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

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 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.

(Clerk) 6/21/06 (Date)

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.

Department of
Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

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

Section 1. General Information
Section 2. Administrative Requirements
Section 3. Emissions Units Specific Conditions
Section 4. Appendices

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.]

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

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

CERTIFIED MAIL – RETURN RECEIPT REQUESTED

RECEIVED
APR 18 2006
BUREAU OF AIR REGULATION

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

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Telephone 813.963.0994 Fax 813.264.7906 www.seminole-electric.com

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 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 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 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 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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APPLICATION INFORMATION

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 — Signature 4/14/06 — Date

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/m^3
Custom Ranges	0-1 to 10000 ppm 0-1 to 10000 mg/m^3
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)

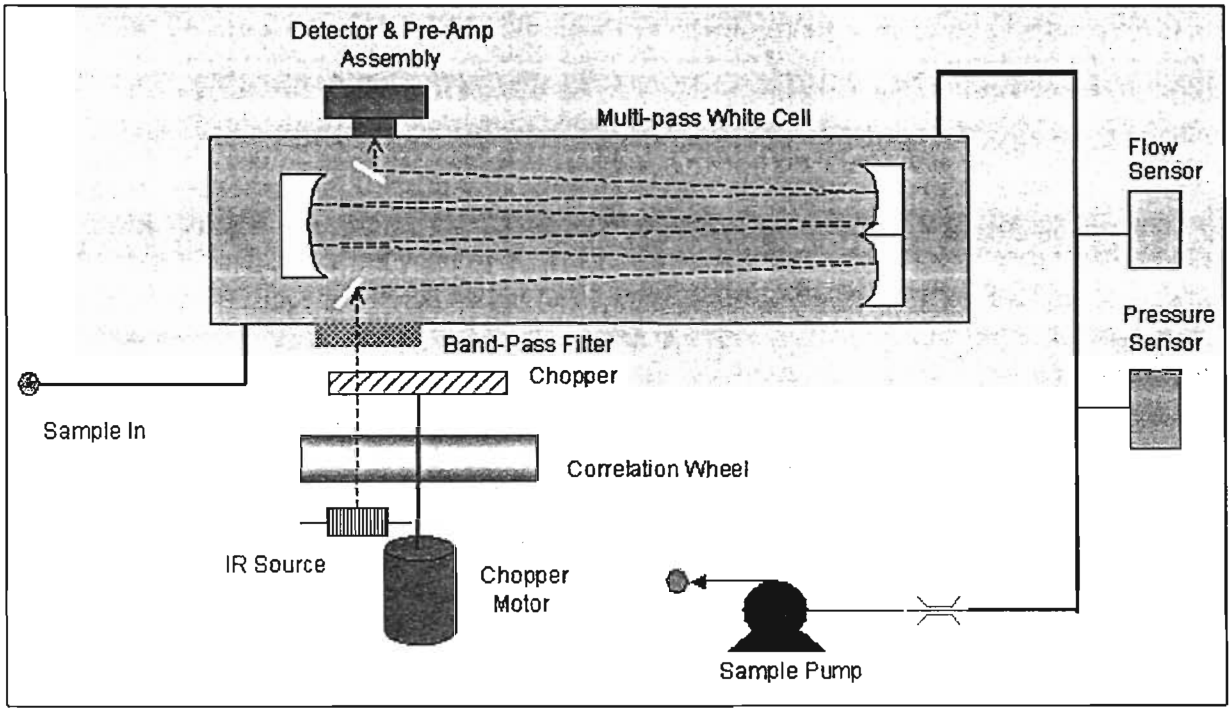
Analyze • Detect • Measure • Control

Thermo ELECTRON CORPORATION

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.

TÜV MANAGEMENT SERVICE ISO 9001

Lit _48CEID_8/05

Thermo ELECTRON CORPORATION

Environmental Instruments Air Quality Instruments
27 Forge Parkway
Franklin, MA 02038
(866) 282-0430
(508) 520-0430
(508) 520-1460 fax
www.thermo.com/air

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^{o} 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.

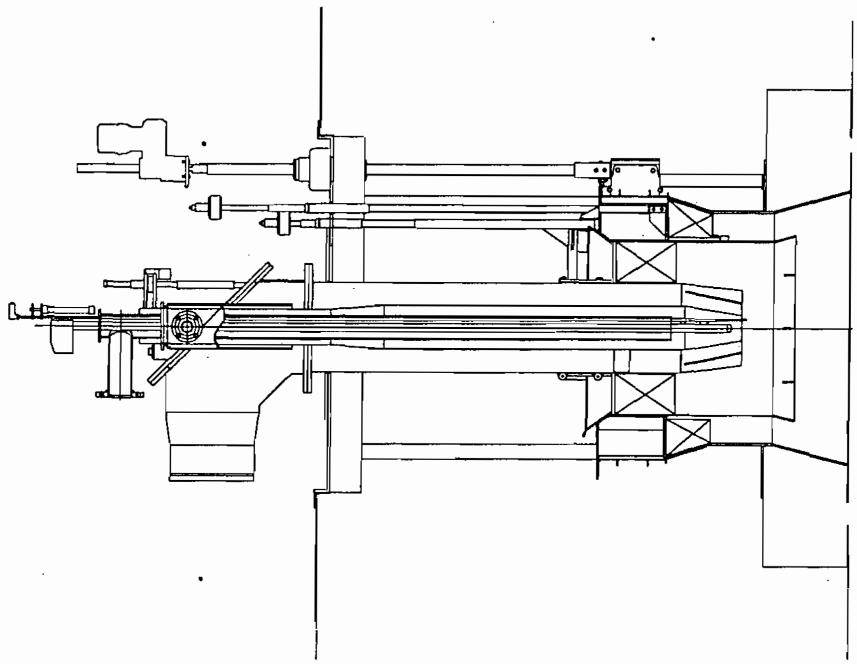


Figure 4-1: Vortex Series Burner

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.

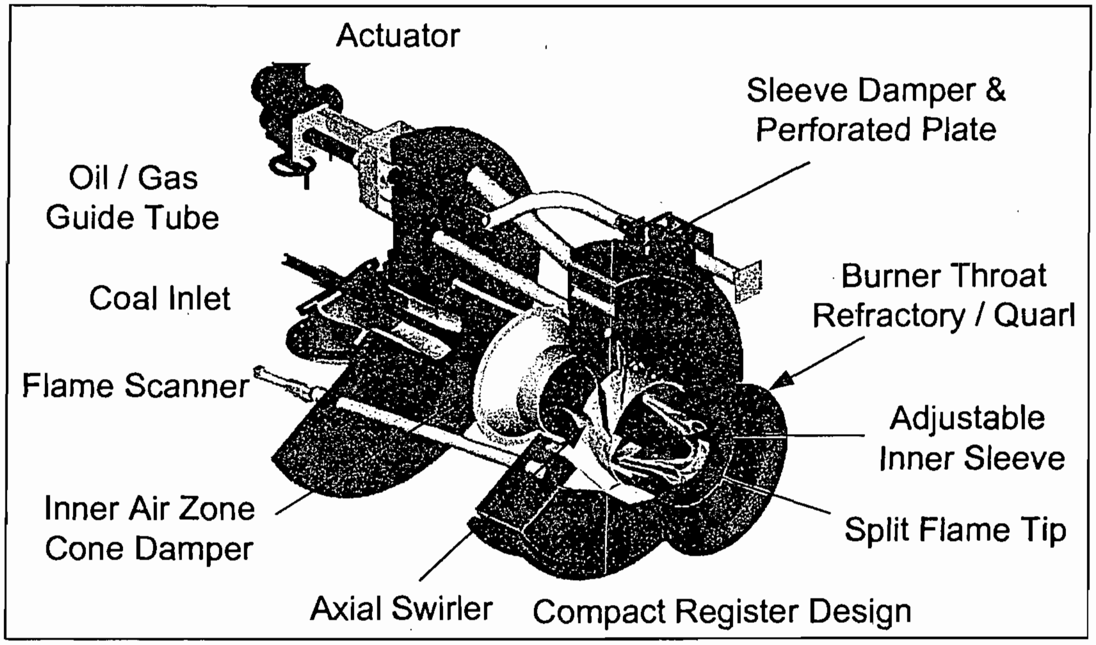
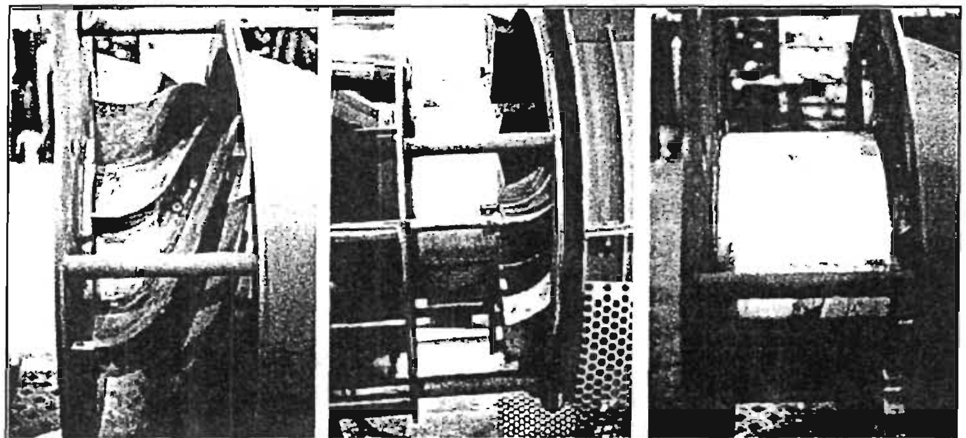


Figure 4-2: Vortex Series Burner Split View

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.

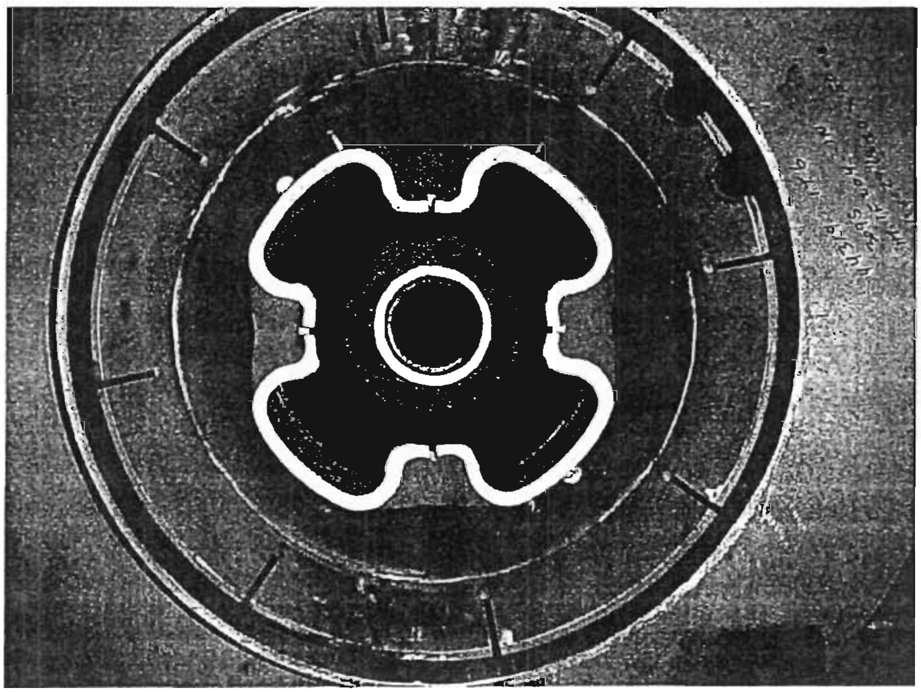


Figure 4-4: Split Flame Coal Nozzle Tip

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.

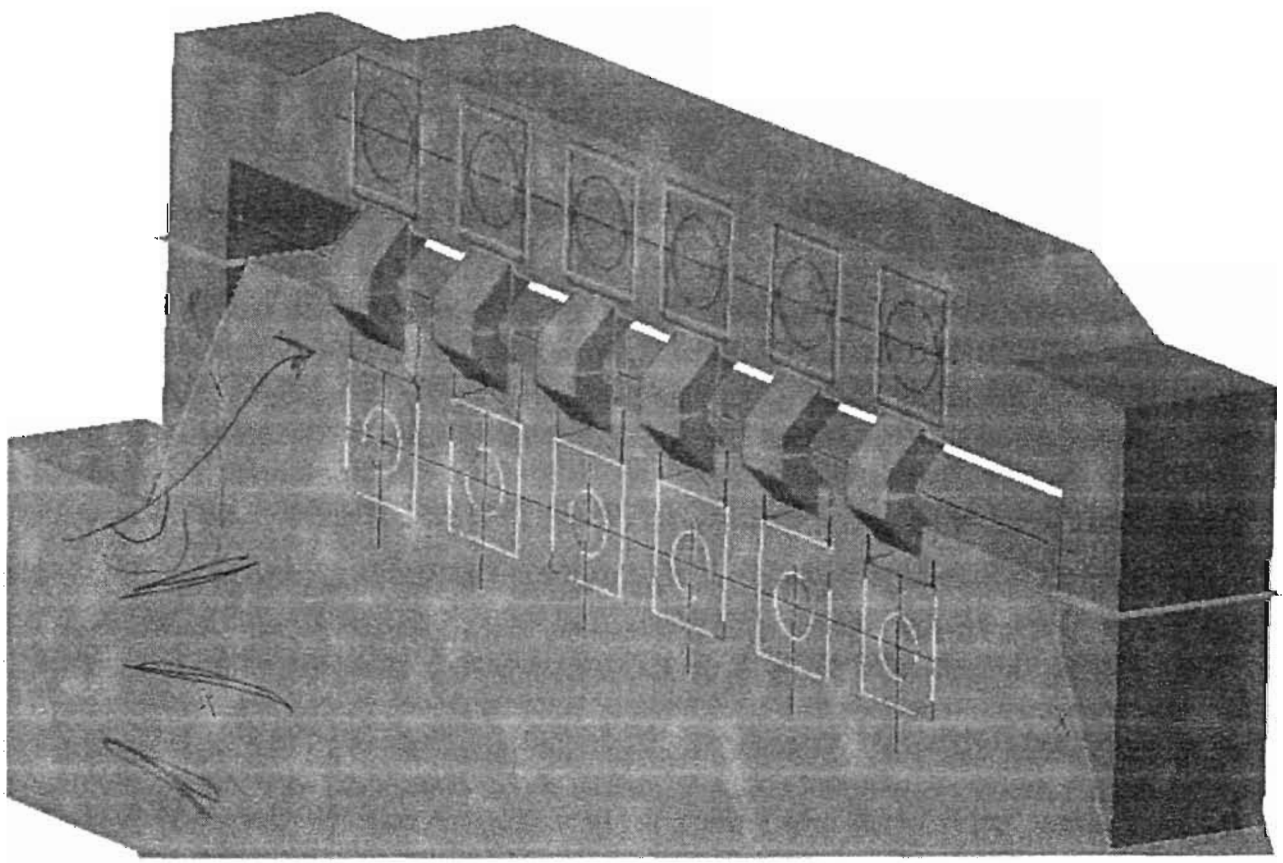


Figure 4-7: Concept Isometric View of OFA Jumper Ducts used to Supplement OFA from top of Main Windbox

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.

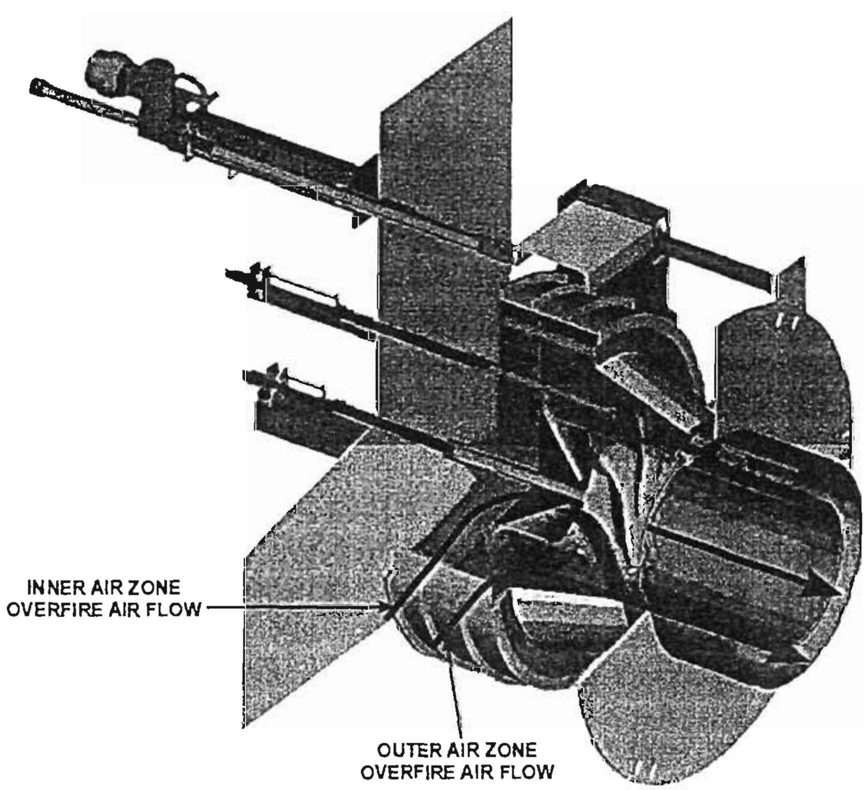


Figure 4-8: Vortex Series OFA Register Split View

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.

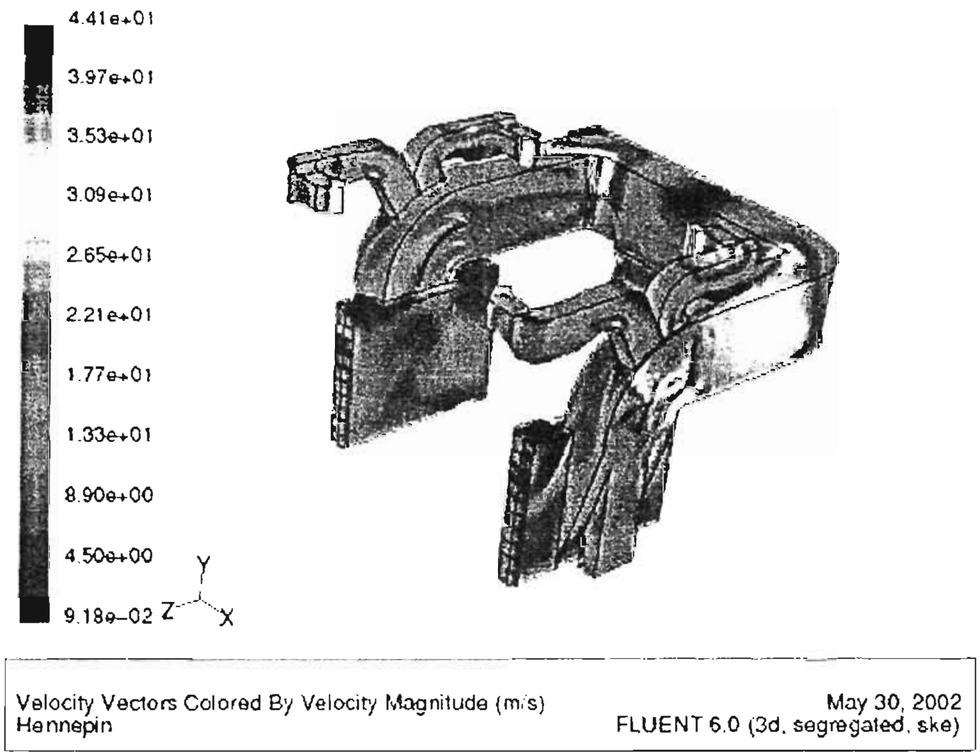


Figure 4-9: Sample CFD Modeling result for Air Flow in Secondary Air Ducts

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.

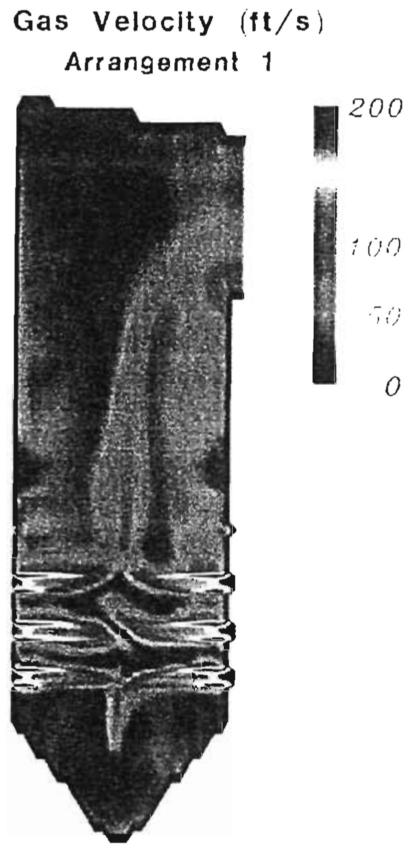


Figure 4-10: Sample CFD Model of an opposed wall fired unit with OFA System

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

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

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. Opalinski 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

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 Bituminous/Subbituminous Coal** **Electric Generation 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

Facility ID : 1070025 **Emissions Unit ID : 001** **SCC : 1-01-002-02**

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

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

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

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

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

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

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

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 (Biti**	
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

Facility ID : 1070025 | Emissions Unit ID : 002 | 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) **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

Facility ID : 1070025 Emissions Unit ID : 002 SCC : 1-01-002-02

1. Pollutant **H107** CAS No. **7664-39-3** **Hydrogen fluoride (Hydrofluoric acid)**		[ ] 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** CAS No. **1336-36-3** **Polychlorinated biphenyls (Aroclors)**		[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** CAS No. **10102-44-0** **Nitrogen Oxides**		[ ] 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

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

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

Facility ID : 1070025 **Emissions Unit ID : 002** **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

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

Facility ID : 1070025 **Emissions Unit ID : 003**

D. EMISSIONS UNIT COMMENT

*: Pollutant subject to emissions limiting standard or emissions cap

Facility ID : 1070025 Emissions Unit ID : 004

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

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

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.

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** **Bulk Materials Conveyors** **Mineral Products** **Limestone** **Limestone conveyor.**	
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

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** **Bulk Materials Unloading Operat** **Mineral Products** **Limestone** **Limestone unloading.**	
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

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

Facility ID : 1070025 Emissions Unit ID : 006

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

Facility ID : 1070025 **Emissions Unit ID : 006**

D. EMISSIONS UNIT COMMENT

Emergency generator engine is operated only for testing purposes.

Facility ID : 1070025 | Emissions Unit ID : 006 | SCC : 2-02-001-02

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 Distillate Oil (Diesel)** **Industrial 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

Facility ID : 1070025 **Emissions Unit ID : 007** **SCC : 2-02-001-02**

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 Distillate Oil (Diesel)** **Industrial 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 subject 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

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

GND

Parcels: 1/1

ORIGIN: TLH

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

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

Day
24MO

Description: PSD-FL-376 application PSD-FL-375 correspondence
Weight: 7 lbs for 1 pcs
Date: 2006-04-21

DHL standard terms and conditions apply.

HARB 6V
ATT

(2L)US30303

WAYBILL: 15854781854 (Non-Negotiable)

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SENDER'S RECEIPT
Waybill #: 15854781854

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: 3.06
Protection: Not Required
Description: PSD-FL-376 application
PSD-FL-375 correspondence

Weight (lbs.): 7
Dimensions: 0 x 0 x 0

Ship Ref: 37550201000 A7 AP255
Service Level: Ground (Est.
delivery in 1 business day(s))

Special Svc:

Date Printed: 4/21/2006
Bill Shipment To: Sender
Bill To Acct: 778941286

DHL Signature (optional) ____________ Route ______ Date ______ Time ______

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EXPRESS

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

NAS

Parcels: 1/1

ORIGIN: TLH

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

Sender's ref. 37550201000 A7 AP255

POST CODE: 80228

Tel: 303-966-2818

Description: PSD-FL-376 application PSD-FL-375 correspondence
Weight: 7 lbs for 1 pcs
Date: 2006-04-21

DHL standard terms and conditions apply.

EGEH 9E

(2L)US80228

WAYBILL: 15854943355 (Non-Negotiable)

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SENDER'S RECEIPT
Waybill #: 15854943355

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: 17.32
Protection: Not Required
Description: PSD-FL-376 application PSD-FL-375 correspondence

Weight (lbs.): 7
Dimensions: 0 x 0 x 0

Ship Ref: 37550201000 A7 AP255
Service Level: Next Day 3:00 (Next business day by 3 PM)

Special Svc:

Date Printed: 4/21/2006
Bill Shipment To: Sender
Bill To Acct: 778941286

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Exp 3

BEFORE THE STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Final Permit No. PSD-FL-375
Project No. 1070025-005-AC
Siting No. PA 78-10A2

SIERRA CLUB, INC.

Appellant,

vs.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION, and SEMINOLE ELECTRIC COOPERATIVE, INC.,

Appellees.

_______________________________________/

NOTICE OF APPEAL

NOTICE IS GIVEN that Appellant, SIERRA CLUB, INC., appeals to the First District Court of Appeal the Notice of Final Permit and Final Permit for Seminole Generating Station, SGS Unit 3 issued by the Florida Department of Environmental Protection and rendered September 5, 2008.

The nature of the permit appealed is a final administrative order granting an air pollution permit and authorizing Seminole Electric Cooperative to construct a new 750 megawatt pulverized coal-fired supercritical steam generating unit. A copy of the Notice of Final Permit and the Final Permit are attached as Exhibit A.

This appeal is filed under the provisions of section 120.68, Florida Statutes; rules 9.190(b), 9.030(b)(1)(C) and 9.110 of the Florida Rules of Appellate Procedure; and 40 C.F.R. § 124.10(b)(1), 40 C.F.R. § 124.13, and 40 C.F.R. § 124.19(a).

Respectfully submitted this 3rd day of October, 2008.

Alisa A. Coe
Fla. Bar No. 0010187
David G. Guest
Fla. Bar No. 0267228
Earthjustice
P. O. Box 1329
Tallahassee, Florida 32302
(850) 681-0031 (tel)
(850) 681-0020 (fax)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing has been provided by US Mail and electronic service this 3rd day of October, 2008 to the persons listed below:

James R. Frauen, Project Director Seminole Electric Cooperative 16313 North Dale Mabry Hwy Tampa, FL 33618 jfrauen@seminole–electric.com	Scott Osbourn, PE Golder Associates, Inc. 5100 W. Lemon Street Suite 114 Tampa, FL 33609 sosbourn@golder.com	Ken Kosky, PE Golder Associate, Inc. 6241 NW 23rd Street, Suite 500 Gainesville, FL 32653 Kkosky@golder.com

James Alves, Esq Robert Manning, Esq. Counsel for Seminole Electric Hopping, Green & Sams, P.A. PO Box 6526 Tallahassee, Florida 32314-6526 jalves@hgslaw.com rmanning@hgslaw.com	Chris Kirts Northeast District (JX) 7825 Baymeadows Way, Suite B200 Jacksonville, Florida 32256-7577 Christopher.Kirts@dep.state.fl.us	Phyllis Fox, Ph.D. 745 White Pines Ave. Rockledge, Florida 32955 phyllisfox@gmail.com
Kathleen Forney USEPA REGION 4 61 Forsyth Street, S.W. Atlanta, GA 30303-8960 Forney.kathleen@epa.gov	Joanne Spalding, Esq. Kristin Henry, Esq. Sierra Club 85 Second Street, Second Floor San Francisco, CA 94105 Kristin.Henry@sierraclub.org Joanne.spalding@sierraclub.org	Catherine Collins U.S. Fish and Wildlife Service National Wildlife Refuge System Branch of Air Quality 7333 W. Jefferson Ave., Suite 375 Lakewood , CO 80235-2017 Catherine_collins@fws.gov
George Cavros, Esq. On behalf of NRDC and Southern Alliance for Clean Energy 120 East Oakland Park Oakland Park, FL 33334-1100 gcavros@att.net	Jack Chisolm, Esq. Deputy General Counsel Florida Department of Environmental Protection 3900 Commonwealth Blvd MS 35 Tallahassee, FL 32399-3000 lisa.light@dep.state.fl.us	

[signature]

Attorney

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, Florida 33618

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

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

Enclosed is the final air construction permit, which authorizes the construction of a nominal 750 MW pulverized coal-fired supercritical steam generating unit. The proposed work will be conducted at the existing Seminole Electric facility, which is located in east of U.S. Highway 17, approximately seven miles north of Palatka, Putnam County. The project is subject to the preconstruction requirements for the Prevention of Significant Deterioration (PSD) of Air Quality pursuant to Rule 62-212.400 of the Florida Administrative Code (F.A.C.). As noted in the attached Final Determination, no changes were made to this permit from the draft permit that was publicly noticed. This permit is issued pursuant to Chapter 403, Florida Statutes (F.S.).

Any party to this order has the right to seek judicial review of it under Section 120.68, F.S. 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 (Department) 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 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Trina Vielhauer, Chief
Bureau of Air Regulation

Exhibit A

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit was hereby attached and sent via electronic mail and a link to the Final Permit and Final Determination was sent with received receipt requested via electronic mail to the persons listed below.

Mr. James R. Frauen, SECI (jfrauen@seminole-electric.com)
Mr. Scott Osbourn, Golder (scsbourn@golder.com)
Mr. Ken Kosky, Golder (kkosky@golder.com)
Mr. Robert Manning, Hopping, Green & Sams (rmanning@hgslaw.com)
Mr. Chris Kirts, NED (Christopher.Kirts@dep.state.fl.us)
Ms. Phyllis Fox, Ph.D. (phyllisfox@gmail.com)
Ms. Kathleen Forney (forney.kathleen@epa.gov)
Ms. Kristin Henry, Sierra Club (Kristin.Henry@sierraclub.org)
Ms. Joanne Spalding, Sierra Club (joanne.spalding@sierraclub.org)
Ms. Catherine Collins, U.S. Fish and Wildlife Service (catherine_collins@fws.gov)
Mr. George Cavros, on behalf of Natural Resources Defense Council and Southern Alliance for Clean Energy (gcavros@att.net)

Clerk Stamp

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

Elizabeth Walker 9/5/08
(Clerk) (Date)

FINAL DETERMINATION

Seminole Electric Cooperative, Inc.
Seminole Generating Station
DEP File No. 1070025-005-AC

The Department distributed a public notice package on August 25, 2006 to allow the applicant, Seminole Electric Cooperative, Inc. (SECI) to construct a new supercritical coal-fired steam generating unit at the existing Seminole Generating Station (SGS), 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 September 8, 2006. Since the Draft Permit was issued, the federal Clean Air Interstate and Clean Air Mercury Rules (CAMR) have been vacated by the federal courts. This litigation is not yet final but it appears a case-by-case determination of maximum achievable control technology (MACT) will be required for SECI Unit 3 due to the vacature of CAMR. The Department will require an application for case-by-case MACT and will issue its determination thereof in a separate agency action.

COMMENTS/CHANGES

Comments were received by the Department from Mitchell Williams, a local resident on September 12, 2006. Comments were received from EPA Region 4 by letter dated October 5, 2006. Comments were received from the applicant by letter dated September 27, 2006. Comments were also received from the Sierra Club by letter dated October 9, 2006. On March 9, 2007 the applicant and the Sierra Club entered into a Settlement Agreement, to which the permitting authority was not a party and which was outside of the Prevention of Significant Deterioration (PSD) process that resolves all timely-received comments submitted by the applicant and the Sierra Club related to the draft PSD permit. To the extent the applicant wants to incorporate those changes into an air construction permit for that facility, an application to revise the PSD permit may be submitted. Finally, comments were received from the Natural Resources Defense Council and Southern Alliance for Clean Energy by letter dated July 3, 2008 almost 2 years after the end of the public comment period. These comments were not timely but are in the Department's files. Other timely received comments are addressed below:

EPA Comment 1. Netting Analysis

a. Florida Department of Environmental Protection (FDEP) indicates on page 5 of the technical evaluation that the Unit 1 and Unit 2 baseline period for the nitrogen oxides netting analysis is calendar years 2001-2002. In accordance with FDEP's rules, the baseline period for EUSGUs must be "within the 5-year period immediately preceding the date a complete permit application is received by the Department." Since the Unit 3 PSD permit application was not deemed complete until July 3, 2006, not all of calendar year 2001 is available for baseline emissions calculations unless FDEP explicitly deems a different (earlier) period to be more representative of normal source operation. FDEP should explain why emissions during all of calendar year 2001 are available for baseline emissions calculations purposes.

b. Referencing FDEP's regulations, a decrease in emissions is creditable in a netting analysis only if "It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change." We do not find in the technical evaluation (which is a key part of the public record for this permitting action) any assessment of this qualitative significance requirement with regard to the creditable emissions decreases proposed for avoidance of PSD review for sulfur dioxide, nitrogen oxides, and sulfuric acid mist.

RESPONSE:

a. During a February 2006 meeting which was held with the applicant to discuss the processing of the SGS Unit 3 application, FDEP agreed to calendar year 2001 as the first available year available for calculating baseline emissions. The application was received approximately 2 weeks later, on March 9, 2006.

b. FDEP affirms that it has determined the increases from the SGS Unit 3 project have a lesser qualitative significance than do the decreases from the SGS Units 1 and 2 pollution control upgrade project.

EPA Comment 2: Clarification of Pound-per-Hour Emissions Limits

a. Condition III.A.10 in the draft permit consists of a table with emissions limits labeled as either "BACT Emission Limits" or "Non-BACT Established Emission Limits." (The acronym BACT means best available control technology.) The limits are listed in terms of pounds (lb)/ per million British thermal units (MMBtu) and in terms of lb/hour (hr) "equivalent." We are not sure what is meant by the word "equivalent." Specifically, we are not sure if the lb/hr "equivalent" values are enforceable permit limits. If not, they should be made enforceable unless the following statement in Condition III.A.4 represents an enforceable restriction: "The steam generator shall be designed for a maximum heat input of 7,500 MMBtu per hour of coal." Unless the permit contains an enforceable restriction on maximum heat input, the lb/MMBtu limits by themselves do not provide an enforceable limit on total mass emissions to the atmosphere.

b. The "equivalent" lb/hr rates for the most part are based on the limits in lb/MMBtu times 7,500 MMBtu/hr. There appears to be an error in the volatile organic compound (VOC) equivalent lb/hr rate of 16.7 lb/hr. The stated VOC limit is 0.0034 lb/MMBtu which yields a value of 25.5 lb/hr when multiplied by 7,500 MMBtu/hr.

RESPONSE:

a. The intent of the permit is to make the heat input an enforceable restriction. The lb/hr "equivalent" values are listed for informational purposes only.

b. Agreed that this was a calculation error. This error will be corrected when the Department issues a case-by-case MACT determination in the near future.

EPA Comment 3: Particulate Matter Emissions Limits

a. The particulate matter (PM)/PM less than 10 microns (PM_{10}) emissions limit specified in Condition III.A.15 of the draft permit is for filterables only. Condensables are to be measured and reported but are not restricted by an emissions limit. Most recent permits for EUSGU pulverized coal boilers have included an emissions limit for condensables in addition to (or in combination with) and emissions limit for filterables. We recommend that the final permit include place holder language that will allow setting an emissions limit for condensables after testing has demonstrated that condensables can be measured accurately.

b. In Condition III.A.15, FDEP specifies that the PM/PM_{10} emissions limit of 0.013 lb/MMBtu applies "while firing 100% coal." We recommend that this condition be rephrased to indicate the emissions limit that applies when firing a mixture of coal and petcoke as well as when firing coal only.

RESPONSE:

a. As EPA suggests, if testing demonstrates that condensables can be measured accurately, the Department may address this issue in the future.

b. The Department will delete the words "while firing 100% coal" from Condition III.A.15 when the Department issues its case-by-case MACT determination in the near future.

EPA Comment 4: PM Continuous Emissions Monitoring System (CEMS)

a. The draft permit does not require use of a PM CEMS to assess compliance with the filterable PM/PM_{10} emissions limit. Since a PM CEMS can be used with a wet plume, we recommend that a PM CEMS be required to demonstrate compliance with the filterables limit.

b. If a PM CEMS is not required, we recommend that FDEP require some other continuously monitored parameter to indicate acceptable performance of the dry electrostatic precipitator which is the primary PM control device. Please advise us if FDEP intends to wait until issuance of a title V permit before specifying such parameter monitoring requirements.

RESPONSE: The Department intends to wait until issuance of the Title V permit before specifying parameter monitoring requirements.

EPA Comment 5: Startup and Shutdown

a. Startup and shutdown are part of normal source operation for Unit 3. Any pollutants emitted from Unit 3 during startup and shutdown that are subject to PSD review are therefore subject to BACT requirements. If the numeric BACT emissions limits for regular operation can not be met during startup and shutdown, then numeric limits need to be established for startup and shutdown operations or work practice BACT requirements should be established. We understand that FDEP intends for best management practices (including the 60-hour-per-month restriction in Condition III.A.29.b) to be used for minimization of emissions during startup and shutdown.. If it is FDEP's position that adherence to best management practices represents BACT for startup and shutdown, we request that this be stated in the final determination. Please note that numeric emissions limits for startup and shutdown have been addressed by the EPA Environmental Appeals Board (EAB) in two recent PSD permit appeals for coal-fired EUSGUs. (See the August 24, 2006, EAB order for the Prairie State Generating Station project in Illinois and the September 27, 2006, EAB order for the Indeck-Ellwood project in Illinois.)

b. The allowance of 60 hours per month (equivalent to 30 days per year) for startup, shutdown, and malfunction seems excessive for a 750-megawatt EUSGU. We would expect such a unit would not be in a condition of startup, shutdown, or malfunction this often throughout its lifetime.

c. Condition III.A.30 of the draft permit contains a parenthetical phrase indicating that emissions measured during startup, shutdown, and malfunction are to be included for demonstration of compliance with annual emissions limits. We recommend that the final permit contain a direct statement rather than just a parenthetical phrase making clear that startup, shutdown, and malfunction emissions must be included when demonstrating compliance with annual emissions limits.

RESPONSE:

a. The Department intends for the adherence to "best management practices" to represent BACT for the purpose of startup and shutdown.

b. The Department does not expect that this large steam generating unit will be in a startup or shutdown condition very often. However, the Department is aware that supercritical boilers have fairly complicated start-up systems due to ramping operation being required and difficulty in establishing metal matching conditions (see: http://www.hitachi.us/supportingdocs/forbus/powerindustrial/CG2004.pdf).

c. The permit requires startup, shutdown, and malfunction emissions be included when demonstrating compliance with annual emissions limits regardless of whether that phrase is in parenthesis or not. No change is required.

EPA Comment 6: Compliance Demonstration for Coal/Petcoke Blend

a. In Condition III.A.22 of the draft permit, FDEP requires an initial compliance demonstration "when firing 100% coal." Please consider whether an initial compliance test is also needed for a blend of 70 percent coal and 30 percent petcoke. In other words, please assess whether a coal/petcoke blend might be the worst case for some pollutants. This comment is prompted in part by the fact that the carbon monoxide emissions limits in Conditions III.A.10 and 11 are higher for the all-fuel case than for the 100-percent coal case.

b. Condition III.A.23 of the draft permit does not include a specification of the fuel blend to be evaluated during subsequent annual compliance testing. We recommend that FDEP indicate whether such testing is to be based on firing 100 percent coal only, a coal/petcoke blend only, or both.

RESPONSE: The Department expects only few differences in "worst-case" emissions depending upon the fuel-type being fired. For example, it is anticipated that the BACT established emission level of PM may be higher while firing 100% coal versus the coal/petcoke blend, as will the emissions of mercury. However, the elevated sulfur levels in petcoke make the removal of sulfur dioxide (SO_2) emissions more challenging for the co-firing operation, even though the SO_2 limit was not established by BACT. It is not anticipated that the emissions of carbon monoxide (CO) will be significantly different depending upon the fuel being fired. The higher CO emission level (0.15 lb/MMBtu) which is authorized in Condition III.A.11.b is intended to accommodate the wide variety of "non-steady-state" conditions which the unit will be subject to, such as load-changing, soot-blowing, etc. No change was made.

EPA Comment 7: Facility-wide Emissions Limits

In Condition III.A.2 of the draft permit, FDEP establishes facility-wide emissions limits for sulfur dioxide, sulfuric acid mist, mercury, and nitrogen oxides. FDEP further states that these limits apply to Units 1, 2, and 3, the zero liquid discharge spray dryers, and the cooling towers. Please check to make sure that FDEP meant to include cooling towers. Cooling towers do not typically emit the four pollutants with facility-wide emissions limits.

RESPONSE: It is correct that cooling towers do not typically emit these four pollutants; however, no change is made to the permit in response to this comment.

EPA Comment 8: Coal Preparation and Nonmetallic Mineral Processing

In the technical evaluation (page 9 and 10), FDEP states that the emissions units affected by the PSD permit have to comply with a list of regulations. The regulations in this list include the federal new source performance standards (NSPS) for coal preparation plants and nonmetallic mineral processing plants. However, the draft permit does not include permit conditions for coal preparation units or limestone (nonmetallic mineral) handling units. If any of the NSPS listed in the technical evaluation do not apply, please delete them.

RESPONSE: The coal preparation units and limestone handling units are existing units and the applicable requirements are already identified in the facility's other permits. There is no need to repeat these requirements in this permit. No change was required.

EPA Comment 9: Carbon Burnout Permit Provision

Condition III.A.43 of the draft permit (applicable to Unit 3), specifies daily recordkeeping requirements for the "operation and configuration" of a carbon burnout unit "such that the permittee can demonstrate compliance with the emission limitations of the affected emissions units." We recommend that FDEP specify exactly what records are required by this condition.

RESPONSE: The unit must comply with NSPS limits, recordkeeping and reporting. In addition, this unit will have a CEMS. These provisions will adequately address this issue and no change was made to the permit.

EPA Comment 10: Integrated Gasification Combined Cycle (IGCC)

FDEP's technical evaluation (pages 11-12) contains a brief discussion of reasons for not considering IGCC as part of a BACT analysis for the proposed PC boiler. We will point out that, pursuant to section 165(a)(2) of the Clean Air Act, it may be necessary for FDEP to address any substantive comments proposing IGCC as an alternative to the proposed project.

RESPONSE: The Department is satisfied that this issue has been adequately addressed.

EPA Comment 11: Unit 3 Nitrogen Oxides Emissions

Based on the netting analysis, PSD review (including a best available control technology determination) is not required for nitrogen oxides (NO_x) emissions. For the record, however, we wish to comment that the proposed NO_x emissions limit for Unit 3 of 0.07 lb/MMBtu is not representative of the lowest emission rate that could be expected for a newly designed supercritical pulverized coal boiler firing bituminous coal.

RESPONSE: No response required.

Mitchell Williams Comment:

"I suggest that you put an immediate hold on the construction of the third coal plant by Seminole Electric Co-op in Palatka at this time. This is 2006 not 1936. I assume that the design is a familiar one that any plant manager in 1936 would recognize (Babcock & Wilcox turbo-alternators with reheat etc). Only the computer control room would look new. Same old low efficiency antique stuff.

In its place they should be allowed to build a 21 Century plant and get Florida ahead of (not behind) California.

Here is what is needed. A coke-fired furnace (no scrubber needed) using 95% pure oxygen for combustion. To keep the gasifier cool enough to prevent melting, a heavy injection of superheated steam would be mixed with the stream of pure oxygen. At these temperatures (1800°F plus) steam reduces the carbon to carbon monoxide and the hydrogen is released to BURN AGAIN. Meaning that the plant runs partly on water. Possibly as much as 25% of the fuel could be water injected as superheated steam. This same trick can be used with a hot, air breathing furnace but the inert gases in the air prevent full efficiency of the process, and only 2 or 3% of the fuel can be water.

By using oxygen, coke, and steam you might reduce the total coke consumption by nearly half for the same power output. Meaning the exhaust from the plant would have half as much C02 (reduced greenhouse gases) and no nitrous oxides at all.

Since you then would have a really hot fire at your fingertips you might as well go whole hog in optimizing the design.

Throw out all the steam pipes except the ones to supply the steam to the gasifier. In their place substitute a closed cycle gas turbine with helium or C02 as the working fluid. All this shrinks down the entire plant to a fraction of its original size.

It also might be built much faster with modified jet, rocket, and refrigeration parts.

Making all this oxygen at the plant will mean they will have rivers of surplus liquid nitrogen and hot water to sell for cooling and heating purposes. This could help reduce the waste of electricity for these purposes.

And the fuel efficiency of the plant should be VERY HIGH. This same trick can be done with any fuel burning plant that has a high carbon content in the fuel (wood, oil, sewage, sludge, goat manure etc). It will be less effective with natural gas as there is less carbon in it, so only a reduced amount of water can be burned with it. However, pure oxygen can also greatly increase the efficiency of any fuel burning plant by eliminating the inert gases from the system. Convection heat is greatly reduced and radiant heat is greatly increased making even steam plants much smaller for a given output.

If you should have any doubts concerning what is presented here you can ask any of the rocket people at the Cape. They are always quick to tell you how the turbo-pumps on the Space Shuttle Main Engines (about the size of outboard motors) produce 100,000 horsepower each, and could easily light a small city."

<u>RESPONSE:</u> {Note: The following was excerpted from the July 6, 2006 Public Service Commission Staff Analysis for Seminole Unit 3 Need Determination}

"As part of the evaluation process, Seminole hired Burns & McDonnell to assist them in selecting the appropriate technology and provide a detailed, screening level evaluation of the cost of building and operating the preferred alternative. This request initially led to the August 2004 Feasibility Study. This study contains the results of the economic analyses of three alternative self-build projects: A new Brownfield 600 MW sub-critical solid fuel generating unit; a new Brownfield 600 MW supercritical solid fuel generating unit; and a new Greenfield 500 MW gas fired combined cycle unit. Other generating technologies were assessed, but were not considered for new generation at this time due to insufficient operational experience and information on cost and reliability of technology. The study found that the 20 year levelized bus bar cost for the three viable alternatives showed that the supercritical unit was the lowest at \$52.77/MWh; sub-critical unit at \$52.97/MWh; and combined cycle unit at \$75.48/MWh. Seminole's interest in increasing the output of SGS Unit 3 from 600 MW to 750 MW led to the February 2005 Feasibility Study. This study, which is an update of Seminole's August 2004 Feasibility Study, concluded that both the supercritical and sub-critical solid fuel generating units were feasible and would be substantially more economically sized at 750 MW than at 600 MW (the 20 year levelized bus bar cost declined to \$48.85/MWh for the supercritical coal unit, and to

$49.15/MWh for the sub-critical coal unit). Both remained far less expensive than a conventional gas fired combined cycle unit. Therefore, Seminole decided that 750 MW of base load capacity should be added in the 2012 time frame. The estimated capital cost for the 750 MW supercritical SGS Unit 3 project is approximately $1.4 billion in 2012 dollars. SGS Unit 3 will be located at Seminole's Generating Station (SGS) on a 1922 acre site in northeast Putnam County, approximately five miles from the City of Palatka. SGS Unit 3 will be a pulverized coal, balanced draft unit employing supercritical steam pressure and temperature with a mechanical draft cooling tower for condenser cooling water. The primary advantages of supercritical steam cycles over sub-critical steam cycles are improved plant efficiency due to elevated operating pressure and temperature, lower emissions and lower fuel consumption. SGS Unit 3 will also employ state-of-the-art emission control equipment to further reduce emissions."

CONCLUSION

The final action of the Department is to issue the permit with no changes from the draft permit.

PERMITTEE:

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

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

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

PROJECT AND LOCATION

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

STATEMENT OF BASIS

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

Joseph Kahn, P.E., Director
Division of Air Resource Management

Date: 9/3/08

FACILITY DESCRIPTION

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

PROJECT DESCRIPTION

Seminole proposes to integrate SGS Unit 3 into the existing, certified SGS Site located north of Palatka in Putnam County. SGS Unit 3 will be a nominal 750 MW (net) pulverized coal-fired supercritical steam generating unit located adjacent to the existing SGS Units 1 and 2. Seminole anticipates beginning commercial operation of Unit 3 in 2012. The addition of SGS Unit 3 will increase the total output capability of the SGS by almost 60 percent. The design of SGS Unit 3 will maximize the co-use of existing site facilities to the greatest extent possible, including fuel handling facilities (SGS Unit 3 proposes the same fuel slate as SGS Units 1 and 2). The project also includes a new Zero Liquid Discharge (ZLD) Spray Dryer System, a new emergency generator, and a new 26-cell mechanical draft cooling tower.

SGS Unit 3 will feature supercritical pulverized coal technology with modern emission controls. The Unit 3 air pollution control equipment will include wet Flue Gas Desulfurization (FGD) for SO_2 removal, selective catalytic reduction (SCR) for control of nitrogen oxides (NO_X), electrostatic precipitator (ESP) for collection and removal of fine particles, a Wet ESP (WESP) for control of sulfuric acid mist (SAM), with fluoride (HF) and mercury (Hg) removal to be accomplished through co-benefits of the above technologies. Fuel (coal and petroleum coke) for SGS Unit 3 will be delivered by an existing rail system. No. 2 diesel fuel will be used for startup, shutdown and for firing the Zero Liquid Discharge (ZLD) Spray Dryers as well as an Emergency Generator (unregulated emissions unit).

EMISSIONS UNITS

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

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

REGULATORY CLASSIFICATION

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

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

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

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

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

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

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

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

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

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

PERMITTING AUTHORITY

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

COMPLIANCE AUTHORITY

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

APPENDICES

The following Appendices are attached as part of this permit.

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

RELEVANT DOCUMENTS:

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

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

SECTION II. ADMINISTRATIVE REQUIREMENTS

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

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

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

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

5. Source Obligation.

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

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

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

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

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

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

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

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

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

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

APPLICABLE STANDARDS AND REGULATIONS

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

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

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

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

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

EQUIPMENT DESCRIPTION

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

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

CONTROL TECHNOLOGY

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

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

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

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

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

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

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

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

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

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

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

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

PERFORMANCE REQUIREMENTS

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

9. Authorized Fuels:

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

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

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

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

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

EMISSIONS STANDARDS

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

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

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

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

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

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

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

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

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

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

Memorandum

Florida Department of
Environmental Protection

TO: Trina Vielhauer

THRU: J. F. Koerner JK

FROM: M. P. Halpin MJ

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

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

FLORIDA

Department of Environmental Protection

Jeb Bush
Governor

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

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

Section 1. General Information

Section 2. Administrative Requirements

Section 3. Emissions Units Specific Conditions

Section 4. Appendices

Michael G. Cooke, Director
Division of Air Resources Management

(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; 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 NO_x, 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

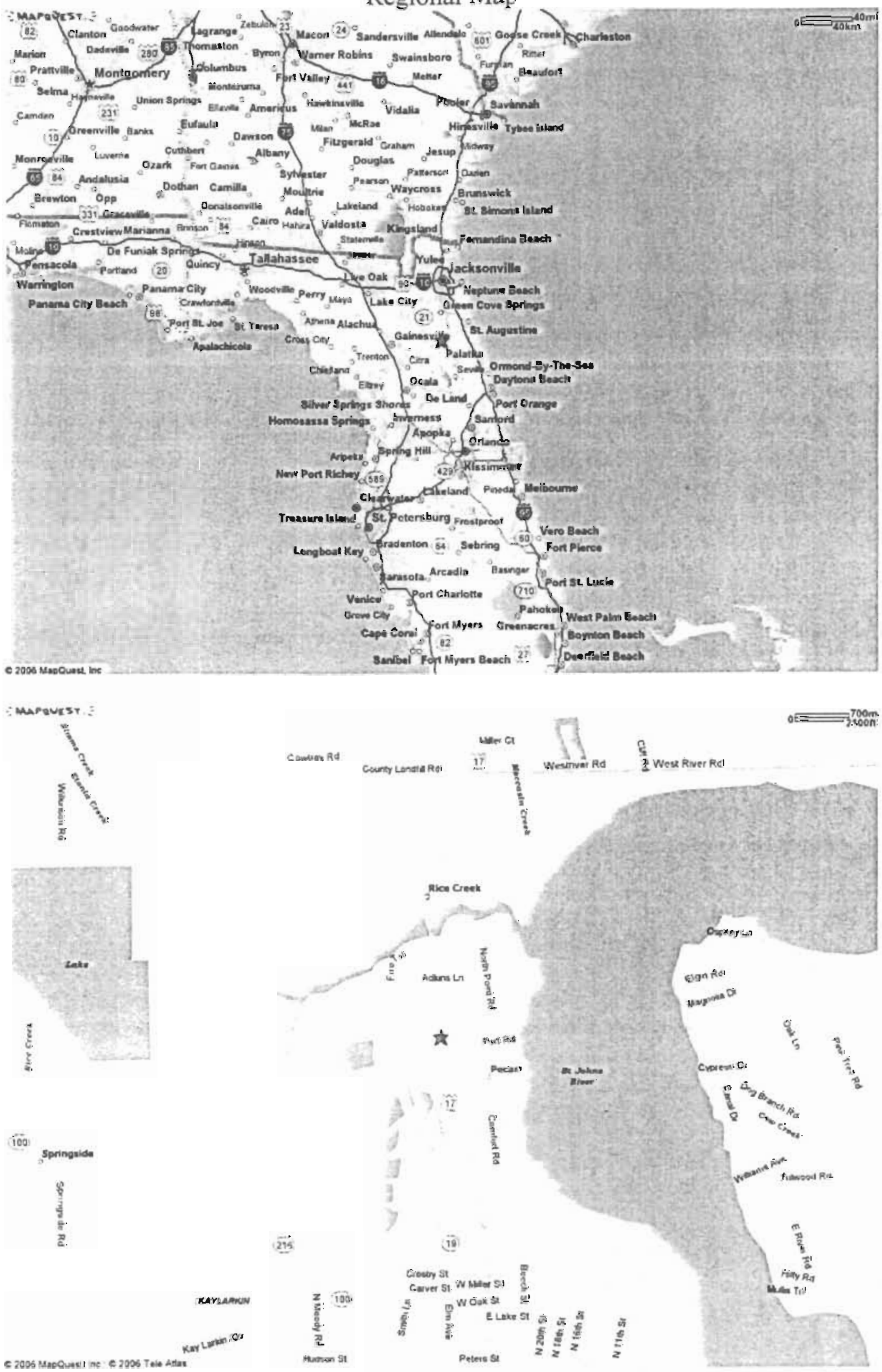
2.3 Facility Category

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

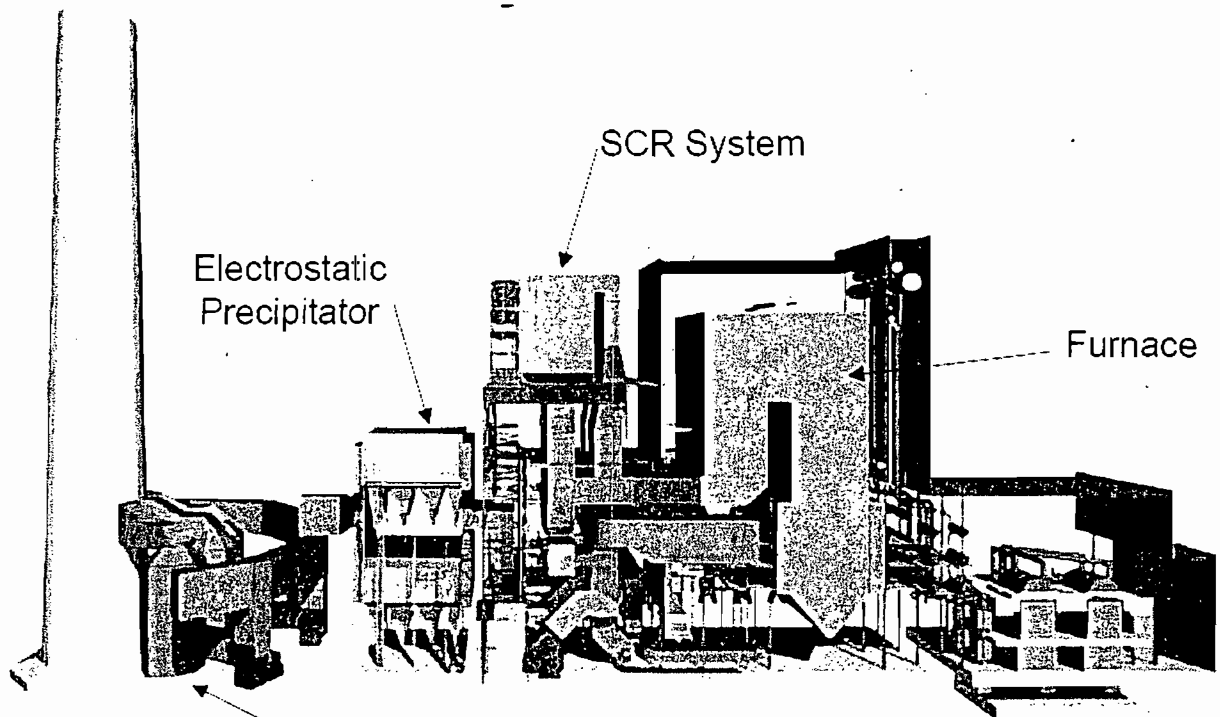
This project addresses the following emissions units:

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.

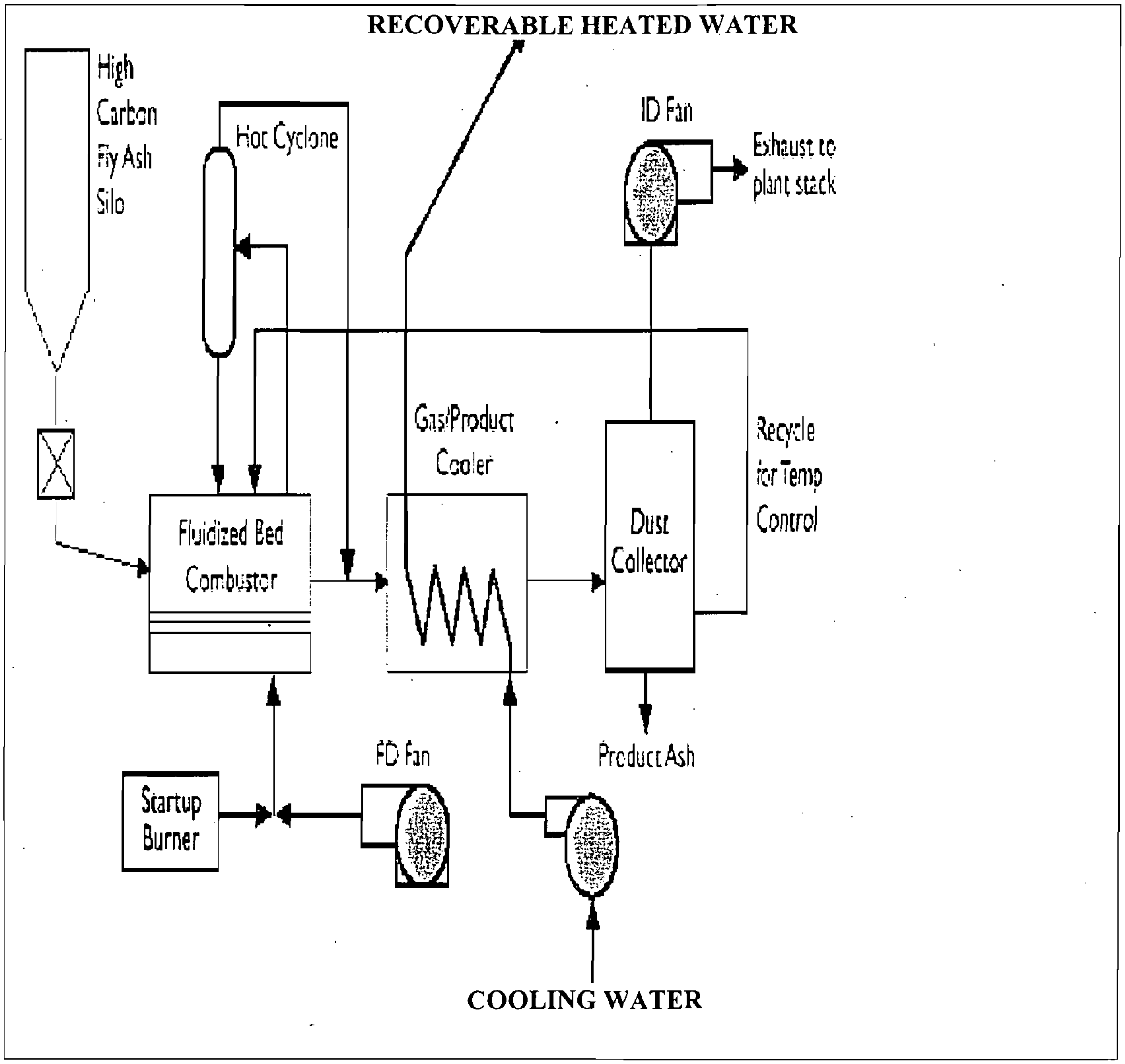
Pollutant	Baseline Actual Emissions (TPY)	Projected Actual Emissions (TPY)	Net Emissions Change (TPY)	Significant Emission Rate (TPY)	PSD Review Required?
SO_2	29074	29113	39	40	NO
NO_X	23289	21638	39	40	NO
CO	13451	13550	99	100	NO
VOC	108	147	39	40	NO
PM	822	846	24	25	NO
PM_{10}	822	836	14	15	NO
SAM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

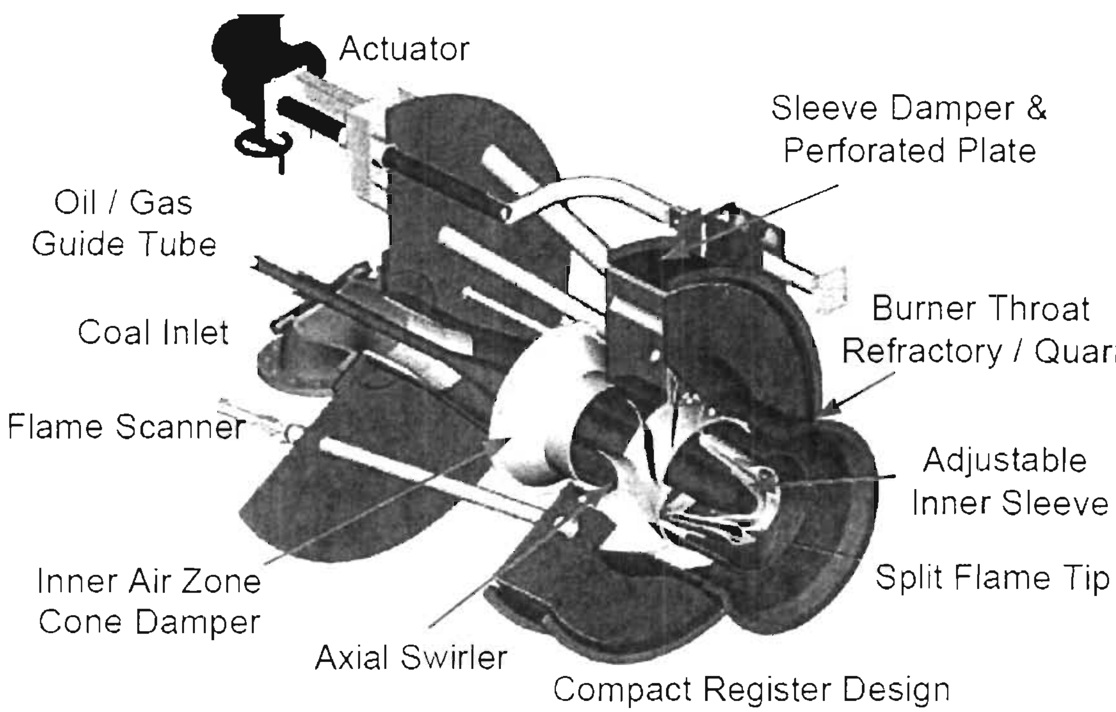
The table below represents the expected maximum emission rates from the CBO Unit (only), prior to any reductions from the Units 1 and 2 pollution control systems. Note that this table does not include the ancillary equipment emissions (i.e., baghouses) of PM/PM_{10}.

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):

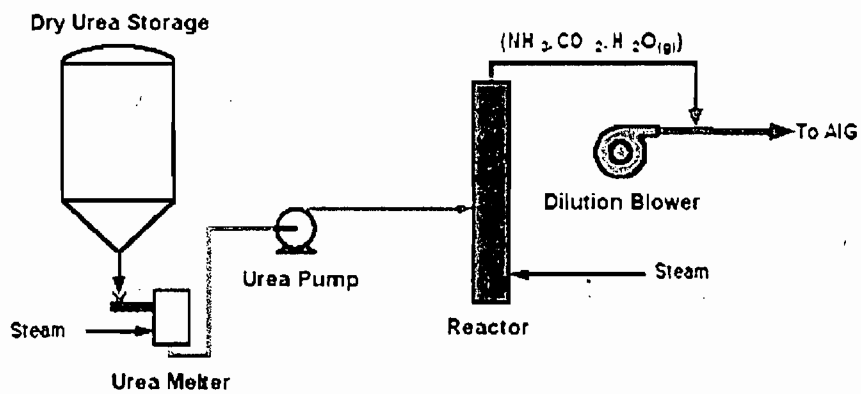
"In 1971 Foster Wheeler began development of low NO_X burners for coal fired boilers with the promulgation of New Source Performance Standards (NSPS). The first generation Controlled Flow (CF) design burner was demonstrated in 1976. Three years later the second generation Controlled Flow/Split Flame 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

APPENDIX GC
GENERAL PERMIT CONDITIONS [F.A.C. 62-4.160]

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.