RECEIVED

AUG 2 9 2001

BUREAU OF AIR REGULATION

APPLICATION FOR MODIFICATION OF PETROLEUM COKE AND COAL HANDLING FACILITIES

CEDAR BAY COGENERATION FACILITY JACKSONVILLE, FLORIDA

Prepared For:

Cedar Bay Generating Company, L.P.
9640 Eastport Road
Jacksonville, Florida 32218

Prepared By:

Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

July 2001
0137573

DISTRIBUTION:
10 Copies - Cedar Bay
2 Copies - Golder Associates Inc

PART I

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

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

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **Cedar Bay Generating Company, L.P.**	
2. Site Name: **Cedar Bay Cogeneration Facility**	
3. Facility Identification Number: **0310337** [ ] Unknown	
4. Facility Location: **U.S. Generating Cedar Bay Facility** Street Address or Other Locator: **9640 Eastport Road** City: **Jacksonville** County: **Duval** Zip Code: **32226**	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **Jeffery Walker, Environmental Manager**
2. Application Contact Mailing Address: Organization/Firm: **U.S. Generating Company** Street Address: **9640 Eastport Road (PO Box 26324 Zip Code: 32226-6324)** City: **Jacksonville** State: **FL** Zip Code: **32218**
3. Application Contact Telephone Numbers: Telephone: (**904**) **751-4000, Ext. 22** Fax: (**904**) **751-7320**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	8-29-01
2. Permit Number:	0310337-005-AC
3. PSD Number (if applicable):	PSD-FL-137A (Revision)
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit 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: ______________________

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

Current construction permit number: ______________________

Operation permit number to be revised: ______________________

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected: ______________________

[ ] Title V air operation permit revision 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 number to be revised: ______________________

Reason for revision: ______________________

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[X] Air construction permit to construct or modify one or more emissions units.

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

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

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: **Bruce Smith, General Manager**
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: **Cedar Bay Generating Company** Street Address: **P.O. Box 26324** City: **Jacksonville** State: **FL** Zip Code: **32226-6324**
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: (**904**) **751-4000, Ext. 18** Fax: (**904**) **751-7320**
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [**X**], if so) or the responsible official (check here [ ], if so) 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.* Signature: Bruce Smith Date: 8/28/01

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: **Kennard F. Kosky** Registration Number: **14996**
2.	Professional Engineer Mailing Address: Organization/Firm: **Golder Associates Inc.** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653-1500**
3.	Professional Engineer Telephone Numbers: Telephone: (**352**) **336 - 5600** Fax: (**352**) **336 - 6603**

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 [ ], 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 [X], if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Signature ______________________ Date August 9, 2001

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
001	CFB Boiler A	AC1D	NA
002	CFB Boiler B	AC1D	NA
003	CFB Boiler C	AC1D	NA
034	Pet Coke Truck Unloading and Conveyors	AC1F	NA

Application Processing Fee

Check one: [ ] Attached - Amount: $: ________________ [X] Not Applicable

Construction/Modification Information

1. Description of Proposed Project or Alterations: **Applicant is seeking authorization to co-fire up to 35 percent of petroleum coke with coal in the 3 existing circulating fluidized bed (CFB) boilers. A new truck unloading area for petroleum coke will be added. This will include a truck dump, transfer conveyor, dozer trap, and coal blending conveyor.**	
2. Projected or Actual Date of Commencement of Construction	**1 DEC 2001**
3. Projected Date of Completion of Construction:	**1 DEC 2002**

Application Comment

This application is a request to co-fire petroleum coke with coal under 40 CFR 52.21(b)(21)(v) as a non-PSD modification. The facility has a final Title V permit 0310337-002-AV. The facility was initially permitted under Florida's Power Plant Siting Act (PPSA) DEP File PA88-24 and received Permit No. PSD-FL-137.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17**	East (km): **441.610**	North (km): **3365.552**	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): **30 / 25 / 21**		Longitude (DD/MM/SS): **81 / 36 / 23**	
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):			

Facility Contact

1. Name and Title of Facility Contact: **Jeffery Walker, Environmental Manager**
2. Facility Contact Mailing Address: Organization/Firm: **U.S. Generating Company** Street Address: **9640 Eastport Road** City: **Jacksonville** State: **FL** Zip Code: **32226**
3. Facility Contact Telephone Numbers: Telephone: (**904**) **751-4000, Ext. 22** Fax: (**904**) **751-7320**

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [X] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [X] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [ ] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters):	

List of Applicable Regulations

The applicable facility regulation contained in the Title V permit will not change as a result of this application.

B. FACILITY POLLUTANTS

<u>List of Pollutants Emitted</u>

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
PM	**A**				**Particulate Matter – Total**
PM_{10}	**A**				**Particulate Matter – PM_{10}**
NO_X	**A**				**Nitrogen Oxides**
SO_2	**A**				**Sulfur Dioxide**
CO	**A**				**Carbon Monoxide**
VOC	**A**				**Volatile Organic Compounds**
SAM	**B**				**Sulfuric Acid Mist**

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1.	Area Map Showing Facility Location: [X] Attached, Document ID: See Part II [ ] Not Applicable [ ] Waiver Requested
2.	Facility Plot Plan: [X] Attached, Document ID: See Part II [ ] Not Applicable [ ] Waiver Requested
3.	Process Flow Diagram(s): [X] Attached, Document ID: See Part II [ ] Not Applicable [ ] Waiver Requested
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: [X] Attached, Document ID: See Part II [ ] Not Applicable
7.	Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [ ] Attached, Document ID: ________ [X] Not Applicable
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID: ________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [X] Not Applicable
10. Alternative Methods of Operation: [ ] Attached, Document ID: ________ [X] Not Applicable
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID: ________ [X] Not Applicable
12. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:________ [X] Not Applicable
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID: ________) or previously submitted to DEP (Date and DEP Office:________) [ ] Plan to be submitted to CEPPO (Date required:________) [X] Not Applicable
14. Compliance Report and Plan: [ ] Attached, Document ID:________ [X] Not Applicable
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID: ________ [X] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J 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.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (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.

2. 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.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Boiler A

4. Emissions Unit Identification Number: [ ] No ID
ID: **001** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**25-JAN-1994**	**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

Circulating Fluidized Bed (CFB) Boiler A with limestone injection for SO_2 emissions reduction. Ammonia injection for NO_x emissions reduction. Fuel is primarily bituminous coal with No. 2 fuel oil for startup. Combustion products are flue gas with fly ash and bed ash.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):

   Baghouse
   Efficiency = (1-emission)/load = 0.0055 gr/acr / 19.5 gr/acr = 99.97%

   Ammonia injection
   Efficiency = 54% for NO_x (estimated)

   Dry limestone injection
   Efficiency from 89 to 95% based on Quarterly Reports

   Air preheater
   Reduction Efficiency not determined.
   Intake air is preheated via flue gas to reduce fuel requirements.

   Control of Oxygen
   Reduction Efficiency not determined.
   Flue gas recirculates with intake air.

2. Control Device or Method Code(s): **016, 032/107, 041, 027, 033**

Emissions Unit Details

1. Package Unit: **NA**
   Manufacturer: **Foster Wheeler** Model Number: **Pyroflow®**
2. Generator Nameplate Rating: MW
3. Incinerator Information:
   Dwell Temperature: °F
   Dwell Time: seconds
   Incinerator Afterburner Temperature: °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		1,063	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:	104,000 lb/hr coal; 39,000 ton/month coal; 390,000 TPY coal		
4. Maximum Production Rate:	800,000 lb/hr steam		
5. Requested Maximum Operating Schedule:			
24	hours/day	7	days/week
52	weeks/year	8,760	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Limits set by PSD-FL-137A** **CFB Boilers A, B, and C feed a common steam turbine with a nominal rating of 250 MW and supply steam to an adjacent recycled liner board mill.**			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60.40a	Applicability >250 MMBtu/hr
40 CFR 60.41a	Definitions
40 CFR 60.42a	Standard for particulate matter
40 CFR 60.43a(a)	Standard for sulfur dioxide
40 CFR 60.43a(g)	Compliance with the emission limitation and percent reduction requirements
40 CFR 60.44a	Standard for nitrogen oxides
40 CFR 60.46a	Compliance provisions
40 CFR 60.47a	Emission monitoring
40 CFR 60.48a	Compliance determination procedures and methods
40 CFR 60.49a	Reporting requirements
FAC 62-204.800	Standards of performance for New Stationary Sources
FAC 62-210.550	Stack Height Policy
FAC 62-210.700	Excess Emissions
FAC 62-212-300	General preconstruction review
FAC 62-212-400	Prevention of Significant Deterioration
FAC 62-296.405	Fossil Fuel Steam Generators with more than 240 MMBtu/hr heat input
FAC 62-296.570(4)(a)	Reasonable Available Control Technology - Requirements for major VOC and NO_x emission Facilities
FAC 62-296.702	Fossil Fuel Steam Generators
FAC 62-296.711	Material Handling, Sizing, Screening, Crushing, and Grinding Operations
FAC 62-297.401(5)	EPA Method 5
FAC 62-297.401(6)	EPA Method 6
FAC 62-297.401(7)	EPA Method 7
FAC 62-297.401(8)	EPA Method 8
FAC 62-297.401(9)	EPA Method 9
FAC 62-297.401(10)	EPA Method 10
FAC 62-297.401(12)	EPA Method 12
FAC 62-297.401(13)	EPA Method 13
FAC 62-297.401(15)	EPA Method 15
FAC 62-297.401(17)	EPA Method 17
FAC 62-297.401(19)	EPA Method 19
FAC 62-297.401(25)	EPA Method 25
FAC 62-297.401(32)(a)	EPA Method 101A
FAC 62-297.401(35)	EPA Method 104
FAC 62-297.401(41)	EPA Method 201
FAC 62-297.520	EPA Performance Specifications
FAC 62-297.570	Test Reports
FAC 62-297.620	Exceptions and Approval of Alternate Procedures and Requirements

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **B1**	2. Emission Point Type Code: **2**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Boiler Stack (B1)

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:
001 = Boiler A; 002 = Boiler B; 003 = Boiler C

5. Discharge Type Code: **V**	6. Stack Height: **403** feet	7. Exit Diameter: **13.26** feet
8. Exit Temperature: **265** °F	9. Actual Volumetric Flow Rate: **1,004,000** acfm	10. Water Vapor: **5** %

11. Maximum Dry Standard Flow Rate: **895,403** dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **441.871** North (km): **3365.587**

14. Emission Point Comment (limit to 200 characters):

The 3 CFB boilers share a common stack designated as point B1. Flue gas from the boilers is discharged through this stack. Prior to the stack, each flue gas stream is passed through a baghouse which removes fly ash.

Stack information based on Title V Application.

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): a) **Segment 1 of 2: Bituminous coal used in boiler (when co-firing with petroleum coke).** b) **Segment 2 of 2.**		
2. Source Classification Code (SCC): **1-01-002-17**	3. SCC Units: **Tons burned**	
4. Maximum Hourly Rate: **29.9**	5. Maximum Annual Rate: **258,575**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **1.7% per load, 1.2% annual**	8. Maximum % Ash: **10 (typical)**	9. Million Btu per SCC Unit: **20.4**
10. Segment Comment (limit to 200 characters): **Based on 65% coal (by weight). See Part II, Appendix B.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): a) **Segment 1 of 2.** b) **Segment 2 of 2: Petroleum coke used in boiler when co-firing with coal.**		
2. Source Classification Code (SCC): **1-01-008-01**	3. SCC Units: **tons burned**	
4. Maximum Hourly Rate: **16.1**	5. Maximum Annual Rate: **139,233**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **6**	8. Maximum % Ash: **0.5 (typical)**	9. Million Btu per SCC Unit: **28**
10. Segment Comment (limit to 200 characters): **Based on 35% petroleum coke (by weight). See Part II, Appendix B.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	016	027	EL
PM_{10}	016	027	EL
NO_X	032/107	027	EL
SO_2	041	027	EL
CO	033	027	EL
VOC	027		EL
SAM	041	027	EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 318.9 lb/hour 866 tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.30 lb/MMBtu* 0.20 lb/MMBtu** Reference: Permit PA-88-24A, PSD-FL-137B	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): 1,063 MMBtu/hr x 0.3 lb/MMBtu = 318.9 lb/hr 1,063 MMBtu/hr x 0.2 lb/MMBtu x 8,760 hr/yr x ton/2,000 lb x 0.93 (capacity factor) = 866 TPY	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Limited by modification to PSD-FL-137. * 3-hour rolling average; ** 30-day rolling average. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: see comment	4. Equivalent Allowable Emissions: 318.9 lb/hour 866 tons/year
5. Method of Compliance (limit to 60 characters): Continuous Emissions Monitoring	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 3-hour rolling average for SO_2 = 0.30 lb/MMBtu 30-day rolling average for SO_2 = 0.20 lb/MMBtu Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **186** lb/hour **649** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.175 lb/MMBtu** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.175 lb/MMBtu - 186 lb/hr** **Annual potential emissions based on maximum emissions for 3 boilers so that PSD is not triggered. See Part II.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **See Part II.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **186** lb/hour **649** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous Emissions Monitoring and Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See Part II** **8-hour rolling average for CO = 0.175 lb/MMBtu**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control: **54% (estimated)**
3. Potential Emissions: **180.7** lb/hour **736.1** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.17 lb/MMBtu*** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.17 lb/MMBtu = 180.7 lb/hr** **180.7 lb/hr x 8,760 hr/yr x ton/2,000 lb x 0.93 (capacity factor) = 736.1 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Limited by modification to PSD-FL-137. * 30-day rolling average. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.**	

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **180.7** lb/hour **736.1** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous Emissions Monitoring and Method 7, 7A, B, C, D, or E**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **30-day rolling average for NO_x = 0.17 lb/MMBtu** **Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.0** lb/hour **57.6** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.015** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.015 lb/MMBtu = 16 lb/hr** **Annual potential emissions based on maximum emissions for 3 boilers so that PSD is not triggered. See Part II.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **See Part II**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **16.0** lb/hour **57.6** tons/year
5. Method of Compliance (limit to 60 characters): **Method 18 or 25**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See Part II** **0.015 lb/MMBtu VOC**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM (TSP)**	2. Total Percent Efficiency of Control: **99.97%**
3. Potential Emissions: **19.1** lb/hour **78** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.018 lb/MMBtu** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**

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

1,063 MMBtu/hr x 0.018 lb/MMBtu = 19.1 lb/hr
19.1 lb/hr x 8,760 hr/yr x ton/2,000 lbs x 0.93 (capacity factor) = 78 TPY

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

Limited by modification to PSD-FL-137. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **19.1** lb/hour **78** tons/year

5. Method of Compliance (limit to 60 characters):

Method 5 or 17, 40 CFR Appendix A

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

0.018 lb/MMBtu
Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control: **99.97%**	
3. Potential Emissions: **19.1** lb/hour **78** tons/year		4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: **0.018 lb/MMBtu** Reference: **PSD-FL-137A**		7. Emissions Method Code: **5**

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

1,063 MMBtu/hr x 0.018 lb/MMBtu = 19.1 lb/hr
19.1 lb/hr x 8,760 hr/yr x ton/2,000 lbs x 0.93 (capacity factor) = 78 TPY

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

Limited by modification to PSD-FL-137. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **19.1** lb/hour **78** tons/year

5. Method of Compliance (limit to 60 characters):

Method 5 or 17, 40 CFR Appendix A

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

0.018 lb/MMBtu
Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.50** lb/hour **2.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **4.66×10^{-4} lb/MMBtu** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.000466 lb/MMBtu = 0.5 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Limited by modification to PSD-FL-137. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.**	

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **0.50** lb/hour **2.0** tons/year
5. Method of Compliance (limit to 60 characters): **Method 8**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **4.66×10^{-4} lb/MMBtu** **Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE, VES**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **COM, Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **27% opacity for oil-burning during startup PSD-FL-137A**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 1

1. Parameter Code: **See comment**	2. Pollutant(s):
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Manufacturer: **various** Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Baghouse flue has CEMs for NO_x, SO_2, CO, CO_2, and VE. Manufacturers, models, and serial numbers previously submitted.**	

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

Supplemental Requirements

1. Process Flow Diagram [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested	
2. Fuel Analysis or Specification [X] Attached, Document ID: Part II [ ] Not Applicable [ ] Waiver Requested	
3. Detailed Description of Control Equipment [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested	
4. Description of Stack Sampling Facilities [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested	
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 [ ] Waiver Requested	
7. Operation and Maintenance Plan [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested	
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID: ________ [X] Not Applicable	
9. Other Information Required by Rule or Statute [X] Attached, Document ID: See Part II [ ] Not Applicable	
10. Supplemental Requirements Comment:	

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
    [ ] Attached, Document ID: ________ [X] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
    [ ] Attached, Document ID: ________ [X] Not Applicable

13. Identification of Additional Applicable Requirements
    [ ] Attached, Document ID: ________ [X] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID: ________ [X] Not Applicable

15. Acid Rain Part 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: ________

    [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID: ________

    [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
    Attached, Document ID: ________

    [X] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J 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.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (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.

2. 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.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Boiler B

4. Emissions Unit Identification Number: [ ] No ID
ID: **002** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**25-JAN-1994**	**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

Circulating Fluidized Bed (CFB) Boiler B with limestone injection for SO_2 emissions reduction. Ammonia injection for NO_x emissions reduction. Fuel is primarily bituminous coal with No. 2 fuel oil for startup. Combustion products are flue gas with fly ash and bed ash.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Baghouse** **Efficiency = (1-emission)/load = 0.0055 gr/acr / 19.5 gr/acr = 99.97%** **Ammonia injection** **Efficiency = 54% for NO_x (estimated)** **Dry limestone injection** **Efficiency from 89 to 95% based on Quarterly Reports** **Air preheater** **Reduction Efficiency not determined.** **Intake air is preheated via flue gas to reduce fuel requirements.** **Control of Oxygen** **Reduction Efficiency not determined.** **Flue gas recirculates with intake air.**
2. Control Device or Method Code(s): **016, 032/107, 041, 027, 033**

Emissions Unit Details

1. Package Unit: **NA** Manufacturer: **Foster Wheeler**	Model Number: **Pyroflow®**
2. Generator Nameplate Rating:	MW
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		**1,063**	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:	**104,000 lb/hr coal; 39,000 ton/month coal; 390,000 TPY coal**		
4. Maximum Production Rate:	**800,000 lb/hr steam**		
5. Requested Maximum Operating Schedule:			
	24 hours/day	**7**	days/week
	52 weeks/year	**8,760**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):			

Limits set by PSD-FL-137A

CFB Boilers A, B, and C feed a common steam turbine with a nominal rating of 250 MW and supply steam to an adjacent recycled liner board mill.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60.40a	Applicability >250 MMBtu/hr
40 CFR 60.41a	Definitions
40 CFR 60.42a	Standard for particulate matter
40 CFR 60.43a(a)	Standard for sulfur dioxide
40 CFR 60.43a(g)	Compliance with the emission limitation and percent reduction requirements
40 CFR 60.44a	Standard for nitrogen oxides
40 CFR 60.46a	Compliance provisions
40 CFR 60.47a	Emission monitoring
40 CFR 60.48a	Compliance determination procedures and methods
40 CFR 60.49a	Reporting requirements
FAC 62-204.800	Standards of performance for New Stationary Sources
FAC 62-210.550	Stack Height Policy
FAC 62-210.700	Excess Emissions
FAC 62-212-300	General preconstruction review
FAC 62-212-400	Prevention of Significant Deterioration
FAC 62-296.405	Fossil Fuel Steam Generators with more than 240 MMBtu/hr heat input
FAC 62-296.570(4)(a)	Reasonable Available Control Technology - Requirements for major VOC and NO_x emission Facilities
FAC 62-296.702	Fossil Fuel Steam Generators
FAC 62-296.711	Material Handling, Sizing, Screening, Crushing, and Grinding Operations
FAC 62-297.401(5)	EPA Method 5
FAC 62-297.401(6)	EPA Method 6
FAC 62-297.401(7)	EPA Method 7
FAC 62-297.401(8)	EPA Method 8
FAC 62-297.401(9)	EPA Method 9
FAC 62-297.401(10)	EPA Method 10
FAC 62-297.401(12)	EPA Method 12
FAC 62-297.401(13)	EPA Method 13
FAC 62-297.401(15)	EPA Method 15
FAC 62-297.401(17)	EPA Method 17
FAC 62-297.401(19)	EPA Method 19
FAC 62-297.401(25)	EPA Method 25
FAC 62-297.401(32)(a)	EPA Method 101A
FAC 62-297.401(35)	EPA Method 104
FAC 62-297.401(41)	EPA Method 201
FAC 62-297.520	EPA Performance Specifications
FAC 62-297.570	Test Reports
FAC 62-297.620	Exceptions and Approval of Alternate Procedures and Requirements

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **B1**	2. Emission Point Type Code: **2**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Boiler Stack (B1)**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **001 = Boiler A; 002 = Boiler B; 003 = Boiler C**	

5. Discharge Type Code: **V**	6. Stack Height: **403** feet	7. Exit Diameter: **13.26** feet
8. Exit Temperature: **265** °F	9. Actual Volumetric Flow Rate: **1,004,000** acfm	10. Water Vapor: **5** %

11. Maximum Dry Standard Flow Rate: **895,403** dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: **17** East (km): **441.871** North (km): **3365.587**	
14. Emission Point Comment (limit to 200 characters): **The 3 CFB boilers share a common stack designated as point B1. Flue gas from the boilers is discharged through this stack. Prior to the stack, each flue gas stream is passed through a baghouse which removes fly ash.** **Stack information based on Title V Application.**	

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **a) Segment 1 of 2: Bituminous coal used in boiler (when co-firing with petroleum coke).** **b) Segment 2 of 2.**		
2. Source Classification Code (SCC): **1-01-002-17**	3. SCC Units: **Tons burned**	
4. Maximum Hourly Rate: **29.9**	5. Maximum Annual Rate: **258,575**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **1.7% per load,** **1.2% annual**	8. Maximum % Ash: **10 (typical)**	9. Million Btu per SCC Unit: **20.4**
10. Segment Comment (limit to 200 characters): **Based on 65% coal (by weight). See Part II, Appendix B.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **a) Segment 1 of 2.** **b) Segment 2 of 2: Petroleum coke used in boiler when co-firing with coal.**		
2. Source Classification Code (SCC): **1-01-008-01**	3. SCC Units: **tons burned**	
4. Maximum Hourly Rate: **16.1**	5. Maximum Annual Rate: **139,233**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **6**	8. Maximum % Ash: **0.5 (typical)**	9. Million Btu per SCC Unit: **28**
10. Segment Comment (limit to 200 characters): **Based on 35% petroleum coke (by weight). See Part II, Appendix B.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	016	027	EL
PM_{10}	016	027	EL
NO_X	032/107	027	EL
SO_2	041	027	EL
CO	033	027	EL
VOC	027		EL
SAM	041	027	EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **318.9** lb/hour **866** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.30 lb/MMBtu* 0.20 lb/MMBtu**** Reference: **Permit PA-88-24A, PSD-FL-137B**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.3 lb/MMBtu = 318.9 lb/hr** **1,063 MMBtu/hr x 0.2 lb/MMBtu x 8,760 hr/yr x ton/2,000 lb x 0.93 (capacity factor) = 866 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Limited by modification to PSD-FL-137. * 3-hour rolling average; ** 30-day rolling average. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **see comment**	4. Equivalent Allowable Emissions: **318.9** lb/hour **866** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous Emissions Monitoring**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **3-hour rolling average for SO_2 = 0.30 lb/MMBtu** **30-day rolling average for SO_2 = 0.20 lb/MMBtu** **Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **186** lb/hour **649** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.175 lb/MMBtu** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.175 lb/MMBtu - 186 lb/hr** **Annual potential emissions based on maximum emissions for 3 boilers so that PSD is not triggered. See Part II.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **See Part II.**	

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **186** lb/hour **649** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous Emissions Monitoring and Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See Part II** **8-hour rolling average for CO = 0.175 lb/MMBtu**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control: **54% (estimated)**
3. Potential Emissions: **180.7** lb/hour **736.1** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.17 lb/MMBtu*** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.17 lb/MMBtu = 180.7 lb/hr** **180.7 lb/hr x 8,760 hr/yr x ton/2,000 lb x 0.93 (capacity factor) = 736.1 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Limited by modification to PSD-FL-137. * 30-day rolling average. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **180.7** lb/hour **736.1** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous Emissions Monitoring and Method 7, 7A, B, C, D, or E**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **30-day rolling average for NO_x = 0.17 lb/MMBtu** **Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.0** lb/hour **57.6** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.015** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.015 lb/MMBtu = 16 lb/hr** **Annual potential emissions based on maximum emissions for 3 boilers so that PSD is not triggered. See Part II.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **See Part II**	

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **16.0** lb/hour **57.6** tons/year
5. Method of Compliance (limit to 60 characters): **Method 18 or 25**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See Part II** **0.015 lb/MMBtu VOC**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM (TSP)**	2. Total Percent Efficiency of Control: **99.97%**
3. Potential Emissions: **19.1** lb/hour **78** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.018 lb/MMBtu** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**

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

1,063 MMBtu/hr x 0.018 lb/MMBtu = 19.1 lb/hr
19.1 lb/hr x 8,760 hr/yr x ton/2,000 lbs x 0.93 (capacity factor) = 78 TPY

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

Limited by modification to PSD-FL-137. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **19.1** lb/hour **78** tons/year

5. Method of Compliance (limit to 60 characters):

Method 5 or 17, 40 CFR Appendix A

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

0.018 lb/MMBtu
Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control: **99.97%**
3. Potential Emissions: **19.1** lb/hour **78** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.018 lb/MMBtu** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.018 lb/MMBtu = 19.1 lb/hr** **19.1 lb/hr x 8,760 hr/yr x ton/2,000 lbs x 0.93 (capacity factor) = 78 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Limited by modification to PSD-FL-137. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **19.1** lb/hour **78** tons/year
5. Method of Compliance (limit to 60 characters): **Method 5 or 17, 40 CFR Appendix A**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **0.018 lb/MMBtu** **Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.50** lb/hour **2.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **4.66×10^{-4} lb/MMBtu** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.000466 lb/MMBtu = 0.5 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Limited by modification to PSD-FL-137. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.**	

Allowable Emissions Allowable Emissions **1** of **1**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **0.50** lb/hour **2.0** tons/year
5. Method of Compliance (limit to 60 characters): **Method 8**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **4.66×10^{-4} lb/MMBtu** **Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE, VES**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **COM, Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **27% opacity for oil-burning during startup PSD-FL-137A**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 1

1. Parameter Code: **See comment**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **various** Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Baghouse flue has CEMs for NO_x, SO_2, CO, CO_2, and VE. Manufacturers, models, and serial numbers previously submitted.**	

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

Supplemental Requirements

1. Process Flow Diagram [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: Part II [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
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 [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID: ________ [X] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: See Part II [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
    [ ] Attached, Document ID:________ [X] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
    [ ] Attached, Document ID:________ [X] Not Applicable

13. Identification of Additional Applicable Requirements
    [ ] Attached, Document ID:________ [X] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [X] Not Applicable

15. Acid Rain Part 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:________

    [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID:________

    [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
    Attached, Document ID:________

    [X] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J 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.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (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.

2. 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.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Boiler C

4. Emissions Unit Identification Number: [ ] No ID [ ] ID Unknown
ID: **003**

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**25-JAN-1994**	**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

Circulating Fluidized Bed (CFB) Boiler C with limestone injection for SO_2 emissions reduction. Ammonia injection for NO_x emissions reduction. Fuel is primarily bituminous coal with No. 2 fuel oil for startup. Combustion products are flue gas with fly ash and bed ash.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):

Baghouse
Efficiency = (1-emission)/load = 0.0055 gr/acr / 19.5 gr/acr = 99.97%

Ammonia injection
Efficiency = 54% for NO_x (estimated)

Dry limestone injection
Efficiency from 89 to 95% based on Quarterly Reports

Air preheater
Reduction Efficiency not determined.
Intake air is preheated via flue gas to reduce fuel requirements.

Control of Oxygen
Reduction Efficiency not determined.
Flue gas recirculates with intake air.

2. Control Device or Method Code(s): **016, 032/107, 041, 027, 033**

Emissions Unit Details

1. Package Unit: **NA**		
Manufacturer: **Foster Wheeler**	Model Number: **Pyroflow®**	
2. Generator Nameplate Rating:	MW	
3. Incinerator Information:		
Dwell Temperature:		°F
Dwell Time:		seconds
Incinerator Afterburner Temperature:		°F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		1,063	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:		104,000 lb/hr coal; 39,000 ton/month coal; 390,000 TPY coal	
4. Maximum Production Rate:		800,000 lb/hr steam	
5. Requested Maximum Operating Schedule:			
	24 hours/day	7	days/week
	52 weeks/year	8,760	hours/year

6. Operating Capacity/Schedule Comment (limit to 200 characters):

Limits set by PSD-FL-137A

CFB Boilers A, B, and C feed a common steam turbine with a nominal rating of 250 MW and supply steam to an adjacent recycled liner board mill.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60.40a	Applicability >250 MMBtu/hr
40 CFR 60.41a	Definitions
40 CFR 60.42a	Standard for particulate matter
40 CFR 60.43a(a)	Standard for sulfur dioxide
40 CFR 60.43a(g)	Compliance with the emission limitation and percent reduction requirements
40 CFR 60.44a	Standard for nitrogen oxides
40 CFR 60.46a	Compliance provisions
40 CFR 60.47a	Emission monitoring
40 CFR 60.48a	Compliance determination procedures and methods
40 CFR 60.49a	Reporting requirements
FAC 62-204.800	Standards of performance for New Stationary Sources
FAC 62-210.550	Stack Height Policy
FAC 62-210.700	Excess Emissions
FAC 62-212-300	General preconstruction review
FAC 62-212-400	Prevention of Significant Deterioration
FAC 62-296.405	Fossil Fuel Steam Generators with more than 240 MMBtu/hr heat input
FAC 62-296.570(4)(a)	Reasonable Available Control Technology - Requirements for major VOC and NO_x emission Facilities
FAC 62-296.702	Fossil Fuel Steam Generators
FAC 62-296.711	Material Handling, Sizing, Screening, Crushing, and Grinding Operations
FAC 62-297.401(5)	EPA Method 5
FAC 62-297.401(6)	EPA Method 6
FAC 62-297.401(7)	EPA Method 7
FAC 62-297.401(8)	EPA Method 8
FAC 62-297.401(9)	EPA Method 9
FAC 62-297.401(10)	EPA Method 10
FAC 62-297.401(12)	EPA Method 12
FAC 62-297.401(13)	EPA Method 13
FAC 62-297.401(15)	EPA Method 15
FAC 62-297.401(17)	EPA Method 17
FAC 62-297.401(19)	EPA Method 19
FAC 62-297.401(25)	EPA Method 25
FAC 62-297.401(32)(a)	EPA Method 101A
FAC 62-297.401(35)	EPA Method 104
FAC 62-297.401(41)	EPA Method 201
FAC 62-297.520	EPA Performance Specifications
FAC 62-297.570	Test Reports
FAC 62-297.620	Exceptions and Approval of Alternate Procedures and Requirements

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **B1**	2. Emission Point Type Code: **2**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Boiler Stack (B1)

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:
001 = Boiler A; 002 = Boiler B; 003 = Boiler C

5. Discharge Type Code: **V**	6. Stack Height: **403** feet	7. Exit Diameter: **13.26** feet
8. Exit Temperature: **265** °F	9. Actual Volumetric Flow Rate: **1,004,000** acfm	10. Water Vapor: **5** %

11. Maximum Dry Standard Flow Rate: **895,403** dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **441.871** North (km): **3365.587**

14. Emission Point Comment (limit to 200 characters):

The 3 CFB boilers share a common stack designated as point B1. Flue gas from the boilers is discharged through this stack. Prior to the stack, each flue gas stream is passed through a baghouse which removes fly ash.

Stack information based on Title V Application.

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **a) Segment 1 of 2: Bituminous coal used in boiler (when co-firing with petroleum coke).** **b) Segment 2 of 2.**		
2. Source Classification Code (SCC): **1-01-002-17**	3. SCC Units: **Tons burned**	
4. Maximum Hourly Rate: **29.9**	5. Maximum Annual Rate: **258,575**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **1.7% per load,** **1.2% annual**	8. Maximum % Ash: **10 (typical)**	9. Million Btu per SCC Unit: **20.4**
10. Segment Comment (limit to 200 characters): **Based on 65% coal (by weight). See Part II, Appendix B.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **a) Segment 1 of 2.** **b) Segment 2 of 2: Petroleum coke used in boiler when co-firing with coal.**		
2. Source Classification Code (SCC): **1-01-008-01**	3. SCC Units: **tons burned**	
4. Maximum Hourly Rate: **16.1**	5. Maximum Annual Rate: **139,233**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **6**	8. Maximum % Ash: **0.5 (typical)**	9. Million Btu per SCC Unit: **28**
10. Segment Comment (limit to 200 characters): **Based on 35% petroleum coke (by weight). See Part II, Appendix B.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	016	027	EL
PM_{10}	016	027	EL
NO_X	032/107	027	EL
SO_2	041	027	EL
CO	033	027	EL
VOC	027		EL
SAM	041	027	EL

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **318.9** lb/hour **866** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.30 lb/MMBtu* 0.20 lb/MMBtu**** Reference: **Permit PA-88-24A, PSD-FL-137B**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.3 lb/MMBtu = 318.9 lb/hr** **1,063 MMBtu/hr x 0.2 lb/MMBtu x 8,760 hr/yr x ton/2,000 lb x 0.93 (capacity factor) = 866 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Limited by modification to PSD-FL-137. * 3-hour rolling average; ** 30-day rolling average. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **see comment**	4. Equivalent Allowable Emissions: **318.9** lb/hour **866** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous Emissions Monitoring**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **3-hour rolling average for SO_2 = 0.30 lb/MMBtu** **30-day rolling average for SO_2 = 0.20 lb/MMBtu** **Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control: **54% (estimated)**
3. Potential Emissions: **180.7** lb/hour **736.1** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.17 lb/MMBtu*** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.17 lb/MMBtu = 180.7 lb/hr** **180.7 lb/hr x 8,760 hr/yr x ton/2,000 lb x 0.93 (capacity factor) = 736.1 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Limited by modification to PSD-FL-137. * 30-day rolling average. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **180.7** lb/hour **736.1** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous Emissions Monitoring and Method 7, 7A, B, C, D, or E**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **30-day rolling average for NO_x = 0.17 lb/MMBtu** **Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **16.0** lb/hour **57.6** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.015** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.015 lb/MMBtu = 16 lb/hr** **Annual potential emissions based on maximum emissions for 3 boilers so that PSD is not triggered. See Part II.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **See Part II**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **16.0** lb/hour **57.6** tons/year
5. Method of Compliance (limit to 60 characters): **Method 18 or 25**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See Part II** **0.015 lb/MMBtu VOC**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM (TSP)**	2. Total Percent Efficiency of Control: **99.97%**
3. Potential Emissions: **19.1** lb/hour **78** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.018 lb/MMBtu** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.018 lb/MMBtu = 19.1 lb/hr** **19.1 lb/hr x 8,760 hr/yr x ton/2,000 lbs x 0.93 (capacity factor) = 78 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Limited by modification to PSD-FL-137. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **19.1** lb/hour **78** tons/year
5. Method of Compliance (limit to 60 characters): **Method 5 or 17, 40 CFR Appendix A**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **0.018 lb/MMBtu** **Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control: **99.97%**
3. Potential Emissions: **19.1** lb/hour **78** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.018 lb/MMBtu** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.018 lb/MMBtu = 19.1 lb/hr** **19.1 lb/hr x 8,760 hr/yr x ton/2,000 lbs x 0.93 (capacity factor) = 78 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Limited by modification to PSD-FL-137. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **19.1** lb/hour **78** tons/year
5. Method of Compliance (limit to 60 characters): **Method 5 or 17, 40 CFR Appendix A**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **0.018 lb/MMBtu** **Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.50** lb/hour **2.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **4.66 x 10^{-4} lb/MMBtu** Reference: **PSD-FL-137A**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **1,063 MMBtu/hr x 0.000466 lb/MMBtu = 0.5 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Limited by modification to PSD-FL-137. Annual emissions limited for 3 boilers when co-firing coke with coal to not trigger PSD review. See Part II.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **See Part II**	4. Equivalent Allowable Emissions: **0.50** lb/hour **2.0** tons/year
5. Method of Compliance (limit to 60 characters): **Method 8**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **4.66 x 10^{-4} lb/MMBtu** **Annual emissions for 3 boilers limited when co-firing petroleum coke with coal to not trigger PSD review. See Part II.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE, VES**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **COM, Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **27% opacity for oil-burning during startup PSD-FL-137A**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 1

1. Parameter Code: **See comment**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **various** Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Baghouse flue has CEMs for NO_x, SO_2, CO, CO_2, and VE. Manufacturers, models, and serial numbers previously submitted.**	

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

Supplemental Requirements

1. Process Flow Diagram [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: Part II [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
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 [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID: ________ [X] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: See Part II [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
    [ ] Attached, Document ID:________ [X] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
    [ ] Attached, Document ID:________ [X] Not Applicable

13. Identification of Additional Applicable Requirements
    [ ] Attached, Document ID:________ [X] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [X] Not Applicable

15. Acid Rain Part 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:________

    [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID:________

    [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
    Attached, Document ID:________

    [X] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J 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.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

2. 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.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Truck unloading and conveyors associated with petroleum coke unloading.

4. Emissions Unit Identification Number: [ ] No ID
ID: **034** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

Emission unit consists of truck dump, transfer stock-out conveyor (truck or rail), dozer trap (truck or rail), and blending conveyor (truck or rail).

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Water spraying as needed to reduce fugitive dust emissions.**
2. Control Device or Method Code(s): **061**

Emissions Unit Details

1. Package Unit: **NA** Manufacturer:	Model Number:	
2. Generator Nameplate Rating:	MW	
3. Incinerator Information:		
Dwell Temperature:		°F
Dwell Time:		seconds
Incinerator Afterburner Temperature:		°F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:				mmBtu/hr
2. Maximum Incineration Rate:	lb/hr			tons/day
3. Maximum Process or Throughput Rate:		**48.3 tons/hr**		
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
	24	hours/day	**7**	days/week
	52	weeks/year	**8,760**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum throughput rate based on 35 percent by weight of petroleum coke for CFB boilers. See Part II.**				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

Rule 62-296.320(4)(c)1.
Rule 62-296.320(4)(c)3.
Rule 62-296.320(4)(c)4.

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See Part II**	2. Emission Point Type Code: **4**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Fugitive emissions from truck unloading and associated conveyor.**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **F**	6. Stack Height: feet	7. Exit Diameter: feet
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: East (km): North (km):	
14. Emission Point Comment (limit to 200 characters): **Points of emission include truck dump, stock-out conveyor, dozer trap, and blending conveyor. See Part II.**	

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Petroleum Coke, Mineral Products -- Bulk materials unloading operation**		
2. Source Classification Code (SCC): **3-05-104-04**	3. SCC Units: **Tons processed**	
4. Maximum Hourly Rate: **43.9**	5. Maximum Annual Rate: **384,939**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **6**	8. Maximum % Ash: **0.5**	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): **Petroleum coke for 3 CFB Boilers. See Part II.**		

Segment Description and Rate: Segment ____ of ____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	061		WP
PM_{10}	061		WP

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM (TSP)**	2. Total Percent Efficiency of Control: **70**
3. Potential Emissions: **0.034** lb/hour **0.124** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **See Part II** Reference:	7. Emissions Method Code: **3**
8. Calculation of Emissions (limit to 600 characters): **See Part II.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **Work Practice**	4. Equivalent Allowable Emissions: **0.034** lb/hour **0.124** tons/year
5. Method of Compliance (limit to 60 characters): **Water spraying as needed.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.016** lb/hour **0.059** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **See Part II** Reference:	7. Emissions Method Code: **3**
8. Calculation of Emissions (limit to 600 characters): **See Part II**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **Work Practice**	4. Equivalent Allowable Emissions: **0.016** lb/hour **0.059** tons/year
5. Method of Compliance (limit to 60 characters): **Water spraying as needed.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment (limit to 200 characters): Rule 62-296.320(4)(b)1. F.A.C.	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

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):	

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

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: See Part II [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
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 [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [X] Attached, Document ID: See Part II [ ] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: See Part II [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
    [ ] Attached, Document ID:________ [X] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
    [ ] Attached, Document ID:________ [X] Not Applicable

13. Identification of Additional Applicable Requirements
    [ ] Attached, Document ID:________ [X] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [X] Not Applicable

15. Acid Rain Part 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:________

    [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID:________

    [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
    Attached, Document ID:________

    [X] Not Applicable

PART II

1.0 INTRODUCTION

Cedar Bay Generating Company, L.P. (Cedar Bay), is seeking authorization from the Florida Department of Environmental Protection (FDEP) to co-fire up to 35 percent (by weight) of petroleum coke with coal at the Cedar Bay Cogeneration Facility (Facility). Specifically, Cedar Bay requests FDEP to change the Prevention of Significant Deterioration (PSD) permit for the Facility (PSD-FL-137) and Title V permit to modify the Conditions of Certification that were issued for the Facility under the Florida Electrical Power Plant Siting Act (PPSA; PA 88-24). Although a change to the Facility's PSD permit is being requested to allow the co-firing of petroleum coke, there will not be any significant net emissions increase at the Facility, and thus the requirements of the PSD review process are not triggered.

There are four power plants in Florida that currently are authorized to co-fire petroleum coke with coal. These units include St. John River Power Park Units 1 and 2, Seminole Electric Cooperative's Seminole Units 1 and 2, City of Lakeland's McIntosh Unit 3, and Tampa Electric Company's Big Bend Units 3 and 4. All of these units are pulverized coal units with wet flue gas desulfurization and electrostatic precipitators. At these facilities, the authorizations for co-firing up to 25-percent petroleum coke with coal involved no PSD review. When co-firing petroleum coke with coal, no significant increase in annual emissions of particulate matter (PM), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and sulfuric acid mist was made a permit condition of these authorizations. Petroleum coke has been successfully co-fired in many of these units for about 5 years.

More recently, FDEP authorized Jacksonville Electric Authority to repower Northside Units 1 and 2 using coal and petroleum coke. Up to 100 percent of petroleum coke was authorized by FDEP (PSD-FL-265). These units are circulating fluidized bed (CFB) boilers.

The existing Cedar Bay Cogeneration Facility is located at 9640 Eastport Road, Jacksonville, Duval County, Florida (Figure 1). The cogeneration facility consists of three CFB boilers and associated facilities. The CFB boilers, designated as Boilers A, B, and C, use coal as the primary fuel. No. 2 fuel oil is only used as a supplemental fuel, primarily for start-ups. SO_2 emissions are controlled using limestone injection into the CFB boilers and emissions of NO_x are controlled using selective non-catalytic reduction (SNCR). The reaction products of the limestone and SO_2, as well as PM generated from combustion are controlled with baghouses.

Golder Associates Inc. (Golder) was contracted to prepare the necessary air permit application seeking authorization to co-fire up to 35 percent (by weight) of petroleum coke with coal. The air permit application consists of the appropriate applications form [DEP Form 62-210.900(1)], a technical description of the project (Part II Section 2.0), and rule applicability for the project (Part II Section 3.0).

2.0 PROJECT DESCRIPTION

2.1 FEASIBILITY OF CO-FIRING PETROLEUM COKE

A feasibility study was conducted by Foster Wheeler Energy Services, Inc. (Foster Wheeler) for co-firing petroleum coke with coal in the three Cedar Bay CFB boilers. The full report is attached as Appendix A. The report concludes that co-firing up to 20-percent petroleum coke (by weight) with coal at maximum continuous rating (MCR) is technically feasible without any changes to the boiler systems. For up to 35-percent petroleum coke (by weight) with coal, changes to the limestone feed system are needed. The report concludes that air pollution control systems are capable of maintaining the emissions at the current levels. Based on the results of this feasibility report, authorization of up to 35-percent petroleum coke with coal is being requested in this application with the changes noted in the report.

The PSD permit and the Title V permit (Final Permit No. 0310377-002-AV) for the Facility have specific conditions that limit the amount of coal, limestone, bottom ash, and flyash handled at the Facility. Table 1 presents a comparison of the information in the Foster Wheeler report for co-firing 35-percent petroleum coke with coal. As shown on the table, the projected amounts at MCR will be less, and in some cases much less, than the amount currently authorized for coal.

2.2 HISTORICAL EMISSIONS FOR CEDAR BAY COGENERATION FACILITY

The production information and actual emissions reported in the Annual Operating Reports submitted to FDEP for the years 1997 through 2000 are summarized in Table 2. The reported emissions are for carbon monoxide (CO), NO_x, SO_2, PM (identified as PM_{10} in the table), volatile organic compounds (VOC), and sulfuric acid mist. These reported emissions are based on continuous emission monitoring (CEM) systems for CO, NO_x, and SO_2. Testing is conducted annually for the other pollutants.

As shown in the table, the production and emissions have been relatively constant over the last 4 years. Capacity factors for the three units have been at or near 90 percent.

2.3 PETROLEUM COKE HANDLING

The Facility currently receives coal by rail and limestone by truck. When co-firing petroleum coke with coal, facilities will be added to the existing coal yard to receive coke by rail or truck, store coke on a separate portion of the existing coal storage area, and blend coke with coal. Petroleum coke received by rail will utilize the same unloading methods as currently used for coal. When transferred to the coal storage pile, the petroleum coke will be separated from coal using a conveyor. A new dozer trap and blending conveyor will be used for both rail and truck delivery. For delivery by truck, a new truck dump will be added to the north end of the existing coal yard. From the truck dump, a new conveyor will convey the petroleum coke to a storage pile, which will be located in a portion of the existing coal storage area. The dozer trap will be added to receive petroleum coke from the storage pile for blending. A blending conveyor, with a weight scale, will transfer the petroleum coke to the crusher house. Figure 2 presents a site plan showing the location of the new facilities, and Figure 3 presents a simplified process flow diagram for truck unloading.

Potential increases in fugitive emissions may occur as a result of the material handling operations associated with the additional limestone usage. However, the fugitive emissions from storing petroleum coke will not likely be higher than the fugitive emissions from the current operation with coal. Coal is stored in the same area and transported to the crusher house using bulldozers and conveyors. Indeed, the fugitive emissions associated with using petroleum coke will be lower because petroleum coke has a higher heating value and less is needed for the same amount of heat input to the CFB boilers.

The estimated potential increases in fugitive emissions are 0.124 ton per year (TPY) for PM and 0.059 TPY for PM_{10} based on receiving petroleum coke by truck. This method of delivery would produce worst-case emissions since the truck dump will not be covered like the existing rail receiving facility. Water spraying was assumed as the method reasonably available to control fugitive emissions. The calculations of fugitive emissions are presented in Appendix B. As noted in the appendix, the methods used were the same as used in the original PSD permit application and Title V permit application.

No additional fugitive PM emissions will result for other operations. Control devices (i.e., baghouses or bag filters) control fugitive PM in the crusher house, storage silos, and ash handling operations.

3.0 RULE APPLICABILITY

Under Federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a pre-construction permit issued. EPA has approved Florida's State Implementation Plan (SIP), which contains PSD regulations. therefore, PSD approval authority has been granted to the FDEP. For projects approved under the Florida PPSA, the PSD program is delegated.

A "major facility" is defined as any 1 of 28 named source categories that have the potential to emit 100 TPY or more, or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. Once a new source is determined to be a "major facility" for a particular pollutant, any pollutant emitted in amounts greater than the PSD significant emission rates is subject to PSD review. For an existing source for which a modification is proposed, the modification is subject to PSD review if the net increase in emissions due to the modification is greater than the PSD significant emission rates.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 Code of Federal Regulations (CFR) 52.21, *Prevention of Significant Deterioration of Air Quality*. The State of Florida has adopted the federal PSD regulations by reference [Rule 62-212.400, Federal Administrative Code (F.A.C.)]. Major facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

- Control technology review,
- Source impact analysis,
- Air quality analysis (monitoring),
- Source information, and
- Additional impact analyses.

The Cedar Bay Cogeneration Facility is a major source. Co-firing of petroleum coke is an operational change, and physical changes will be made to receive and handle petroleum coke. In addition, physical changes may be made to the boiler systems (i.e., limestone feed system). Therefore, the project is a modification as defined in the Department Rules in 62-210.200 and under the PSD rules in 62-212.400 F.A.C. PSD review would be required for the project if there were a significant net increase in emissions. For the proposed co-firing of petroleum coke with coal, there will be no significant net increase in actual emissions.

Determining the amount of the change, if any, in the Facility's emission should be performed by following the requirements in 40 CFR Parts 52.21(b)(21)(v) and 52.21(b)(33). These applicable rules are stated below:

> **52.21(b)(21)(v)** For an electric utility steam generating unit (other than a new unit or the replacement of an existing unit) actual emissions of the unit following the physical or operational change shall equal the representative actual annual emissions of the unit, provided the source owner or operator maintains and submits to the Administrator on an annual basis for a period of 5 years from the date the unit resumes regular operation, information demonstrating that the physical or operational change did not result in an emissions increase. A longer period, not to exceed 10 years, may be required by the Administrator if he determines such a period to be more representative of normal source post-change operations.
>
> **52.21(b)(33)** Representative actual annual emissions means the average rate, in tons per year, at which the source is projected to emit a pollutant for the two-year period after a physical change or change in the method of operation of a unit, (or a different consecutive two-year period within 10 years after that change, where the Administrator determines that such period is more representative of normal source operations), considering the effect any such change will have on increasing or decreasing the hourly emissions rate and on projected capacity utilization. In projecting future emissions the Administrator shall:
>
> > **(i)** Consider all relevant information, including but not limited to, historical operational data, the company's own representations, filings with the State or Federal regulatory authorities, and compliance plans under title IV of the Clean Air Act; and
> >
> > **(ii)** Exclude, in calculating any increase in emissions that results from the particular physical change or change in the method of operation at an electric utility steam generating unit, that portion of the unit's emissions following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole.

These requirements have been included in many of the co-firing permits authorized by the Department. Cedar Bay Cogeneration Company, L.P. requests that these requirements be included in a federally enforceable modification to the existing PSD and Title V permits for the Facility, and included in the PPSA Conditions of Certification for the Facility to authorize co-firing up to 35-percent (by weight) of petroleum coke with coal. The Facility has CEM systems for SO_2, NO_x, and CO that would demonstrate compliance with the requested condition. Individual stack tests, pursuant to the existing permit conditions, would be conducted for PM, PM_{10}, VOC, and sulfuric acid mist when co-firing the maximum mixture of petroleum coke with coal. This mixture would not exceed 35-percent (by weight) petroleum coke with coal. This maximum amount of petroleum coke co-fired with coal will be maintained at the level demonstrating that there is no significant net increase in emissions. If this mixture were less than 35 percent (by weight), additional testing would be conducted at any higher percentages of petroleum coke but would not exceed 35-percent by weight.

Table 1. Material Usage of Coal, Limestone, Bottom Ash and Fly Ash for Co-firing Petroleum Coke with Coal at Cedar Bay Cogeneration Facility

	Units	Coal	Co-Firing	Difference	Permit Limits	Title V Permit Condition
Fuel	lb/hr/unit[a]	82,500	78,000	-4,500	104,000	Section III. A.3.
	lb/hr/plant[b]	247,500	234,000	-13,500	312,000	Section III. A.3.
	tons/month[c]	89,100	84,240	-4,860	117,000	Section III. A.3.
	tons/year[d]	1,008,167	953,176	-54,991	1,170,000	Section III. A.3.
Limestone	lb/hr/unit[a]	12,500	22,500	10,000	NA	
	lb/hr/plant[b]	37,500	67,500	30,000	NA	
	tons/month[c]	13,500	24,300	10,800	27,000	Section III. B.1.
	tons/year[d]	152,753	274,955	122,202	320,000	Section III. B.1.
Fly Ash	lb/hr/unit[a]	13,000	15,500	2,500	NA	
	lb/hr/plant[b]	39,000	46,500	7,500	NA	
	tons/month[c]	14,040	16,740	2,700	28,000	Section III. B.1.
	tons/year[d]	158,863	189,413	30,551	336,000	Section III. B.1.
Bottom Ash	lb/hr/unit[a]	4,200	7,000	2,800	NA	
	lb/hr/plant[b]	12,600	21,000	8,400	NA	
	tons/month[c]	4,536	7,560	3,024	8,000	Section III. B.1.
	tons/year[d]	51,325	85,541	34,217	88,000	Section III. B.1.

Footnotes: [a] from Foster Wheeler Report for one CFB unit.
[b] based on three CFB units.
[c] based on 24 hour/day and 30 days/month per permit condition.
[d] based on 8,760 hours/year at 93% capacity factor.

Note: Data on usage from Foster Wheeler Report and based on lb/hr values for a single unit.
Calculations based on 3 CFB units.

Table 2. Operating Parameters for Cedar Bay Cogeneration Plant, Years 1997-2000

			AOR Year			
Unit	Parameter	Unit	1997	1998	1999	2000
1063 MMBtu/hr Boiler 1-A	Hours Operated	hrs	8,013	8,204	7,968	7,651
	Fuel Usage	tons	331,642	334,181	324,598	320,199
	Fuel Heat Content	MMBtu/ton	23.8	21.5	23.8	23.9
	Fuel Heat Content	Btu/lb	11,900	10,750	11,900	11,950
	Heat Input	MMBtu/hr	985.0	875.8	969.6	1000.2
	Capacity Factor		92.7%	82.4%	91.2%	94.1%
	CO emissions	tons/yr	176.0	208.0	196.3	179.2
	CO based lb/MMBtu		0.045	0.058	0.051	0.047
	NO_x emissions	tons/yr	593.1	581.6	587.56	594.4
	NO_x based lb/MMBtu		0.150	0.162	0.152	0.155
	PM_{10} emissions	tons/yr	49.4	67.2	66.4	48.1
	PM_{10} based lb/MMBtu		0.013	0.019	0.017	0.0126
	Sulfuric Acid Mist	tons/yr	0.120	0.120	0.120	0.115
	SAM based lb/MMBtu		3.04E-05	3.34E-05	3.09E-05	3.00E-05
	SO_2 emissions	tons/yr	659.0	658.1	659.7	650.5
	SO_2 based lb/MMBtu		0.167	0.183	0.171	0.170
	VOC emissions	tons/yr	3.30	3.20	5.18	4.97
	VOC based lb/MMBtu		0.0008	0.0009	0.0013	0.0013
1063 MMBtu/hr Boiler 1-B	Hours Operated	hrs	8,053	7,786	8,008	7,731
	Fuel Usage	tons	316,400	306,430	316,369	318,602
	Fuel Heat Content	MMBtu/ton	23.8	23.4	23.0	24.0
	Fuel Heat Content	Btu/lb	11,900	11,700	11,500	12,000
	Heat Input	MMBtu/hr	935.1	920.9	908.7	989.1
	Capacity Factor		88.0%	86.6%	85.5%	93.0%
	CO emissions	tons/yr	141.0	145.4	167.5	157.7
	CO based lb/MMBtu		0.037	0.041	0.047	0.041
	NO_x emissions	tons/yr	558.3	545.8	577.1	597.6
	NO_x based lb/MMBtu		0.148	0.152	0.163	0.156
	PM_{10} emissions	tons/yr	49.0	49.0	61.6	60.2
	PM_{10} based lb/MMBtu		0.013	0.014	0.017	0.016
	Sulfuric Acid Mist	tons/yr	0.110	0.110	0.120	0.116
	SAM based lb/MMBtu		2.92E-05	3.07E-05	3.40E-05	3.03E-05
	SO_2 emissions	tons/yr	636.0	618.5	622.0	671.0
	SO_2 based lb/MMBtu		0.169	0.173	0.176	0.176
	VOC emissions	tons/yr	8.30	8.30	9.25	8.93
	VOC based lb/MMBtu		0.0022	0.0023	0.0026	0.0023
1063 MMBtu/hr Boiler 1-C	Hours Operated	hrs	8,091	8,275	7,960	7,696
	Fuel Usage	tons	322,289	332,388	321,602	315,590
	Fuel Heat Content	MMBtu/ton	23.8	23.4	23.8	24.0
	Fuel Heat Content	Btu/lb	11,900	11,700	11,900	12,000
	Heat Input	MMBtu/hr	948.0	939.9	961.6	984.2
	Capacity Factor		89.2%	88.4%	90.5%	92.6%
	CO emissions	tons/yr	179.0	196.2	218.5	179.2
	CO based lb/MMBtu		0.047	0.050	0.057	0.047
	NO_x emissions	tons/yr	574.6	589.0	576.8	587.1
	NO_x based lb/MMBtu		0.150	0.151	0.151	0.155
	PM_{10} emissions	tons/yr	51.1	62.1	65.7	56.9
	PM_{10} based lb/MMBtu		0.013	0.016	0.017	0.015
	Sulfuric Acid Mist	tons/yr	0.120	0.120	0.119	0.115
	SAM based lb/MMBtu		3.13E-05	3.09E-05	3.12E-05	3.05E-05
	SO_2 emissions	tons/yr	614.0	659.0	644.5	643.6
	SO_2 based lb/MMBtu		0.160	0.169	0.168	0.170
	VOC emissions	tons/yr	3.20	3.20	3.46	3.35
	VOC based lb/MMBtu		0.0008	0.0008	0.0009	0.0009
Total Emissions for 3 Boilers	Capacity Factor		89.9%	85.8%	89.0%	93.2%
	Heat Input	10^6 MMBtu	23.09	22.13	22.66	22.87
	CO emissions	tons/yr	496.0	549.6	582.3	516.0
	NO_x emissions	tons/yr	1726.0	1716.4	1741.5	1779.0
	PM_{10} emissions	tons/yr	149.5	178.3	193.7	165.2
	Sulfuric Acid Mist	tons/yr	0.4	0.4	0.4	0.3
	SO_2 emissions	tons/yr	1909.0	1935.6	1926.2	1965.1
	VOC	tons/yr	14.8	14.7	17.9	17.3

Notes:

Million BTU per ton burned listed in Title V as 24.0 (calculated).

Maximum hourly rate = 52 tph

Maximum annual rate = 390,000 tpy

Maximum heat input to each boiler shall not exceed 1,063 MMBtu/hr. This reflects a combined total of 3,189 MMBtu/hr for all three units.

Boilers may operate continuously (8,760 hr/yr) but shall not exceed - 25.98 x 106 MMBtu/yr total annual heat input.

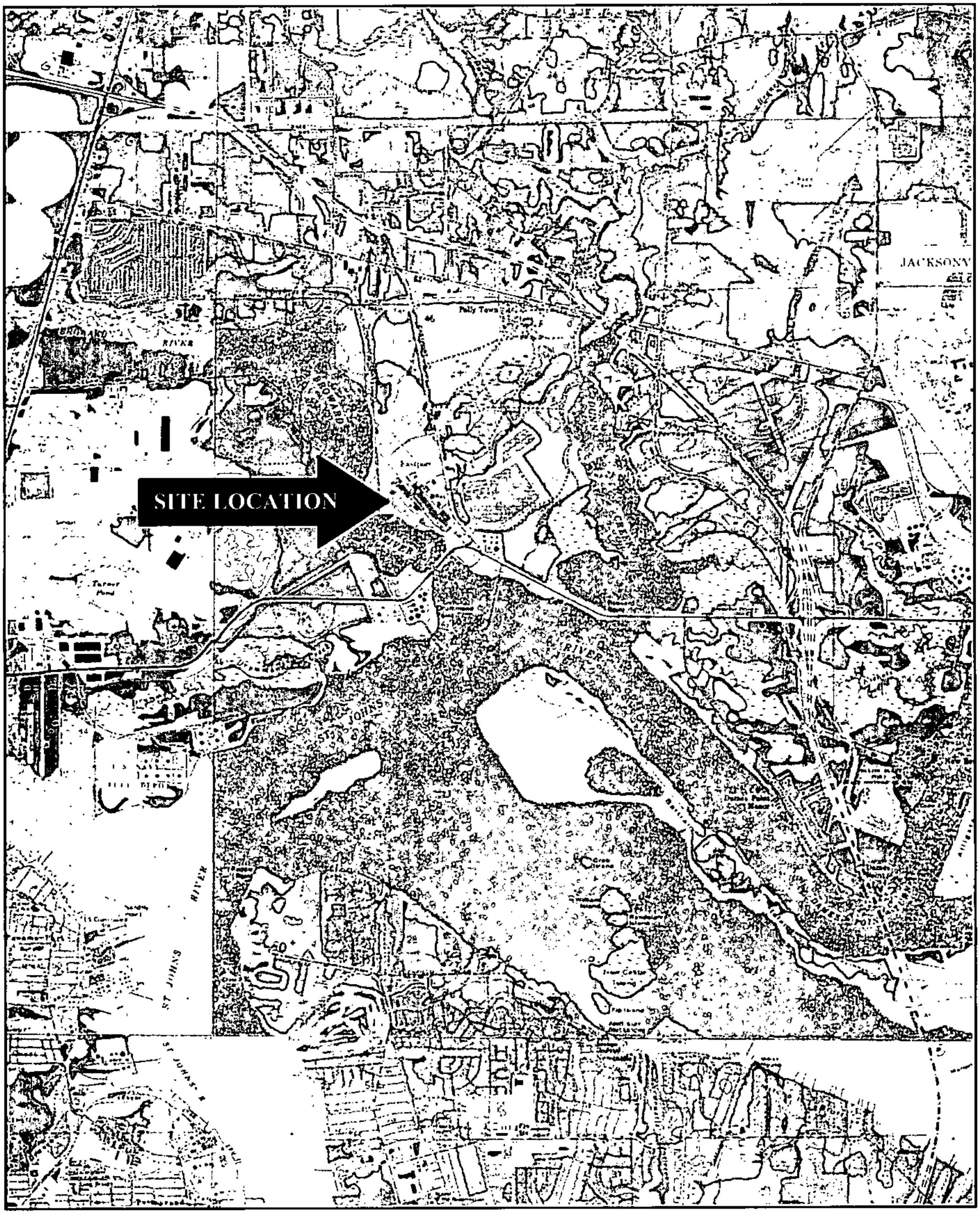


Figure 1
Cedar Bay Cogeneration Facility - Site Location

Source: Golder, 2001.

N 0 600 1200 Scale in Meters

Golder Associates

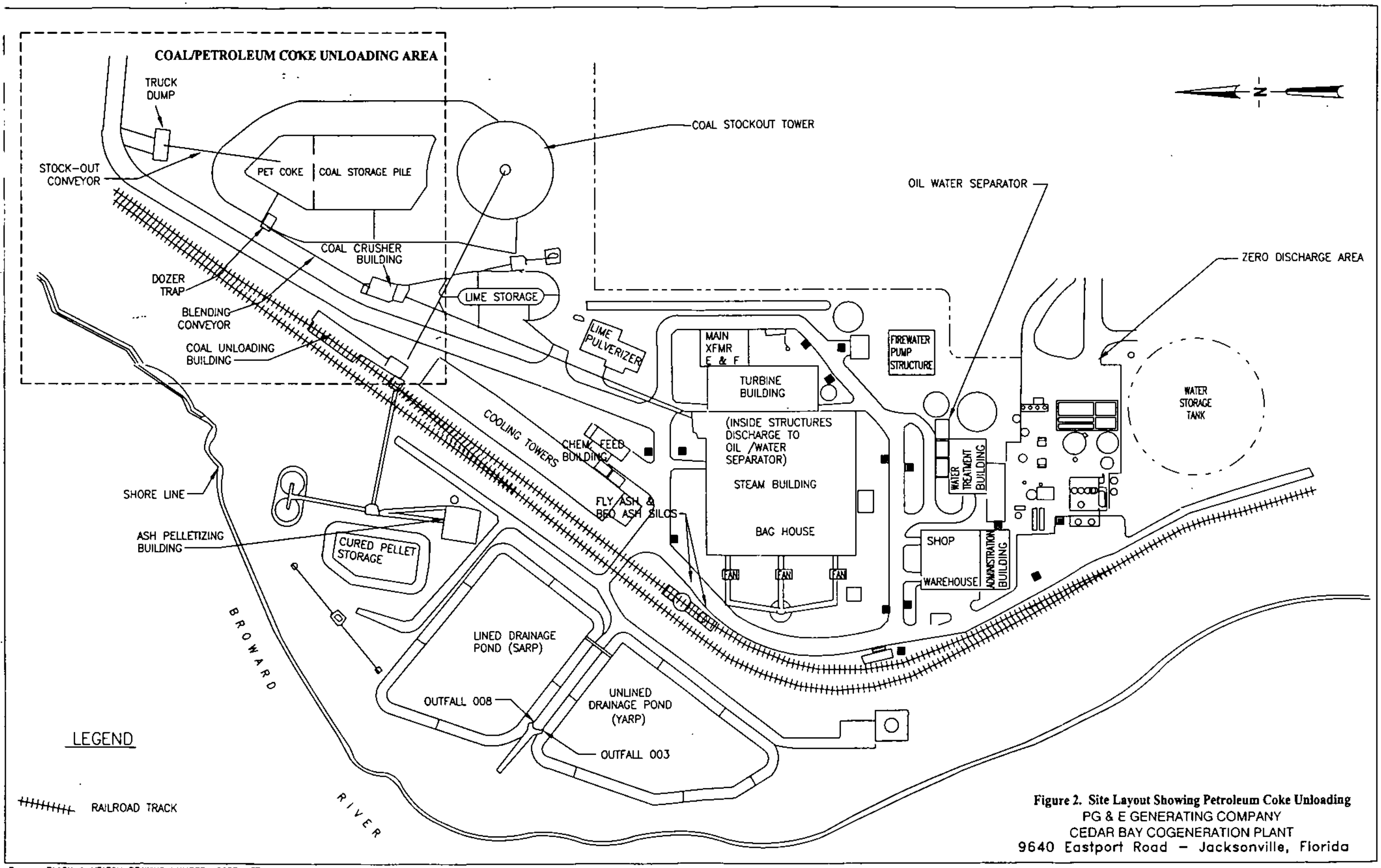


Figure 2. Site Layout Showing Petroleum Coke Unloading
PG & E GENERATING COMPANY
CEDAR BAY COGENERATION PLANT
9640 Eastport Road – Jacksonville, Florida

Source: BLACK & VEATCH DRAWING NUMBER 15637-1STU-S3400 REVISION 3. DATED: 1-6-92

0137573\4\4.4\4.4.2\Figure 2.dwg (7/12/01 by ARZ)

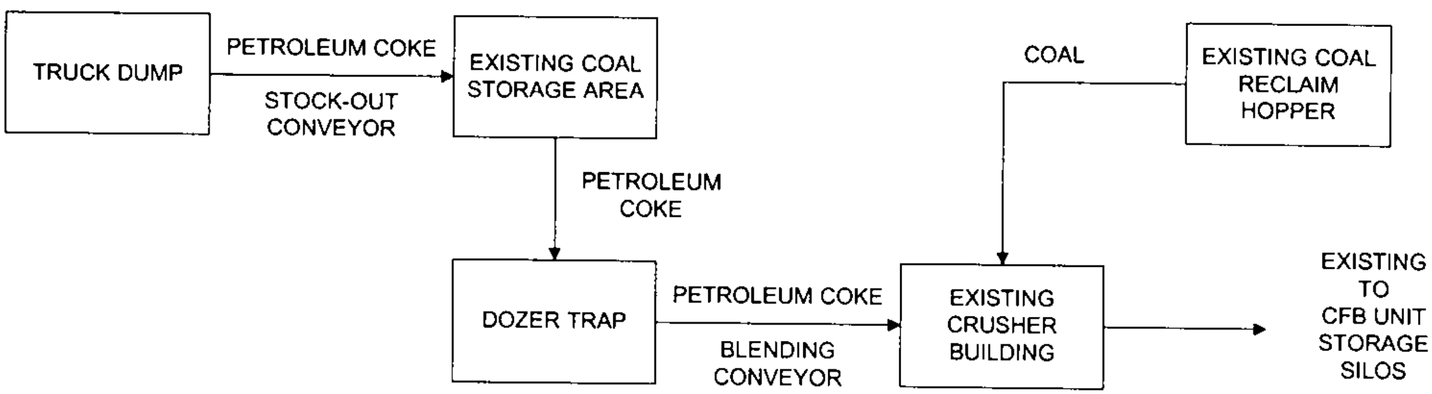


Figure 3
Process Flow Diagram for Petroleum Coke Unloading
Cedar Bay Cogeneration Facility
Jacksonville, Florida

Process Flow Legend:
Solid / Liquid
Gas
Steam

Golder Associates

APPENDIX A

REPORT ON FEASIBILITY STUDY FOR CO-FIRING PETROLEUM COKE IN CEDAR BAY CFB BOILERS

FOSTER WHEELER ENERGY SERVICES, INC.

Report on Feasibility Study for Co-firing Petroleum Coke in Cedar Bay CFB Boilers

for

PG&E National Energy Group
Cedar Bay Generating Company, L.P.
Jacksonville, Florida

Report on Feasibility Study for Co-firing Petroleum Coke in Cedar Bay CFB Boilers

for

PG&E National Energy Group
Cedar Bay Generating Company, L.P.
Jacksonville, Florida

Prepared by:

____

Song Wu, Principal Engineer

Engineering Technology Department, FWDC

Approved by:

____

PK Chelian

Manager Engineering / FWESI

EXECUTIVE SUMMARY

This is an engineering study by Foster Wheeler Energy Services Inc for the co-firing of petroleum coke and bituminous coal in the CFB boilers at PG&E National Energy Group's Cedar Bay Plant. The plant provided the fuel analyses of four candidate petroleum cokes for this study. The main objective of the study is to evaluate the potential impact of co-firing on the boiler capacity, emissions, CFB process as well as on the major auxiliary equipment.

Boiler "C" was designated for the study. Boilers A, B and C are similar. The process and operating conditions of the May 22, 1999 performance evaluation test on this boiler form the basis for the study.

The following are highlights of the study:

The boiler can deliver the same MCR capacity while co-firing petroleum coke at different blend ratios subject to equipment modifications / system improvements identified in this report. While co-firing petroleum coke all the emissions (SO_2, NOx, CO and particulate matter) can be maintained at the current levels. Due to the usually low concentrations of trace elements in the petroleum coke, the trace element emissions including mercury are also expected to be at the current level or lower.

The boiler as such can readily co-fire up to 20% petroleum coke by heat input. The equipment upgrades proposed for co-firing higher blend ratios are as explained below. For co-firing ratio in the range of 20% to 35% coke by heat input the changes are limited to limestone feed system. For blend ratio in the range of 35% to 65% modification to loopseal configuration and loopseal fluidizing nozzles would be necessary to increase the solids flow capacity. For blend ratios higher than 65% modification to boiler heating surfaces, upgrading of limestone preparation and transport system as well as bottom ash handling system would be required.

The conclusion of this study is co-firing petroleum coke up to 80% by heat input would be feasible by appropriate modifications to the present equipment. The boiler as such can co-fire petroleum coke up to 20% by heat input. All the emissions including trace elements could be maintained at the present level while firing coal only.

TABLE OF CONTENTS

CONTENTS **PAGE**

1.0 INTRODUCTION

Foster Wheeler Energy Services, Inc. (FWESI) was awarded a contract for engineering study by Cedar Bay Generating Company, L.P. (CBGC) to evaluate co-firing of petroleum coke and bituminous coal in the CFB boilers at the Cedar Generating Plant. CBGC provided the fuel analyses of four candidate petroleum cokes for this study. The main objective of the study is to evaluate the potential for co-firing petroleum coke at different proportions without impacting the present level of boiler emissions. The limitations if any on the boiler process as well as on the major auxiliary equipment were identified to facilitate co-firing petroleum coke at the maximum proportion.

The plant has three identical CFB boilers (A, B & C). Boiler "C" performance data from the last performance evaluation test was selected as the basis for this study.

2.0 BOILER DESCRIPTION

PG&E national energy group operates three 745,000 lb/hr, 1005 °F main steam, 1005 °F reheat steam and 1980 psig Foster Wheeler CFB boilers at the Cedar Bay Cogeneration Facility in Jacksonville, Florida. The steam is used to generate power for sale to Florida Power and Light Co. Process steam is also sold to an adjacent recycled-liner board mill owned by Seminole Kraft Corp. The power plant is operated in an automatic dispatch mode which requires the plant to cycle load on a daily basis.

Each boiler has two cyclones with fuel being fed to the furnace from four 50% capacity feed systems through six feed points. Four feed points are located in the loopseal return legs and two are on the front wall. Limestone is pneumatically fed to the furnace through eight (8) injection points to control the SO_2 emission (permit level: 0.3 lb/MMBtu 3-hour average and 0.2 lb/MMBtu 30 day average and 318.9 lb/hr 30 day average). Bottom ash removal from the furnace is through three water-cooled screw coolers. Fly ash collected by the baghouse is transported to the main flyash silo. The boiler is also equipped with a fly ash reinjection system to improve sorbent utilization. An aqueous ammonia injection system is used to control the NOx emissions (permit level 0.17 lb/MMBtu 30 day average and 180.7 lb/hr 30 day average).

3.0 BASIS FOR STUDY

The reference point for the study is the four-hour average data from the performance evaluation test on Boiler "C". The following are the main assumptions used for the study,

- Boiler load at 100% MCR corresponds to a main steam flow of 767,160 lb/hr;
- Coal and limestone analyses from the last test is used for this study;
- One coke (CBGC supplied analysis coke #4) is selected to be studied for 6 coke blend ratios (0%, 20%, 40%, 50%, 60%, 80% coke by heat input).
- Heat and mass balance data is provided for the case of 50% blend using coke #4 at the boiler

load of 745,000 klb/hr and 700,000 klb/hr .

- Heat and mass balance data is also provided for 50% coke/coal blend using Coke #1 and coke #3 at 767,160 lb/hr.

4.0 FEED STOCK EVALUATION

4.1 Petroleum Coke Analyses

The chemical analyses of four candidate coke samples are summarized in Table 1.

Table 1 Fuel Analysis Data (%as fired unless otherwise indicated)

FUEL TYPE	Coke #1	Coke #2	Coke #3	Coke #4	CB Bit Coal
Fixed C	84.83	80.57	85.89	82.34	49.98
Volatile	9.46	9.46	11.32	9.51	34.30
Ash	0.57	0.37	0.58	0.37	8.72
Moisture	5.14	9.6	2.21	7.78	7
Total.	100.00	100.00	100.00	100.00	100.00
S	4.09	5.84	5.17	5.45	1.52
H	3.53	3.52	3.76	3.37	4.94
C	84.58	80.57	85.88	81.23	72.79
N	1.59		1.61	1.66	1.35
O	0.50		0.78	0.14	3.68
Ash	0.60	0.37	0.58	0.37	8.72
H2O	5.14	9.60	2.21	7.78	7.00
Total	100.00	99.90	100.00	100.00	100.00
V, ppm	2410*	1815	808*	683*	
Ni, ppm	316*	340	217*	167*	
HHV, as fired, Btu/lb	14512.0	13712.0	14557.0	13923.0	12557.0
HHV, dry basis, Btu/lb	15298	15168	14886	15098	13502
VM, %daf	10.03	10.51	11.64	10.35	40.70
C/H Ratio, -	23.96	22.89	22.84	24.10	14.73
SO_2 input, lb/MMBtu	5.64	8.52	7.10	7.83	2.42

*Calculated based on fuel ash analyses; may be lower than actual content in fuel

The four petroleum cokes have fairly similar C/H ratios and volatile matter contents (% daf) that are typical of delayed coke. The heating values on a dry basis also fall into a very narrow range (less than 3.0 % difference).

The main difference lies in the sulfur content, which in terms of lb/MMBtu of SO_2 input for coke #2 is 15% higher than coke #1. High sulfur content in the coke will require a high percent sulfur capture and greater limestone usage than current level.

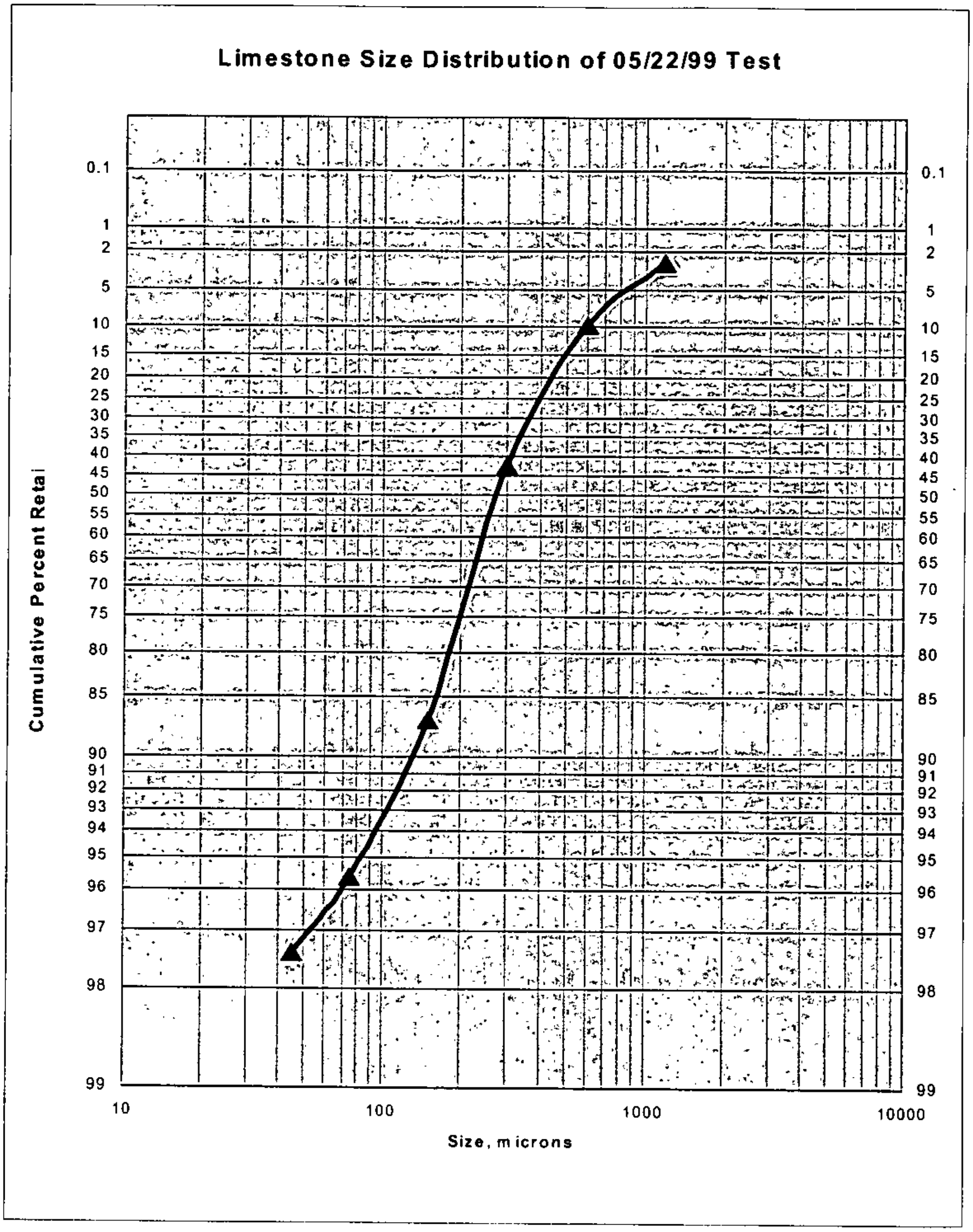
In this project, since petroleum coke is co-fired with coal, the risk of vanadium related problems is low. Since all four petroleum cokes are similar in terms of fuel analysis, coke #4 is selected for detailed study because it has a typical and more complete chemical analysis. Coke #1 and coke #3 are studied only for a blend ratio of 50% coke by heat input.

4.2 Coal and Limestone

The coal and limestone compositions as determined based on the May 22, 1999 performance evaluation test are used for this study. The coal analysis is shown in Table 1. Table 2 gives the limestone analysis. Figure 1 is the size distribution of the limestone.

Table 2 Limestone Analyses (wt% as received)

	Reference Limestone
CaCO3	95.84
MgCO3	0.52
Inert	3.28
Moisture	0.37
Total	100.00
RI, mol/mol	2.70



Limestone Size Distribution of 05/22/99 Test
Cumulative Percent Retai
0.1
1
2
5
10
15
20
25
30
35
40
45
50
55
60
65
70
75
80
85
90
91
92
93
94
95
96
97
98
99
10
100
1000
10000
Size, microns

Figure 1

5.0 IMPACT ON BOILER PROCESSES

5.1 Boiler Emissions Overview

The projected stack emission levels of SO_2, NOx, and CO are plotted in Figure 2. The SO2 emission is controlled by limestone addition and the current level can be maintained for the entire range of blend ratios. More discussion on sulfur capture and limestone consumption is given in the next section.

The current level of NOx can also be maintained with the existing ammonia injection system.

The predicted CO emission is lower while co-firing coke than the case of firing coal only. As shown in Figure 2, when firing 50% coke blend, about 40% reduction in CO can be expected, as compared to coal firing.

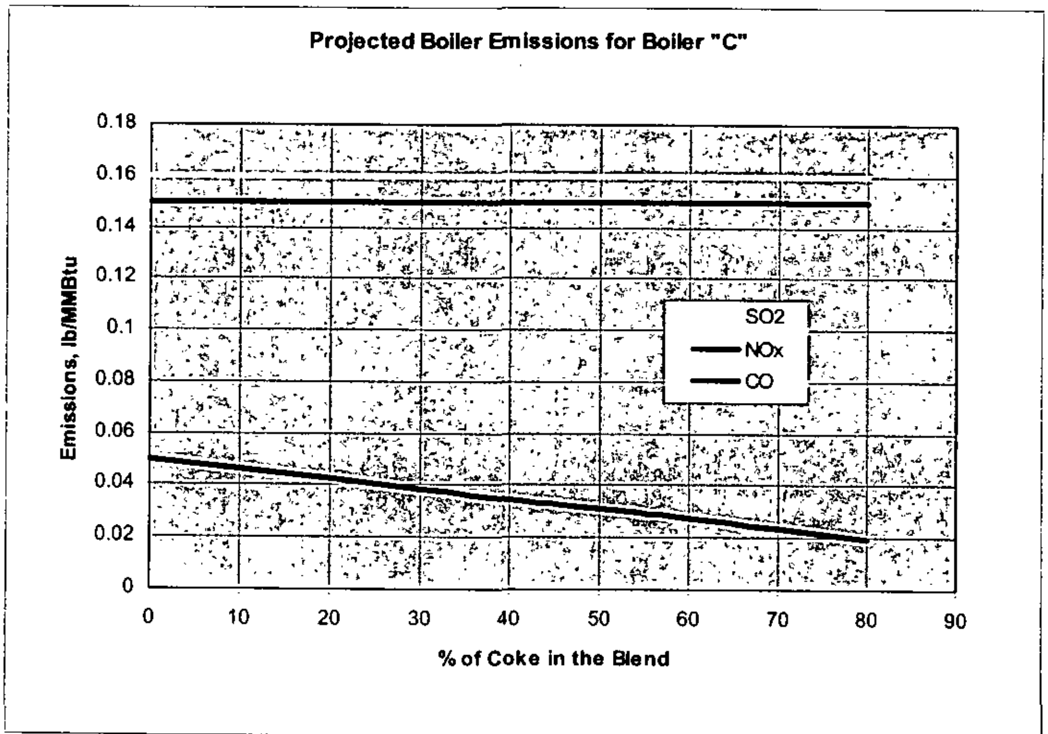


Figure 2

There should be no problem in maintaining the particulate matter emission rate when co-firing petcoke with coal. A detailed examination of the baghouse performance is given in section 6.5.

Currently, the plant is running with coal only and with very low levels of trace element emissions Due to the various thermal processes occurring in an oil refinery, the trace element concentrations, such as mercury, lead and fluoride in the heavy residue coke are extremely low (very significantly lower than that of typical coal). Considering the very low concentrations in petroleum coke, it is expected the trace elements emissions while co-firing petcoke will be lower than the present level.

5.2 Sulfur Capture and Limestone Requirement

Due to the high sulfur content in coke, the sulfur input increases rapidly while co-firing. Figure 3 shows the uncontrolled SO_2 levels and sulfur capture requirement for different blend ratios. For high blend ratios the percent sulfur capture in the high nineties are necessary in order to maintain the present level of emission.

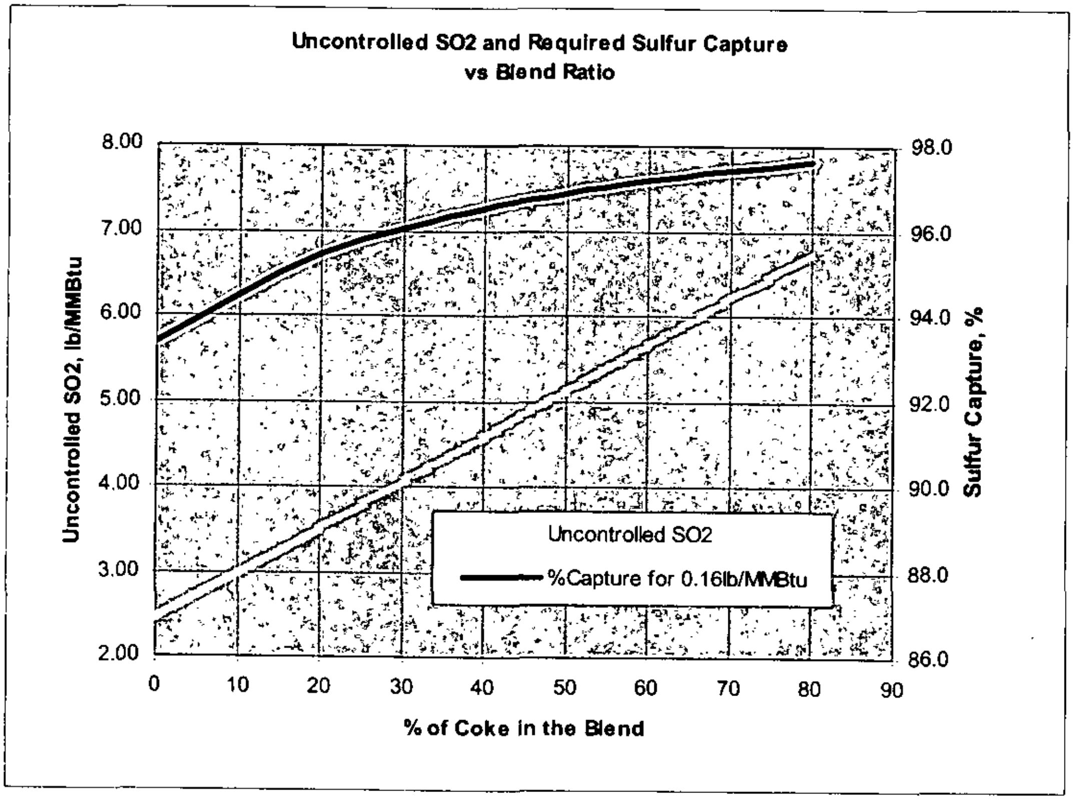


Figure 3

Figure 4 shows the projected limestone requirements at different blend ratios. When firing a 50% blend, the limestone flow rate is 25,600 lb/hr, or, 210% of the limestone flow when firing 100% coal.

Currently, the plant is controlling average SO_2 emissions at about 0.16 lb/MMBtu, or 80% of the permit level (0.20 lb/MMBtu). This control target is quite conservative. With a properly tuned SO_2 trim mechanism of the limestone feed rate control it is possible to smooth out the fluctuations in the feed rate. With these considerations, Foster Wheeler believes that the current level of SO_2 emission can be maintained.

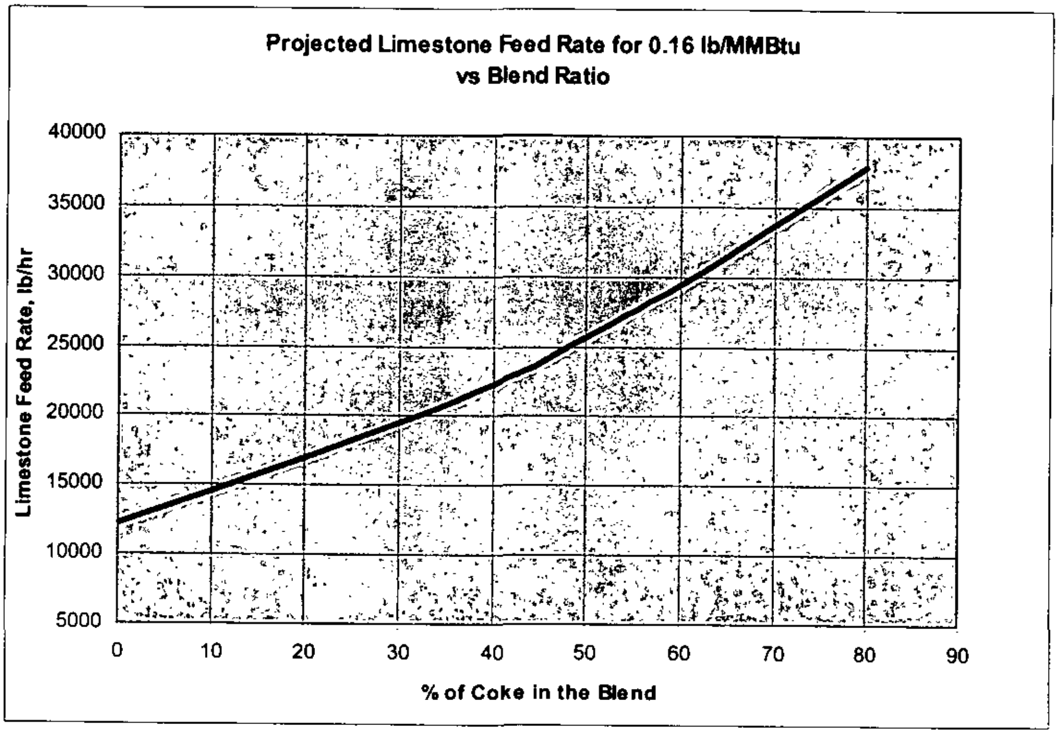


Figure 4

5.3 NOx Emissions and NH_3 Consumption

Due to its low volatile matter content, petroleum coke combustion in CFBs usually generates low NOx emissions. It is anticipated that NOx emissions while co-firing will be lower than firing 100% bituminous coal. Figure 5 presents the projected uncontrolled NOx emission levels developed based on commercial experience of CFB boilers firing petroleum coke. Also plotted in Figure 5 is the current control target of 0.15 lb/MMBtu of NOx (permit level: 0.17 lb/MMBtu).

Figure 5 indicates that at higher coke blending ratios, the NOx level before NH_3 injection and the required NOx reduction percentage is lower. Therefore less ammonia injection is needed when more coke is fired. Figure 6 depicts the projected aqueous ammonia (30.3% purity) flow at various blend ratios. A 35% reduction in ammonia consumption can be expected by firing a 50% coke, 50% coal blend.

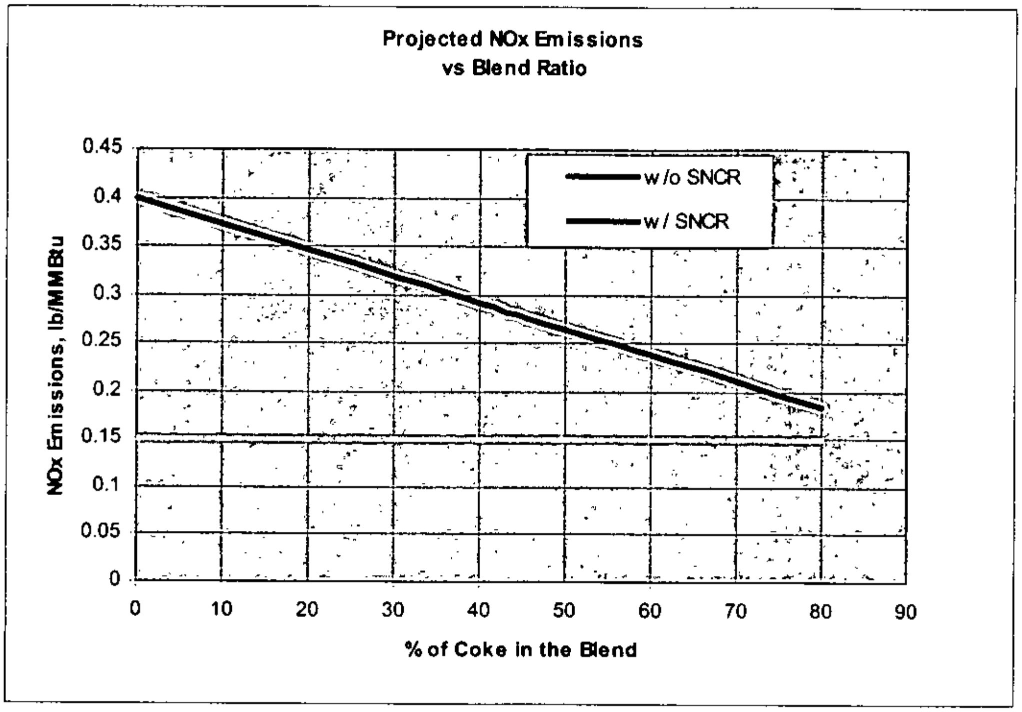


Figure 5

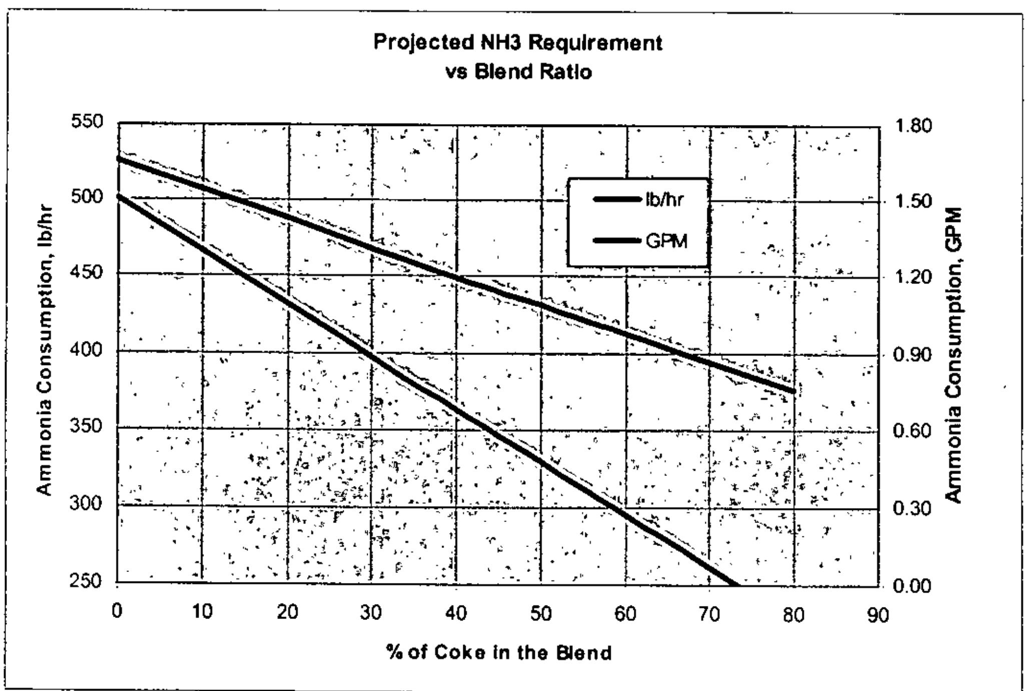


Figure 6

5.4 Other Process Impact

Solids Throughput and Ash Split: Due to the high sulfur content and large limestone requirement related to petroleum coke, the solids throughput of the CFB system will increase when co-firing coke (see Figure 7 for solids throughput). Therefore during co-firing, there is adequate amount of circulating material. However, because an increased portion of the circulating bed material will be limestone products, the limestone sizing becomes more critical. The limestone size distribution indicated in Figure 1 is suggested for the coke firing. The existing equipment should be capable of producing limestone of the appropriate size distribution.

The bottom ash fraction is also predicted and the results are shown in Figure 7.

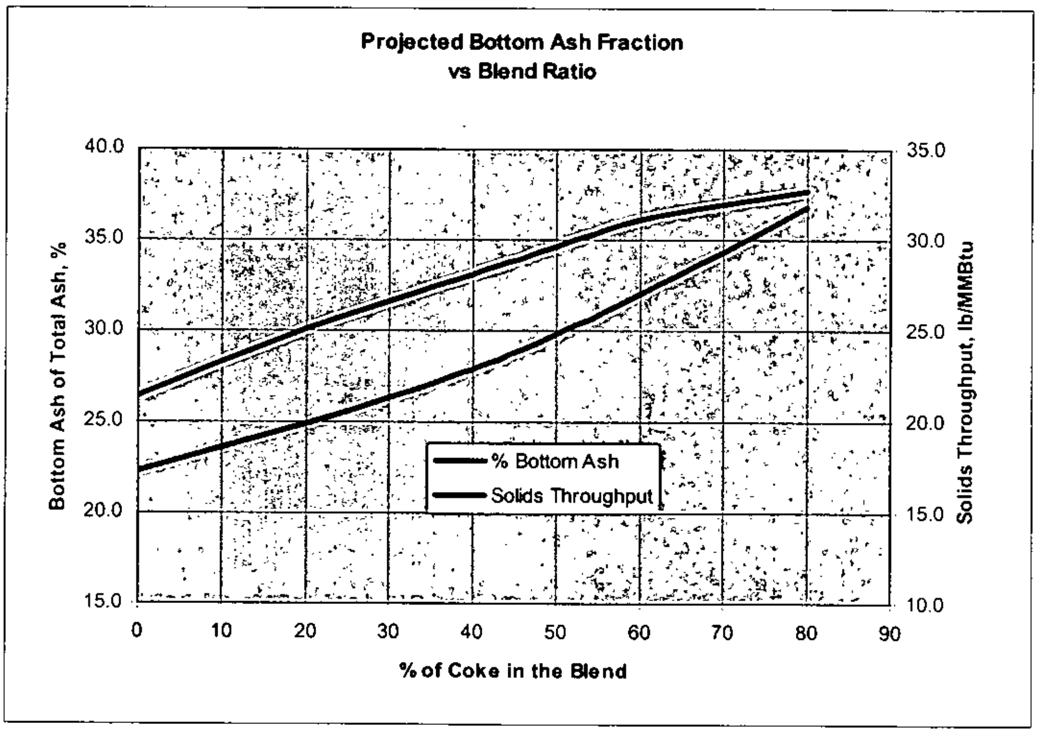


Figure 7

Furnace and Backend Heat Transfer, Temperatures and Fouling: On one hand, as discussed above, there will be an increased amount of solids throughput with coke co-firing, which should lead to higher solids circulating rate and better heat transfer, and thus lower furnace temperatures. On the other hand, coke-fired CFB boilers are known to have greater fouling tendency in the heat transfer surfaces than CFB boilers fired with only coal. Although in the furnace, the circulating material tends to scrub the tube surfaces to keep them clean, fouling could lead to reduced heat transfer and higher combustor temperature. Considering the above competing factors, it is expected that the combustor temperature will not be much different as compared to the 100% coal fired case. Other factors such as load, excess air and primary air to total air ratio will have more dominant impact on furnace temperature.

When co-firing coke, deposit formation on tubes in the back pass may increase, more frequent sootblowing may be necessary to maintain adequate heat transfer.

Erosion Tendency: The main factors determining surface erosion rates are particle velocity (which depends on gas velocity), particle abrasiveness and solids loading. There is a slight reduction in gas velocity due to co-firing. Although solids throughput is higher for co-firing cases, because of the low ash content of the coke, the additional solids products are mainly spent limestone particles that are relatively soft. Therefore, surface erosion is not expected to accelerate during coke co-firing.

6.0 IMPACT ON BOILER AUXILARY EQUIPMENT

6.1 Fuel Handling Equipment

The fuel feeding system consists of two fuel silos and four gravimetric belt feeders, of which two feed the two front wall feed points, the other two feed into chain conveyers (two for each side) which deliver fuel to the four feed chutes on the loopseal return legs. The maximum feeder capacity is 50,000 lb/hr per feeder. Each fuel silo feeds to one front wall and one rear wall feeder on the side of the boiler where the silo is located.

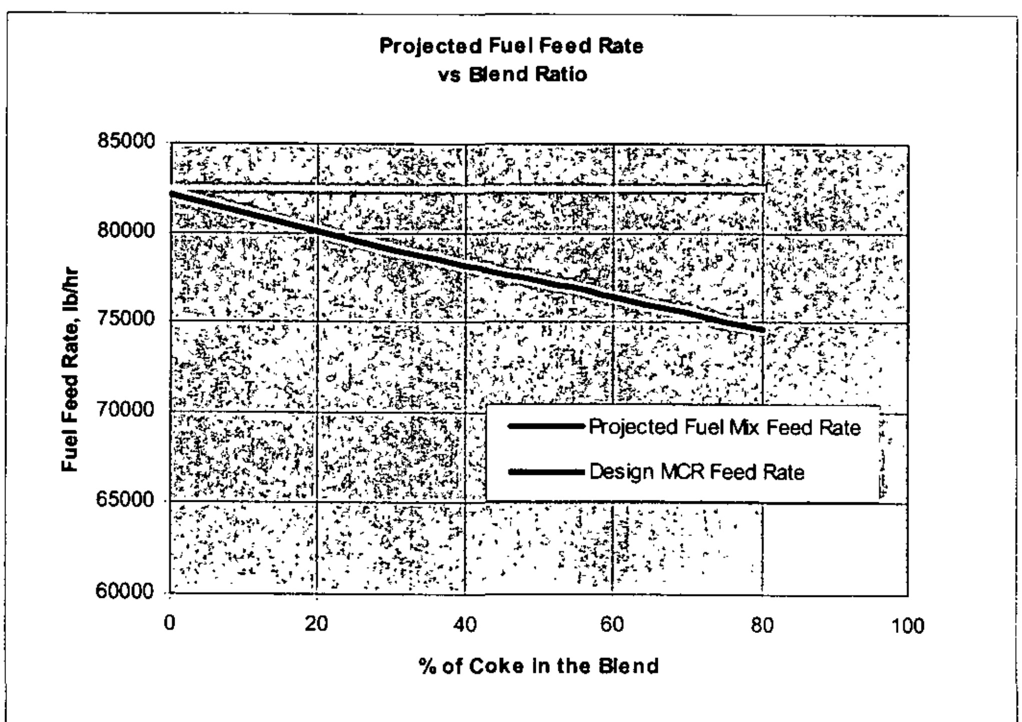


Figure 8

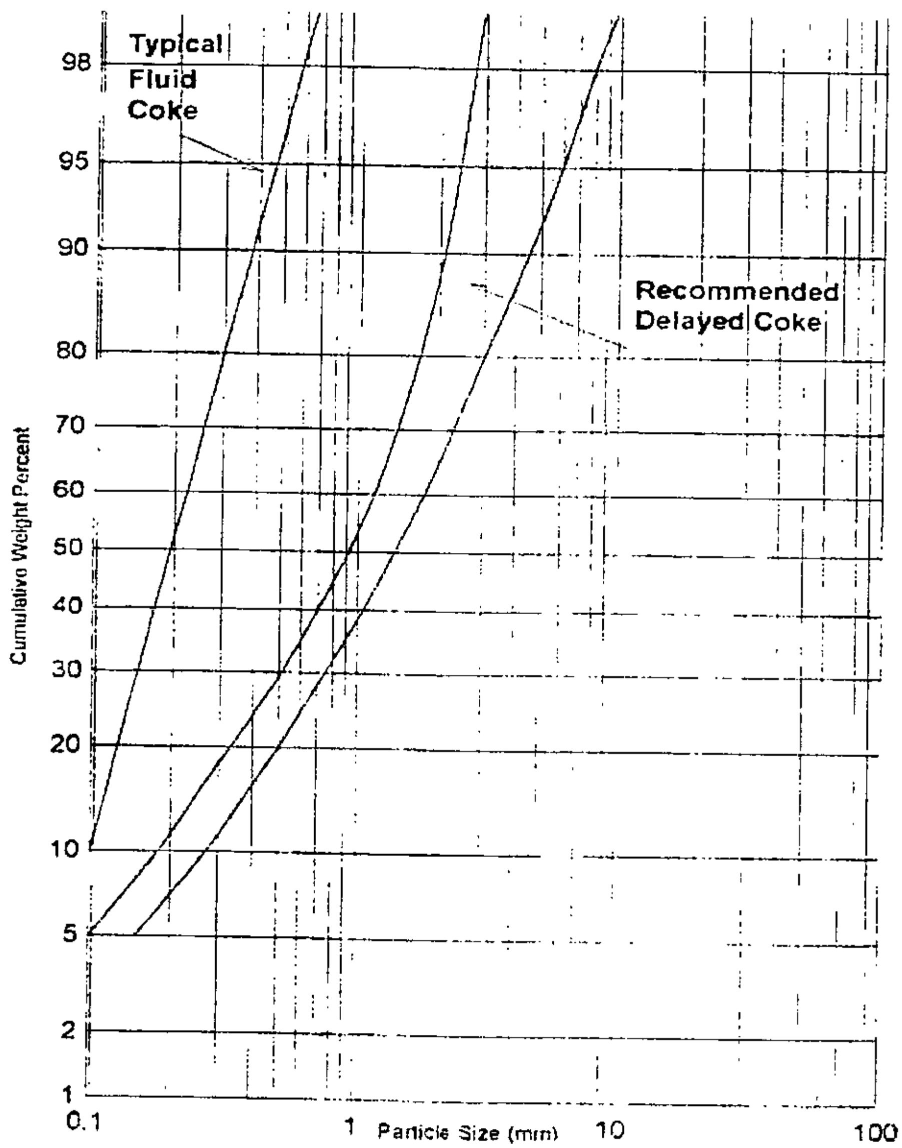


Figure 9 Typical Petcoke Size Distribution

Projected fuel feeding rates are plotted in Figure 8. Because coke has higher heating value, the feed rate reduces with increasing blending ratio and for all blend ratios the fuel feed rates are less than the design MCR coal feed rate. Therefore fuel feeding system capacity has plenty of redundancy for co-firing.

Handling of delayed coke is similar to that of coal. The main difference lies in the heating value, volatile matter and sulfur content. Ideally, in order to have good feed material consistency, the coal and coke should be premixed before loading to the fuel silo. This way all six feed points of the boiler will receive the same fuel blend to ensure uniform conditions in the furnace. Premixed fuel feeding is recommended for a co-firing test.

Figure 9 provides recommended size distribution range for delayed coke.

6.2 Limestone Handling System

The limestone system consists of limestone crushers, a limestone silo, two gravimetric belt feeders and two pneumatic transport trains that deliver limestone to eight feed points of the boiler (three front, three rear, one on each side). The design capacity of each feed chain is 16,000lb/hr (8 ton/hr). However, the plant has reported that the actual feed rate is limited at 4.2 ton/hr per feeder by the rotary valve capacity.

The limestone feed rates for different blend ratios are shown in Figure 4. The current set up can provide limestone for a co-firing blend ratio of about 20%. For higher blend ratios, the rotary valves downstream of the belt feeders have to be modified to match the design capacity of the rest of the feed system (16,000 lb/hr each chain). The maximum feed capacity can cover the projected limestone feed rates for up to 65% coke co-firing.

As an alternative, a base amount of limestone can be premixed with fuel and fed through the fuel feeders (which has plenty of capacity), the rest of the required limestone can be fed through the limestone system for SO_2 emissions control. For long-term co-firing, the rotary valves need to be upgraded in capacity. A third limestone feed train of same capacity may be installed to provide necessary redundancy.

6.3 PA, SA and ID Fans

Projected flow rate requirements for the three fans are plotted in Figure 10. Air and gas flow decrease slightly with the increasing blend ratio. Therefore at the max load (767,000lb/hr main steam flow), the fans are not expected to be a limiting factor.

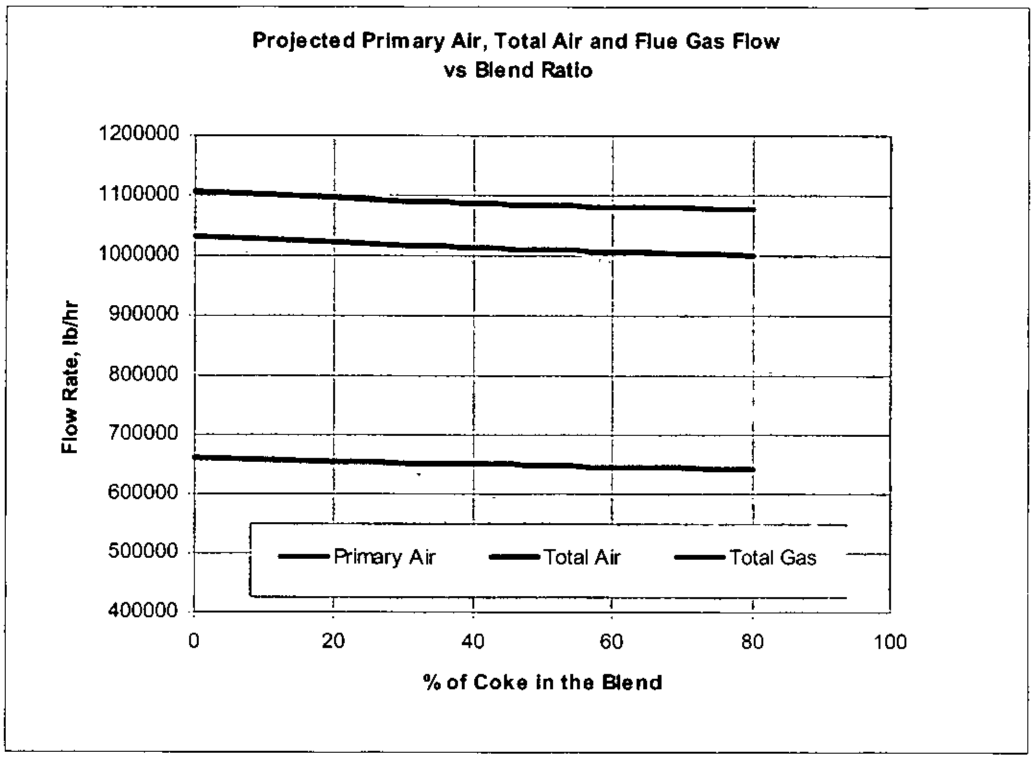


Figure 10

The flow requirement of high-pressure blowers for loopseals would be same as the current operation up to a coke blend of 35%.

6.4 Bottom Ash Handling

Bottom ash handling system consists of ash drains (3), ash cooling screws (3) and ash conveyers to transport ash to the ash silo. The ash drain/cooling screw design capacity is 2,950 lb/hr, and maximum capacity is 5,500 lb/hr.

The ash handling capacity of two cooling screws in service (with the third screw in standby) is used as reference in comparison with the projected bottom ash flow rates in Figure 11.

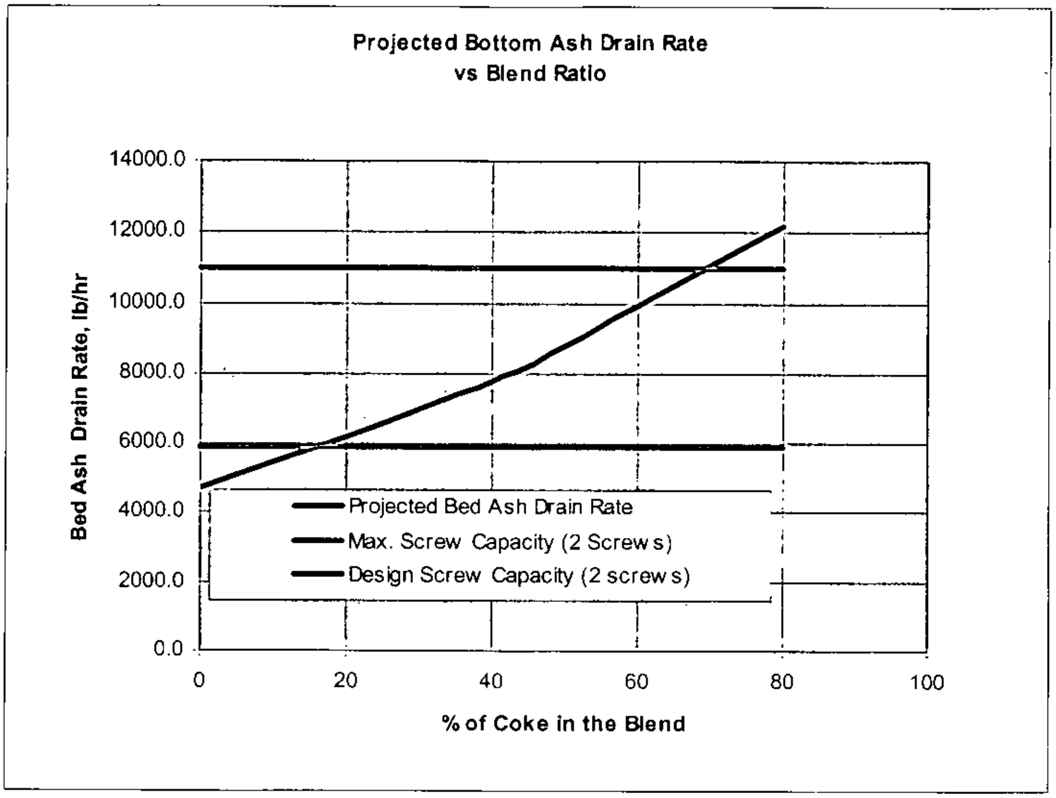


Figure 11

It appears that the maximum capacity of the two screws will allow up to 70% coke co-firing.

6.5 Flyash Handling Equipment

Fly ash system consists of the air heater hopper, baghouse, and pneumatic (vacuum) transport system that transport ash to the ash silo.

The impact on baghouse can be judged from the ash and gas flows. Figure 12 shows that the projected fly ash flow increases with increasing blend ratio, but the flue gas volume flow reduces slightly with co-firing. Although the flue gas volumes are higher than design flue gas volume (297,700 ACFM), the plant had often run with even higher volume flow without problems. The particulate loading for the 80% coke blend is 6.7 grains/ACF which is very low as compared to the design loading of 19.5 grains ACF specified by the baghouse vendor. The high design solids inlet loading of baghouse included the additional loading from fly ash re-injection (FAR) system. The FAR system is not being used at the plant. Based on the above, it is expected that the existing baghouse can maintain current emission levels, although more frequent back-purging/cleaning cycles may be necessary.

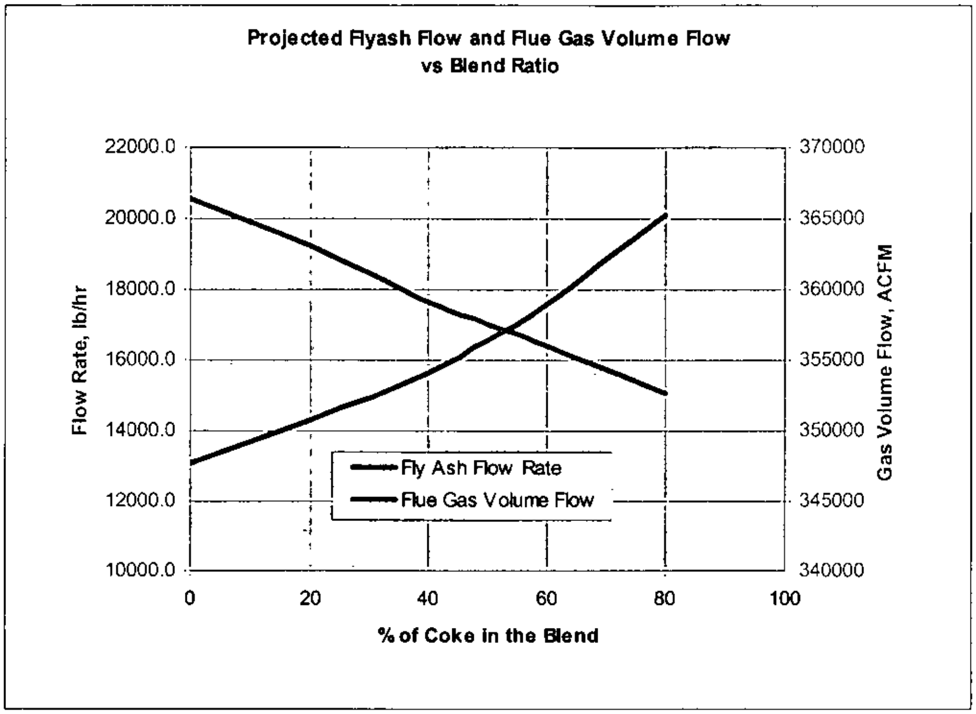


Figure 12

6.6 Start Up Burners

There are currently six #2 oil fired start up burners (1 on front wall, 3 on rear wall and 1 on each side wall). Each burner is 68 MMBtu/hr in capacity, making the total SUB capacity of 384 MMBtu/hr, or 37% of the heat input at the reference load. The burner capacity will be adequate for start-up.

7.0 CONCLUSIONS AND RECOMMENDATIONS

An engineering study has been completed for the co-firing of petroleum coke at PG&E National Energy Group's Cedar Bay Plant. Boiler "C" is designated for the study. The process and operating conditions of the May 22, 1999 performance evaluation test, including the test coal and limestone, form the basis for the study. Four candidates of petroleum coke were evaluated and one (coke #4) was selected for detailed engineering study. The following conclusions can be made,

1. On a dry basis, all four coke analyses have similar chemical compositions that are typical of delayed coke, except sulfur content, which has significant variation. Lower sulfur content is desirable due to associated limestone cost. On a normalized lb/MMBtu basis, coke #1 has the lowest sulfur content; #3 and #4 are higher; and #2 has the highest sulfur content.

2. When co-firing petroleum coke, SO_2, NOx and particulate matter emissions can be maintained at the current levels with existing equipment. Reductions in CO emissions are expected for coke

co-firing. Due to the usually very low concentrations of trace elements in the petroleum coke, the trace element emissions, including mercury, are also expected to be similar to or less than the current levels.

3. Due to high sulfur content in coke, percent sulfur capture in the mid to high nineties will be required to meet SO_2 compliance for co-firing, which should not be a problem. Limestone feed rates will be much higher than the current level. For 50% coke by heat input case, the projected limestone flow is 210% of the current consumption rate.

4. The uncontrolled NOx concentration before the DeNOx system will be lower when co-firing coke. Thus a smaller percentage reduction is required for the DeNOx system, resulting in a smaller ammonia consumption rate. A 35% reduction in ammonia consumption can be expected when firing a 50% coke blend.

5. The solids throughput and bottom ash fraction are expected to increase with higher coke blend ratios.

6. Furnace temperatures are expected to be close to the current levels. High levels of coke co-firing are known to have increased fouling tendency. The surfaces in the backpass are likely to have more ash deposit and more vigorous sootblowing may be needed.

7. Erosion rate of heat transfer surfaces when co-firing coke is not expected to exceed the current level at comparable boiler load.

8. Coke co-firing will require a lower fuel feed rate and slightly less combustion air and generates less flue gas. Therefore, fuel feeding system, PA, SA and ID fans are not expected to be limiting factors for co-firing at the reference load.

9. Startup burner capacity is adequate for start with coke blend.

10. Rotary valves downstream of the limestone feeders is a limiting factor in the limestone handling system which limit feeder capacity to 4.3 ton/hr, as compared to feeder design capacity of 8 ton/hr. The current limestone feeding system can support up to about 20% coke-co-firing. If the rotary valves are upgraded, the system maximum capacity could cover up to 65% coke co-firing. If all three boilers are co-firing coke in the future, capacity of limestone crushing and transport to the boiler house would also need to be upgraded.

11. Baghouse is expected to maintain the particulate emissions at current emission levels even though the solid loading at the baghouse inlet will be much higher than the current levels. More frequent back purging/cleaning is expected but is within the design capacity.

12. Bottom ash drain and cooling screw capacities are expected to be adequate for co-firing up to 70% coke by heat input.

APPENDIX B

CALCULATIONS:

FUGITIVE DUST COAL PETROLEUM COKE USAGE

Calculations of Petroleum Coke and Limestone Unloading

Petroleum Coke Fugitive Emissions:
The same equations as the PSD Approval and Title V Permit Application are used to determine fugitive emissions. AP-42, 4th Edition 11.2.3:

$EF = k \times (0.0032) \times (U/5)^{1.3}/(M/2)^{1.4}$

where: EF is the emission factor in lb/ton
k is particle size factor; 0.74 for PM and 0.35 for PM_{10}
U is wind speed; 7.8 miles/hour previously used
M is percent moisture; 6 percent previously used

$EF_{PM} = 0.74 \times (0.0032) \times (7.8/5)^{1.3}/(6/2)^{1.4}$

$EF_{PM} =$ 0.0009067 lb/ton

$EF_{PM10} = 0.35 \times (0.0032) \times (7.8/5)^{1.3}/(6/2)^{1.4}$

$EF_{PM10} =$ 0.0004289 lb/ton

Control efficiency = 70% based on water spraying.

Specific Condition Section III. A3. limit fuel use to:

	Pet Coke:	Coal Limits:
Annual	390,950 tons/year	1,117,000 tons/year
Monthly	40,950 tons/month	117,000 tons/month
Hourly	109,200 lb/hr	312,000 lb/hr

Petroleum Coke based on 35 percent by weight of permit limits. This is conservative since petroleum coke has higher heating content and less weight would be needed to reach load than coal. (See calculations of petroleum coke usage based on maximum heat input for each unit.)

PM Emisions from Truck Dump:

	Uncontrolled	Controlled
Annual	0.177 tons/year	0.053 tons/year
Monthly	0.019 tons/month	0.006 tons/month
Hourly	0.050 lb/hr	0.015 lb/hr

PM_{10} Emissions from Truck Dump:

	Uncontrolled	Controlled
Annual	0.084 tons/year	0.025 tons/year
Monthly	0.009 tons/month	0.003 tons/month
Hourly	0.023 lb/hr	0.007 lb/hr

PM Emisions from Conveyor to Pile:

	Uncontrolled	Controlled
Annual	0.177 tons/year	0.053 tons/year
Monthly	0.019 tons/month	0.006 tons/month
Hourly	0.050 lb/hr	0.015 lb/hr

PM_{10} Emissions from Conveyor to Pile:

	Uncontrolled	Controlled
Annual	0.084 tons/year	0.025 tons/year
Monthly	0.009 tons/month	0.003 tons/month
Hourly	0.023 lb/hr	0.007 lb/hr

Limestone Fugitive Emissions:

Annual	129,600 tons/year
Monthly	10,800 tons/month
Hourly	30,000 lb/hr

Based on increase in limestone usage from Foster Wheeler Report. Coal only estimated at 12,500 lb/hr/unit and co-firing at 35% petroleum coke is 22,500 lb/hr/unit. Same emission factor used as coal.

PM Emisions from Additional Limestone

	Uncontrolled	Controlled
Annual	0.059 tons/year	0.018 tons/year
Monthly	0.005 tons/month	0.001 tons/month
Hourly	0.014 lb/hr	0.004 lb/hr

PM_{10} Emissions from Additional Limestone

	Uncontrolled	Controlled
Annual	0.028 tons/year	0.008 tons/year
Monthly	0.002 tons/month	0.001 tons/month
Hourly	0.006 lb/hr	0.002 lb/hr

Total PM Emisions from Co-firing

	Uncontrolled	Controlled
Annual	0.413 tons/year	0.124 tons/year
Monthly	0.042 tons/month	0.013 tons/month
Hourly	0.113 lb/hr	0.034 lb/hr

Total PM_{10} Emissions from Co-firing

	Uncontrolled	Controlled
Annual	0.195 tons/year	0.059 tons/year
Monthly	0.020 tons/month	0.006 tons/month
Hourly	0.053 lb/hr	0.016 lb/hr

Calculations of Maximum Coal and Petroleum Coke when Co-firing at 35% Petroleum Coke by Weight

Total Heat Input (MMBtu/hr) = [0.65 total lb/hr (coal) x heat content(coal) + 0.35 total lb/hr (pet coke) x heat content (pet coke)]/10^6
Coal = 0.65 total; Pet coke = 0.35 total; Coal = 0.65 x pet coke/0.35; therefore Coal = 0.65/0.35 Pet coke or 1.857 pet coke

Heat Input	1,063 MMBtu/hr/unit			
lb/hr pet coke =	35.00% lb/hr (coal)			

Calculation using Current Coal and Average Pet Coke Heat Contents:

Heat content Coal = 12,557 Btu/lb Pet Coke = 14,176 Btu/lb

1,063MMBtu/hr = total [0.65 lb/hr coal x 12,557 Btu/lb + 0.35 x 14,176Btu/lb)]/10^6
1,063MMBtu/hr * 10^6 = [1.857 lb/hr x 12,557 Btu/lb + lb/hr x 14,176 Btu/lb)]
1,063MMBtu/hr * 10^6 = 2.857 lb/hr pet coke x (12,557 Btu/lb + 14,176Btu/lb)
1,063MMBtu/hr * 10^6 /(12,557 Btu/lb + 14,176Btu/lb)= 2.857 lb/hr
2.857 lb/hr = 1,063MMBtu/hr * 10^6 /(12,557 Btu/lb + 14,176Btu/lb)

lb/hr total =	80,999			
lb/hr coal =	52,649 &	heat input (MMBtu/hr) =	661	62%
lb/hr pet coke =	28,350 &	heat input (MMBtu/hr) =	402	38%
Total lb/hr =	80,999 &	heat input (MMBtu/hr) =	1,063	100%

	Total	Coal	Pet Coke
Maximum 1 Unit	80,999 lb/hr	52,649 lb/hr	28,350 lb/hr
	29,160 tons/month	18,954 tons/month	10,206 tons/month
	349,915 tons/year	227,445 tons/year	122,470 tons/year
Maximum 3 Units	242,996 lb/hr	157,948 lb/hr	85,049 lb/hr
	87,479 tons/month	56,861 tons/month	30,618 tons/month
	976,262 tons/year	634,571 tons/year	341,692 tons/year

Calculation using Low Coal and Typical Pet Coke Heat Contents:

Max Heat Input = 1,063 MMBtu/hr/unit
Heat content Coal = 10,221 Btu/lb Pet Coke = 14,000 Btu/lb

1,063MMBtu/hr = total [0.65 lb/hr coal x 10,221 Btu/lb + 0.35 x 14,000Btu/lb)]/10^6
1,063MMBtu/hr * 10^6 = [1.857 lb/hr x 10,221 Btu/lb + lb/hr x 14,000Btu/lb)]
1,063MMBtu/hr * 10^6 = 2.857 lb/hr pet coke x (10,221 Btu/lb + 14,000Btu/lb)
1,063MMBtu/hr * 10^6 /(10,221 Btu/lb + 14,000Btu/lb)= 2.857 lb/hr
2.857 lb/hr = 1,063MMBtu/hr * 10^6 /(10,221 Btu/lb + 14,000Btu/lb)

lb/hr total =	92,085			
lb/hr coal =	59,855 &	heat input (MMBtu/hr) =	612	57.55%
lb/hr pet coke =	32,230 &	heat input (MMBtu/hr) =	451	42.45%
Total =	92,085 &	heat input (MMBtu/hr) =	1,063	

	Total:	Coal	Pet Coke
Maximum 1 units:	92,085 lb/hr	59,855 lb/hr	32,230 lb/hr
	33,151 tons/month	21,548 tons/month	11,603 tons/month
	397,808 tons/year	258,575 tons/year	139,233 tons/year
Maximum 3 Units	276,256 lb/hr	179,566 lb/hr	96,690 lb/hr
	99,452 tons/month	64,644 tons/month	34,808 tons/month
	1,109,885 tons/year	721,425 tons/year	388,460 tons/year