. No comments were received other than those from the applicant, which are identified within the Final Determination (attached).

I recommend your approval.

Attachments

/mph

Joe -
we spoke with Seminole about our responses to their comments & they are OK.
Trina

FINAL DETERMINATION

- Seminole Electric Cooperative, Inc.
Seminole Generating Station
DEP File No. 1070025-004-AC

The Department distributed a public notice package on May 5, 2006 to allow the applicant, Seminole Electric Cooperative, Inc. (SECI) to install pollution control equipment on Seminole Generating Station (SGS) Units 1 and 2 located at 890 US Highway 17, North of Palatka, Putnam County. The Public Notice of Intent to Issue concerning the Draft Permit was published in the Palatka Daily News on May 13, 2006.

COMMENTS/CHANGES

No comments were received by the Department from the public. No comments were received from EPA. Comments were received from the applicant by letter dated May 19, 2006. The applicants comments are summarized below and the Department's responses are included following each comment.

Minor edits: Cover page (Authorized representative Title), page 2 (Project Description), page 5 (Specific Condition 2 – added the word "may" prior to the variety of FGD improvements being contemplated, and Specific Condition 3 – struck reference to approved drawings and plans, since there were none), page 6 (Specific Condition 6 – added a sentence specifying gross MW rating, and "Emissions Standards" note - specified that interim limits become effective once changes are completed), page 7 (Specific Conditions 10 - allowed EPA Method 8A, Specific Conditions 11 and 16 – changed Rule Cites), and page 9 (Specific Condition 1 – changed language from "no additional emissions occur" to "emissions are minimized").

RESPONSE: These changes are acceptable, with the exception of the suggested "Emissions Standards" note, which is accepted in part (see the remainder of this Determination).

Page 4, Condition 7: Provide an option to submit the Title V application when the renewal is due (July, 2009), since this is reasonably close to the expected air construction completion date.

RESPONSE: Per Rule, the Department is unable to accommodate this change.

Page 6, Condition 8: Change NO_X emission limits from 30-day rolling to 12-month rolling averages.

RESPONSE: The Department agrees. The NO_X limit has been established in the permit for 2 reasons – for PSD netting and CAIR emission allotments. In both cases, the regulatory requirement is annual; hence a 12-month rolling average is appropriate.

Page 6, Condition 9: Change CO emission limit from a 0.20 lb/MMBtu 12-month rolling average to a 13,448 TPY 12-month rolling limit. Add an initial compliance test to demonstrate the vendor's burner guarantee of 0.20 lb/MMBtu.

RESPONSE: The Department agrees in part. The CO limit of 0.20 lb/MMBtu was placed in the permit to demonstrate that the vendor's burner guarantee could be met. However, the regulatory requirement is that there can be no increase in CO emissions above the baseline of 13,448 TPY (PSD netting). The Department notes that by meeting the 0.20 lb/MMBtu emission rate specified in the draft permit which was publicly noticed, the effective PSD annual emission rate is 12,565 TPY. Absent the applicant agreeing to an additional public notice to accommodate an "apparent" increase in CO emissions of 883 TPY, a 12-month rolling total (federally enforceable) of 12,565 will be allowed.

Page 7, Condition 12: Change the Hg limit from 0.36 TPY (combined for Units 1 and 2) to 0.59 TPY (combined for Units 1, 2 and 3). The applicant notes that the basis for Hg limits on Units 1 and 2 is the upcoming CAMR, as well as PSD netting. For the purposes of PSD netting, the regulatory requirement is established from the baseline emissions of 0.65 TPY, hence a facility limit of 0.59 TPY *still* represents a reduction in mercury emissions.

RESPONSE: The Department agrees. The proposed facility limit (Units 1, 2, and 3) of 0.59 TPY ensures that both the PSD netting and the CAMR requirements can be met.

NOTE: The Department acknowledges that the Draft Permit included the following typographical error: the mercury emissions standard should have been "0.36 TPY" and not "0.036 TPY". This standard represented the total emissions from Units 1 and 2.

Page 9, Condition 5: The condition should be revised to provide for the (more restrictive) Subpart Db NO_X emission limit of 0.20 lb/MMBtu on a 30-day rolling average, for the steam generating unit configured to accept the operating CBO™ Unit emissions.

RESPONSE: The Department agrees and will also add item "d." to Page 6, Condition 8, reflecting the same issue.

Emissions Standards Note (Page 6) and Condition 17 (Page 8): These two sections of the permit establish the effective date of the emissions standards and notification requirements to the initial coal fires in SGS Unit 3. The applicant requested that these provisions be tied to "initial commercial startup" rather than the "initial coal fires".

RESPONSE: The Department does not accept the requested changes, which could allow the project to exceed the PSD significant emissions rates.

Changes to Technical Evaluation and Preliminary Determination: Several changes proposed by applicant.

RESPONSE: Since there exists no requirement for the subject document to be re-issued (i.e. there is no BACT Determination), the Department makes no response to SECI's suggested changes.

ADDITIONAL CHANGES

For the purposes of providing the applicable Citation, the Department adds the word [Design] after Conditions 2 through 6 (Pages 5 and 6).

For the purposes of clarification, the Department changes the word "total" to "emissions rate" in Conditions 7.c, 8.c and 10.c (Pages 6 and 7).

For the purpose of clarification, the Department eliminates the words "(except NOx)" in Condition 5, Page 9.

CONCLUSION

The final action of the Department is to issue the permit with the minor changes described above.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

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

Authorized Representative:
James R. Frauen, Project Director

Air Permit No. 1070025-004-AC
Seminole Generating Station
Units 1-2 Pollution Controls Upgrade

Enclosed is Final Air Permit No. 1070025-004-AC, which authorizes the construction and/or upgrade of pollution control equipment for Units 1 and 2 at the existing Seminole Generating Station. The existing power plant is located at 890 North U.S. Highway 17, north of Palatka, in Putnam County, Florida. As noted in the attached Final Determination, only minor changes and clarifications were made. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty (30) days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 6/21/06 to the persons listed:

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

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Mary L Harvey (Clerk) 6/21/06 (Date)

PERMITTEE

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

Authorized Representative:
James R. Frauen, Project Director

Air Permit No. 1070025-004-AC
Seminole Generating Station
Units 1-2 Pollution Controls Upgrade
Facility ID No. 1070025
SIC No. 4911
Permit Expires: December 31, 2009

PROJECT AND LOCATION

This permit authorizes the construction and/or upgrade of pollution control equipment for Units 1 and 2 at the existing Seminole Generating Station, which is located at 890 North U.S. Highway 17, north of Palatka, in Putnam County, Florida. The map coordinates are: Zone 17; 438.80 km East; and 3289.20 km North.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403, F.S., and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. 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. This air construction permit supplements all other valid air construction and operation permits.

CONTENTS

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

6/21/2006
(Date)

FACILITY AND PROJECT DESCRIPTION

The existing Seminole Generating Station (SGS) consists of two 714.6 megawatt, electric, coal fired steam electric generators; a coal handling and storage system; a limestone unloading, handling and storage system; and a flue gas desulphurization (FGD) sludge stabilization system.

This project includes the replacement of the low NO_X burners; the addition of SCRs, an alkali injection system and carbon burnout (CBO); and improvements to the existing FGD system and steam turbines. The following units are affected by this air construction permit:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
001	Steam Generation	SGS (Existing) Unit 1 upgraded to 735.9 MW
002	Steam Generation	SGS (Existing) Unit 2 upgraded to 735.9 MW
009	Materials Handling	Carbon Burn-Out (CBO™) Feed Fly Ash Silo (New)
010	Materials Handling	CBO™ Product Fly Ash Storage Dome (New)
011	Materials Handling	CBO™ Product Fly Ash Loadout Storage Silo (New)
012	Materials Handling	CBO™ Product Fly Ash Fugitives (New)
013	Hot Water Generation	CBO™ Process Fluidized Bed Combustor (New) NSPS Subpart Db

REGULATORY CLASSIFICATION

Title III: The existing facility is a major source of hazardous air pollutants (HAP).

Title IV: The existing facility operates units subject to the acid rain provisions of the Clean Air Act.

Title V: The existing facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.

PSD: The existing facility is a PSD-major facility in accordance with Rule 62-212.400, F.A.C., although this project does not trigger a PSD Review.

1. Permitting Authority: All documents related to applications for permits to construct, modify, or operate emissions units at this facility 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 permit applications shall also be sent to the Compliance Authority.

2. 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.

3. Appendices: The following Appendices are attached as part of this permit: Appendix GC (General Conditions).

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C. 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 62-4, 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

5. 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.]

6. Construction Approval: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Rule 62-210.200(76), F.A.C. defines *construction* as, "Construction –

   (a) The act of performing on-site fabrication, erection, installation or modification of an emissions unit or facility of a permanent nature, including installation of foundations or building supports; laying of underground pipe work or electrical conduit; and fabrication or installation of permanent storage structures, component parts of an emissions unit or facility, associated support equipment, or utility connections. Land clearing and other site preparation activities are not a part of the construction activities.

   (b) For the purposes of Rules 62-212.300, 62-212.400, 62-212.500, and 62-212.720, F.A.C., construction means any physical change or change in the method of operation (including fabrication, erection, installation, or modification of an emissions unit) that would result in a change in emissions.

   (c) For the purposes of the provisions of 40 CFR Parts 60 and 61, adopted by reference in Rule 62-204.800, F.A.C., construction means fabrication, erection, or installation of an affected facility.

   (d) For the purposes of the provisions of 40 CFR Part 63, adopted by reference in Rule 62-204.800, F.A.C., construction means the on-site fabrication, erection, or installation of an affected source. Construction does not include the removal of all equipment comprising an affected source from an existing location and reinstallation of such equipment at a new location. The owner or operator of an existing affected source that is relocated may elect not to reinstall minor ancillary equipment including piping, ductwork, and valves. However, removal and reinstallation of an affected source will be construed as reconstruction if it satisfies the criteria for reconstruction as defined in this section. The costs of replacing minor ancillary equipment must be considered in determining whether the existing affected source is reconstructed." Such permits shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

7. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions units. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after completion of work and commencing operation. 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. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. EU 001 and 002 – Boilers No. 1 and 2

This section of the permit addresses the following existing emissions units:

Emissions Unit Nos. 001 and 002
Steam Electric Generator Nos. 1 and 2 are existing, 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. Steam Electric Generator Nos. 1 and 2 are each equipped with an electrostatic precipitator (ESP) to control particulate matter, a wet limestone flue gas desulphurization (FGD) unit to control sulfur dioxide, and low NO_X burners and low excess-air firing to control nitrogen oxides. {Permitting note(s): IMPORTANT REGULATORY CLASSIFICATIONS - The emissions units are regulated under Acid Rain, Phase II and 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(5), F.A.C., Prevention of Significant Deterioration (PSD); and Rule 62-212.400(6), 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.}

PREVIOUS APPLICABLE REQUIREMENTS

1. Other Permits: The conditions of this permit supplement all previously issued air construction and operation permits for this emissions unit. Unless otherwise specified, these conditions are in addition to all other applicable permit conditions and regulations. [Rule 62-4.070, F.A.C.]

EQUIPMENT AND CONSTRUCTION

2. Flue Gas Desulphurization System (FGD) Upgrade: In order to reduce the emissions of sulfur dioxide, the permittee shall make upgrades to the existing Units 1 and 2 scrubbers so as to improve the SO_2 removal efficiency from approximately 87 to 95%. The improvements may include the following types of work: scrubber module modifications, upgrades to the modules mist eliminator wash system, expansion of the oxidation air system, modifications to the existing sparger rings in the absorber recycle tanks, upgrades to the Effluent Processing Facility (EPF) System and a new gypsum conveyor system. The upgrades will allow SGS to meet the 0.67 lb/MMBtu SO_2 emission limits specified in this permit. [Design]

3. Selective Catalytic Reduction (SCR) Systems: The permittee shall construct, tune, operate, and maintain a new SCR system for Units 1 and 2, to reduce emissions of nitrogen oxides (NO_X) as described in the application. The SCR system shall be designed to achieve a NO_X emission rate of no more than 0.07 lb/MMBtu. An SCR reagent system shall be installed, consisting of a new urea to ammonia processing system and associated bulk storage systems. The SCR system shall be designed for a maximum ammonia slip rate of 5 ppmvd @ 15% O_2. [Design]

4. Low NO_X Burner Replacement: The permittee shall replace, tune, operate and maintain low NO_X burners on Units 1 and 2. Additionally, the existing burner inlet systems will be modified to ensure even air flow, and the Overfire Air System (OFA) will be modified to utilize at least six ports per wall compared with the existing system design of four ports per wall. These replacements are designed to achieve the Acid Rain Program NO_X annual average emission limit of 0.46 lb/MMBtu, which will be effective in 2008. [Design]

5. Alkali Injection System: The permittee shall construct and operate a new alkali injection system on Units 1 and 2 to mitigate the potential impacts of SO_3 formation resulting from the operation of the SCR control systems. The design criteria shall ensure that sulfuric acid mist emissions do not increase above the sulfuric acid mist emissions baseline. [Design]

6. Turbine Upgrade: Each existing steam turbine for Units 1 and 2 shall be upgraded for increased unit

efficiency, and in order to recover portions of the lost electrical output from powering the above additions. Such efficiency improvements may include blade and/or rotor redesigns and replacements. The nominal gross MW rating per unit will increase from 714.6 to 735.9 MW although each boiler maximum heat input will remain at 7,172 MMBtu/hr. [Design]

PERFORMANCE REQUIREMENTS

This permit does not alter any specifications or limitations included in previous permits that define permitted capacities such as heat input rates, fuel consumption, or hours of operation. It does not authorize any additional fuels or such other methods of operation.

EMISSIONS STANDARDS

A concurrent application is being processed for a new SGS Unit 3. Where affected, the below emission standards are shown for this project (Pollution Control Upgrades) as "interim" limits which become effective once all upgrades are complete. As of the first monitoring period following the establishment of initial coal fires in SGS Unit 3, the latter "permanent" emission limits will become effective.

7. Sulfur Dioxide (SO_2):
   a. The interim Sulfur Dioxide emissions from Units 1 and 2 shall not exceed 0.67 lb/MMBtu (combined for Units 1 and 2), based upon a 24 hour block average via CEMS.
   b. The permanent limits shall be 0.38 lb/MMBtu (combined for Units 1 and 2), based upon a 24 hour block average via CEMS.
   c. The combined emission rate shall be computed by adding the total lbs emitted for both Units 1 and 2, divided by the total MMBtu heat input for both Units 1 and 2 for each 24-hour block period.

   [PSD Avoidance]

8. Nitrogen Oxides (NO_X):
   a. The interim Nitrogen Oxide emissions from Units 1 and 2 shall not exceed 0.46 lb/MMBtu, based upon a 12-month rolling average. Compliance shall be determined by data collected from the certified continuous emissions monitor (CEM).
   b. The permanent limits shall be 0.33 lb/MMBtu (combined for Units 1 and 2), based upon a 12-month rolling average via CEMS.
   c. The combined emission rate shall be computed by adding the total lbs emitted for both Units 1 and 2, divided by the total MMBtu heat input for both Units 1 and 2 for each 12-month rolling period.
   d. When operating the CBO fluidized bed combustor, the affected Steam Electric Generating Unit shall not exceed 0.20 lb/MMBtu NO_X emissions based on a 30-day rolling average via CEMS.

   [40 CFR Parts 72 and 76; NSPS Subpart Db and PSD Avoidance]

9. Carbon Monoxide (CO)/Volatile Organic Compounds (VOC): The emission of Carbon Monoxide shall not exceed 12,565 TPY based upon a 12-month rolling total. The existing CO emission monitors which are installed in the stack shall be certified according to 40 CFR Part 60 and the data collected shall be combined and utilized to demonstrate compliance annually. Also, initial performance test data shall be submitted to demonstrate compliance with the burner CO guarantee of 0.20 lb/MMBtu. For VOC, an initial stack test (only) shall be required in order to demonstrate that the emissions do not exceed the established baseline emission rate of 0.06 lb/ton of coal. Testing shall be according to EPA Method 18, 25, 25A or 25B.
   [PSD Avoidance]

10. Sulfuric Acid Mist (SAM):

   a. The interim Sulfuric Acid Mist emissions from Units 1 and 2 shall not exceed 0.096 lb/MMBtu, based upon an initial stack test (only) via EPA Method 8 or 8A.

   b. The permanent limits shall be 0.031 lb/MMBtu (combined for Units 1 and 2), based upon annual stack test via EPA Method 8 or 8A.

   c. The combined emission rate shall be computed measuring the lb/MMBtu emission rate on each unit, multiplying each unit's maximum emission rate by its annual heat input (MMBtu), adding the total lbs emitted for both Units 1 and 2, and dividing by the total MMBtu heat input for both Units 1 and 2.

   [PSD Avoidance]

11. Particulate Matter (PM/PM_{10}): The emission limit for particulate matter shall not exceed 0.03 lb/MMBtu on each individual unit, as measured by an annual stack test via EPA Method 5B. [Current Title V Limit]

12. Mercury (Hg): The permanent emission limitation for mercury shall be 0.59 tons per year (combined for Units 1, 2 and any future emission units), based upon annual stack tests via EPA Method 101A or 108 or CEMS (when operational and certified). The combined total shall be computed by measuring the lb/MMBtu emission rate on each unit, multiplying each unit's emission rate by its annual heat input (MMBtu) and adding the total lbs emitted, divided by 2000. [Requested by Applicant]

EMISSIONS PERFORMANCE TESTING

13. Test Notification: The permittee shall notify the Compliance Authority in writing at least 15 days prior to any required tests. The notification shall include: the scheduled date, approximate start time, test team, contact name and phone number, description of unit to be tested, and the tests to be performed. [Rule 62-297.310(7)(a)9, F.A.C.]

14. Ammonia Slip. Performance Tests: Within 60 days after completing construction of each SCR system and bringing each unit on line, the permittee shall conduct tests to determine the ammonia slip rate in accordance with EPA Method CTM-027 or other methods approved by EPA. Subsequent tests shall be conducted during each federal fiscal year. If tests show ammonia slip emissions are greater than 5 ppmvd @ 15% O_2, the permittee shall take corrective actions such as repair, addition of catalyst, replacement of catalyst, etc. The corrective actions which are taken shall be submitted with the test data. [Rules 62-4.070(3) and 62-297.310(7), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

15. NO_X and SO_2 CEMS: The permittee shall demonstrate compliance with the emissions standards specified in this permit with data collected from the existing NOx, SO_2, CO_2, and stack gas flow rate continuous monitors installed pursuant to the Acid Rain requirements. [Rules 62-4.070(3) and 62-212.400, F.A.C.]

16. CO CEMS: To demonstrate compliance, the permittee shall certify, calibrate, operate and maintain a continuous emissions monitoring system (CEMS) to continuously monitor and record the emissions of carbon monoxide. The existing Thermo Electron Corp Model 48C monitors may be utilized for this purpose, provided that they are able to demonstrate compliance with 40 CFR 60 Appendix B, Performance Specification 4 and Appendix F, Quality Assurance Procedures. CEMS shall monitor and record data during all periods of Units 1 and 2 operation, including startup, shutdown, malfunction or emergency conditions, but not including continuous monitoring system breakdowns, repairs, calibration checks, or zero and span adjustments. For each calendar quarter, monitor availability shall be 95% or greater. If unable to achieve this level, the permittee shall submit a report identifying the problems in achieving 95% monitor availability and a plan of corrective actions. The permittee shall implement the reported corrective actions within the next calendar quarter. [Rules 62-4.070(3), F.A.C. and requested by applicant]

RECORDS AND REPORTS

17. Test Reports: The permittee shall prepare and submit reports for all required tests in accordance with the provisions of Rule 62-297.310(8), F.A.C. The report shall include copies of the continuous monitoring records. Additionally, an official notification shall be made to the Compliance Authority 72 hours prior to the establishment of initial coal fires in SGS Unit 3, for the purpose of complying with the limits herein.

This section of the permit addresses the following emissions units:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
009	Materials Handling	Carbon Burn-Out (CBO™) Feed Fly Ash Silo
010	Materials Handling	CBO™ Product Fly Ash Storage Dome
011	Materials Handling	CBO™ Product Fly Ash Loadout Storage Silo
012	Materials Handling	CBO™ Product Fly Ash Fugitives
013	Hot Water Generation	CBO™ Process Fluidized Bed Combustor NSPS Subpart Db

DESIGN AND ESSENTIAL POTENTIAL TO EMIT (PTE) PARAMETERS

1. CBO™ Process Fluidized Bed Combustor: The maximum design heat input rate to the CBO™ Process Fluidized Bed Combustor (EU-013) shall be 114.7 MMBtu/hr. The emissions from the CBO™ Process Fluidized Bed Combustor shall be routed back to Units 1 and 2 flue gas ductwork, upstream of the ESP, SCR and FGD System, so as to ensure that emissions are minimized. [Design; Rules 62-210(PTE) and 62-4.070(3), F.A.C.]

2. Baghouse Controls: Particulate emissions from Emission Units Nos. 009, 010 and 011 shall be controlled by baghouses that are designed, operated, and maintained to achieve a particulate matter design specification of 0.01 grains/acf of exhaust. New and replacement bags shall meet these specifications based on vendor design information. No particulate matter emissions tests are required. The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Design; Rules 62-4.070(3) and 62-210.650, F.A.C.]

3. Hours of Operation: Emission Unit Numbers 009, 010, 011, 012 and 013 associated with the Carbon Burnout Unit are each allowed to operate continuously (8760 hrs/yr). [Rule 62-210.200(PTE), F.A.C.]

EMISSION LIMITATIONS AND PERFORMANCE STANDARDS

4. Authorized Fuels: Only fly ash generated from EU-001 and 002 may be used as fuel for the CBO™ Process Fluidized Bed Combustor (EU-013), except for the purposes of start-up. Start-up fuel shall be distillate fuel oil, limited to 0.5% sulfur and 14,300 gallons per calendar year. Records of fuel oil consumed for EU-013, demonstrating compliance with this condition shall be kept on-site so as to be readily available for review. Additionally, SGS shall totalize fuel usage data for annual (AOR) reporting. [Design; Rule 62-4.070(3), F.A.C.]

5. NSPS Provisions: EU-013 shall comply with the requirements of 40 CFR 60, Subpart Db. As a result of the configuration identified in above Condition 1, demonstration of the Subpart limits shall be allowed via the existing SGS Units 1 and 2 CEMS and stack testing. SGS shall include this demonstration upon initial installation and annually thereafter. [Note: Due to the configuration, there will be no practical method to test the CBO™ Unit separately. However, the combined emissions from the steam generating unit with the CBO™ Unit (when operating) shall comply with the NSPS NO_X limit of 0.20 lb/MMBtu on a 30 day rolling average via CEMS. The CBO™ Unit exhaust shall only be routed to one unit at a time.]

6. Baghouse Exhausts: As determined by EPA Method 9 observations, visible emissions shall not exceed 5% opacity from each baghouse exhaust point for Emissions Unit Nos. 009, 010 and 011. [Design; Rules 62-4.070(3), 62-210.650, and 62-297.620(4) F.A.C.]

7. Fugitive Dust Control: The following requirements shall be met to minimize fugitive dust emissions from the storage and handling facilities, including haul roads and CBO-related operations:
   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.

8. Maximum Expected Emissions: The following table identifies the maximum expected emissions, design specifications and fugitives associated with the CBO™ Process. This table is shown for convenience purposes and does not represent additional, allowable emission limitations beyond those listed within the permit. [Design]

Emissions Unit No.	Control Device	Exhaust Flow Rate (dscfm)	PM Emission Rate (gr/dscf)	PM Emission Rate (lb/hr)	PM Emission Rate (TPY)
009	Baghouse	3,000	0.01	0.3	1.1
010	Baghouse	6,000	0.01	0.5	2.3
011	Baghouse	6,000	0.01	0.5	2.3
012	Paved Roads; Watering	---	---	0.1	0.2
TOTALS				1.4	5.8

TEST METHODS AND PROCEDURES

9. Test Notification: At least 15 days prior to the date on which each formal compliance test is to begin, the permittee shall notify the Compliance Authority of: the date, time, and place of the test; and the contact person who will be responsible for coordinating and having the test conducted. [Rule 62-297.310(7)(a)9, F.A.C.]

10. Compliance Tests: Each baghouse exhaust point for EU-009, EU-010, and EU-011 shall be tested to demonstrate initial compliance with the specified opacity standard. The initial tests shall be conducted within 60 days after achieving permitted capacity, but not later than 180 days after initial operation of the unit. Thereafter, each baghouse exhaust point for EU-009, EU-010, and EU-011 shall be tested to demonstrate compliance with the specified opacity standard during each federal fiscal year (October 1st to September 30th) and within the 12-month period prior to renewing the operation permit. [Rule 62-297.310(7)(a)1 and 4, F.A.C.]

11. Test Procedures: All tests shall be conducted in accordance with EPA Method 9, which is described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Tests shall also comply with the applicable requirements of Rule 62-297.310, F.A.C. Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur. [Rules 62-204.800 and 62-297.310(4) and (5), F.A.C.; 40 CFR 60, Appendix A]

12. Special Compliance Tests: When the Compliance Authority, 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 Compliance Authority. [Rule 62-297.310(7)(b), F.A.C.]

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

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

G.14 The permittee shall comply with the following:

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

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

c) Records of monitoring information shall include:

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

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

1. Article Addressed to:

Mr. Jim Frauen
Seminole Electric Cooperative, Inc.
Payne Creek Generating Station
16313 North Dale Mabry Highway
Tampa, Florida 33618

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number
(Transfer from service label) 7000 1670 0013 3110 0253

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7000 1670 0013 3110 0253

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	

Postmark Here

Mr. Jim Frauen
Seminole Electric Cooperative, Inc.
Payne Creek Generating Station
16313 North Dale Mabry Highway
Tampa, Florida 33618

PS Form 3800, May 2000 See Reverse for Instructions

Florida Department of
Environmental Protection

Memorandum

TO: Trina Vielhauer

THRU: J. F. Koerner JK

FROM: M. P. Halpin MH

DATE: April 28, 2006

SUBJECT: Seminole Electric Cooperative, Inc.
Pollution Control Upgrades including CAIR/CAMR
DEP File No. 1070025-004-AC

Attached is the public notice package for Seminole Electric Cooperative's Seminole Generating Station (SGS) air construction permit. This is an existing facility which is currently in the process of adding pollution controls to its two existing steam generating units in Palatka. The modification incorporates a proposal to meet the CAIR and CAMR requirements, as well as provide for emission reductions adequate to provide some PSD netting for a planned Unit 3 (covered in a separate application).

I recommend your approval.

/mph

Attachments

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Jim Frauen
Seminole Electric Cooperative, Inc.
Payne Creek Generating Station
16313 North Dale Mabry Highway
Tampa, Florida 33618

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Julie Luders ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) Julie Luders

C. Date of Delivery 6/23/06

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

JUN 2 3 2006 33618 HOLLYWOOD BRANCH

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number
(Transfer from service label) 7000 1670 0013 3110 0253

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

OFFICIAL USE

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	

Postmark Here

7000 1670 0013 3110 0253

Mr. Jim Frauen
Seminole Electric Cooperative, Inc.
Payne Creek Generating Station
16313 North Dale Mabry Highway
Tampa, Florida 33618

PS Form 3800, May 2000 *See Reverse for Instructions*