PETROLEUM COKE PROJECT
CONSTRUCTION PERMIT APPLICATION

SEMINOLE POWER PLANT

Prepared for:

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

Tampa, Florida

Prepared by:

ECT

Environmental Consulting & Technology, Inc.

3701 Northwest 98th Street
Gainesville, Florida 32606

ECT No. 96354-0100

November 1996

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FLORIDA DEP LOGO

Department of
Environmental Protection

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

This section of the Application for Air Permit form identifies the facility and provides general information on the scope and purpose of this application. This section also includes information on the owner or authorized representative of the facility (or the responsible official in the case of a Title V source) and the necessary statements for the applicant and professional engineer, where required, to sign and date for formal submittal of the Application for Air Permit to the Department. If the application form is submitted to the Department using ELSA, this section of the Application for Air Permit must also be submitted in hard-copy.

Identification of Facility Addressed in This Application

Enter the name of the corporation, business, governmental entity, or individual that has ownership or control of the facility; the facility site name, if any; and the facility's physical location. If known, also enter the facility identification number.

1. Facility Owner/Company Name: **Seminole Electric Cooperative, Inc.**	
2. Site Name: **Seminole Power Plant**	
3. Facility Identification Number: **1070025**	[ ] Unknown
4. Facility Location: Street Address or Other Locator: **890 U.S. Highway North** City: **Palatka** County: **Putnam** Zip Code: **32177**	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Permit Number:	
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official:
   Mr. James Duren
   Vice-President, Technical Division

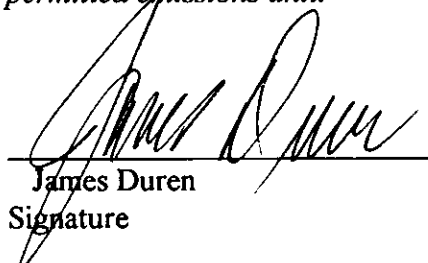
2. Owner/Authorized Representative or Responsible Official Mailing Address:

   Organization/Firm: **Seminole Electric Cooperative, Inc.**
   Street Address: **16313 North Dale Mabry Highway**
   City: **Tampa** State: **FL** Zip Code: **33618-1342**

3. Owner/Authorized Representative or Responsible Official Telephone Numbers:
   Telephone: **(813) 963-0994** Fax: **(813) 264-7906**

4. Owner/Authorized Representative or Responsible Official Statement:

   I, the undersigned, am the owner or authorized representative of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., of the Title V source addressed in this application, whichever is applicable. 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. 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 any permitted emissions unit.*



James Duren
Signature

11-19-96
Date

* Attach letter of authorization if not currently on file.

INTRODUCTION

The Seminole Electric Cooperative, Inc. (SECI), Seminole Power Plant located in Palatka, Putnam County, Florida, is a baseload electric generation facility. The Seminole Power Plant consists of two steam boilers (Unit Nos. 1 and 2); two steam turbines; a recirculating cooling water system; coal, limestone, fly ash, bottom ash, and flue gas desulfurization (FGD) sludge stabilization facilities; fuel oil storage tanks; water treatment facilities; a railcar maintenance facility; and ancillary support equipment. Unit Nos. 1 and 2 each have a maximum heat input of 7,172 million British thermal units per hour (MMBtu/hr) for a maximum load rating of 714.6 megawatt (MW). Unit Nos. 1 and 2 are presently fired with coal. No. 2 fuel oil is used for startups and flame stabilization.

Operation of the Seminole Power Plant is currently authorized by U.S. Environmental Protection Agency (EPA) Prevention of Significant Deterioration (PSD) Permit No. PSD-FL-018 and Florida Power Plant Siting Act (PPSA) Certification No. PA 78-10. In June 1996, SECI submitted an application for a Title V operation permit.

The Florida Department of Environmental Regulation (FDEP) authorized SECI to conduct performance tests of coal/petroleum coke (petcoke) fuel blends for comparison to baseline coal emissions. A copy of the FDEP performance test authorization letter is provided in Appendix D. Following verbal approval from FDEP, SECI conducted the coal/petcoke performance tests from November 28, 1995, through January 9, 1996. The performance test results were submitted to FDEP in February 1996.

An analysis to determine whether future long-term firing of coal/petcoke fuel blends would constitute a modification subject to PSD review pursuant to Section 62-212.400, Florida Administrative Code (F.A.C.), was prepared based on the performance test results, fuel analyses, historical emissions data, EPA emission factors, and evaluation of pollution control system capabilities. The analysis of PSD applicability is provided in Appendix E.

The analysis demonstrates that PSD review is not applicable to this permit modification request.

This submittal constitutes SECI's application for the permanent use of petcoke at the Seminole Power Plant and is submitted to satisfy the requirements of Rule 62-210.300(1), F.A.C. SECI requests that the current Seminole Power Plant permits (EPA PSD Permit No. PSD-FL-018 and Florida PPSA Certification No. PA 78-10) be modified to allow for the combustion of coal and petcoke fuel blends on a permanent basis as an alternative method of operation. Specifically, approval to combust blends of coal and petcoke containing up to 30 percent by weight petcoke is requested. Also, as discussed in Appendix F, approval is requested to utilize No. 2 fuel oil to generate electrical capacity. Proposed permit conditions reflecting the use of petroleum coke are provided in Appendix G. SECI also requests that the information contained in this construction permit application be considered as an amendment to the previously submitted Title V permit application and that terms and conditions authorizing the use of petcoke at the Seminole Power Plant be included in the draft Title V permit.

Scope of Application

This Application for Air Permit addresses the following emissions unit(s) at the facility. An Emissions Unit Information Section (a Section III of the form) must be included for each emissions unit listed.

Emissions Unit ID	Description of Emissions Unit	Permit Type
001	Steam Electric Generator No. 1	AC1B
002	Steam Electric Generator No. 2	AC1B

Purpose of Application and Category

Check one (except as otherwise indicated):

Category I: All Air Operation Permit Applications Subject to Processing Under Chapter 62-213, F.A.C.

This Application for Air Permit is submitted to obtain:

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for an existing facility which is classified as a Title V source.

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number: _____

[ ] Air operation permit renewal under Chapter 62-213, F.A.C., for a Title V source.

Operation permit to be renewed: _____

[ ] Air operation permit revision for a Title V source to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number: _____

Operation permit to be revised: _____

[ ] Air operation permit revision or administrative correction for a Title V source to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. Also check Category III.

Operation permit to be revised/corrected: _____

[ ] Air operation permit revision for a Title V source for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit to be revised: _____

Reason for revision: _____

_____

Category II: All Air Operation Permit Applications Subject to Processing Under Rule 62-210.300(2)(b), F.A.C.

This Application for Air Permit is submitted to obtain:

[ ] Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s): _____

[ ] Renewal air operation permit under Rule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed: _____

[ ] Air operation permit revision for a synthetic non-Title V source. Give reason for revision; e.g., to address one or more newly constructed or modified emissions units.

Operation permit to be revised: _____

Reason for revision: _____

_____

Category III: All Air Construction Permit Applications for All Facilities and Emissions Units

This Application for Air Permit is submitted to obtain:

[X] Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any: **PSD-FL-018 and PA 78-10**

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

Current operation permit number(s): _____

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Application Processing Fee

Check one:

[ ] Attached - Amount: $ [X] Not Applicable.

Construction/Modification Information

1. Description of Proposed Project or Alterations:

Seminole Electric Cooperative, Inc. (SECI) was authorized by FDEP to conduct performance tests of coal/petroleum coke (petcoke) fuel blends for comparison to baseline coal emissions (see Appendix D for a copy of the FDEP performance test authorization letter). SECI conducted the performance tests from November 28, 1995 through January 9, 1996. The performance test results were submitted to FDEP in February 1996.

The results from the performance tests, fuel analyses, historical emissions data , AP-42 emission factors, and evaluation of air pollution control equipment were used to determine whether future long-term firing of coal/petcoke fuel blends would constitute a modification subject to Prevention of Significant Deterioration (PSD) review pursuant to Rule 62-212.400, F.A.C. This analysis of PSD applicability is provided in Appendix E. The analysis demonstrates that PSD review is not applicable to this permit modification request.

SECI requests that the current Seminole Power Plant permits [Environmental Protection Agency (EPA) Prevention of Significant Deterioration (PSD) Permit PSD-FL-018 and Florida Power Plant Siting Act (PPSA) Certification PA 78-10] be modified to allow for the combustion of coal and petcoke fuel blends on a permanent basis as an alternative method of operation. Specifically, approval to combust blends of coal and petcoke containing up to 30 percent by weight petcoke is requested. SECI also requests that the information contained in this construction permit application be considered as an amendment to the previously submitted Title V permit application, and that terms and conditions authorizing the use of petcoke at the Seminole Power Plant be included in the draft Title V permit.

2. Projected or Actual Date of Commencement of Construction:
As soon as FDEP authorization is received.

3. Projected Date of Completion of Construction:

N/A

Professional Engineer Certification

1.	Professional Engineer Name: **Thomas W. Davis** Registration Number: **36777**
2.	Professional Engineer Mailing Address: Organization/Firm: **Environmental Consulting & Technology, Inc.** Street Address: **3701 Northwest 98th Street** City: **Gainesville** State: **FL** Zip Code: **32606-5004**
3.	Professional Engineer Telephone Numbers: Telephone: **(352) 332-0444** Fax: **(352) 332-6722**

4. 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.

If the purpose of this application is to obtain a Title V source 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 schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [X] 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.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision 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.

Thomas W. Davis
Signature

11/8/96
Date

(seal)

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact:
   Mr. Mike Opalinski
   Director of Environmental Affairs

2. Application Contact Mailing Address:

   Organization/Firm: **Seminole Electric Cooperative, Inc.**
   Street Address: **16313 North Dale Mabry Highway**
   City: **Tampa** State: **FL** Zip Code: **33618-1342**

3. Application Contact Telephone Numbers:
   Telephone: **(813) 963-0994** Fax: **(813) 264-7906**

Application Comment

N/A

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17** East (km): **438.80** North (km): **3,289.20**			
2. Facility Latitude/Longitude: **N/A** Latitude (DD/MM/SS): Longitude (DD/MM/SS):			
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters): **N/A**			

Facility Contact

1. Name and Title of Facility Contact: **Ms. Brenda Shiver** **Environmental Compliance Specialist**
2. Facility Contact Mailing Address: Organization/Firm: **Seminole Electric Cooperative, Inc.** Street Address: **P.O. Box 1577** City: **Palatka** State: **FL** Zip Code: **32178-1577**
3. Facility Contact Telephone Numbers: Telephone: **(904) 328-9255** Fax: **(904) 328-5551**

Facility Regulatory Classifications

1. Small Business Stationary Source? [ ] Yes [X] No [ ] Unknown
2. Title V Source? [X] Yes [ ] No
3. Synthetic Non-Title V Source? [ ] Yes [X] No
4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)? [X] Yes [ ] No
5. Synthetic Minor Source of Pollutants Other than HAPs? [ ] Yes [X] No
6. Major Source of Hazardous Air Pollutants (HAPs)? [X] Yes [ ] No
7. Synthetic Minor Source of HAPs? [ ] Yes [X] No
8. One or More Emissions Units Subject to NSPS? [X] Yes [ ] No
9. One or More Emission Units Subject to NESHAP? [ ] Yes [X] No
10. Title V Source by EPA Designation? [ ] Yes [X] No
11. Facility Regulatory Classifications Comment (limit to 200 characters): **N/A**

B. FACILITY REGULATIONS

Rule Applicability Analysis (Required for Category II applications and Category III applications involving non Title-V sources. See Instructions.)

N/A

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

See Appendix A of SECI's June 1996 Title V permit application for a complete list of applicable requirements.	

C. FACILITY POLLUTANTS

Facility Pollutant Information

1. Pollutant Emitted	2. Pollutant Classification
Carbon Monoxide (CO)	**A**
Nitrogen Oxides (NO_x)	**A**
Sulfur Dioxide (SO_2)	**A**
Particulate Matter Less Than 10 Microns (PM_{10})	**A**
Particulate Matter (PM)	**A**
Volatile Organic Compounds (VOC)	**A**
Hydrogen Chloride (H106)	**A**
Hydrogen Fluoride (H107)	**A**
Total Hazardous Air Pollutants (HAPS)	**A**

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Detail Information: Pollutant of N/A

1. Pollutant Emitted:
2. Requested Emissions Cap: (lb/hour) (tons/year)
3. Basis for Emissions Cap Code:
4. Facility Pollutant Comment (limit to 400 characters):

Facility Pollutant Detail Information: Pollutant of

1. Pollutant Emitted:
2. Requested Emissions Cap: (lb/hour) (tons/year)
3. Basis for Emissions Cap Code:
4. Facility Pollutant Comment (limit to 400 characters):

E. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location: [X] Attached, Document ID:_____ [ ] Not Applicable [ ] Waiver Requested **Appendix A**
2. Facility Plot Plan: [X] Attached, Document ID:_____ [ ] Not Applicable [ ] Waiver Requested **Appendix B**
3. Process Flow Diagram(s): [X] Attached, Document ID:_____ [X] Not Applicable [ ] Waiver Requested **Appendix C**
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID:_____ [X] Not Applicable [ ] Waiver Requested
5. Fugitive Emissions Identification: [ ] Attached, Document ID:_____ [X] Not Applicable [ ] Waiver Requested
6. Supplemental Information for Construction Permit Application: [ ] Attached, Document ID:_____ [X] Not Applicable

Additional Supplemental Requirements for Category I Applications Only **N/A**

7. List of Proposed Exempt Activities: [ ] Attached, Document ID:_____ [ ] Not Applicable
8. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:_____ [ ] Equipment/Activities On site but Not Required to be Individually Listed [ ] Not Applicable
9. Alternative Methods of Operation: [ ] Attached, Document ID:_____ [ ] Not Applicable
10. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:_____ [ ] Not Applicable

11. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:_____ [ ] Not Applicable
12. Compliance Assurance Monitoring Plan: [ ] Attached, Document ID:_____ [ ] Not Applicable
13. Risk Management Plan Verification: [ ] Plan Submitted to Implementing Agency - Verification Attached, Document ID:_____ [ ] Plan to be Submitted to Implementing Agency by Required Date [ ] Not Applicable
14. Compliance Report and Plan: [ ] Attached, Document ID:_____ [ ] Not Applicable
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:_____ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through L as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application. Some of the subsections comprising the Emissions Unit Information Section of the form are intended for regulated emissions units only. Others are intended for both regulated and unregulated emissions units. Each subsection is appropriately marked.

A. TYPE OF EMISSIONS UNIT (Regulated and Unregulated Emissions Units)

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one:

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

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

2. Single Process, Group of Processes, or Fugitive Only? Check one:

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

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

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

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section (limit to 60 characters): **Steam Electric Generator No. 1**		
2. Emissions Unit Identification Number: [ ] No Corresponding ID [ ] Unknown **001**		
3. Emissions Unit Status Code: **A**	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code: **49**
6. Emissions Unit Comment (limit to 500 characters): **N/A**		

Emissions Unit Control Equipment

A.

1. Description (limit to 200 characters): **Electrostatic Precipitator System**
2. Control Device or Method Code: **010**

B.

1. Description (limit to 200 characters):
Wet Limestone Flue Gas Desulfurization (FGD)

2. Control Device or Method Code: **067**

C.

1. Description (limit to 200 characters):
Low NO_x Burners

2. Control Device or Method Code: **024**

D.

1. Description (limit to 200 characters): **Low Excess-Air Firing**
2. Control Device or Method Code: **029**

E.

1. Description (limit to 200 characters):
2. Control Device or Method Code:

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Details

1. Initial Startup Date: **N/A**		
2. Long-term Reserve Shutdown Date: **N/A**		
3. Package Unit: **N/A** Manufacturer:	Model Number:	
4. Generator Nameplate Rating:	**714.6** MW	
5. Incinerator Information: **N/A** Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		°F seconds °F

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:		**7,172** mmBtu/hr
2. Maximum Incineration Rate: **N/A**	lb/hr	tons/day
3. Maximum Process or Throughput Rate: **N/A**		
4. Maximum Production Rate: **N/A**		
5. Operating Capacity Comment (limit to 200 characters):		

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule:		
	24 hours/day	**7** days/week
	52 weeks/year	**8,760** hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Rule Applicability Analysis (Required for Category II applications and Category III applications involving non Title-V sources. See Instructions.)

N/A

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

A complete listing of all federal and state applicable requirements for Unit No. 1 was submitted with the June 1996 initial Seminole Power Plant Title V permit application.	

E. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **U-001**	
2. Emission Point Type Code: [X] 1 [ ] 2 [ ] 3 [ ] 4	
3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **N/A**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**	
5. Discharge Type Code: [ ] D [ ] F [ ] H [ ] P [ ] R [X] V [ ] W	
6. Stack Height:	**675** feet
7. Exit Diameter:	**36.0** feet
8. Exit Temperature:	**128** °F

9. Actual Volumetric Flow Rate:	**1,600,000** acfm
10. Percent Water Vapor : **N/A**	%
11. Maximum Dry Standard Flow Rate: **N/A**	dscfm
12. Nonstack Emission Point Height: **N/A**	feet
13. Emission Point UTM Coordinates: **N/A** Zone: East (km): North (km):	
14. Emission Point Comment (limit to 200 characters):	

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **Coal used in Unit No. 1**	
2. Source Classification Code (SCC): **1-01-002-02**	
3. SCC Units: **tons burned (all solid fuels)**	
4. Maximum Hourly Rate: **326**	5. Maximum Annual Rate: **2,855,760**
6. Estimated Annual Activity Factor: **N/A**	
7. Maximum Percent Sulfur: **3.30**	8. Maximum Percent Ash: **11.0**
9. Million Btu per SCC Unit: **22**	
10. Segment Comment (limit to 200 characters): **Coal sulfur content is 3.0 weight % on a monthly average basis.** **Coal-fired unit. No. 2 fuel oil used for startups, flame stabilization, emergency reserve capacity during statewide energy shortages, and limited supplemental load. SECI intends to initiate the utilization of up to 500,000 gallons per year of on-spec used oil (in lieu of No. 2 fuel oil) within the current permit cycle.** **Data provided in Fields 4, 5, and 9 based on a nominal coal heating value of 11,000 Btu/lb on an as-received basis and maximum heat input of 7,172 MMBtu/hr.**	

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment **2** of **2**

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **Coal and petroleum coke used in Unit No. 1**	
2. Source Classification Code (SCC): **1-01-002-02**	
3. SCC Units: **tons burned (all solid fuels)**	
4. Maximum Hourly Rate: **310**	5. Maximum Annual Rate: **2,715,600**
6. Estimated Annual Activity Factor: **N/A**	
7. Maximum Percent Sulfur: **4.41**	8. Maximum Percent Ash: **8.0**
9. Million Btu per SCC Unit: **23.1**	
10. Segment Comment (limit to 200 characters): **Data provided in Fields 4, 5, 7, 8, and 9 based on a 70/30 weight percent blend of coal/petroleum coke on an as-received basis. Composite sulfur content in Field 7 is based on 3.3% S for coal and 7.0% S for petroleum coke.** **No. 2 fuel oil used for startups, flame stabilization, emergency reserve capacity during statewide energy shortages, and limited supplemental load. SECI intends to initiate the utilization of up to 500,000 gallons per year of on-spec used oil (in lieu of No. 2 fuel oil) within the current permit cycle.** **Data provided in Fields 4, 5, and 9 based on nominal coal and petroleum coke heating values of 11,000 and 13,000 Btu/lb, respectively, on an as-received basis.**	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - SO2	**067**		**EL**
2 - NOX	**024**	**029**	**EL**
3 - PM	**010**		**EL**
4 - CO			**NS**
5 - PM10	**010**		**NS**
6 - VOC			**NS**
7 - H106 HCL			**NS**
8 - H107 HF			**NS**
9 - HAPS			**NS**

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **SO2**

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

3. Potential Emissions: **7,130.0** lb/hour **31,229.4** tons/year

4. Synthetically Limited?
   [ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions: **N/A**
   [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year

6. Emission Factor: **N/A**
   Reference:

7. Emissions Method Code:
   [X] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

Potential hourly and annual emission rates set equal to equivalent allowable emission rates.

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

Total percent efficiency of control (Field 2) is applicable to coal combustion only and is an overall removal efficiency; i.e., includes coal washing credit.

Potential emissions (Field 3) reflects coal combustion only which is worst-case fuel.

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: **RULE**
2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **0.994 lb/mmBtu**
4. Equivalent Allowable Emissions: **7,130.0** lb/hour **31,229.4** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous emissions monitoring system (CEMS)**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **40 CFR 60, Subpart Da (coal fuel only).** **Requested allowable emissions (Field 3) and equivalent allowable emissions (Field 4) are applicable to coal combustion only. Field 3 (.994 lb/MMBtu) based on maximum SO_2 emission rate (7,130 lb/hr) and maximum heat input (7,172 MMBtu/hr). Depending on unwashed coal sulfur content and level of coal washing, the SO_2 emission rate (Field 3) may increase up to 1.2 lb/MMBtu under other, lower load operating conditions. However, maximum allowable lb/hr and tpy SO_2 rates will not exceed those shown in Field 4 for these other operating conditions.** **Allowable emissions (Field 3) in lb/MMBtu is on a 30-day rolling average basis.**

Allowable Emissions (Pollutant identified on front of page)

B.

1. Basis for Allowable Emissions Code: **RULE**
2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **90 percent overall reduction**
4. Equivalent Allowable Emissions: **7,130.0** lb/hour **31,229.4** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous emissions monitoring system (CEMS).**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **40 CFR 60, Subpart Da (coal fuel only).** **Allowable emissions (Field 3) in percent overall reduction is on a 30-day rolling average basis.**

C.

1. Basis for Allowable Emissions Code: **ESCPSD**
2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **0.912 lb/MMBtu**
4. Equivalent Allowable Emissions: **6,540** lb/hour **28,645** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous emissions monitoring system (CEMS) and fuel analyses.**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Requested allowable emissions (Field 3) and equivalent allowable emissions (Field 4) are applicable to 70/30 percent by weight coal/petcoke blend at the maximum heat input rate of 7,172 MMBtu/hr. Depending on unwashed coal sulfur content and level of coal washing, the SO_2 emission rate (Field 3) may increase up to 1.05 lb/MMBtu under other, lower load operating conditions. However, maximum allowable lb/hr and tpy SO_2 rates will not exceed those shown in Field 4 for these other operating conditions.** **Allowable emissions (Field 3) in lb/MMBtu is on a 30-day rolling average basis.**

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **NOX**

2. Total Percent Efficiency of Control: **65 %**

3. Potential Emissions: **4,303.2** lb/hour **18,848.0** tons/year

4. Synthetically Limited?
   [ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:
   [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year

6. Emission Factor: **N/A**
   Reference:

7. Emissions Method Code:
   [X] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

Potential hourly and annual emission rates set equal to equivalent allowable emission rates.

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

Potential emissions (Field 3) reflects coal combustion only which is worst-case fuel.

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: **RULE**
2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **0.6 lb/mmBtu**
4. Equivalent Allowable Emissions: **4,303.2** lb/hour **18,848.0** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous emissions monitoring system (CEMS).**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **40 CFR 60, Subpart Da (coal fuel only).** **Requested allowable emissions (Field 3) and equivalent allowable emissions (Field 4) are applicable to coal combustion only.** **Allowable emissions (Field 3) in lb/MMBtu is on a 30-day rolling average basis.**

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **PM**

2. Total Percent Efficiency of Control: **99.6** %

3. Potential Emissions: **215.2** lb/hour **924.4** tons/year

4. Synthetically Limited?
   [ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:
   [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year

6. Emission Factor: **N/A**
   Reference:

7. Emissions Method Code:
   [X] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

Potential hourly and annual emission rates set equal to equivalent allowable emission rates.

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

Potential emissions (Field 3) reflects coal combustion only which is worst-case fuel.

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: **RULE**
2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **0.03 lb/mmBtu**
4. Equivalent Allowable Emissions: **215.2** lb/hour **924.4** tons/year
5. Method of Compliance (limit to 60 characters): **Annual testing using EPA Reference Method 5B.**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **40 CFR 60, Subpart Da (coal fuel only).** **Requested allowable emissions (Field 3) and equivalent allowable emissions (Field 4) are applicable to coal combustion only.**

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Visible Emissions Limitation: Visible Emissions Limitation **1** of **1**

1. Visible Emissions Subtype: **VE**
2. Basis for Allowable Opacity: **[X]** Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **20 %** Exceptional Conditions: **27 %** Maximum Period of Excess Opacity Allowed: **6** min/hour
4. Method of Compliance: **Continuous Opacity Monitoring System (COMS).**
5. Visible Emissions Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**

Visible Emissions Limitation: Visible Emissions Limitation of

1. Visible Emissions Subtype:
2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour
4. Method of Compliance:
5. Visible Emissions Comment (limit to 200 characters):

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System: Continuous Monitor 1 of 5

1. Parameter Code: **EM**	2. Pollutant(s): **SO2**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Thermo-Environmental Instruments, Inc.** Model Number: **43B** Serial Number: **43B-46935-277**	
5. Installation Date: **5/31/94**	
6. Performance Specification Test Date: **10/19/94**	
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR Part 60, Subpart Da and 40 CFR Part 75.**	

Continuous Monitoring System: Continuous Monitor 2 of 5

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Thermo-Environmental Instruments, Inc.** Model Number: **42D** Serial Number: **42D-46961-277**	
5. Installation Date: **5/31/94**	
6. Performance Specification Test Date: **10/19/94**	
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR Part 60, Subpart Da and 40 CFR Part 75.**	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System: Continuous Monitor **3** of **5**

1. Parameter Code: **VE**	2. Pollutant(s): **N/A**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Lear Siegler** Model Number: **4500** Serial Number: **0622058/054**	
5. Installation Date: **5/31/94**	
6. Performance Specification Test Date: **11/7/95**	
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR Part 60, Subpart Da and 40 CFR Part 75.**	

Continuous Monitoring System: Continuous Monitor **4** of **5**

1. Parameter Code: **CO2**	2. Pollutant(s): **N/A**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Thermo-Environmental Instruments, Inc.** Model Number: **41H** Serial Number: **41H-42927-268**	
5. Installation Date: **5/31/94**	
6. Performance Specification Test Date: **10/19/94**	
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR Part 75**	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System: Continuous Monitor **5** of **5**

1. Parameter Code: **FLOW**	2. Pollutant(s): **N/A**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Environmental Measurement Research Corporation** Model Number: **EMRC** Serial Number: **0462**	
5. Installation Date: **5/31/94**	
6. Performance Specification Test Date: **10/19/94**	
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR Part 75**	

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 (limit to 200 characters):	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION
(Regulated and Unregulated Emissions Units)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

   If the emissions unit addressed in this section emits particulate matter or sulfur dioxide, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for particulate matter or sulfur dioxide. Check the first statement, if any, that applies and skip remaining statements.

   [X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

[ ] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[X] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code:			
PM	[X] C	[ ] E	[ ] Unknown
SO2	[X] C	[ ] E	[ ] Unknown
NO2	[U] C	[ ] E	[ ] Unknown
4. Baseline Emissions:			
PM		lb/hour	tons/year
SO2		lb/hour	tons/year
NO2			tons/year
5. PSD Comment (limit to 200 characters):			

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements for All Applications

1. Process Flow Diagram [X] Attached, Document ID: **Attachment C** [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [ ] Attached, Document ID:_____ [ ] Not Applicable [X] Waiver Requested **Previously submitted with Title V permit application.**
3. Detailed Description of Control Equipment [ ] Attached, Document ID:_____ [ ] Not Applicable [X] Waiver Requested **Previously submitted with Title V permit application.**
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:_____ [ ] Not Applicable [X] Waiver Requested **Previously submitted with Title V permit application.**
5. Compliance Test Report [ ] Attached, Document ID [ ] Previously submitted, Date:_____ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:_____ [X] Not Applicable **Previously submitted with Title V permit application.**
7. Operation and Maintenance Plan [ ] Attached, Document ID:_____ [X] Not Applicable
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID:_____ [X] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:_____ [X] Not Applicable

Additional Supplemental Requirements for Category I Applications Only N/A

10. Alternative Methods of Operation [ ] Attached, Document ID:_____ [ ] Not Applicable
11. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:_____ [ ] Not Applicable
12. Identification of Additional Applicable Requirements [ ] Attached, Document ID:_____ [ ] Not Applicable
13. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:_____ [ ] Not Applicable
14. Acid Rain Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:_____ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:_____ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:_____ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:_____ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through L as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application. Some of the subsections comprising the Emissions Unit Information Section of the form are intended for regulated emissions units only. Others are intended for both regulated and unregulated emissions units. Each subsection is appropriately marked.

A. TYPE OF EMISSIONS UNIT (Regulated and Unregulated Emissions Units)

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one:

[X] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

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

2. Single Process, Group of Processes, or Fugitive Only? Check one:

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

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

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

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section (limit to 60 characters): **Steam Electric Generator No. 2**		
2. Emissions Unit Identification Number: [ ] No Corresponding ID [ ] Unknown **002**		
3. Emissions Unit Status Code: **A**	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code: **49**
6. Emissions Unit Comment (limit to 500 characters): **N/A**		

Emissions Unit Control Equipment

A.

1. Description (limit to 200 characters): **Electrostatic Precipitator System**
2. Control Device or Method Code: **010**

B.

1. Description (limit to 200 characters): **Wet Limestone Flue Gas Desulfurization (FGD)**
2. Control Device or Method Code: **067**

C.

1. Description (limit to 200 characters): **Low NO_x Burners**
2. Control Device or Method Code: **024**

D.

1. Description (limit to 200 characters): **Low Excess-Air Firing**
2. Control Device or Method Code: **029**

E.

1. Description (limit to 200 characters):
2. Control Device or Method Code:

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Details

1. Initial Startup Date: **N/A**		
2. Long-term Reserve Shutdown Date: **N/A**		
3. Package Unit: **N/A** Manufacturer:	Model Number:	
4. Generator Nameplate Rating:	**714.6** MW	
5. Incinerator Information: **N/A** Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		°F seconds °F

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:		**7,172** mmBtu/hr
2. Maximum Incineration Rate: **N/A**	lb/hr	tons/day
3. Maximum Process or Throughput Rate: **N/A**		
4. Maximum Production Rate: **N/A**		
5. Operating Capacity Comment (limit to 200 characters):		

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule:		
	24 hours/day	**7** days/week
	52 weeks/year	**8,760** hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Rule Applicability Analysis (Required for Category II applications and Category III applications involving non Title-V sources. See Instructions.)

N/A

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

A complete listing of all federal and state applicable requirements for Unit No. 2 was submitted with the June 1996 initial Seminole Power Plant Title V permit application.	

E. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **U-002**	
2. Emission Point Type Code: [X] 1 [ ] 2 [ ] 3 [ ] 4	
3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **N/A**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**	
5. Discharge Type Code: [ ] D [ ] F [ ] H [ ] P [ ] R [X] V [ ] W	
6. Stack Height:	**675** feet
7. Exit Diameter:	**36.0** feet
8. Exit Temperature:	**128** °F

9. Actual Volumetric Flow Rate:	**1,600,000** acfm
10. Percent Water Vapor : **N/A**	%
11. Maximum Dry Standard Flow Rate: **N/A**	dscfm
12. Nonstack Emission Point Height: **N/A**	feet
13. Emission Point UTM Coordinates: **N/A** Zone: East (km): North (km):	
14. Emission Point Comment (limit to 200 characters):	

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **Coal used in Unit No. 2**	
2. Source Classification Code (SCC): **1-01-002-02**	
3. SCC Units: **tons burned (all solid fuels)**	
4. Maximum Hourly Rate: **326**	5. Maximum Annual Rate: **2,855,760**
6. Estimated Annual Activity Factor: **N/A**	
7. Maximum Percent Sulfur: **3.30**	8. Maximum Percent Ash: **11.0**
9. Million Btu per SCC Unit: **22**	
10. Segment Comment (limit to 200 characters): **Coal sulfur content is 3.0 weight % on a monthly average basis.** **Coal-fired unit. No. 2 fuel oil used for startups, flame stabilization, emergency reserve capacity during statewide energy shortages, and limited supplemental load. SECI intends to initiate the utilization of up to 500,000 gallons per year of on-spec used oil (in lieu of No. 2 fuel oil) within the current permit cycle.** **Data provided in Fields 4, 5, and 9 based on a nominal coal heating value of 11,000 Btu/lb on an as-received basis and maximum heat input of 7,172 MMBtu/hr.**	

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): **Coal and petroleum coke used in Unit No. 2**	
2. Source Classification Code (SCC): **1-01-002-02**	
3. SCC Units: **tons burned (all solid fuels)**	
4. Maximum Hourly Rate: **310**	5. Maximum Annual Rate: **2,715,600**
6. Estimated Annual Activity Factor: **N/A**	
7. Maximum Percent Sulfur: **4.41**	8. Maximum Percent Ash: **8.0**
9. Million Btu per SCC Unit: **23.1**	
10. Segment Comment (limit to 200 characters): **Data provided in Fields 4, 5, 7, 8, and 9 based on a 70/30 weight percent blend of coal/petroleum coke on an as-received basis. Composite sulfur content in Field 7 is based on 3.3% S for coal and 7.0% S for petroleum coke.** **No. 2 fuel oil used for startups, flame stabilization, emergency reserve capacity during statewide energy shortages, and limited supplemental load. SECI intends to initiate the utilization of up to 500,000 gallons per year of on-spec used oil (in lieu of No. 2 fuel oil) within the current permit cycle.** **Data provided in Fields 4, 5, and 9 based on nominal coal and petroleum coke heating values of 11,000 and 13,000 Btu/lb, respectively, on an as-received basis.**	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - SO2	**067**		**EL**
2 - NOX	**024**	**029**	**EL**
3 - PM	**010**		**EL**
4 - CO			**NS**
5 - PM10	**010**		**NS**
6 - VOC			**NS**
7 - H106 HCL			**NS**
8 - H107 HF			**NS**
9 - HAPS			**NS**

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **SO2**

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

3. Potential Emissions: **7,130.0** lb/hour **31,229.4** tons/year

4. Synthetically Limited?
   [ ] Yes [**X**] No

5. Range of Estimated Fugitive/Other Emissions: **N/A**
   [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year

6. Emission Factor: **N/A**
   Reference:

7. Emissions Method Code:
   [**X**] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

Potential hourly and annual emission rates set equal to equivalent allowable emission rates.

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

Total percent efficiency of control (Field 2) is applicable to coal combustion only and is an overall removal efficiency; i.e., includes coal washing credit.

Potential emissions (Field 3) reflects coal combustion only which is worst-case fuel.

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: **RULE**
2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **0.994 lb/mmBtu**
4. Equivalent Allowable Emissions: **7,130.0** lb/hour **31,229.4** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous emissions monitoring system (CEMS)**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **40 CFR 60, Subpart Da (coal fuel only).** **Requested allowable emissions (Field 3) and equivalent allowable emissions (Field 4) are applicable to coal combustion only. Field 3 (.994 lb/MMBtu) based on maximum SO_2 emission rate (7,130 lb/hr) and maximum heat input (7,172 MMBtu/hr). Depending on unwashed coal sulfur content and level of coal washing, the SO_2 emission rate may increase up to 1.2 lb/MMBtu under other, lower load operating conditions. However, maximum allowable lb/hr and tpy SO_2 rates will not exceed those shown in Field 4 for these other operating conditions.** **Allowable emissions (Field 3) in lb/MMBtu is on a 30-day rolling average basis.**

Allowable Emissions (Pollutant identified on front of page)

B.

1. Basis for Allowable Emissions Code: **RULE**
2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **90 percent overall reduction**
4. Equivalent Allowable Emissions: **7,130.0** lb/hour **31,229.4** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous emissions monitoring system (CEMS).**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **40 CFR 60, Subpart Da (coal fuel only).** **Allowable emissions (Field 3) in percent overall reduction is on a 30-day rolling average basis.**

C.

1. Basis for Allowable Emissions Code: **ESCPSD**
2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **0.904 lb/MMBtu**
4. Equivalent Allowable Emissions: **6,482** lb/hour **28,391** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous emissions monitoring system (CEMS) and fuel analyses.**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **Requested allowable emissions (Field 3) and equivalent allowable emissions (Field 4) are applicable to 70/30 percent by weight coal/petcoke blend at the maximum heat input rate of 7,172 MMBtu/hr. Depending on unwashed coal sulfur content and level of coal washing, the SO_2 emission rate (Field 3) may increase up to 1.04 lb/MMBtu under other, lower load operating conditions. However, maximum allowable lb/hr and tpy SO_2 rates will not exceed those shown in Field 4 for these other operating conditions.** **Allowable emissions (Field 3) in lb/MMBtu is on a 30-day rolling average basis.**

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **NOX**

2. Total Percent Efficiency of Control: **65 %**

3. Potential Emissions: **4,303.2** lb/hour **18,848.0** tons/year

4. Synthetically Limited?
   [ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:
   [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year

6. Emission Factor: **N/A**
   Reference:

7. Emissions Method Code:
   [X] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

Potential hourly and annual emission rates set equal to equivalent allowable emission rates.

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

Potential emissions (Field 3) reflects coal combustion only which is worst-case fuel.

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: **RULE**
2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **0.6 lb/mmBtu**
4. Equivalent Allowable Emissions: **4,303.2** lb/hour **18,848.0** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous emissions monitoring system (CEMS).**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **40 CFR 60, Subpart Da (coal fuel only).** **Requested allowable emissions (Field 3) and equivalent allowable emissions (Field 4) are applicable to coal combustion only.** **Allowable emissions (Field 3) in lb/MMBtu is on a 30-day rolling average basis.**

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Pollutant Detail Information:

1. Pollutant Emitted: **PM**

2. Total Percent Efficiency of Control: **99.6** %

3. Potential Emissions: **215.2** lb/hour **924.4** tons/year

4. Synthetically Limited?
   [ ] Yes [X] No

5. Range of Estimated Fugitive/Other Emissions:
   [ ] 1 [ ] 2 [ ] 3 _____ to _____ tons/year

6. Emission Factor: **N/A**
   Reference:

7. Emissions Method Code:
   [X] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5

8. Calculation of Emissions (limit to 600 characters):

Potential hourly and annual emission rates set equal to equivalent allowable emission rates.

9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):

Potential emissions (Field 3) reflects coal combustion only which is worst-case fuel.

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: **RULE**
2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **0.03 lb/mmBtu**
4. Equivalent Allowable Emissions: **215.2** lb/hour **924.4** tons/year
5. Method of Compliance (limit to 60 characters): **Annual testing using EPA Reference Method 5B.**
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): **40 CFR 60, Subpart Da (coal fuel only).** **Requested allowable emissions (Field 3) and equivalent allowable emissions (Field 4) are applicable to coal combustion only.**

B.

1. Basis for Allowable Emissions Code:
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:
4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Visible Emissions Limitation: Visible Emissions Limitation **1** of **1**

1. Visible Emissions Subtype: **VE**
2. Basis for Allowable Opacity: [**X**] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour
4. Method of Compliance: **Continuous Opacity Monitoring System (COMS).**
5. Visible Emissions Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**

Visible Emissions Limitation: Visible Emissions Limitation of

1. Visible Emissions Subtype:
2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour
4. Method of Compliance:
5. Visible Emissions Comment (limit to 200 characters):

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System: Continuous Monitor **1** of **5**

1. Parameter Code: **EM**	2. Pollutant(s): **SO2**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Thermo-Environmental Instruments, Inc.** Model Number: **43B** Serial Number: **43B-46929-277**	
5. Installation Date: **5/31/94**	
6. Performance Specification Test Date: **10/19/94**	
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR Part 60, Subpart Da and 40 CFR Part 75.**	

Continuous Monitoring System: Continuous Monitor **2** of **5**

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Thermo-Environmental Instruments, Inc.** Model Number: **42D** Serial Number: **42D-46969-277**	
5. Installation Date: **5/31/94**	
6. Performance Specification Test Date: **10/19/94**	
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR Part 60, Subpart Da and 40 CFR Part 75.**	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System: Continuous Monitor **3** of **5**

1. Parameter Code: **VE**	2. Pollutant(s): **N/A**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Lear Siegler** Model Number: **4500** Serial Number: **12206852/854**	
5. Installation Date: **5/31/94**	
6. Performance Specification Test Date: **11/7/95**	
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR Part 60, Subpart Da and 40 CFR Part 75.**	

Continuous Monitoring System: Continuous Monitor **4** of **5**

1. Parameter Code: **CO2**	2. Pollutant(s): **N/A**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Thermo-Environmental Instruments, Inc.** Model Number: **41H** Serial Number: **41H-44966-273**	
5. Installation Date: **5/31/94**	
6. Performance Specification Test Date: **10/19/94**	
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR Part 75**	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System: Continuous Monitor 5 of 5

1. Parameter Code: **FLOW**	2. Pollutant(s): **N/A**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Environmental Measurement Research Corporation** Model Number: **EMRC** Serial Number: **0463**	
5. Installation Date: **5/31/94**	
6. Performance Specification Test Date: **10/19/94**	
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR Part 75**	

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 (limit to 200 characters):	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION
(Regulated and Unregulated Emissions Units)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

   If the emissions unit addressed in this section emits particulate matter or sulfur dioxide, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for particulate matter or sulfur dioxide. Check the first statement, if any, that applies and skip remaining statements.

   [X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

   [ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

[ ] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[X] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code:			
PM	[X] C	[ ] E	[ ] Unknown
SO2	[X] C	[ ] E	[ ] Unknown
NO2	[U] C	[ ] E	[ ] Unknown

4. Baseline Emissions:		
PM	lb/hour	tons/year
SO2	lb/hour	tons/year
NO2		tons/year

5. PSD Comment (limit to 200 characters):

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements for All Applications

1. Process Flow Diagram [X] Attached, Document ID: **Attachment C** [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [ ] Attached, Document ID:_____ [ ] Not Applicable [X] Waiver Requested **Previously submitted with Title V permit application.**
3. Detailed Description of Control Equipment [ ] Attached, Document ID:_____ [ ] Not Applicable [X] Waiver Requested **Previously submitted with Title V permit application.**
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:_____ [ ] Not Applicable [X] Waiver Requested **Previously submitted with Title V permit application.**
5. Compliance Test Report [ ] Attached, Document ID [ ] Previously submitted, Date:_____ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:_____ [X] Not Applicable **Previously submitted with Title V permit application.**
7. Operation and Maintenance Plan [ ] Attached, Document ID:_____ [X] Not Applicable
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID:_____ [X] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:_____ [X] Not Applicable

Additional Supplemental Requirements for Category I Applications Only N/A

10. Alternative Methods of Operation
[ ] Attached, Document ID:_____ [ ] Not Applicable

11. Alternative Modes of Operation (Emissions Trading)
[ ] Attached, Document ID:_____ [ ] Not Applicable

12. Identification of Additional Applicable Requirements
[ ] Attached, Document ID:_____ [ ] Not Applicable

13. Compliance Assurance Monitoring Plan
[ ] Attached, Document ID:_____ [ ] Not Applicable

14. Acid Rain Application (Hard-copy Required)

[ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
Attached, Document ID:_____

[ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
Attached, Document ID:_____

[ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
Attached, Document ID:_____

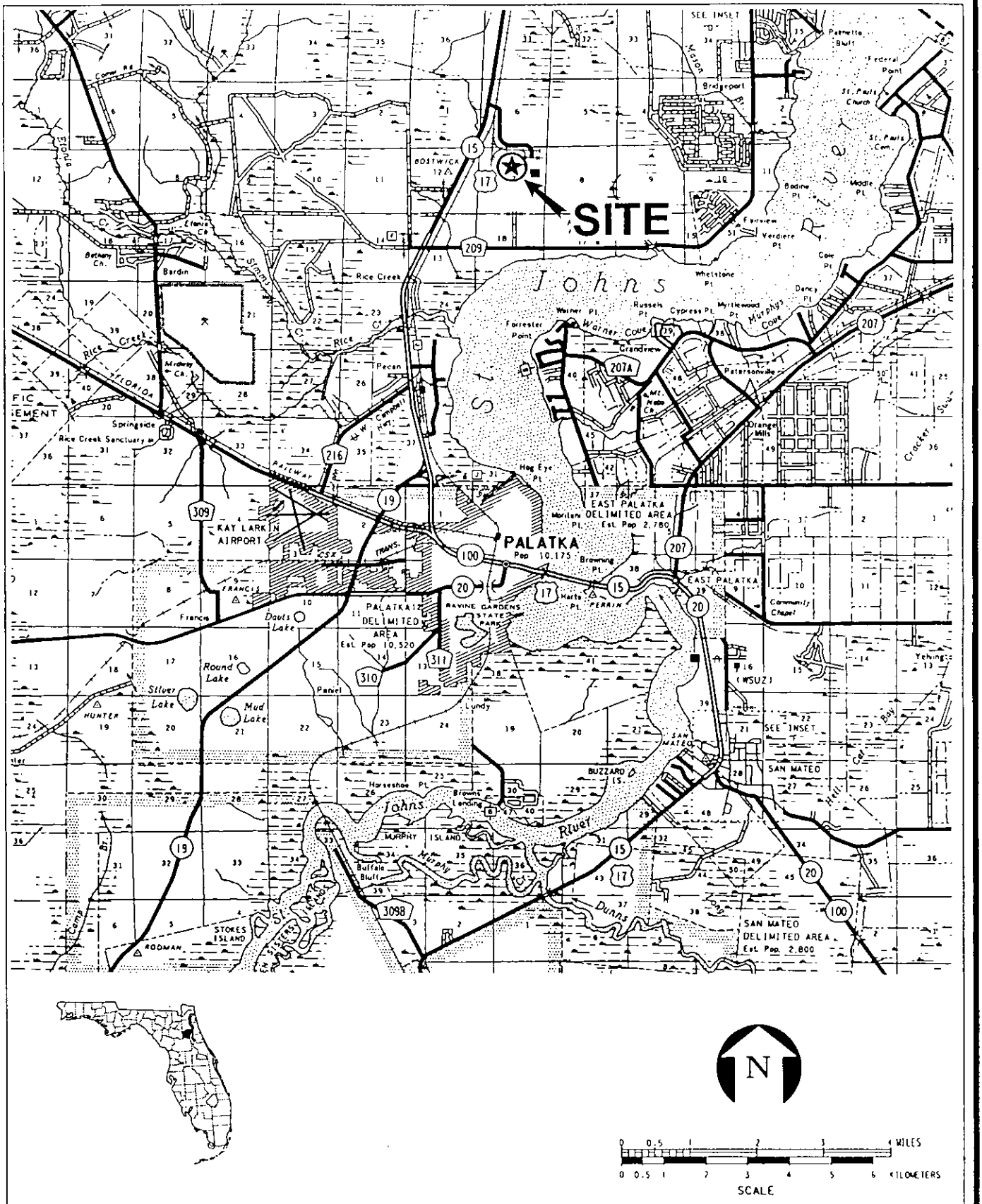
[ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
Attached, Document ID:_____

[ ] Not Applicable

APPENDIX A

AREA MAP

94331-0200/ct



APPENDIX A.

SEMINOLE POWER PLANT LOCATION MAP

Source: D.O.T. Highway Map, 1982

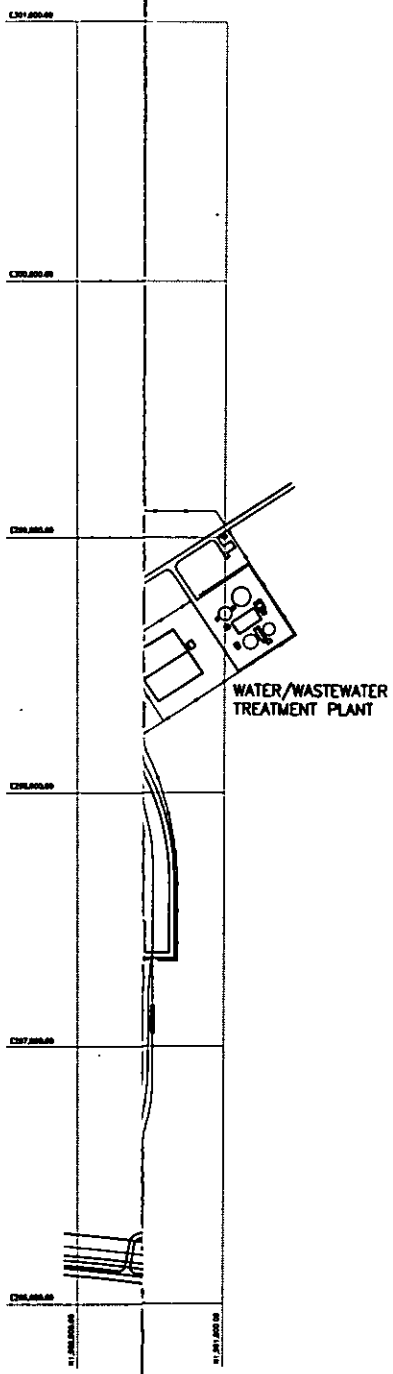
SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

APPENDIX B

FACILITY PLOT PLANS

C:\ACAD\96354\FACIL

08/28/96



GRAPHIC SCALE

0 375 750

SCALE IN FEET

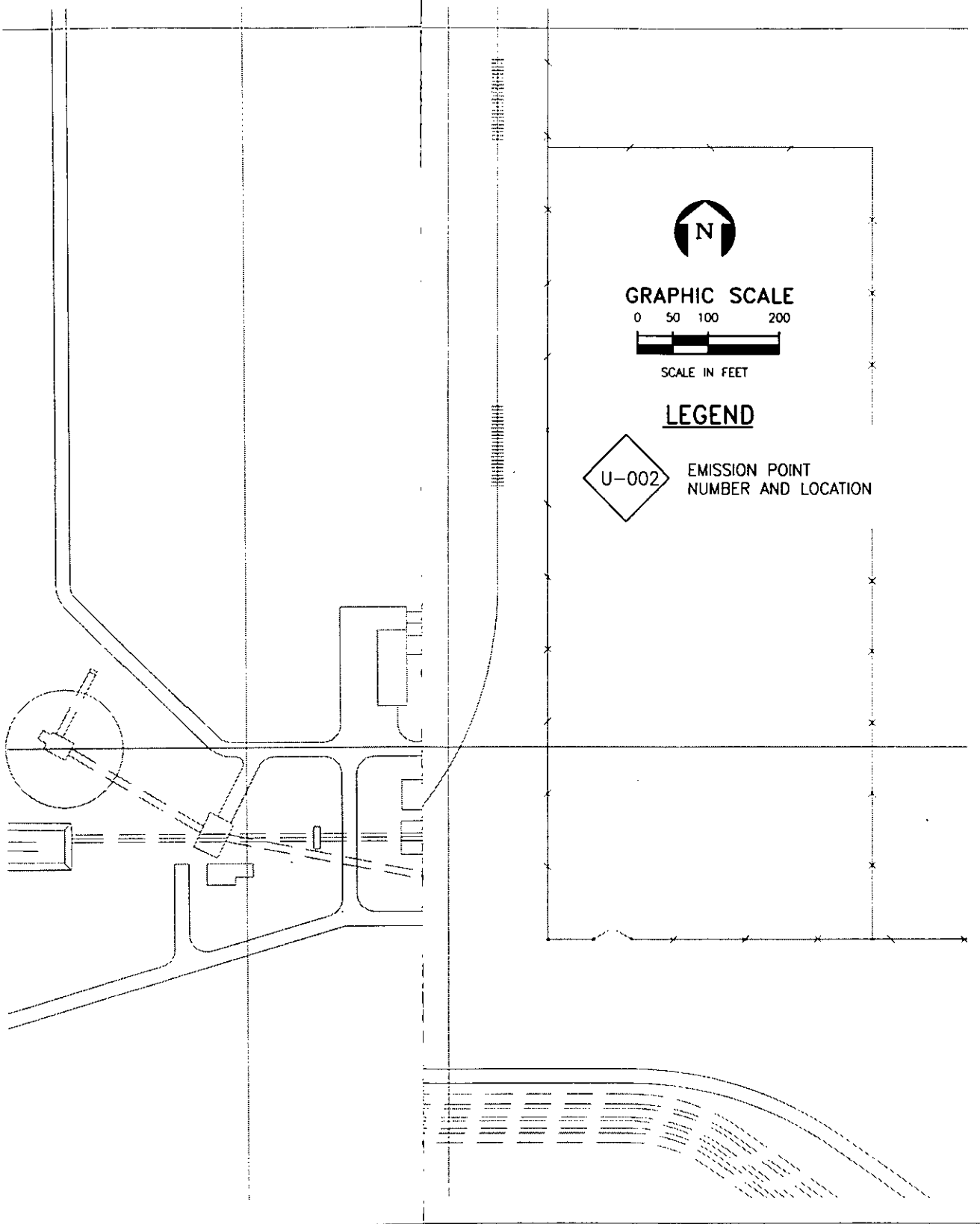
APPENDIX B-1.

OVERALL FACILITY PLOT PLAN

Source: Seminole Electric, 1984.

ECT

Environmental Consulting & Technology, Inc.



APPENDIX B-2.

POWER BLOCK

Source: ECT, 1996.

ECT

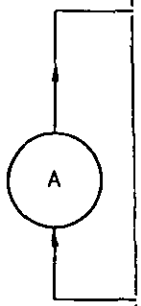
Environmental Consulting & Technology, Inc.

APPENDIX C

PROCESS FLOW DIAGRAM

C:\ACAD\96354\BOIL01

10/17/96



FLUE GAS DESULFURIZATION MODULES

STEAM

N
* (ON-S

* SECI INTENDS TO INITIATE THE UTILIZATION OF UP TO 500,000 GALLONS PER YEAR OF ON-SPEC USED OIL (IN LIEU OF No. 2 FUEL OIL) WITHIN THE CURRENT PERMIT CYCLE.

LEGEND

U-001 EMISSION POINT NUMBER

APPENDIX C.

BOILER PROCESS FLOW DIAGRAM

Source: ECT, 1996.

ECT

Environmental Consulting & Technology, Inc.

APPENDIX D

FDEP PETCOKE PERFORMANCE TESTS AUTHORIZATION LETTER

Final Determination

The draft permit amendment to conduct pollutant emissions test while firing a blend of petroleum coke and coal at Seminole Power Plant Unit No. 1 located in Palatka, Putnam County, Florida, was distributed on September 11, 1995. The Notice of Intent to Issue was published in the Palatka Daily News on September 21, 1995. Copies of the amendment were available for public inspection at the Department offices in Jacksonville and Tallahassee.

No comments were submitted by the National Park Service, U.S. Environmental Protection Agency or the public. The only comment submitted by the applicant was a change to Condition 4 of the Specific Conditions. The Department agrees with the applicant and will change Specific Condition 4 to require Seminole to take three separate as-fired samples during the particulate matter test run, but to analyze one composite (instead of three analyses) of these three samples for the parameters required by the condition.

The final action of the Department will be to issue the permit amendment with the change noted above.

Department of
Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

December 11, 1995

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. M. P. Opalinski
Director of Environmental Affairs
Seminole Electric Cooperative Incorporated
16313 North Dale Mabry Highway
Post Office Box 27200
Tampa, Florida 33688

Dear Mr. Opalinski:

Re: Amendment of PSD-FL-018
Seminole Power Plant, Palatka, Unit No. 1
Petroleum Coke/Coal Performance Test Request

The Department has reviewed the request from Seminole Electric Cooperative Inc. (SECI) dated April 12 and supplementary information dated June 2 and August 3 to conduct performance tests while firing petroleum coke/coal blends at Seminole Power Plant, Palatka, Unit No. 1.

You are hereby authorized to conduct performance tests for pollutant emissions on Seminole Power Plant Unit No. 1 in Palatka, Putnam County while firing blends of petroleum coke (petcoke) and bituminous coal (coal). All Conditions of Certification and Conditions of Approval in your Site Certification and PSD Permit related to air pollution emission limits and control equipment remain in force.

The performance tests will be conducted in order to gather data regarding pollutant emissions and operational limitations while firing blends of petcoke and coal containing a maximum of 30 percent (% by weight) petcoke. Screening to determine whether future long-term firing of petcoke/coal blends constitutes a modification subject to a review for Prevention of Significant Deterioration (PSD) shall be performed in accordance with Chapter 403, F.S.; Chapters 62-210 through 62-297 and 62-4, F.A.C.; and, Title 40, Code of Federal Regulations (CFR; July 1, 1994 version). The procedure will consist of a comparison of estimates of "representative actual annual emissions" while burning petcoke/coal blends against past actual emissions while burning coal (or estimates of past actual emissions developed from 100 percent coal baseline performance tests).

The performance test results along with any modification application to allow permanent petcoke/coal burning will be reviewed by the Department's Bureau of Air Regulation (BAR) and interested agencies/parties (i.e., DEP Northeast District office, U.S. EPA, National Park Service, etc.).

The performance tests shall be subject to the following conditions:

1. The permittee shall notify, in writing, the Department's BAR office, the Northeast District office, and the Site Certification office at least 15 days prior to commencement of the baseline and the petcoke/coal blend performance tests. A written test result report shall be submitted to these offices within 45 days upon completion of the last test run.

2. The petcoke/coal blend performance tests shall commence by January 15, 1996 and be conducted for not more than 30 days. The tests shall be conducted based on the proposed testing protocol (letter dated August 3, 1995, included as an attachment) to establish steady state operation and to achieve a maximum (30%) blend. If, for any reasons, a steady state operation of 30% petroleum coke-coal blend, or less, is not achieved, or the testing at 30% petcoke blend or less, presents any operational or environmental concerns, the testing shall be curtailed. The Department shall be immediately notified of the problems that have prevented steady state operations and what steps will be initiated to correct the problem. All petcoke/coal blend firing counts against the 30 days of approved time for conducting tests. All testing shall be concluded within 60 days of when petcoke is first introduced into Unit No. 1.

3. Stack emissions from Unit No. 1 shall not exceed the following during baseline and petcoke/coal blend performance tests (based on most stringent of present PSD Permit and Certification Conditions):

   a. Sulfur dioxide (SO_2) - 1.20 pounds per million Btu heat input and 10 percent of the potential combustion concentration (90 percent reduction).

   b. Nitrogen oxides (NO_X) - 0.60 pounds per million Btu heat input and 35 percent of the potential combustion concentration (65 percent reduction.)

   c. Particulate Matter - 0.03 pounds per million Btu heat input and 1 percent of the potential combustion concentration (99 percent reduction).

4. As-burned fuel samples shall be collected and analyzed for the sulfur, nitrogen, and metals (see condition No. 5) content throughout the petroleum coke-coal blend and the baseline coal test periods. Weekly composites from daily sampling shall be required; in addition and during the particulate matter test runs, a minimum of three (3) separate samples shall be taken and a composite of the three samples shall be analyzed.

5. The concentrations of chromium, lead, mercury, nickel, beryllium, vanadium, and zinc in the petcoke/coal blend shall be compared with the concentration of the same metals in the coal used during the baseline tests.

6. The performance test of the petcoke/coal blends shall be limited to a maximum of 30% petcoke, by weight. The maximum weight of the petroleum coke burned during the petcoke/coal blend performance tests shall not exceed 125,000 pounds per hour (averaged over 24 hours).

7. The maximum sulfur content of the coal shall not exceed 3.0 percent, by weight, during the baseline tests and the petroleum coke-coal blend tests. The maximum sulfur content of the petroleum coke shall not exceed 5.5 percent, by weight.

8. SO_2, NO_x, and opacity emissions data shall be recorded using continuous emissions monitors (CEMS) during the baseline and the petcoke/coal blend tests. If the plant CEMS are used for these tests, these systems shall be quality assured pursuant to 40 CFR 60, Appendix F requirements. The data assessment report per 40 CFR 60, Appendix F, for the most recent relative accuracy test audit (RATA) and most recent cylinder gas audit (CGA), shall be submitted with the test report. In addition, stack tests shall be conducted for the pollutants particulate matter (PM; assume that all of PM is PM10), carbon monoxide, and sulfuric acid mist. A satisfactory performance test for each baseline test and each petroleum coke-coal blend shall consist of a minimum of three tests at three runs per test.

9. The pollutant emission results from the petroleum coke/coal blend performance tests shall be used to estimate "representative actual annual emissions" following an operational change per 62-212.200 (2)(d), F.A.C., for comparison with actual emissions per Rule 62-212.200(2)(a), F.A.C. The comparison will form the basis of a PSD applicability determination pursuant to 40 CFR 52.21. The results of baseline performance tests when firing coal will be used only to the extent that such information does not already exist or is insufficient to determine actual emissions.

10. Any performance tests shall be conducted using EPA Reference Methods, as contained in 40 CFR 60 (Standards of Performance for New Stationary Sources), 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants), and 40 CFR 266, Appendix IX (Multi-metals), or any other method approved by the Department, in writing, in accordance with Chapter 62-297, F.A.C.

11. If additional time is needed, the permittee shall request an extension of time and provide the Department with documentation of the progress accomplished to-date and shall identify the work required to complete the performance tests.

12. Daily records (i.e., heat input, steam production, pressure, temperature, MW, fuel input rates, etc.) of boiler operations while firing the petcoke/coal blend and while firing only coal (baseline) during the tests shall be required. Also, daily recordkeeping of the control equipment parameters (i.e., the pH of the scrubbing medium, the mix ratio of the water and medium and the injection rate to the scrubber, the pressure drop across the scrubber, etc.) shall be required and any alteration of the control equipment operational parameters between the baseline and the petroleum coke-coal blend tests shall be documented and summarized in the final report.

13. A Type I or II stack audit may be conducted by the Northeast District office.

14. Complete documentation (recording) of any firing of the petroleum coke-coal blend shall be required (i.e., all CEMs records; testing results; materials utilized, by weight; etc.) and kept on file for a minimum of five years.

15. The authorized petroleum coke-coal blend performance tests shall not result in the release of objectionable odors pursuant to Rule 62-296.320(2), F.A.C.

16. Performance testing shall cease as soon as possible if Unit No. 1 operations are not in accordance with the conditions in the air section of Site Certification No. PA 78-10, PSD Permit No. PSD-FL-018, or this authorization protocol. Performance testing shall not resume until appropriate measures to correct the problem(s) have been implemented.

17. The performance tests for pollutant emissions shall be conducted under the direct supervision and responsible charge of a professional engineer registered in Florida.

18. This Department action is only to authorize the petroleum coke-coal blend performance tests. Any firing of petroleum coke beyond the 30 days of testing within the 60 day period approved to conduct such tests will be deemed a violation of the Site Certification No. PA 78-10 and Permit No. PSD-FL-018.

19. The Northeast District office shall be immediately notified, in writing upon completion of the final test.

20. The testing series shall include emissions tests for each of the petroleum coke/coal blends and pollutants with the source operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the capacity allowed by Site Certification PA 78-10 and Permit PSD-FL-018. If it is impracticable to test at permitted capacity, then the source may be tested at a lesser rate. However, the tests **shall** be conducted at capacities within 10 percent of each other and corrected to the same heat input basis. Furthermore, subsequent source operation with a petroleum coke-coal blend, if requested and approved by the Department, shall be limited to 110 percent of the tested capacity for that blend until new tests are conducted, which requires prior Department authorization.

21. Prior written approval of the pollutants to be tested for and the appropriate test methods are mandatory prior to commencement of testing. The proposal shall be submitted to the Site Certification office, the Department's BAR office, and the Northeast District office for approval.

22. Attachments to be incorporated:
    - o SECI's April 12, 1994 letter
    - o Department's April 25, 1995 letter
    - o SECI's June 2, 1995 letter
    - o SECI's August 3, 1995 letter

This letter amendment must be attached to Permit No. PSD-FL-018 and shall become a part of the permit.

Sincerely,

Howard L. Rhodes, Director
Division of Air Resources
Management

HLR/sa/t

Enclosure

cc: Buck Oven, DEP
Jewell Harper, EPA
Ken Bachor, SECI
Chris Kirts, NED
John Bunyak, NPS

APPENDIX E

PSD APPLICABILITY ASSESSMENT

APPENDIX E - PSD APPLICABILITY ANALYSIS

The primary consideration is whether co-firing petroleum coke at the Seminole Power Plant will cause a significant increase in air emissions. Because the proposed use of petcoke at the Seminole Power Plant will replace the current use of coal (in amounts up to 30 percent by weight), a significant net increase due to the use of petcoke will not occur as long as the emissions resulting from petcoke combustion, for each PSD regulated air pollutant, do not exceed the 2 year historical average coal emission rates.

The pollutants addressed by the PSD regulatory program with respect to significant emission rates are listed in Chapter 62-212, Table 212.400-2, F.A.C; these pollutants and their significant emission rates are shown on Table E-1. For the Seminole Power Plant, measured historical emission rates are obtainable for sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM) for each unit. SO_2 and NO_x are monitored using continuous emissions monitoring systems (CEMS). PM is monitored on an annual basis using EPA Reference Method 5B.

A screening assessment of PSD applicability was first conducted by evaluating the potential for petcoke/coal blends to cause an increase in emission rates in comparison to baseline coal based on the test burn results and fuel characteristics. For emissions of PSD pollutants which do not have any potential to increase, no further analysis was necessary. A further detailed evaluation of potential PSD applicability was conducted for emissions of PSD pollutants identified as having the potential to increase.

Because year-to-year variations in operating hours, load, or coal sulfur content are generally *not* considered operational changes and therefore do *not* constitute modifications under the PSD regulatory program, the comparison of actual emission rates was made on a pound of pollutant per million British thermal unit (lb/MMBtu) heat input basis. As indicated previously, the Seminole Power Plant is a baseload facility. The use of petcoke will not change the electrical generation capacity of the facility nor change its operating

hours from what would have occurred if petcoke were not utilized. Hence, a comparison of actual emissions on a lb/MMBtu basis is the most appropriate measure because it effectively excludes permissible variations in operating hours and production rate. To develop actual emission rate changes in terms of the tons per year (tpy) values shown in Chapter 62-212, Table 212.400-2, F.A.C, average load and operating hours for calender years 1994 and 1995 were used for both the historical and future representative actual annual emissions.

A discussion of the actual emission rate change for each of the PSD pollutants listed on Table E-1 is provided in the following sections.

Sulfur Dioxide (SO_2)

Because of the potentially higher sulfur content of petcoke in comparison to baseline coal, a detailed analysis of PSD applicability based on historical emission rates was conducted. The average 1994/1995 historical SO_2 emission rates obtained from SECI's Annual Operating Reports (AORs) for Units 1 and 2 are 0.740 and 0.715 lb/MMBtu, respectively. It is noted that these actual rates are approximately 25 percent lower than the maximum SO_2 emission rate (i.e., equivalent to 0.994 lb/MMBtu, based on 90 percent removal efficiency during maximum plant heat input) authorized by SECI's current permits. SECI proposes to limit petcoke SO_2 emission rates, on a 30-day rolling average basis, to the historical values noted above. Compliance with the historical emissions values can be verified through mutually acceptable permit conditions in conjunction with fuel blend monitoring. The *maximum* allowable SO_2 emission rates (based on 3.0 percent sulfur coal over a 30-day rolling average period) for a 70/30 coal/petcoke blend are summarized in the following tables. The tables also show current authorized allowable SO_2 emission rates demonstrating that maximum allowable rates will decrease due to the use of coal/petcoke blends.

Table E-1. Significant Emission Rates for PSD Review

Pollutant	Emission Rate (tpy)	Emission Rate (lb/yr)
CO	100	
NO_x	40	
SO_2	40	
Ozone	40 (as VOC)	
PM (TSP)	25	
PM (PM_{10})	15	
Total reduced sulfur (including H_2S)	10	
Reduced sulfur compounds (including H_2S)	10	
Sulfuric acid mist	7	
Fluorides	3	
Vinyl chloride	1	
Lead		1,200
Mercury		200
Asbestos		14
Beryllium		0.8

Source: Chapter 62-212, Table 212.400-2, F.A.C.

Unit 1:

Fuel Type	Maximum Allowable SO_2 Emission Rates		
	(lb/MMBtu)[1]	(lb/hr)	(tpy)
70% Coal	0.994	4,822	21,121
30% Petcoke	0.740	1,718	7,525
70%/30% Coal/Petcoke Blend	0.912	6,540	28,645
100% Coal	0.994	7,130	31,229

Unit 2:

Fuel Type	Maximum Allowable SO_2 Emission Rates		
	(lb/MMBtu)[1]	(lb/hr)	(tpy)
70% Coal	0.994	4,822	21,121
30% Petcoke	0.715	1,660	7,270
70%/30% Coal/Petcoke Blend	0.904	6,482	28,391
100% Coal	0.994	7,130	31,229

[1] Rates shown are based on the maximum coal SO_2 emission rate (7,130 lb/hr) and maximum heat input (7,172 MMBtu/hr) for each unit. Depending on the unwashed coal sulfur content and level of coal washing, SO_2 emission rates may increase up to 1.2 lb/MMBtu for the 70% and 100% coal fuel types, 1.05 lb/MMBtu for 70%/30% coal/petcoke blend (Unit 1), and 1.04 lb/MMBtu for 70%/30% coal/petcoke blend (Unit 2) under other, lower load operating conditions. However, maximum allowable lb/hr and tpy SO_2 emission rates will not exceed the rates shown in the above tables.

Details of the SO_2 emission rate calculations for the values shown in the above summaries are documented in Tables E-2 and E-3 for Units 1 and 2, respectively.

The allowable emission rate summaries shown above represent *maximum* allowable rates; i.e., use of coal containing the highest authorized sulfur content and a 70/30 coal/petcoke blend. Because Units 1 and 2 are subject to NSPS Subpart Da, the allowable SO_2 emission rate for any given 30-day rolling average period due to coal combustion will vary with the sulfur content of the coal; i.e., a 90 percent overall SO_2 removal efficiency is required (including coal washing credit). Therefore, although the allowable SO_2 emission rate in terms of lb/MMBtu for the petcoke portion of the coal/petcoke blend will be fixed at the

Table E-2. Allowable SO_2 Emissions For Unit 1

Parameter	Symbol	Value	Units	Formula
Average 94/95 Coal SO2 Emission Rate from AORs:	CSO2	0.740	lb/MMBtu	
Allowable Coal SO2 Emission Rate	ACSO2	0.994	lb/MMBtu	
Maximum Unit Heat Input:	UHI	7,172	MMBtu/hr	
Coal Heating Value (HHV, dry)	HHVC	27.40	MMBtu/ton	
Petcoke Heating Value (HHV, dry)	HHVP	30.60	MMBtu/ton	
70/30 Coal/Petcoke Blend Heating Value (HHV, dry)	HHVB	28.36	MMBtu/ton	
Coal Weight Fraction of 70/30 Coal/Petcoke Blend	FC	0.70		
Petcoke Weight Fraction of 70/30 Coal/Petcoke Blend	FP	0.30		
70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	BC	252.89	ton/hr	BC = UHI / ((HHVC * FC) + (HHVP * FP))
Petcoke Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	PC	75.87	ton/hr	PC = BC * FP
Petcoke Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	PCHI	2,322	MMBtu/hr	PCHI = PC * HHVP
Petcoke Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	PCHI	2,322	MMBtu/hr	PCHI = UHI / (1 + ((HHVC * FC) / (HHVP * FP))) (consolidated formula)
Petcoke Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input		32.37	% by heat input	(PCHI / UHI) * 100
Maxmum Allowable Petcoke SO2 Emission Rate	PSO2HI PSO2H PSO2A	0.740 1,718 7,525	lb/MMBtu lb/hr ton/yr	CSO2 CSO2 * PCHI PSO2H * (8,760 / 2,000)
Coal Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	CCHI	4,850	MMBtu/hr	UHI - PCHI
Coal Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input		67.63	% by heat input	(CCHI / UHI) * 100
Maximum Allowable Coal SO2 Emission Rate	ACSO2 CSO2H CSO2A	0.994 4,822 21,121	lb/MMBtu lb/hr ton/yr	ACSO2 ACSO2 * CCHI CSO2H * (8,760 / 2,000)
Maximum Allowable 70/30 Coal/Petcoke Blend SO2 Emission Rate	BSO2H BSO2A BSO2HI	6,540 28,645 0.912	lb/hr ton/yr lb/MMBtu	PSO2H + CSO2H BSO2H * (8,760 / 2,000) BSO2H / UHI

Source: ECT, 1996.

Table E-3. Allowable SO_2 Emissions For Unit 2

Parameter	Symbol	Value	Units	Formula
Average 94/95 Coal SO2 Emission Rate from AORs:	CSO2	0.715	lb/MMBtu	
Allowable Coal SO2 Emission Rate	ACSO2	0.994	lb/MMBtu	
Maximum Unit Heat Input:	UHI	7,172	MMBtu/hr	
Coal Heating Value (HHV, dry)	HHVC	27.40	MMBtu/ton	
Petcoke Heating Value (HHV, dry)	HHVP	30.60	MMBtu/ton	
70/30 Coal/Petcoke Blend Heating Value (HHV, dry)	HHVB	25.38	MMBtu/ton	
Coal Weight Fraction of 70/30 Coal/Petcoke Blend	FC	0.70		
Petcoke Weight Fraction of 70/30 Coal/Petcoke Blend	FP	0.30		
70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	BC	252.89	ton/hr	BC = UHI / ((HHVC * FC) + (HHVP * FP))
Petcoke Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	PC	75.87	ton/hr	PC = BC * FP
Petcoke Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	PCHI	2,322	MMBtu/hr	PCHI = PC * HHVP
Petcoke Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	PCHI	2,322	MMBtu/hr	PCHI = UHI / (1 + ((HHVC * FC) / (HHVP * FP))) (consolidated formula)
Petcoke Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input		32.37	% by heat input	(PCHI / UHI) * 100
Maxmum Allowable Petcoke SO2 Emission Rate	PSO2HI PSO2H PSO2A	0.715 1,660 7,270	lb/MMBtu lb/hr ton/yr	CSO2 CSO2 * PCHI PSO2H * (8,760 / 2,000)
Coal Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input	CCHI	4,850	MMBtu/hr	UHI - PCHI
Coal Portion of 70/30 Coal/Petcoke Blend Consumption at Maximum Heat Input		67.63	% by heat input	(CCHI / UHI) * 100
Maximum Allowable Coal SO2 Emission Rate	ACSO2 CSO2H CSO2A	0.994 4,822 21,121	lb/MMBtu lb/hr ton/yr	ACSO2 ACSO2 * CCHI CSO2H * (8,760 / 2,000)
Maximum Allowable 70/30 Coal/Petcoke Blend SO2 Emission Rate	BSO2H BSO2A BSO2HI	6,482 28,391 0.904	lb/hr ton/yr lb/MMBtu	PSO2H + CSO2H BSO2H * (8,760 / 2,000) BSO2H / UHI

Source: ECT, 1996.

historical emission rates, the allowable rates for the coal portion of the blend will vary with coal sulfur content and the coal/petcoke blend ratio. The following algorithms are proposed to implement Subpart Da requirements during the combustion of coal/petcoke blends:

Unit 1:

$$E_{SO2} = [(\%C_{HI} / 100) * (P_S) * (1 - (\% R_o / 100))] + [(1 - (\%C_{HI} / 100)) * (0.74 \text{ lb } SO_2 / \text{MMBtu})] \quad \text{(Eqn. E-1)}$$

Unit 2:

$$E_{SO2} = [(\%C_{HI} / 100) * (P_S) * (1 - (\% R_o / 100))] + [(1 - (\%C_{HI} / 100)) * (0.72 \text{ lb } SO_2 / \text{MMBtu})] \quad \text{(Eqn. E-2)}$$

where:

E_{SO2}	=	allowable SO_2 emission rate; lb SO_2/MMBtu, 30-day rolling average
$\%C_{HI}$	=	percent of coal used on a heat input basis
P_S	=	potential SO_2 combustion concentration (unwashed coal without emission control systems) as defined by NSPS Subpart Da; lb SO_2/MMBtu
$\% R_o$	=	overall percent SO_2 reduction from Equation 19-21 of EPA Reference Method 19. Per NSPS Subpart Da, $\% R_o$ must not be less than 90 percent, 30-day rolling average.

The first term in each equation is the allowable rate for the coal portion of the coal/petcoke blend while the second term addresses the allowable rate due to the petcoke portion of the blend. SECI intends to meet the proposed SO_2 emission limits while using petcoke containing up to 7.0 percent by weight sulfur by increasing the SO_2 removal efficiency of the existing FGD systems. The FGD systems have historically been operated at an average SO_2 removal efficiency of approximately 85 percent which, together with a coal washing credit, complies with the NSPS Subpart Da overall 90 percent SO_2 removal efficiency requirement. By adjusting operational variables such as the liquid to gas ratio (scrubbing

liquid flow rate divided by the exhaust flow rate) and pH of the scrubbing liquid, SECI has demonstrated through past operations that the FGD SO_2 removal efficiency can be increased up to 10 percent above the historical average of 85 percent up to a maximum of 95 percent removal. To meet the proposed SO_2 emission limits, a maximum increase in FGD SO_2 removal efficiency of approximately 2 to 3 percent will be necessary. Therefore, the existing FGD control systems have adequate design capacity to meet the proposed SO_2 emission limits while using a 30 percent by weight petcoke/coal blend having petcoke and coal maximum 30-day average sulfur contents of 7.0 and 3.0 percent by weight, respectively.

Nitrogen Oxides (NO_x)

NO_x emission rates measured during the test burning show a decrease in rates for the 10 percent (12/8/95 test) and 20 percent (12/8/95 test) petcoke blend scenarios and a slight increase for the 30 percent (1/8/96 test) petcoke blend scenario in comparison to the NO_x emission rates obtained during the use of baseline coal (1/4/96 test). The difference in NO_x emission rates for the 30 percent petcoke blend scenario and baseline coal is not significant using the Student's *t* statistical test described in 40 CFR Part 60, Appendix C (reference Table E-4 for details). Other test burns of petcoke/coal blends conducted by Florida utilities also demonstrated that the use of petcoke/coal blends did not cause an increase in NO_x emission rates. Accordingly, the available test data provides reasonable assurance that the use of up to 30 percent by weight petcoke/coal blend at the Seminole Power Plant will not cause a significant increase in NO_x emissions.

Particulate Matter (PM)

The ash content of petcoke (approximately 0.5 percent by weight) is much lower than the ash content of baseline coal (approximately 9 percent by weight). Typically, eighty-five percent by weight of coal ash is contained in the furnace exhaust as fly ash with the remaining fifteen percent by weight found in the furnace bottom ash. Assuming, as a worst-case, that all of the petcoke ash is released as fly ash, use of a 30 percent by weight petcoke/coal blend will result in a decrease in the generation rate of fly ash due to the lower ash content of petcoke. All other factors remaining the same, a decrease in the

Table E-4. Analysis of NO_x Performance Test Data

A. Test Results

Fuel Type	Test Date	Emission Rates (lb NO_x/MMBtu, 3-Hr Averages)							
		Run No. 1	Run No. 2	Run No. 3	Run No. 4	Run No. 5	Run No. 6	Run No. 7	Run No. 8
Baseline Coal	1/4/96	0.543	0.566	0.491	0.552	0.553	0.558	0.547	0.557
30/70 Petcoke/Coal Blend	1/8/96	0.594	0.563	0.582	0.538	0.525	0.537	0.627	0.649

B. Calculations

Fuel Type	Arithmetic Mean (lb NO_x/MMBtu)	Sample Variance S^2	Pooled Estimate S_p	t Statistic
Baseline Coal	0.55	0.000541		
30/70 Petcoke/Coal Blend	0.58	0.002003		
Both Tests			0.0357	1.735
Degrees of Freedom				14
t' (95 percent confidence level)				1.761
Significant Increase (Y/N)				N

Source: ECT, 1996.

quantity of fly ash generated will also cause a decrease in PM emission rates. To illustrate, 100 lb of baseline coal will generate approximately 7.7 lb of fly ash. In contrast, 100 lb of a 30 percent by weight petcoke/coal blend will generate 0.15 lb of fly ash due to the petcoke portion of the blend (assuming all petcoke ash is released as fly ash) and 5.4 lb of fly ash due to the coal portion for a total of 5.55 lb. This total of 5.55 lb of fly ash generated is approximately 28 percent lower than the 7.7 lb value generated by baseline coal. Accordingly, it is concluded that the use of a 30 percent by weight petcoke/coal blend at the Seminole Power Plant will not cause a significant increase in PM emissions. The petcoke/coal test burn results confirm this conclusion; i.e., the use of 30 percent by weight petcoke/coal blend resulted in a lower PM emission rate in comparison to baseline coal.

Carbon Monoxide (CO) and Sulfuric Acid Mist (H_2SO_4)

Estimates of the actual emission rate change for these two air pollutants due to the use of petcoke was determined based on the petcoke test burn data. A summary of the baseline coal and 70/30 coal/petcoke blend test burn data for Unit No. 1 is provided in the following table:

Fuel Type	Test Date	Measured Emission Rates (lb/MMBtu)	
		CO	H_2SO_4
Baseline Coal	1/4/96	0.066	0.031
70%/30% Coal/Petcoke Blend	1/8/96	0.009	0.030

The petcoke test burn results demonstrate that emission rates of CO and H_2SO_4 during combustion of a 70/30 coal/petcoke blend were lower than the baseline coal emission rates. During these series of tests, the FGD SO_2 removal efficiency was approximately the same; i.e., 82.7 percent for the baseline coal test vs. 82.2 percent for the 30 percent petcoke/coal blend test. The measured decrease in H_2SO_4 emissions demonstrates that the FGD system is capable of maintaining H_2SO_4 emissions at or below baseline coal levels during the combustion of higher sulfur content coal/petcoke fuel blends.

Confirmation that future CO and H_2SO_4 emissions during the combustion of coal/petcoke blends are equal to or less than baseline coal levels will be made by conducting annual tests (for a five year period) while burning coal and coal/petcoke blends using EPA Reference Methods 10 (for CO) and 8 (for H_2SO_4).

Lead (Pb), Fluorides (F), Mercury (Hg), and Beryllium (Be)

Because emission rates of these air pollutants will be proportional to the element concentrations in the coal and petcoke fuels, estimates of actual emission rate changes for these air pollutants due to the use of petcoke was determined based on a comparison of baseline coal and petcoke fuel analyses. A summary of typical element concentrations, in lb/MMBtu, is provided in the following table for baseline coal and 100 percent petcoke:

Element	Fuel Concentration (lb/MMBtu)	
	Baseline Coal	100% Petcoke
Lead (Pb)	6.04E-04	3.38E-05
Fluoride (F)	5.28E-03	3.85E-04
Mercury (Hg)	6.04E-06	3.38E-06
Beryllium (Be)	7.55E-05	6.76E-07

The fuel compositions summarized above indicate that emission rates of lead, fluoride, mercury, and beryllium will be lower when petcoke is substituted for coal due to the lower concentrations of these elements present in petcoke.

Ozone [as volatile organic compounds (VOCs)]

Emissions of VOCs from fossil fuel combustion are the due to the partial oxidization of hydrocarbons contained in the fuel. As with most combustion processes, the Seminole Power Plant Unit Nos. 1 and 2 operate with excess air to ensure complete combustion. For this reason, emissions of VOCs from fossil fuel combustion are relatively low. For example, *total* actual VOC emissions from Unit Nos. 1 and 2 in 1995 (as indicated on

SECI's Annual Operating Report) were 108.2 tpy based on the application of AP-42 emission factors. Because emissions of VOCs depend primarily on process operations (i.e., extent of complete combustion) and not on fuel characteristics, no change in VOC emissions (in terms of lb VOC/ton of fuel combusted) is expected due to the substitution of petcoke for coal. This expectation is substantiated by the test burn results which showed lower CO emission rates during the use of coal/petcoke blends in comparison to baseline coal. The lower CO emissions are an indicator of high combustion efficiency; i.e., extent of complete combustion. The high combustion efficiency would also be expected to result in lower VOC emissions due to increased oxidation of fuel hydrocarbons. Actual emission rates of VOCs were estimated using EPA AP-42 emission factors.

Total Reduced Sulfur, Reduced Sulfur Compounds, Asbestos, and Vinyl Chloride

Emissions of these PSD regulated air pollutants due to the combustion of coal and petcoke are considered to be negligible. As mentioned previously, Unit Nos. 1 and 2 are operated with excess air to ensure complete combustion. Therefore, the formation of reduced sulfur or reduced sulfur compounds would be expected to be negligible in the oxidizing atmosphere of a fossil fuel combustion process. EPA reference material pertaining to toxic air pollutant emissions from coal combustion sources do not include any data for asbestos or vinyl chloride.

Summary of Actual Emission Changes for PSD Regulated Air Pollutants

As indicated in Table E-1, the significant emission rates for PSD review are expressed in units of tpy. Summaries of the actual emission rate changes due to the use of up to 30 weight percent petcoke as a replacement for coal for the Seminole Power Plant are shown on Tables E-5 through E-7.

Table E-5. Summary of Actual Emission Rate Changes
PSD Regulated Air Pollutants - Unit No. 1

Average 94/95 Heat Input for Unit No. 1: 41,838,863 MMBtu/yr
Percent of Total Heat Input Replaced by Petcoke : 32.37 %
(for 70/30 coal/petcoke blend)

Pollutant	Emission Factors		Actual Emission Rates[1]		Emission Rate Change[2] (tpy)
	Baseline Coal (lb/MMBtu)	Petcoke/Coal Blends (lb/MMBtu)	Baseline Coal (tpy)	Petcoke/Coal Blends (tpy)	
CO[3]	0.066	0.006	1,380.7	125.5	-1,255.2
NO_x[3]	0.550	0.480	11,505.7	10,041.3	-1,464.4
SO_2	0.740	0.740	15,480.4	15,480.4	0.0
Ozone (as VOC)[4]	0.0022	0.0021	46.0	44.7	-1.4
PM[5]	0.010	0.008	209.2	167.4	-41.8
PM10[5]	0.010	0.008	209.2	167.4	-41.8
Total Reduced Sulfur	Neg.	Neg.	Neg.	Neg.	Neg.
Reduced Sulfur Compounds	Neg.	Neg.	Neg.	Neg.	Neg.
Sulfuric Acid Mist[3]	0.031	0.028	648.5	585.7	-62.8
Fluorides[6]	0.0053	0.0036	110.5	74.9	-35.5
Vinyl Chloride	Neg.	Neg.	Neg.	Neg.	Neg.
Lead[6]	6.04E-04	4.19E-04	12.6	8.8	-3.86
Mercury[6]	6.04E-06	5.18E-06	0.126	0.108	-0.018
Asbestos	Neg.	Neg.	Neg.	Neg.	Neg.
Beryllium[6]	7.55E-05	5.13E-05	0.511	0.347	-0.164

[1] [Emission Factor (lb/MMBtu)] * [Average Heat Input (MMBtu/yr)] * [(1 ton / 2,000 lb)]

[2] [Petcoke (tpy) - Coal (tpy)]

[3] Based on baseline coal (1/4/96) and average of petcoke/coal blend (12/8/95, 12/8/95, and 1/8/96) performance tests.

[4] Based on AP-42 emission factor.

[5] Based on baseline coal (1/4/96) and 30 percent by weight petcoke/coal blend (1/8/96) performance tests.

[6] Based on typical fuel compositions and no credit for air pollution control system emission reduction. Petcoke/coal blend value based on a 30 percent by weight petcoke/coal blend.

Table E-6. Summary of Actual Emission Rate Changes
PSD Regulated Air Pollutants - Unit No. 2

Average 94/95 Heat Input for Unit No. 2: 43,479,548 MMBtu/yr
Percent of Total Heat Input Replaced by Petcoke : 32.37 %
(for 70/30 coal/petcoke blend)

Pollutant	Emission Factors		Actual Emission Rates[1]		Emission Rate Change[2] (tpy)
	Baseline Coal (lb/MMBtu)	Petcoke/Coal Blends (lb/MMBtu)	Baseline Coal (tpy)	Petcoke/Coal Blends (tpy)	
CO[3]	0.066	0.006	1,434.8	130.4	-1,304.4
NO_x[3]	0.550	0.480	11,956.9	10,435.1	-1,521.8
SO_2	0.715	0.715	15,543.9	15,543.9	0.0
Ozone (as VOC)[4]	0.0022	0.0021	47.8	46.4	-1.4
PM[5]	0.010	0.008	217.4	173.9	-43.5
PM10[5]	0.010	0.008	217.4	173.9	-43.5
Total Reduced Sulfur	Neg.	Neg.	Neg.	Neg.	Neg.
Reduced Sulfur Compounds	Neg.	Neg.	Neg.	Neg.	Neg.
Sulfuric Acid Mist[3]	0.031	0.028	673.9	608.7	-65.2
Fluorides[6]	0.0053	0.0036	114.8	77.9	-36.9
Vinyl Chloride	Neg.	Neg.	Neg.	Neg.	Neg.
Lead[6]	6.04E-04	4.19E-04	13.1	9.1	-4.01
Mercury[6]	6.04E-06	5.18E-06	0.131	0.113	-0.019
Asbestos	Neg.	Neg.	Neg.	Neg.	Neg.
Beryllium[6]	7.55E-05	5.13E-05	0.531	0.361	-0.170

[1] [Emission Factor (lb/MMBtu)] * [Average Heat Input (MMBtu/yr)] * [(1 ton / 2,000 lb)]

[2] [Petcoke (tpy) - Coal (tpy)]

[3] Based on baseline coal (1/4/96) and average of petcoke/coal blend (12/8/95, 12/8/95, and 1/8/96) performance tests.

[4] Based on AP-42 emission factor.

[5] Based on baseline coal (1/4/96) and 30 percent by weight petcoke/coal blend (1/8/96) performance tests.

[6] Based on typical fuel compositions and no credit for air pollution control system emission reduction. Petcoke/coal blend value based on a 30 percent by weight petcoke/coal blend.

Table E-7. Summary of Actual Emission Rate Changes PSD Regulated Air Pollutants - Unit Nos . 1 and 2

Pollutant	Emission Rate Change Unit No. 1 (tpy)	Emission Rate Change Unit No. 2 (tpy)	Emission Rate Change Unit Nos. 1and 2 (tpy)	PSD Significant Emission Rate (tpy)	Basis for Reasonable Assurance
CO	-1,255	-1,304	-2,560	100	[1]
NOx	-1,464	-1,522	-2,986	40	[1]
SO2	0	0	0	40	[2]
Ozone (as VOC)	-1	-1	-3	40	[3]
PM	-42	-43	-85	25	[1]
PM10	-42	-43	-85	15	[1]
Total Reduced Sulfur	Neg.	Neg.	Neg.	10	[4]
Reduced Sulfur Compounds	Neg.	Neg.	Neg.	10	[4]
Sulfuric Acid Mist	-63	-65	-128	7	[1]
Fluorides	-36	-37	-72	3	[5]
Vinyl Chloride	Neg.	Neg.	Neg.	1	[6]
Lead	-3.86	-4.01	-7.87	0.6	[5]
Mercury	-0.018	-0.019	-0.037	0.1	[5]
Asbestos	Neg.	Neg.	Neg.	0.007	[6]
Beryllium	-0.164	-0.170	-0.334	0.0004	[5]

Reasonable Assurance Footnotes:

[1] Test burn results

[2] Increase in FGD removal efficiency, as required

[3] AP-42 emission factor; continued high combustion efficiency

[4] Negligible emissions due to oxidizing atmosphere of combustion process

[5] Typical fuel composition

[6] Negligible emissions, if any

APPENDIX F

REQUEST TO UTILIZE NO. 2 OIL TO GENERATE ELECTRICAL CAPACITY

APPENDIX F
REQUEST TO UTILIZE NO. 2 OIL TO GENERATE ELECTRICAL CAPACITY

I. Introduction

Seminole Electric Cooperative, Inc. (Seminole) is permitted to operate two coal-fired electric generating units (Units 1 and 2) at the Seminole Power Plant near Palatka, Florida. Each unit has a design maximum generator rating of 714.6 MW and a normal continuous operating capacity of 659 MW in the summer and 670 MW in the winter. Each unit is equipped with coal handling and processing facilities that enable all loads to be achieved utilizing coal. Coal utilization has been about 3.6 million tons/year and is expected to be 4.0 million tons/year in the near future.

Units 1 and 2 are permitted to utilize No. 2 oil with a maximum sulfur content of 0.5% for start-up and for flame stabilization in all load ranges. Each unit is equipped with an oil ignitor system which has the potential to place enough oil BTU's into the boiler to generate only 45 MW per unit or about 6.3% of the design maximum generator rating. Use of oil is minimized to the extent possible due to its high cost ($5/mmBTU) as compared to coal ($2/mmBTU). In 1995, Units 1 and 2 used a total of 1.38 million gallons of No. 2 oil which was equal to approximately 0.22% of the heat input to each unit.

There are times when a combination of fuel quality, fuel conditions and/or required maintenance on either the coal ball mills (which pulverize coal to a talcum powder consistency prior to burning) or the burners themselves prevents the units from being able to meet all loads with coal only. For example, there are times when either wet coal or coal with a heat content at the low end of the design range could limit the BTU's placed in the boiler.

Each unit is equipped with six ball mills feeding six dedicated burners each, enabling the unit to meet the design rated capacity (714.6 MW). The normal operating load can be met

with five mills (30 burners). There are times when one mill is out for scheduled maintenance and one or more burners from an operating mill may also be out of service, which, depending on which burners were out of service, could prevent the unit from meeting either the normal operating loads or emergency reserve loads.

Historically, when situations occur which prevent loads from being generated by coal, Seminole has purchased capacity from other utilities. The primary reasons are that Seminole Units 1 and 2 are not permitted to burn oil for load and alternative capacity at a lesser cost has been available.

II. Request to Burn Oil for Capacity

Seminole proposes to amend its Conditions of Certification and Prevention of Significant Deterioration (PSD) permit to allow the use of oil to meet Seminole's commitment to provide electrical reserve requirements as required by the Florida Public Service Commission (FPSC) and to meet electrical demand when coal quality, conditions and/or processing or burner equipment prevents meeting demand with coal only. Because Seminole does not propose to alter the existing ignitor system in any manner, oil use could not increase over its current capacity.

III. Rationale

A. Oil to Meet Reserve Capability Requirements

The Florida Public Service Commission (FPSC) requires that each electric utility in the State have reserve electrical capacity equal to at least 15% over its load obligations. Reserve capacity is required in the event that any of the operating generating units experience an outage, supplies from outside the State fail, transmission line(s) fail or customer demand is greater than the operating plants can produce. There are two types of reserve requirements; 1) operating (sometimes called spinning reserves), and 2) installed reserves. The major difference between the two types is that operating reserves have to be available in 10 minutes or less, and installed reserves have to be available in 30 minutes or less. In a statewide emergency requiring the use of reserve capacity, generally the lowest cost reserve capacity is used first and the highest cost capacity would be utilized last

(economic dispatching).

Seminole is currently required to have 90 MW of operating reserve and 220 MW of installed reserve capacity to meet State requirements. Seminole currently obtains a portion of its reserve capacity from using the maximum generating capacity from Seminole Units 1 and 2 and the remainder from purchasing the right to call upon operating and installed reserve capacity from other utilities even though it may not be used in any given day.

As stated previously, Seminole Units 1 and 2 have a normal continuous operating capacity of 659/670 MW (summer/winter) and a maximum design rating of 714.6 MW. Historically, only a portion of the maximum design generator rating from Units 1 and 2 have been used for reserve capacity. There are two levels of maximum rated capacity for the two units. The first is the generating capacity obtained from running the unit with the turbine steam control valves wide open (VWO) and with 5% more steam pressure than normal. In this mode of operation, each unit is able to produce 685 MW in the summer and 696 MW in the winter months. The second mode of operation is VWO, the 5% additional steam pressure and taking the top feedwater heater out-of-service which will reliably produce 711 MW in the winter and summer.

Seminole has only relied on the Seminole Units for the first mode of maximum rated capability because there was concern that: 1) operating with the top feedwater heaters out-of-service for long periods would cause reduced unit availability; 2) the unit had to be operating under 600 MW before the top heater could be taken out of service, and the time necessary to reduce load, take out the heater and increase load would not qualify it as operating reserve capacity and only marginally as installed reserve, and 3) it was not always possible to rely on the coal ball mills to be able to put enough coal into the boilers to reach the maximum load due to ambient air conditions, fuel quality and mill availability.

Seminole has determined that it is economically prudent and technologically feasible to use the maximum rated capacity of Units 1 and 2 to meet its requirements for installed reserve

capacity and eliminate the need to purchase reserve capacity. An operating evaluation has shown that: 1) the additional installed reserve capacity would be called upon for approximately 200 hours/year/unit on an annual basis, and that even on a worst case basis, this utilization should not adversely affect the availability of each unit; 2) the time needed to take the top feedwater heaters out-of-service could not be altered to meet the operating reserve requirement without installing additional steam valves, but the criteria for installed reserves could be reliably met without changes to the steam system, and 3) the fuel reliability needed to qualify as installed reserve capability could be met with the existing oil ignitor system in each unit.

B. Oil to Meet Load Capacity Requirements

As stated previously, situations may occur when Units 1 and 2 are unable to meet their normal continuous operating ratings (NCOR) of 659 MW (summer) and 670 MW (winter). When this condition has existed, Seminole has purchased the capacity to meet the NCOR. However, with the authority to burn oil to meet NCOR, Seminole would be able to generate this capacity if no other was available and be able to purchase the capacity through economy broker sales in lieu of a straight energy purchase.

Under the economy broker sales arrangement, utilities with the ability to generate capacity with a high cost can match up with a lower cost generator on an hourly basis and the strike price is one-half the difference between the two. This ability would allow Seminole to make hourly arrangements while the coal handling equipment is being maintained or repaired.

Seminole does not anticipate that this authority to burn oil will increase oil use in either case except in a statewide electrical emergency again due to the cost differential between No. 2 oil and any other fuel.

Impacts of Proposed Changes

While Seminole is requesting authority to use No. 2 oil to meet NCOR, it is not anticipated that No. 2 oil will be used due to the availability of other sources of more

economic energy. Seminole does predict that Units 1 and 2 could be called upon to provide a maximum of 45 MW for 200 hours/year/unit to meet reserve capacity requirements. If it is assumed oil will be used to supply this capacity, air emissions would actually decrease.

Units 1 and 2 are permitted to burn No. 2 oil with a maximum sulfur content of 0.5%. Using 0.5%S No. 2 oil to generate 45 MW needed to reach 711 MW would reduce SO_2 emissions when compared to generating the electricity only from coal. The following is a per unit comparison of the hourly and annual SO_2 emissions from generating the reserve MW's with coal and No. 2 oil. The values reflect removing 84% of the SO_2 in each units' flue gas desulfurization system.

	Coal	Oil	Diff.
Hourly SO_2 (lbs/MMBTU)	0.76	0.08	-0.68
Annual SO_2 (tons)	34.2	3.6	-30.6

It is presumed that NO_x emissions would likewise be reduced since NO_x from oil is roughly one-half that from coal. However, even in a worst cast scenario of 45 MW being derived from oil, the oil would only constitute 6.3% of the hourly heat input to the boiler so the change in NO_x emissions would be undistinguishable. For the expected 200 hours/year of operation in this condition, the annual heat input to the boiler would be 0.14%.

Seminole is also requesting concurrence that the de minimis use of No. 2 oil in Units 1 and 2 not require Seminole to modify its current CEM program to derive new emission limitations as specified in 40 CFR 60, Subpart Da when different fuels are co-fired. As stated previously, in a worst cast scenario, oil would only constitute 6.3% of the instantaneous hourly heat input (0.14% annually). On an annual basis and again based on a worst case scenario, oil would only account for 0.43% of the annual heat input including start-up oil and flame stabilization oil. It would be impractical to modify the CEM program for the few hours oil is used for reserve capacity (if any is used at all) to determine supplemental fuel emission limits which, when calculated in a 30 DRA, would

produce a non-detectable change.

For example, if 45 MW were generated by oil to meet reserve requirements for 5 hours/day for 4 consecutive days and oil constituted 6.3% of the heat input during the hours it was used, the daily NO_x emission limitation would change from 0.6 lbs/mmBTU to 0.596 lbs/mmBTU using the formula in 40 CFR 60.44a(c). Since Subpart Da standards are on a 30 day rolling average (DRA), the first day of use would change the 30 DRA from 0.6 lbs/mmBTU to 0.5999 lbs/mmBTU. At the end of the fourth day, the 30 DRA would be 0.5995 lbs/mmBTU. In each case, the results would be rounded to 0.6 lbs/mmBTU.

The SO_2 limitation results would have similar results. In the above example, 40 CFR 43a(h) requires that 90% removal from the FGD system be required, therefore, the change in the first day of the 30 DRA would be 1.1998 lbs SO_2/mmBTU and the fourth would be 1.1993 lbs SO_2/mmBTU and, therefore, rounded to 1.2 lbs/mmBTU.

APPENDIX G - PROPOSED PERMIT CONDITIONS

Permit PSD-FL-018 Conditions of Approval

1. Add new Section D as follows:

D. FOR THE ELECTRIC UTILITY UTILITY STEAM GENERATING UNITS WHEN BURNING COAL/PETROLEUM COKE FUEL BLENDS

Stack emissions from Units 1 and 2 shall not exceed the limitations contained in Items 1, 2, and 3 below when burning blends of coal and petroleum coke:

Item 1 - Sulfur Dioxide Emissions

(a) Unit 1:

$$E_{SO2} = [(\%C_{HI} / 100) * (P_S) * (1 - (\% R_o / 100))] + [(1 - (\%C_{HI} / 100)) * (0.74 \text{ lb } SO_2 / \text{MMBtu })] \quad \text{(Eqn. 1)}$$

(b) Unit 2:

$$E_{SO2} = [(\%C_{HI} / 100) * (P_S) * (1 - (\% R_o / 100))] + [(1 - (\%C_{HI} / 100)) * (0.72 \text{ lb } SO_2 / \text{MMBtu })] \quad \text{(Eqn. 2)}$$

where:

- E_{SO2} = allowable SO_2 emission rate; lb SO_2/MMBtu, 30-day rolling average
- $\%C_{HI}$ = percent of coal used on a heat input basis
- P_S = potential SO_2 combustion concentration (unwashed coal without emission control systems) as defined by NSPS Subpart Da; lb SO_2/MMBtu, 30-day rolling average
- $\% R_o$ = overall percent SO_2 reduction from Equation 19-21 of EPA Reference Method 19. Per NSPS Subpart Da, $\% R_o$ must not be less than 90%, 30-day rolling average
- 0.74 = historical 2-year annual average SO_2 emission rate for Unit No. 1; lb/MMBtu
- 0.72 = historical 2-year annual average SO_2 emission rate for Unit No. 2; lb/MMBtu

Item 2 - Nitrogen Oxide Emissions

0.60 lb per million Btu heat input, and 35 percent of the potential combustion concentration (65 percent reduction). Compliance with the 0.60 lb. per million Btu heat input limitation constitutes compliance with the 65 percent reduction requirement.

Item 3 - Particulate Matter Emissions

Particulates - 0.03 lb. per million Btu heat input, and 1 percent of the potential combustion concentration (99 percent reduction). Compliance with the 0.03 lb. per million Btu heat input limitation constitutes compliance with the 99 percent reduction requirement.

Item 4 - Averaging Periods

Compliance with the emission limitations and percent reductions in Conditions of Approval Section D, Items 1 and 2 shall be determined on a 30-day rolling average.

Item 5 - Fuel Specifications

Fuels fired shall consist of coal or a coal/petroleum coke blend containing a maximum of 30.0 percent petroleum coke by weight. The sulfur content of the petroleum coke shall not exceed 7.0 percent by weight dry basis.

Item 6 - Reporting and Recordkeeping

(a) Documentation verifying that the coal/petroleum coke blends combusted in Units No. 1 and 2 have not exceeded the 30.0 percent maximum petroleum coke by weight limit specified by Condition of Approval, Section D., Item 5 shall be maintained and submitted to the Department's Northeast District Office with each annual report.

(b) The Permittee shall maintain and submit to the Department on an annual basis for a period of five years from the date the units begin firing petroleum coke, data demonstrating that the operational change associated with the use of petroleum coke did not result in a significant emission increase pursuant to Rule 62-210.200(12)(d), F.A.C.

Item 7 - Handling of Petroleum Coke

All prior conditions of approval that address coal handling shall also apply to the handling of petroleum coke.

2. Add new Section E as follows:

E. FOR THE ELECTRIC UTILITY STEAM GENERATING UNITS WHEN BURNING NO. 2 FUEL OIL

No. 2 fuel oil may be co-fired with solid fuel for start-ups, flame stabilization, emergency reserve capacity during statewide energy shortages, and limited supplemental load.