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BUREAU OF AIR REGULATION

APPLICATION TO MODIFY CO/SO_2 EMISSION LIMITS

OKEELANTA POWER L.P.
SOUTH BAY, FLORIDA

Prepared by:

Golder Associates
6241 NW 23rd Street
Gainesville, Florida
32653-1500

Prepared for:

Okeelanta Power L.P.
21250 U.S. Highway 27
South Bay, Florida
33493

December 2000
0037584Y/F1

DISTRIBUTION:
6 Copies - FDEP
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1 Copy - Golder Associates Inc.

PERMIT APPLICATION FORM

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: **Okeelanta Power L.P.**	
2. Site Name: **Okeelanta Power L.P.**	
3. Facility Identification Number: **0990332**	[ ] Unknown
4. Facility Location: **6 miles south of South Bay on US 27** Street Address or Other Locator: **8001 U.S. Highway 27 South** City: **South Bay** County: **Palm Beach** Zip Code: **33493**	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **James Meriwether, Environmental and Safety Manager**
2. Application Contact Mailing Address: Organization/Firm: **Okeelanta Power L.P.** Street Address: **8001 U.S. Highway 27 South** City: **South Bay** State: **FL** Zip Code: **33493**
3. Application Contact Telephone Numbers: Telephone: (**561**) **993 - 1003** Fax: (**561**) **996 - 6596**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	1-2-01
2. Permit Number:	0990332-014-AC
3. PSD Number (if applicable):	PSD-FL-196M
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: **Ricardo Lima, Vice President - General Manager**
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: **Okeelanta Power L.P.** Street Address: **8001 U.S. Highway 27 South** City: **South Bay** State: **FL** Zip Code: **33493**
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: **(561) 996 - 9072** Fax: **(561) 992 - 7326**
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [✓], 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 R A Lima Date 12/27/00

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: **David Buff** Registration Number: **19011**
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 [X], if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

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

David A. Buff — 12/21/00

Signature — Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
030	Cogen Boiler A	AC1A	
031	Cogen Boiler B	AC1A	
032	Cogen Boiler C	AC1A	

Application Processing Fee

Check one: [X] Attached - Amount: $: 7,500 [ ] Not Applicable

Title V Core List

Effective:03/25/97

CHAPTER 62-256, F.A.C.: OPEN BURNING AND FROST PROTECTION FIRES, effective 11-30-94

CHAPTER 62-257, F.A.C: ASBESTOS NOTIFICATION AND FEE, effective 03/24/96

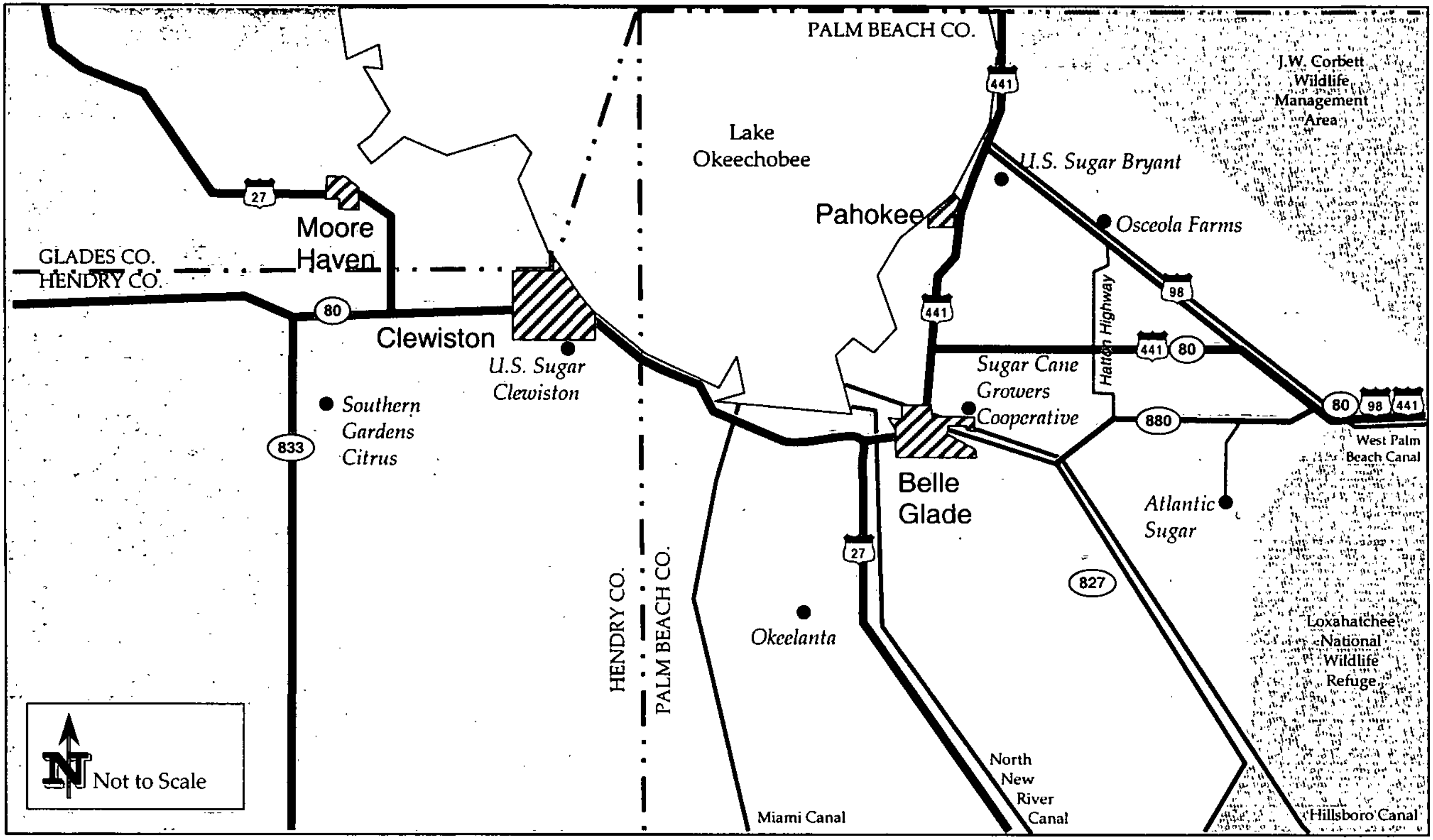
CHAPTER 62-281, F.A.C: MOTOR VEHICLE AIR CONDITIONING REFRIGERANT RECOVERY AND RECYCLING, effective 03-07-96

CHAPTER 62-296, F.A.C.: STATIONARY SOURCES - EMISSION STANDARDS, effective 03-13-96

62-296.320(2), F.A.C.: Objectionable Odor Prohibited.
62-296.320(3), F.A.C.: Industrial, Commercial, and Municipal Open Burning Prohibited
62-296.320(4)(c), F.A.C.: Unconfined Emissions of Particulate Matter

ATTACHMENT OC-FI-C1

AREA MAP SHOWING FACILITY LOCATION



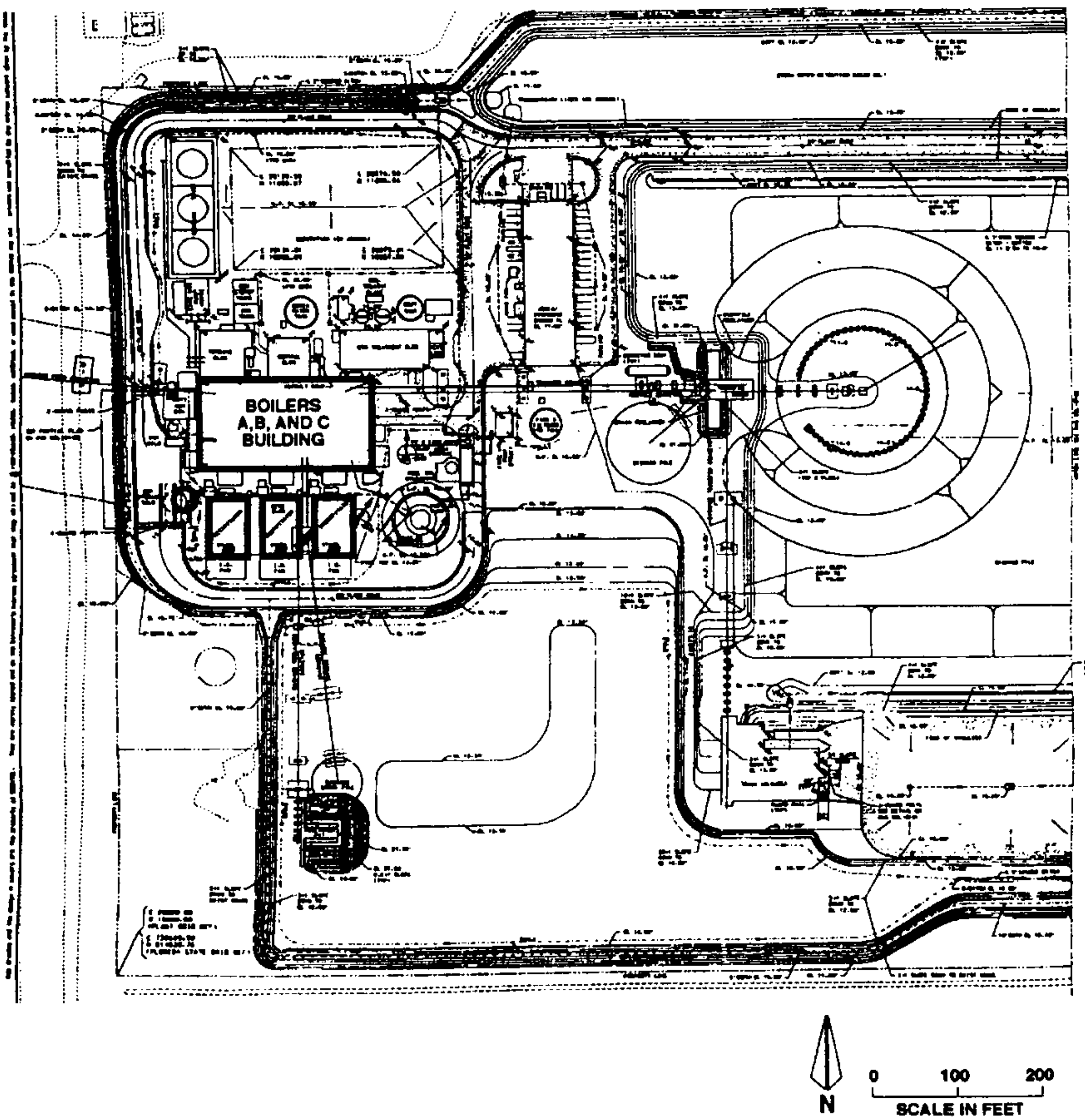
Attachment OC-FI-C1
Location of Okeelanta Power L.P.

Source: Golder Associates Inc., 2000

Golder Associates

ATTACHMENT OC-FI-C2

FACILITY PLOT PLAN



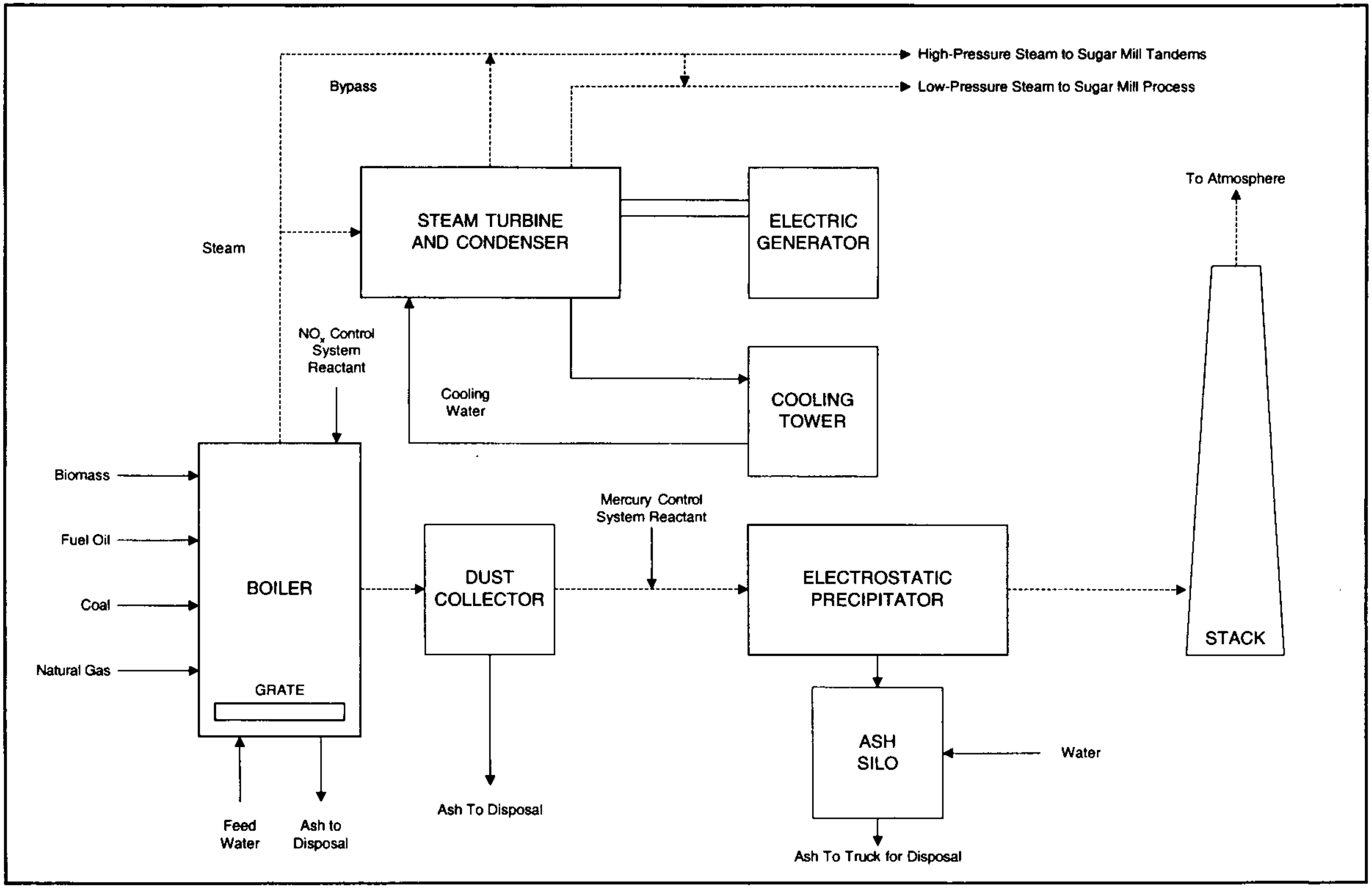
Attachment OC-FI-C2
Plot Plan of Okeelanta L.P. Facility

Golder Associates

Source: Bechtel, 1996; Golder, 2000.

ATTACHMENT OC-FI-C3

PROCESS FLOW DIAGRAM



Attachment OC-FI-C3
Simplified Flow Diagram
Okeelanta Power Cogeneration Facility
South Bay, FL

Process Flow Legend
Solid/Liquid ⟶
Steam - - - ->

Filename: 0037584Y/F1/WP/OC-FI-C3.VSD (Page 2)
Date: 12/08/00

Golder Associates

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):

Cogen Boiler A fired by Biomass/No. 2 oil/coal/natural gas

4. Emissions Unit Identification Number: [ ] No ID
ID: **030** [ ] ID Unknown

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

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

74.9 MW gross generating capacity for entire facility.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **ESP - Electrostatic Precipitator – High Efficiency** **Selective Non-catalytic Reduction for NO_X** **Activated Carbon Adsorption** **Multiple Cyclone w/o Fly Ash Reinjection**
2. Control Device or Method Code(s): **10, 107, 48, 76**

Emissions Unit Details

1. Package Unit: Manufacturer:	Model Number:	
2. Generator Nameplate Rating:	**75** 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:		715 mmBtu/hr	
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
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 heat input rates: Biomass - 715 MMBtu/hr; No. 2 Fuel Oil - 490 MMBtu/hr; Coal - 490 MMBtu/hr; Natural Gas – 605 MMBtu/hr			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attached Document	

EU ID 030 : Cogen Boiler No. 1 Rule Applicability for Okeelanta Power L.P.

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart A	40CFR60.1	Subpart A – General Provisions	
APPLICABLE	60 Subpart A	40CFR60.7	Notification and Record Keeping	
APPLICABLE	60Subpart A	40CFR60.8	Performance Testing	
APPLICABLE	60 Subpart A	40CFR60.11	Compliance with standards and maintenance requirements.	
APPLICABLE	60 Subpart A	40CFR60.12	Circumvention.	
APPLICABLE	60 Subpart A	40CFR60.13	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.19	General notification and reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.40a	Subpart Da - NSPS for Electric Utility Units for which construction commenced after Sept. 18, 1978.	
APPLICABLE	60 Subpart Da	40CFR60.42a	Standard for particulate matter	
APPLICABLE	60 Subpart Da	40CFR60.43a	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(a)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(b)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(d)(2)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(g)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(h)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.44a	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.44a(a)	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.44a(c)	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.46a	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(a)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(b)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(c)	Compliance provisions.	
NON-APPLICABLE	60 Subpart Da	40CFR60.46a(d)	Compliance provisions.	Cogen Boiler No. 1 does not have a flue gas desulfurization system.
APPLICABLE	60 Subpart Da	40CFR60.46a(e)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(f)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(g)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(h)	Compliance provisions.	
NON-APPLICABLE	60 Subpart Da	40CFR60.46a(i)	Compliance provisions.	Cogen Boiler No. 1 has not been modified after July 7, 1997.
APPLICABLE	60 Subpart Da	40CFR60.47a	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(a)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(b)(2)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(b)(3)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(c)(1)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(d)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(e)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(f)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(g)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(h)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(i)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(j)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.48a	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(a)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(b)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(c)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(d)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(e)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.49a	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(a)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(b)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(c)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(d)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(f)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(g)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(h)	Reporting requirements	

EU ID 030 : Cogen Boiler No. 1 Rule Applicability for Okeelanta Power L.P.

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart Da	40CFR60.49a(i)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(j)	Reporting requirements	
APPLICABLE	60 Subpart Ea	40CFR60.50a(d)	Standards of performance for municipal waste combustors	
APPLICABLE	60 Subpart Ea	40CFR60.50b(j)	Standards of performance for municipal waste combustors	
APPLICABLE	62-204	62-204.800(7)2.	NSPS Subpart Da adopted by reference.	
APPLICABLE	62-296 <	62-296	STATIONARY SOURCES - EMISSION STANDARDS	
APPLICABLE	62-296 <	62-296.405(2)	Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input.	
NON-APPLICABLE	62-296 <	62-296.406	Fossil Fuel Steam Generators with less than 250 Million Btu per Hour Heat Input, New and Existing Em	Cogen Boiler No. 1 has a heat input of >250 MMBtu/hr.
NON-APPLICABLE	62-296 <	62-296.410	Carbonaceous Fuel Burning Equipment.	Not more stringent or different than NSPS.
APPLICABLE	62-296 >	62-296.500	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.500(2)(a)	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.500(2)(c)	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.570	Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NOx-Emitting Facili	
APPLICABLE	62-296 >	62-296.570(1)	Applicability.	
APPLICABLE	62-296 >	62-296.570(1)(a)	Applicability.	
APPLICABLE	62-296 >	62-296.570(2)	Compliance Requirements.	
APPLICABLE	62-296 >	62-296.570(3)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(b)6.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(c)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.620		
NON-APPLICABLE	62-296 >	62-296.700	Reasonably Available Control Technology (RACT) Particulate Matter.	Okeelanta Power is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.702	Fossil Fuel Steam Generators.	Okeelanta Power is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.703	Carbonaceous Fuel Burners.	Okeelanta Power is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
APPLICABLE	62-297	62-297	STATIONARY SOURCES - EMISSIONS MONITORING	
APPLICABLE	62-297	62-297.310	General Compliance Test Requirements.	
APPLICABLE	62-297	62-297.401	Compliance Test Methods.	
APPLICABLE	62-297	62-297.401(1)(a)	EPA Method 1 - Sample and Velocity Traverses for Stationary sources - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(10)	EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources - 40 CFR 60 Appen	
APPLICABLE	62-297	62-297.401(12)	EPA Method 12 - Determination of Inorganic Lead Emissions from Stationary Sources - 40 CFR 60 Append	
APPLICABLE	62-297	62-297.401(13)	EPA Methods 13A and 13B.	
APPLICABLE	62-297	62-297.401(18)	EPA Method 18 - Measurement of Gaseous Organic Compound Emissions by Gas Chromatography - 40 CFR 60	
APPLICABLE	62-297	62-297.401(19)	EPA Method 19 - Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide a	
APPLICABLE	62-297	62-297.401(2)	EPA Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate - 40 CFR 60 Appendix A.	

EU ID 030 : Cogen Boiler No. 1 Rule Applicability for Okeelanta Power L.P.

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	62-297	62-297.401(25)	EPA Method 25 - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Ap	
APPLICABLE	62-297	62-297.401(3)	EPA Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight - 40 CF	
APPLICABLE	62-297	62-297.401(32)	EPA Method 101 - Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants	
APPLICABLE	62-297	62-297.401(35)	EPA Method 104 - Determination of Beryllium Emissions from Stationary Sources - 40 CFR 61 Appendix B	
APPLICABLE	62-297	62-297.401(39)	EPA Method 108 - Determination of Particulate and Gaseous Arsenic Emissions - 40 CFR 61 Appendix B.	
APPLICABLE	62-297	62-297.401(4)	EPA Method 4 - Determination of Moisture Content in Stack Gases - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(41)	EPA Method 201 - Determination of PM10 Emissions (Exhaust Gas Recycle Procedure) - 40 CFR 51 Appendi	
APPLICABLE	62-297	62-297.401(5)	EPA Method 5 - Determination of Particulate Emissions from Stationary Sources - 40 CFR 60 Appendix A	
APPLICABLE	62-297	62-297.401(6)	EPA Method 6 - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(6)(c)	EPA Method 6C - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(7)	EPA Method 7 - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(7)(e)	EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(8)	EPA Method 8 - Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sour	
APPLICABLE	62-297	62-297.401(9)	EPA Test Method 9	

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? **BLR A**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **199** feet	7. Exit Diameter: **10.0** feet
8. Exit Temperature: **295** °F	9. Actual Volumetric Flow Rate: **246,000** 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): **Stack parameters based on biomass firing.**		

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

Segment Description and Rate: Segment 1 of 5

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Bagasse**		
2. Source Classification Code (SCC): **10101101**	3. SCC Units: **Tons Burned (all solid fuels)**	
4. Maximum Hourly Rate: **97.865**	5. Maximum Annual Rate: **857,295**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash: **1.0**	9. Million Btu per SCC Unit: **7.306**
10. Segment Comment (limit to 200 characters): **Total biomass all three boilers = 1,436,945 TPY based on 46.1% heat input from wood and 53.9% from bagasse.**		

Segment Description and Rate: Segment 2 of 5

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Wood Fired Boiler**		
2. Source Classification Code (SCC): **10100903**	3. SCC Units: **Tons Burned (all solid fuels)**	
4. Maximum Hourly Rate: **79.374**	5. Maximum Annual Rate: **695,271**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.3**	8. Maximum % Ash: **9.0**	9. Million Btu per SCC Unit: **9.008**
10. Segment Comment (limit to 200 characters): **Total biomass all three boilers = 1,436,945 TPY based on 46.1% heat input from wood and 53.9% from bagasse.**		

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

Segment Description and Rate: Segment 3 of 5

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Distillate Oil - Grades 1 and 2 Oil**		
2. Source Classification Code (SCC): **10100501**	3. SCC Units: **Thousand Gallons Burned (all liquid fuels)**	
4. Maximum Hourly Rate: **3.551**	5. Maximum Annual Rate: **10,639**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **138**
10. Segment Comment (limit to 200 characters): **Maximum annual rate represents 24.9% oil firing on a heat input basis. Total No. 2 fuel all three boilers = 19,533,086 gal/yr.**		

Segment Description and Rate: Segment 4 of 5

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Bituminous Coal - Spreader Stoker**		
2. Source Classification Code (SCC): **10100204**	3. SCC Units: **Tons Burned (all solid fuels)**	
4. Maximum Hourly Rate: **20.417**	5. Maximum Annual Rate: **44,920**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.70**	8. Maximum % Ash: **3.70**	9. Million Btu per SCC Unit: **24**
10. Segment Comment (limit to 200 characters): **Maximum annual rate = 18.0% coal-firing on a heat input basis. Total coal all three boilers = 44,920 TPY (9.6% coal burning on a heat input basis).**		

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

Segment Description and Rate: Segment 5 of 5

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler -- Natural Gas**		
2. Source Classification Code (SCC): **10100601**	3. SCC Units: **MMscf Burned**	
4. Maximum Hourly Rate: **0.605**	5. Maximum Annual Rate: **1,468**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,000**
10. Segment Comment (limit to 200 characters): **Maximum annual rate represents 24.9% gas firing on a heat input basis. Total natural gas all three boilers = 2,696 MMscf/yr.**		

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	076	010	EL
PM_{10}	076	010	EL
SO_2			EL
NO_X	107		EL
CO			EL
VOC			EL
PB	076	010	EL
SAM			EL
FL			EL
H114	048		EL
H021	076	010	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: **588** lb/hour **696.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1.2 lb/MMBtu** Reference: **40 CFR 60 Subpart Da**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **1.2 lb/MMBtu x 490 MMBtu/hr = 588.0 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **1,154.3 TPY total for all three boilers.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.20 lb/MMBtu**	4. Equivalent Allowable Emissions: **143.0** lb/hour **313.2** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous SO_2 monitor**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions: 0.2 lb/MMBtu 24-hr avg; Annual-0.10 lb/MMBtu. Based on biomass firing.**	

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: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.20 lb/MMBtu**	4. Equivalent Allowable Emissions: **588** lb/hour **646.8** tons/year
5. Method of Compliance (limit to 60 characters): **Limit coal burning to 18.0% for any single boiler.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Basis for Allowable Emissions Code: NSPS. Based on coal firing**	

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: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 lb/MMBtu**	4. Equivalent Allowable Emissions: **24.5** lb/hour **36.7** tons/year
5. Method of Compliance (limit to 60 characters): **Limit fuel oil burning to 24.9% for any single boiler.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on No. 2 fuel oil firing and BACT.**	

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: **715** lb/hour **1,096.3** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1 lb/MMBtu** Reference: **Boiler design**	7. Emissions Method Code:

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

1.0 lb/MMBtu x 715 MMBtu/hr = 715.0 lb/hr
0.35 lb/MMBtu x 715 MMBtu/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 1,096.3 TPY

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

1.0 lb/MMBtu as a 24-hr average; 0.35 lb/MMBtu as an annual average. Total for all three boilers = 2,012.5 TPY.

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: **0.35 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour **1,096.3** tons/year

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

EPA Method 10 annually.

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

lb/MMBtu limit based on 12-month rolling average. All three boilers limited to 2,012.5 TPY.

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: **17.6** lb/hour **34.39** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.036 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters): **0.036 lb/MMBtu x 490 MMBtu/hr = 17.6 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on coal firing, 50.4 TPY total for all boilers.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.036 lb/MMBtu**	4. Equivalent Allowable Emissions: **17.6** lb/hour **19.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 8 once every 5 years.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on coal firing.**	

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: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.012 lb/MMBtu**	4. Equivalent Allowable Emissions: **8.6** lb/hour **19.10** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 8 once every 5 years**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on biomass firing.**	

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: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.0015 lb/MMBtu**	4. Equivalent Allowable Emissions: **0.74** lb/hour **1.1** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 8 once every 5 years.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on No. 2 fuel oil firing.**	

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: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**	

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

Continuous Monitoring System: Continuous Monitor 1 of 5

1. Parameter Code: **VE**	2. Pollutant(s):
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Manufacturer: **Durag** Model Number: **D-R281-31-AV** Serial Number: **31019**	
5. Installation Date: **01-Oct-1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60, Subpart Da**	

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

Supplemental Requirements

1.	Process Flow Diagram [X] Attached, Document ID: OC-FI-C3 [ ] Not Applicable [ ] Waiver Requested
2.	Fuel Analysis or Specification [X] Attached, Document ID: OC-EU1-J2 [ ] Not Applicable [ ] Waiver Requested
3.	Detailed Description of Control Equipment [X] Attached, Document ID: OC-EU1-J3 [ ] 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: Attachment A [X] Not Applicable
9.	Other Information Required by Rule or Statute [ ] Attached, Document ID: _______ [X] 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

ATTACHMENT OC-EU1-J2

FUEL ANALYSIS OR SPECIFICATION

ATTACHMENT OC-EU1-J2
DESIGN FUEL SPECIFICATIONS[a] FOR THE OKEELANTA POWER COGENERATION FACILITY

Parameter		Biomass				
		Bagasse	Wood Waste	No. 2 Fuel Oil	Bituminous Coal	Natural Gas
Specific Gravity		–	–	0.865	–	–
Heating Value	(Btu/lb)	3,653	4,504	19,175	12,000	–
Heating Value	(Btu/gal)	–	–	138,000	–	–
Heating Value	(Btu/scf)					1,000
Ultimate Analysis (dry basis percentage):						
Carbon		48.93	49.58	87.01	82.96	
Hydrogen		6.14	5.87	12.47	5.41	
Nitrogen		0.25	0.40	0.02	1.58	
Oxygen		43.84	40.90	0.00	5.72	
Sulfur		0.03	0.07	0.05	0.67	
Ash/Inorganic		1.0	9.0	0.00	3.66	
Moisture		52	37	–	4.5	

[a] Represents average fuel characteristics.

Sources: Okeelanta Power, 2000.
Combustion Engineering, 1981.

ATTACHMENT OC-EU1-J3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

ATTACHMENT OC-EU1-J3
DETAILED DESCRIPTION OF CONTROL EQUIPMENT

The cogeneration facility utilizes several emission control techniques to reduce emissions. A selective non-catalytic reduction (SNCR) system is used to reduce NO_X emissions. Further, the cogeneration boilers minimize CO and VOC through proper furnace design and good combustion practices, including: control of combustion air and combustion temperature; distribution of fuel on the combustion grate; and controls over the furnace loads and transient conditions. Particulate emissions are controlled by an ESP. Multiple cyclones were installed during the 2000 calendar year to improve control of particulate emissions. Mercury emissions are controlled through a carbon injection system and the ESP system.

Electrostatic Precipitator

The EPS's for the Okeelanta Power facility are manufactured by Flakt, Inc. Design specifications for the ESP (one per boiler) are provided below:

Chambers = 1

Collecting Plate = 12.30 ft L x 39.37 ft H

Fields/Chamber = 3

Specific Collection Area = 200 ft^2/1,000 acfm (minimum)

Gas Velocity = <4 ft/s

Pressure Drop = less than 2.8 inches H_2O

Operating Temperature = 350°F

Ash Handling = Trough hopper with screw conveyor

Particulate removal efficiency: >99.2%

NO_X Control System

The NO_X control system design employs a urea injection system manufactured by Nalco-Fueltech for NO_X control. The technology is a selective non-catalytic reduction process, which reduces NO_X emissions through chemical reaction with urea. In the process, urea is injected into the flue gas stream and reacts with nitrogen oxides to form nitrogen and water vapor.

The NO_X control system includes the following major components:

- Carrier air compressors.
- Urea tank.
- Urea/air flow controls.
- Control panel.
- Injection manifolds and injectors.
- Valves and instrumentation.

A single urea storage tank system is installed to supply urea to all three boilers. Urea for injection into the boilers is drawn from the tank. Two injection zones are used to provide injection at full and part load conditions. Each zone has six injectors. Zone switching valves will direct the urea/carrier mixture to the appropriate injection zone.

Specifications for the urea injection system to meet the NO_X emission rate of 0.15 lb/MMBtu when firing biomass or No. 2 fuel oil, and 0.17 lb/MMBtu when firing coal, are provided below (on a per boiler basis):

Urea injection rate - 65 gal/hr (max)
Ammonia Slip - Biomass, No. 2 fuel oil - 25 ppm (max)
- Coal - 65 ppm (max)

Mercury Control System

The mercury control system is supplied by ABB Environmental Systems and Chemco, Inc. A volumetric feeder with integral supply hopper meters activated carbon for injection at a point in the ductwork between the ESP and the ID fan. This promotes turbulent mixing and provides adequate residence time. A blower system transports the carbon to the injection point. The ESP will effectively capture the activated carbon particles along with the boiler fly ash (which also contains some carbon). The system is designed to inject up to 13 lb/hr of carbon into the flue gases of each boiler.

Dust Control System

The cyclone dust collectors will be supplied by Barron Industries, Model 460 Tube Base III 9K15-2023 AU. These are mechanical cyclone dust collectors which remove larger size particulate matter prior to the ESP. There are 460 Cyclone tubes in all.

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

June 22, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. James Meriwether
Environmental Manager
Okeelanta Cogeneration Facility
Post Office Box 9
South Bay, Florida 33493

RE: DEP File No. 0990332-010-AC (PSD-FL-196F)
Permit Modifications

Dear Mr. Meriwether:

This is in response to Golder Associates' letter dated December 14, 1998 and fee received February 2, 1999 requesting changes to the subject construction permit. The Department considered the requests and agrees to modify the permit conditions as indicated below. The request for revising the 0.35 lb CO/MMBtu limit from a 24-hour averaging time to a 30-day rolling average was approved. However, the requested increase to 0.5 lb CO/MMBtu was not granted based on our conclusion from the test data that the longer term average can be met at 0.35 lb/MMBtu. The requested modifications of provisions related to excess emissions and other changes are indicated by the underlined additions.

The permit is hereby modified as shown below. The excess fee paid will be refunded separately.

SPECIFIC CONDITION NO. 20

Visible emissions from any boiler shall not exceed 20 percent opacity, 6-minute average, except up to 27 percent opacity is allowed for up to 6 minutes in any 1-hour period. Based on a maximum heat input to each boiler of 715 MMBtu/hr for biomass fuels and 490 MMBtu/hr for No. 2 fuel oil and coal, stack emissions shall not exceed any limit shown in the following table:

	EMISSION LIMIT (per boiler) [d]						Total [e] Three Boilers
	Biomass		No. 2 Oil		Bit. Coal		
Pollutant	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(TPY)
Particulate (TSP)	0.03	21.5	0.03	14.7	0.03	14.7	172.5
Particulate (PM_{10})	0.03	21.5	0.03	14.7	0.03	14.7	172.5
Sulfur Dioxide							
3-hour average					1.2	588.0	
24-hour average	0.10	71.5	0.05	24.5	1.2	588.0	
Annual Average							
(Bagasse)	0.02 a				1.2 a		1,154.3 f
(Wood Waste)	0.05a c						
Nitrogen Oxides							
Annual average	0.15 a	107.3 a	0.15 a	73.5 a	0.17 a	83.3 a	862.5

Mr. James Meriwether
June 22, 1999
Page 2

Carbon Monoxide ~~24-hour~~ 30-day rolling avg.	0.35 a	250.3 a	0.35 a	171.5 a	0.35 a	171.5 a	2,012.5
Volatile Organic Compounds	0.06	42.9	0.03	14.7	0.03	14.7	345
Lead (Bagasse)	2.5×10^{-5} b	0.018 b	8.9×10^{-7}	0.0004	6.4×10^{-5}	0.031	0.454 f
" (Wood Waste)	1.6×10^{-4} c	0.114 c					
Mercury (Bagasse)	5.43×10^{-6} b	0.0039 b	2.4×10^{-6}	0.00118	8.4×10^{-6}	0.0041	0.0300 f
" (Wood Waste)	4.0×10^{-6} c	0.0029 c					
Beryllium	---	---	3.5×10^{-7}	0.00017	5.9×10^{-6}	0.0029	0.0052
Fluorides	---	---	6.3×10^{-6}	0.0003	0.024	11.8	21.2
Sulfuric Acid Mist	0.003	2.15	0.0015	0.74	0.036	17.6	34.6

Table Notes:

a Compliance based on 30-day rolling average, per 40 CFR 60, Subpart Da.

[CO Limit: Although carbon monoxide (CO) emissions are not regulated by NSPS Subpart Da, compliance shall be demonstrated in a similar manner. The CO emissions from each boiler shall not exceed 0.35 pounds per MMBTU based on a 30-day (boiler operating days) rolling average. Compliance with this standard shall be demonstrated by continuous emissions monitoring data. The 30-day rolling average shall be determined by calculating the arithmetic average of all hourly emission rates for 30 successive boiler operating days. The 1-hour averages shall be expressed in lb/MMBTU of heat input and are calculated using at least two valid data points. Calculation of the 30-day rolling average shall consist of at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the permittee shall supplement emission data with other monitoring systems approved by the EPA Administrator or the reference methods and procedures as described in 40 CFR 60.47a.]

b Emission limit for bagasse. Subject to revision after testing pursuant to Specific Condition Nos. 24 and 25.

c Emission limit for wood waste. Subject to revision after testing pursuant to Specific Condition Nos. 24 and 25.

d The emission limit shall be prorated when more than one type of fuel is burned in a boiler.

e Limit heat input from No. 2 fuel to less than 24.9 of total heat input on a calendar quarter basis, coal to 69,720 tons during any 12-month period, and the combination of oil and coal to less than 24.9 of the total heat input on a calendar quarter basis.

f Compliance based on a 12-month rolling average for any fuel combination.

The permittee shall comply with the excess emissions rule contained in Rule 62-210.700, F.A.C. In addition, the permittee is allowed excess emissions during startup, ~~and~~ shutdown and malfunction in accordance with permit condition No. 21. ~~, provided such excess emissions do not exceed a duration of four hours, and such emissions in excess of two hours do not exceed six (6) times per year.~~ Periods of startup, shutdown and malfunction shall be defined as:

a. *Startup* is the commencement of operation of a boiler which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which may result in excess emissions. Periods of startup for each boiler shall end once steam generation reaches 150,000 pounds per hour.

b. *Shutdown* is the cessation of the operation of a boiler for any purpose after steam generation drops below 150,000 pounds per hour.

c. *Malfunction* is any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

[Rule 62-210.200 (179), (258), (275), F.A.C. and Rule 62-4.070(3), F.A.C.]

SPECIFIC CONDITION NO. 21

a. Within 60 calendar days after achieving the maximum capacity at which each unit will be operated, but no later than 180 operating days after initial startup, the permittee shall conduct emission compliance tests for all air pollutants listed in Specific Condition No. 20 (including visible emissions). Test shall be conducted during normal operations (i.e., within 10 percent of the heat input). The permittee shall furnish the Department a written report of the results of such performance tests within 45 days of completion of the tests. The performance tests will be conducted in accordance with the provisions of 40 CFR 60.46a.

b. Compliance with emission limitations for each fuel stated in Specific Condition No. 20 above shall be demonstrated using EPA Methods, as contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources), continuous emissions monitoring data, or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants), or any other method as approved by the Department, in accordance with F.A.C. Rule 62-297.620. A test protocol shall be submitted for approval to the Bureau of Air Regulation at least 90 days prior to testing.

EPA Method*	For Determination of
1	Selection of sample site and velocity traverses.
2	Stack gas flow rate when converting concentrations to or from mass emission limits.
3 or 3A	Gas analysis when needed for calculation of molecular weight or percent O_2.
4	Moisture content when converting stack velocity to dry volumetric flow rate for use in converting concentrations in dry gases to or from mass emission limits.
5	Particulate matter concentration and mass emissions.
201 or 201A	PM_{10} emissions.
6, 6C, or 19	Sulfur dioxide emissions from stationary sources.
7, or 7E	Nitrogen oxide emissions from stationary sources.
8 (modified)	Sulfuric acid mist. **
9	Visible emission determination of opacity. - At least three one hour runs to be conducted simultaneously with particulate testing. - At least one truck unloading into the mercury reactant storage silo (from start to finish).
10	Carbon monoxide emissions from stationary sources.
12	Determination of inorganic lead emissions from stationary sources.
13A or 13B	Fluoride emissions from stationary sources.
18 or 25	Volatile organic compounds concentration.
101A	Determination of particulate and gaseous mercury emissions.

EPA Method*	For Determination of
104	Determination of beryllium emissions from stationary sources.
108	Determination of particulate and gaseous arsenic emissions.
EMTIC Test Method CTM-012.WPF	Chromium and copper emissions.

* Other approved EPA test methods may be substituted for the listed method unless the Department has adopted a specific test method for the air pollutant.

** Test for sulfuric acid mist only required when coal is burned at the facility.

c. Continuous emission monitoring data required by this permit shall be collected and recorded during all periods of operation including startup, shutdown, and malfunction, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Although recorded, emissions during periods of startup, shutdown and malfunction may be excluded from the averaging calculations required to determine compliance with the emissions standards, not to exceed four (4) hours during startup, four (4) hours during shutdown, nor two (2) hours during malfunction in a 24-hour period. Excess Emissions beyond these periods shall be recorded and included in the averaging calculations required to determine compliance with the emissions standards. The permittee shall submit to the regulating agencies a Quarterly Excess Emissions Report within 30 days of the end of each calendar quarter. The report shall identify the date, time, and description of each startup, shutdown, and malfunction resulting in excess emissions. It shall also identify any steps taken to mitigate emissions during any malfunction as well as any corrective actions taken.

[Air Permit PSD-FL-196; Rule 62-210.700, F.A.C.; 40 CFR 60.8; and 40 CFR 60.46a]

d. Excess emissions resulting from startup, shutdown or malfunction of a boiler shall be permitted for standards based on short-term averaging periods (shorter than 24-hour averages) as specified in this permit, providing:

a. The operators implement best operational practices to minimize emissions, and

b. Excess emissions do not exceed four (4) hours for startup, four (4) hours for shutdown, nor two (2) hours for malfunction in any 24-hour period (day).

Within one (1) working day of excess emissions due to a malfunction, the permittee shall notify the regulating agencies of the date, time, description, steps to taken to minimize emissions, and actions taken to correct the problem.

Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited. Excess emissions of standards based on long-term averaging periods (24-hour averages or longer) are not permitted because compliance is demonstrated by continuous monitor and provisions of this permit allow exclusion of monitoring data for periods of startup, shutdown, and malfunction.

[Rule 62-210.700, F.A.C.; Rule 62-4.070(3), F.A.C.; 40 CFR 60.8; and 40 CFR 60.46a]

This permit is issued pursuant to Chapter 403, Florida Statutes. A copy of this letter shall be filed with the referenced permit and certification and shall become part of the permit. Any party to this order has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within thirty (30) days after this order is filed with the clerk of the Department.

Sincerely,

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 6-24-99 to the person(s) listed:

Mr. James Meriwether, Okeelanta Power Limited Partnership*
Mr. James Stormer, Palm Beach County Health Department
Mr. Phil Barbaccia, SD – DEP
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS

Clerk Stamp

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

Kari Tober 6-24-99
(Clerk) Date)

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):

Cogen Boiler B fired by Biomass/No. 2 oil/coal/natural gas

4. Emissions Unit Identification Number: [ ] No ID
ID: **031** [ ] ID Unknown

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

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

74.9 MW gross generating capacity for entire facility.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **ESP - Electrostatic Precipitator** **Selective Non-catalytic Reduction for NO_X** **Activated Carbon Injection System** **Multiple Cyclone w/o Fly Ash Injection**
2. Control Device or Method Code(s): **10, 107, 48, 76**

Emissions Unit Details

1. Package Unit: Manufacturer:	Model Number:	
2. Generator Nameplate Rating:	**75** 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:		715 mmBtu/hr	
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
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 heat input rates: Biomass - 715 MMBtu/hr; No. 2 Fuel Oil - 490 MMBtu/hr; Coal - 490 MMBtu/hr; Natural Gas – 605 MMBtu/hr			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attached Document	

EU ID 031 : Cogen Boiler No. 2 Rule Applicability for Okeelanta Power L.P.

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart A	40CFR60.1	Subpart A – General Provisions	
APPLICABLE	60 Subpart A	40CFR60.7	Notification and Record Keeping	
APPLICABLE	60Subpart A	40CFR60.8	Performance Testing	
APPLICABLE	60 Subpart A	40CFR60.11	Compliance with standards and maintenance requirements.	
APPLICABLE	60 Subpart A	40CFR60.12	Circumvention.	
APPLICABLE	60 Subpart A	40CFR60.13	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.19	General notification and reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.40a	Subpart Da - NSPS for Electric Utility Units for which construction commenced after Sept. 18, 1978.	
APPLICABLE	60 Subpart Da	40CFR60.42a	Standard for particulate matter	
APPLICABLE	60 Subpart Da	40CFR60.43a	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(a)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(b)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(d)(2)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(g)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(h)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.44a	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.44a(a)	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.44a(c)	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.46a	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(a)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(b)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(c)	Compliance provisions.	
NON-APPLICABLE	60 Subpart Da	40CFR60.46a(d)	Compliance provisions.	Cogen Boiler No. 2 does not have a flue gas desulfurization system.
APPLICABLE	60 Subpart Da	40CFR60.46a(e)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(f)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(g)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(h)	Compliance provisions.	
NON-APPLICABLE	60 Subpart Da	40CFR60.46a(i)	Compliance provisions.	Cogen Boiler No. 2 has not been modified after July 7, 1997.
APPLICABLE	60 Subpart Da	40CFR60.47a	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(a)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(b)(2)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(b)(3)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(c)(1)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(d)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(e)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(f)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(g)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(h)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(i)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(j)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.48a	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(a)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(b)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(c)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(d)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(e)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.49a	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(a)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(b)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(c)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(d)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(f)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(g)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(h)	Reporting requirements	

EU ID 031 : Cogen Boiler No. 2 Rule Applicability for Okeelanta Power L.P.

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart Da	40CFR60.49a(i)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(j)	Reporting requirements	
APPLICABLE	60 Subpart Ea	40CFR60.50a(d)	Standards of performance for municipal waste combustors	
APPLICABLE	60 Subpart Ea	40CFR60.50b(j)	Standards of performance for municipal waste combustors	
APPLICABLE	62-204	62-204.800(7)2.	NSPS Subpart Da adopted by reference.	
APPLICABLE	62-296 <	62-296	STATIONARY SOURCES - EMISSION STANDARDS	
APPLICABLE	62-296 <	62-296.405(2)	Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input.	
NON-APPLICABLE	62-296 <	62-296.406	Fossil Fuel Steam Generators with less than 250 Million Btu per Hour Heat Input, New and Existing Em	Cogen Boiler No. 2 has a heat input of >250 MMBtu/hr.
NON-APPLICABLE	62-296 <	62-296.410	Carbonaceous Fuel Burning Equipment.	Not more stringent or different than NSPS.
APPLICABLE	62-296 >	62-296.500	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.500(2)(a)	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.500(2)(c)	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.570	Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NOx-Emitting Facili	
APPLICABLE	62-296 >	62-296.570(1)	Applicability.	
APPLICABLE	62-296 >	62-296.570(1)(a)	Applicability.	
APPLICABLE	62-296 >	62-296.570(2)	Compliance Requirements.	
APPLICABLE	62-296 >	62-296.570(3)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(b)6.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(c)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.620		
NON-APPLICABLE	62-296 >	62-296.700	Reasonably Available Control Technology (RACT) Particulate Matter.	Okeelanta Power is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.702	Fossil Fuel Steam Generators.	Okeelanta Power is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.703	Carbonaceous Fuel Burners.	Okeelanta Power is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
APPLICABLE	62-297	62-297	STATIONARY SOURCES - EMISSIONS MONITORING	
APPLICABLE	62-297	62-297.310	General Compliance Test Requirements.	
APPLICABLE	62-297	62-297.401	Compliance Test Methods.	
APPLICABLE	62-297	62-297.401(1)(a)	EPA Method 1 - Sample and Velocity Traverses for Stationary sources - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(10)	EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources - 40 CFR 60 Appen	
APPLICABLE	62-297	62-297.401(12)	EPA Method 12 - Determination of Inorganic Lead Emissions from Stationary Sources - 40 CFR 60 Append	
APPLICABLE	62-297	62-297.401(13)	EPA Methods 13A and 13B.	
APPLICABLE	62-297	62-297.401(18)	EPA Method 18 - Measurement of Gaseous Organic Compound Emissions by Gas Chromatography - 40 CFR 60	
APPLICABLE	62-297	62-297.401(19)	EPA Method 19 - Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide a	
APPLICABLE	62-297	62-297.401(2)	EPA Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate - 40 CFR 60 Appendix A.	

EU ID 031 : Cogen Boiler No. 2 Rule Applicability for Okeelanta Power L.P.

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	62-297	62-297.401(25)	EPA Method 25 - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Ap	
APPLICABLE	62-297	62-297.401(3)	EPA Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight - 40 CF	
APPLICABLE	62-297	62-297.401(32)	EPA Method 101 - Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants	
APPLICABLE	62-297	62-297.401(35)	EPA Method 104 - Determination of Beryllium Emissions from Stationary Sources - 40 CFR 61 Appendix B	
APPLICABLE	62-297	62-297.401(39)	EPA Method 108 - Determination of Particulate and Gaseous Arsenic Emissions - 40 CFR 61 Appendix B.	
APPLICABLE	62-297	62-297.401(4)	EPA Method 4 - Determination of Moisture Content In Stack Gases - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(41)	EPA Method 201 - Determination of PM10 Emissions (Exhaust Gas Recycle Procedure) - 40 CFR 51 Appendi	
APPLICABLE	62-297	62-297.401(5)	EPA Method 5 - Determination of Particulate Emissions from Stationary Sources - 40 CFR 60 Appendix A	
APPLICABLE	62-297	62-297.401(6)	EPA Method 6 - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(6)(c)	EPA Method 6C - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(7)	EPA Method 7 - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(7)(e)	EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(8)	EPA Method 8 - Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sour	
APPLICABLE	62-297	62-297.401(9)	EPA Test Method 9	

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? **BLR B**	2. Emission Point Type Code: 1	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: V	6. Stack Height: 199 feet	7. Exit Diameter: 10.0 feet
8. Exit Temperature: 295 °F	9. Actual Volumetric Flow Rate: 246,000 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): **Stack parameters based on biomass firing.**		

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

Segment Description and Rate: Segment 1 of 5

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Bagasse**		
2. Source Classification Code (SCC): **10101101**	3. SCC Units: **Tons Burned (all solid fuels)**	
4. Maximum Hourly Rate: **97.865**	5. Maximum Annual Rate: **857,295**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash: **1.0**	9. Million Btu per SCC Unit: **7.306**
10. Segment Comment (limit to 200 characters): **Total biomass all three boilers = 1,436,945 TPY based on 46.1%heat input from wood and 53.9% from bagasse.**		

Segment Description and Rate: Segment 2 of 5

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Wood Fired Boiler**		
2. Source Classification Code (SCC): **10100903**	3. SCC Units: **Tons Burned (all solid fuels)**	
4. Maximum Hourly Rate: **79.374**	5. Maximum Annual Rate: **695,271**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.3**	8. Maximum % Ash: **9.0**	9. Million Btu per SCC Unit: **9.008**
10. Segment Comment (limit to 200 characters): **Total biomass all three boilers = 1,436,945 TPY based on 46.1% heat input from wood and 53.9% from bagasse.**		

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

Segment Description and Rate: Segment 3 of 5

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Distillate Oil - Grades 1 and 2 Oil**		
2. Source Classification Code (SCC): **10100501**	3. SCC Units: **Thousand Gallons Burned (all liquid fuels)**	
4. Maximum Hourly Rate: **3.551**	5. Maximum Annual Rate: **10,639**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **138**
10. Segment Comment (limit to 200 characters): **Maximum annual rate represents 24.9% oil firing on a heat input basis. Total No. 2 fuel all three boilers = 19,533,086 gal/yr.**		

Segment Description and Rate: Segment 4 of 5

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Bituminous Coal - Spreader Stoker**		
2. Source Classification Code (SCC): **10100204**	3. SCC Units: **Tons Burned (all solid fuels)**	
4. Maximum Hourly Rate: **20.417**	5. Maximum Annual Rate: **44,920**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.70**	8. Maximum % Ash: **3.70**	9. Million Btu per SCC Unit: **24**
10. Segment Comment (limit to 200 characters): **Maximum annual rate = 18.0% coal firing on a heat input basis. Total coal all three boilers = 44,920 TPY (9.6% coal burning on a heat input basis).**		

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

Segment Description and Rate: Segment 5 of 5

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler – Natural Gas**		
2. Source Classification Code (SCC): **10100601**	3. SCC Units: **MMscf Burned**	
4. Maximum Hourly Rate: **0.605**	5. Maximum Annual Rate: **1,468**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,000**
10. Segment Comment (limit to 200 characters): **Maximum annual rate represents 24.9% gas firing on a heat input basis. Total natural gas all three boilers = 2,696 MMscf/yr.**		

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	076	010	EL
PM_{10}	076	010	EL
SO_2			EL
NO_X	107		EL
CO			EL
VOC			EL
PB	076	010	EL
SAM			EL
FL			EL
H114	048		EL
H021	076	010	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: **588** lb/hour **696.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1.2 lb/MMBtu** Reference: **40 CFR 60 Subpart Da**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **1.2 lb/MMBtu x 490 MMBtu/hr = 588.0 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **1,154.3 TPY total for all three boilers.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.20 lb/MMBtu**	4. Equivalent Allowable Emissions: **143.0** lb/hour **313.2** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous SO_2 monitor**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions: 0.2 lb/MMBtu 24-hr avg; Annual-0.10 lb/MMBtu. Based on biomass firing.**	

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: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.20 lb/MMBtu**	4. Equivalent Allowable Emissions: **588** lb/hour **36.7** tons/year
5. Method of Compliance (limit to 60 characters): **Limit coal burning to18.0% for any single boiler.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Basis for Allowable Emissions Code: NSPS. Based on coal firing**	

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: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 lb/MMBtu**	4. Equivalent Allowable Emissions: **24.5** lb/hour **36.7** tons/year
5. Method of Compliance (limit to 60 characters): **Limit fuel oil burning to 24.9% for any single boiler.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on No. 2 fuel oil firing and BACT.**	

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: **715** lb/hour **1,096.3** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1 lb/MMBtu** Reference: **Boiler design**	7. Emissions Method Code:

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

1.0 lb/MMBtu x 715 MMBtu/hr = 715.0 lb/hr
0.35 lb/MMBtu x 715 MMBtu/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 1,096.3 TPY

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

1.0 lb/MMBtu as a 24-hr average; 0.35 lb/MMBtu as an annual average. Total for all three boilers = 2,012.5 TPY.

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: **0.35 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour **1,096.3** tons/year

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

EPA Method 10 annually.

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

lb/MMBtu limit based on 12-month rolling average. All three boilers limited to 2,012.5 TPY.

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: **17.6** lb/hour **34.39** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.036 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters): **0.036 lb/MMBtu x 490 MMBtu/hr = 17.6 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on coal firing, 50.4 TPY total for all boilers.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.036 lb/MMBtu**	4. Equivalent Allowable Emissions: **17.6** lb/hour **19.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 8 once every 5 years.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on coal firing.**	

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: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.012 lb/MMBtu**	4. Equivalent Allowable Emissions: **8.6** lb/hour **19.10** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 8 once every 5 years**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on biomass firing.**	

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: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.0015 lb/MMBtu**	4. Equivalent Allowable Emissions: **0.74** lb/hour **1.1** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 8 once every 5 years.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on No. 2 fuel oil firing.**	

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

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

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

Continuous Monitoring System: Continuous Monitor 5 of 5

1. Parameter Code:	2. Pollutant(s): O_2
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Manufacturer: Yokogowa Model Number: ZA8C Serial Number: JJ113MA345	
5. Installation Date: 01-Oct-1995	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): 40 CFR 60, Subpart Da	

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

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: OC-FI-C3 [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: OC-EU1-J2 [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: OC-EU1-J3 [ ] 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: Attachment A [X] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID: _______ [X] 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):

Cogen Boiler C fired by Biomass/No. 2 oil/coal/natural gas

4. Emissions Unit Identification Number: ID: **033** [ ] No ID [ ] ID Unknown

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

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

74.9 MW gross generating capacity for entire facility.

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:			715 mmBtu/hr	
2. Maximum Incineration Rate:		lb/hr		tons/day
3. Maximum Process or Throughput Rate:				
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 heat input rates: Biomass - 715 MMBtu/hr; No. 2 Fuel Oil - 490 MMBtu/hr; Coal - 490 MMBtu/hr; Natural Gas – 605 MMBtu/hr				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attached Document	

EU ID 032 : Cogen Boiler No. 3 Rule Applicability for Okeelanta Power L.P.

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart A	40CFR60.1	Subpart A – General Provisions	
APPLICABLE	60 Subpart A	40CFR60.7	Notification and Record Keeping	
APPLICABLE	60Subpart A	40CFR60.8	Performance Testing	
APPLICABLE	60 Subpart A	40CFR60.11	Compliance with standards and maintenance requirements.	
APPLICABLE	60 Subpart A	40CFR60.12	Circumvention.	
APPLICABLE	60 Subpart A	40CFR60.13	Monitoring requirements.	
APPLICABLE	60 Subpart A	40CFR60.19	General notification and reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.40a	Subpart Da - NSPS for Electric Utility Units for which construction commenced after Sept. 18, 1978.	
APPLICABLE	60 Subpart Da	40CFR60.42a	Standard for particulate matter	
APPLICABLE	60 Subpart Da	40CFR60.43a	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(a)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(b)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(d)(2)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(g)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.43a(h)	Standard for sulfur dioxide.	
APPLICABLE	60 Subpart Da	40CFR60.44a	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.44a(a)	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.44a(c)	Standard for nitrogen oxides	
APPLICABLE	60 Subpart Da	40CFR60.46a	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(a)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(b)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(c)	Compliance provisions.	
NON-APPLICABLE	60 Subpart Da	40CFR60.46a(d)	Compliance provisions.	Cogen Boiler No. 3 does not have a flue gas desulfurization system.
APPLICABLE	60 Subpart Da	40CFR60.46a(e)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(f)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(g)	Compliance provisions.	
APPLICABLE	60 Subpart Da	40CFR60.46a(h)	Compliance provisions.	
NON-APPLICABLE	60 Subpart Da	40CFR60.46a(i)	Compliance provisions.	Cogen Boiler No. 3 has not been modified after July 7, 1997.
APPLICABLE	60 Subpart Da	40CFR60.47a	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(a)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(b)(2)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(b)(3)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(c)(1)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(d)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(e)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(f)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(g)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(h)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(i)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.47a(j)	Emission monitoring	
APPLICABLE	60 Subpart Da	40CFR60.48a	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(a)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(b)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(c)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(d)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.48a(e)	Compliance determination procedures and methods.	
APPLICABLE	60 Subpart Da	40CFR60.49a	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(a)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(b)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(c)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(d)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(f)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(g)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(h)	Reporting requirements	

EU ID 032 : Cogen Boiler No. 3 Rule Applicability for Okeelanta Power L.P.

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	60 Subpart Da	40CFR60.49a(i)	Reporting requirements	
APPLICABLE	60 Subpart Da	40CFR60.49a(j)	Reporting requirements	
APPLICABLE	60 Subpart Ea	40CFR60.50a(d)	Standards of performance for municipal waste combustors	
APPLICABLE	60 Subpart Ea	40CFR60.50b(j)	Standards of performance for municipal waste combustors	
APPLICABLE	62-204	62-204.800(7)2.	NSPS Subpart Da adopted by reference.	
APPLICABLE	62-296 <	62-296	STATIONARY SOURCES - EMISSION STANDARDS	
APPLICABLE	62-296 <	62-296.405(2)	Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input.	
NON-APPLICABLE	62-296 <	62-296.406	Fossil Fuel Steam Generators with less than 250 Million Btu per Hour Heat Input, New and Existing Em	Cogen Boiler No. 3 has a heat input of >250 MMBtu/hr.
NON-APPLICABLE	62-296 <	62-296.410	Carbonaceous Fuel Burning Equipment.	Not more stringent or different than NSPS.
APPLICABLE	62-296 >	62-296.500	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.500(2)(a)	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.500(2)(c)	Reasonably Available Control Technology (RACT) - Volatile Organic Compounds (VOC) and Nitrogen Oxide	
APPLICABLE	62-296 >	62-296.570	Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NOx-Emitting Facili	
APPLICABLE	62-296 >	62-296.570(1)	Applicability.	
APPLICABLE	62-296 >	62-296.570(1)(a)	Applicability.	
APPLICABLE	62-296 >	62-296.570(2)	Compliance Requirements.	
APPLICABLE	62-296 >	62-296.570(3)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(a)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(b)6.	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.570(4)(c)	Operation Permit Requirements.	
APPLICABLE	62-296 >	62-296.620		
NON-APPLICABLE	62-296 >	62-296.700	Reasonably Available Control Technology (RACT) Particulate Matter.	Okeelanta Power is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.702	Fossil Fuel Steam Generators.	Okeelanta Power is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
NON-APPLICABLE	62-296 >	62-296.703	Carbonaceous Fuel Burners.	Okeelanta Power is located in Palm Beach County, which is not a nonattainment or maintenance area for particulate matter.
APPLICABLE	62-297	62-297	STATIONARY SOURCES - EMISSIONS MONITORING	
APPLICABLE	62-297	62-297.310	General Compliance Test Requirements.	
APPLICABLE	62-297	62-297.401	Compliance Test Methods.	
APPLICABLE	62-297	62-297.401(1)(a)	EPA Method 1 - Sample and Velocity Traverses for Stationary sources - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(10)	EPA Method 10 - Determination of Carbon Monoxide Emissions from Stationary Sources - 40 CFR 60 Appen	
APPLICABLE	62-297	62-297.401(12)	EPA Method 12 - Determination of Inorganic Lead Emissions from Stationary Sources - 40 CFR 60 Append	
APPLICABLE	62-297	62-297.401(13)	EPA Methods 13A and 13B.	
APPLICABLE	62-297	62-297.401(18)	EPA Method 18 - Measurement of Gaseous Organic Compound Emissions by Gas Chromatography - 40 CFR 60	
APPLICABLE	62-297	62-297.401(19)	EPA Method 19 - Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide a	
APPLICABLE	62-297	62-297.401(2)	EPA Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate - 40 CFR 60 Appendix A.	

EU ID 032 : Cogen Boiler No. 3 Rule Applicability for Okeelanta Power L.P.

APPLIC STAT	RULE DESCRIP	RULE NUMBER	RULE TITLE	RATIONALE FOR NON-APPLICABILITY
APPLICABLE	62-297	62-297.401(25)	EPA Method 25 - Determination of Total Gaseous Nonmethane Organic Emissions as Carbon - 40 CFR 60 Ap	
APPLICABLE	62-297	62-297.401(3)	EPA Method 3 - Gas Analysis for Carbon Dioxide, Oxygen, Excess Air, and Dry Molecular Weight - 40 CF	
APPLICABLE	62-297	62-297.401(32)	EPA Method 101 - Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants	
APPLICABLE	62-297	62-297.401(35)	EPA Method 104 - Determination of Beryllium Emissions from Stationary Sources - 40 CFR 61 Appendix B	
APPLICABLE	62-297	62-297.401(39)	EPA Method 108 - Determination of Particulate and Gaseous Arsenic Emissions - 40 CFR 61 Appendix B.	
APPLICABLE	62-297	62-297.401(4)	EPA Method 4 - Determination of Moisture Content in Stack Gases - 40 CFR 60 Appendix A.	
APPLICABLE	62-297	62-297.401(41)	EPA Method 201 - Determination of PM10 Emissions (Exhaust Gas Recycle Procedure) - 40 CFR 51 Appendi	
APPLICABLE	62-297	62-297.401(5)	EPA Method 5 - Determination of Particulate Emissions from Stationary Sources - 40 CFR 60 Appendix A	
APPLICABLE	62-297	62-297.401(6)	EPA Method 6 - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(6)(c)	EPA Method 6C - Determination of Sulfur Dioxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(7)	EPA Method 7 - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(7)(e)	EPA Method 7E - Determination of Nitrogen Oxide Emissions from Stationary Sources - 40 CFR 60 Appendi	
APPLICABLE	62-297	62-297.401(8)	EPA Method 8 - Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sour	
APPLICABLE	62-297	62-297.401(9)	EPA Test Method 9	

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? **BLR C**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **199** feet	7. Exit Diameter: **10.0** feet
8. Exit Temperature: **295** °F	9. Actual Volumetric Flow Rate: **246,000** 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): **Stack parameters based on biomass firing.**		

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

Segment Description and Rate: Segment 1 of 5

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Bagasse**		
2. Source Classification Code (SCC): **10101101**	3. SCC Units: **Tons Burned (all solid fuels)**	
4. Maximum Hourly Rate: **97.865**	5. Maximum Annual Rate: **857,295**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash: **1.0**	9. Million Btu per SCC Unit: **7.306**
10. Segment Comment (limit to 200 characters): **Total biomass all three boilers = 1,436,945 TPY based on 46.1% heat input from wood and 53.9% from bagasse.**		

Segment Description and Rate: Segment 2 of 5

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Wood Fired Boiler**		
2. Source Classification Code (SCC): **10100903**	3. SCC Units: **Tons Burned (all solid fuels)**	
4. Maximum Hourly Rate: **79.374**	5. Maximum Annual Rate: **695,271**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.3**	8. Maximum % Ash: **9.0**	9. Million Btu per SCC Unit: **9.008**
10. Segment Comment (limit to 200 characters): **Total biomass all three boilers = 1,436,945 TPY based on 46.1% heat input from wood and 53.9% from bagasse.**		

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

Segment Description and Rate: Segment 3 of 5

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Distillate Oil - Grades 1 and 2 Oil**		
2. Source Classification Code (SCC): **10100501**	3. SCC Units: **Thousand Gallons Burned (all liquid fuels)**	
4. Maximum Hourly Rate: **3.551**	5. Maximum Annual Rate: **10,639**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **138**
10. Segment Comment (limit to 200 characters): **Maximum annual rate represents 24.9% oil firing on a heat input basis. Total No. 2 fuel all three boilers = 19,533,086 gal/yr.**		

Segment Description and Rate: Segment 4 of 5

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Electric Utility Boiler - Bituminous Coal - Spreader Stoker**		
2. Source Classification Code (SCC): **10100204**	3. SCC Units: **Tons Burned (all solid fuels)**	
4. Maximum Hourly Rate: **20.417**	5. Maximum Annual Rate: **44,920**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.70**	8. Maximum % Ash: **3.70**	9. Million Btu per SCC Unit: **24**
10. Segment Comment (limit to 200 characters): **Maximum annual rate = 18.0% coal firing on a heat input basis. Total coal all three boilers = 44,920 TPY (9.6% coal burning on a heat input basis).**		

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

Segment Description and Rate: Segment 5 of 5

1. Segment Description (Process/Fuel Type) (limit to 500 characters):

   Electric Utility Boiler – Natural Gas

2. Source Classification Code (SCC): **10100601**	3. SCC Units: **MMscf Burned**	
4. Maximum Hourly Rate: **0.605**	5. Maximum Annual Rate: **1,468**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,000**

10. Segment Comment (limit to 200 characters):

    Maximum annual rate represents 24.9% gas firing on a heat input basis. Total natural gas all three boilers = 2,696 MMscf/yr.

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	076	010	EL
PM_{10}	076	010	EL
SO_2			EL
NO_X	107		EL
CO			EL
VOC			EL
PB	076	010	EL
SAM			EL
FL			EL
H114	048		EL
H021	076	010	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: **588** lb/hour **696.0** tons/year	4. Synthetically Limited? [**X**]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1.2 lb/MMBtu** Reference: **40 CFR 60 Subpart Da**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **1.2 lb/MMBtu x 490 MMBtu/hr = 588.0 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **1,154.3 TPY total for all three boilers.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.20 lb/MMBtu**	4. Equivalent Allowable Emissions: **143.0** lb/hour **313.2** tons/year
5. Method of Compliance (limit to 60 characters): **Continuous SO_2 monitor**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions: 0.2 lb/MMBtu 24-hr avg; Annual-0.10 lb/MMBtu. Based on biomass firing.**	

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: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.20 lb/MMBtu**	4. Equivalent Allowable Emissions: **588** lb/hour **646.8** tons/year
5. Method of Compliance (limit to 60 characters): **Limit coal burning to 18.0% for any single boiler.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Basis for Allowable Emissions Code: NSPS. Based on coal firing**	

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: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.05 lb/MMBtu**	4. Equivalent Allowable Emissions: **24.5** lb/hour **36.7** tons/year
5. Method of Compliance (limit to 60 characters): **Limit fuel oil burning to 24.9% for any single boiler.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on No. 2 fuel oil firing and BACT.**	

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: **715** lb/hour **1096.3** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1 lb/MMBtu** Reference: **Boiler design**	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters): **1.0 lb/MMBtu x 715 MMBtu/hr = 715.0 lb/hr** **0.35 lb/MMBtu x 715 MMBtu/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 1,096.3 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **1.0 lb/MMBtu as a 24-hr average; 0.35 lb/MMBtu as an annual average. Total for all three boilers = 2,012.5 TPY.**	

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: **0.35 lb/MMBtu**	4. Equivalent Allowable Emissions: lb/hour **1,096.3** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10 annually.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **lb/MMBtu limit based on 12-month rolling average. All three boilers limited to 2,012.5 TPY.**	

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: **17.6** lb/hour **34.39** tons/year	4. Synthetically Limited? [X]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.036 lb/MMBtu** Reference: **Permit**	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters): **0.036 lb/MMBtu x 490 MMBtu/hr = 17.6 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on coal firing, 50.4 TPY total for all boilers.**	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.036 lb/MMBtu**	4. Equivalent Allowable Emissions: **17.6** lb/hour **19.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 8 once every 5 years.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on coal firing.**	

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: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.012 lb/MMBtu**	4. Equivalent Allowable Emissions: **8.6** lb/hour **19.10** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 8 once every 5 years**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on biomass firing.**	

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: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions

Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.0015 lb/MMBtu**	4. Equivalent Allowable Emissions: **0.74** lb/hour **1.1** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 8 once every 5 years.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Based on No. 2 fuel oil firing.**	

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: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **27** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **40 CFR 60, Subpart Da.**	

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

Continuous Monitoring System: Continuous Monitor 1 of 5

1. Parameter Code: **VE**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Durag** Model Number: **D-R281-31-AV**	Serial Number: **31019**
5. Installation Date: **01-Oct-1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60, Subpart Da**	

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

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

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

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

Continuous Monitoring System: Continuous Monitor 2 of 5

1. Parameter Code: **EM**	2. Pollutant(s): **NO_X**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Thermo Environmental Instruments** Model Number: **42D**	Serial Number: **42D-52618-292**
5. Installation Date: **01-Oct-1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60, Subpart Da**	

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

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

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

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

Continuous Monitoring System: Continuous Monitor 3 of 5

1. Parameter Code: **EM**	2. Pollutant(s): **SO_2**
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Manufacturer: **Thermo Environmental Instruments** Model Number: **43B**	Serial Number: **43B-51400-292**
5. Installation Date: **01-Oct-1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60, Subpart Da**	

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

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

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

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

Continuous Monitoring System: Continuous Monitor 4 of 5

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	[ ] Rule [**X**] Other
4. Monitor Information: Manufacturer: **Thermo Environmental Instruments** Model Number: **48** Serial Number: **48-45334-273**	
5. Installation Date: **01-Oct-1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

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

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

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

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

Continuous Monitoring System: Continuous Monitor 5 of 5

1. Parameter Code:	2. Pollutant(s): O_2
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Yokogowa** Model Number: **ZA8C**	Serial Number: **JJ113MA345**
5. Installation Date: **01-Oct-1995**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **40 CFR 60, Subpart Da**	

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

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: OC-FI-C3 [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: OC-EU1-J2 [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: OC-EU1-J3 [ ] 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: Attachment A [X] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID: _______ [X] 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

ATTACHMENT A

PSD REPORT

TABLE OF CONTENTS

LIST OF TABLES

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1.0 INTRODUCTION

Okeelanta Power Limited Partnership (OkPLP) operates a 74.9 megawatt electric (MWe) cogeneration facility located adjacent to the Okeelanta Corporation sugar mill, approximately 6 miles south of South Bay in Palm Beach County, Florida. The facility combusts primarily biomass (bagasse and wood) in three steam boilers to generate steam and electricity. The cogeneration facility also supplies the adjacent sugar mill with process steam during the sugar cane grinding season, approximately October through March, as well as the associated sugar refinery with process steam year around.

Construction was completed on the facility in 1995, and initial operations began in late 1995. However, the facility was operated at less than design capacity during 1996-1998. The facility operated normally during calendar year 1999.

All fuel burned in the facility boilers has been bagasse, wood and No. 2 fuel oil. Only a relatively small amount of No. 2 fuel oil has been combusted, with the majority of fuel combusted being bagasse and wood.

The OkPLP facility is operating under state construction permit (AC50-219413) and federal PSD permit (PSD-FL-196). The original permits were issued to OkPLP on September 27, 1993. The original permits have been modified several times. The latest amendment was permit no. 0990332-011-AC/PSD-FL-196K, issued October 31, 2000. This permit amended the provisions related to simultaneous operation of the OkPLP cogeneration boilers and the Okeelanta sugar mill boilers. OkPLP has recently requested approval to burn natural gas as a supplemental fuel, and the Department has given notice of its intent to approve this request (draft permit no. 0990332-013-AC; PSD-FL-196L, issued December 1, 2000).

The OkPLP facility boilers currently have emission limits for several pollutants, including carbon monoxide (CO), sulfur dioxide (SO_2), and sulfuric acid mist (SAM). OkPLP operates continuous emission monitoring systems (CEMS) to measure CO and

SO_2 emissions in the flue gases of each of the three cogeneration boilers. The emission limit for CO is 0.35 lb/MMBtu based on a 30-day rolling average. In late 1999, after an unusually wet fall, the 30-day rolling average emission limit was exceeded on the boilers. Since the excursions appear to be related to abnormally high moisture content fuel due to rainfall, and beyond the control of OkPLP, a change in the averaging time associated with the CO limit is indicated. Thus, OkPLP is requesting to change to a 12-month rolling average limit for CO. The requested changes in the CO permit limit will not increase total permitted annual CO emissions to the atmosphere.

The boilers have several limits for SO_2. For wood firing, the limits are 0.10 lb/MMBtu as a 24-hour average, and 0.05 lb/MMBtu as a 30-day rolling average. For bagasse firing, the limits are 0.10 lb/MMBtu as a 24-hour average, and 0.02 lb/MMBtu as a 30-day rolling average. In recent months, there have been several excursions of both the 24-hour average limit and the 30-day rolling average SO_2 emission limits. The reasons for this are believed to be variability in fuel sulfur content as well as the recent installation of the mechanical dust collectors on each boiler. As a result, OkPLP is requesting SO_2 emission limits for both wood and bagasse be increased to 0.20 lb/MMBtu for the 24-hour averaging time, and to 0.10 lb/MMBtu for the 30-day rolling average. An associated increase in the emission limit for SAM to 0.012 lb/MMBtu is also requested.

Permitted short-term SO_2 and SAM emissions due to biomass firing will increase. Permitted annual SO_2 emissions for the facility as a whole will not increase, because the permitted amount of coal burning will be reduced to offset the increase in SO_2 emissions due to burning biomass. This will in turn lower permitted emissions of fluorides. Permitted lead emissions will increase slightly due to the assumption of greater amounts of wood versus bagasse being burned, based on actual historical operation of the OkPLP facility.

Actual annual CO, SO_2, SAM and lead emissions may increase as a result of this request. The increase in actual annual CO, SO_2 and SAM emissions, based on the comparison between current actual emissions and future potential emissions, are above the PSD significant emission rates. Therefore, the changes require PSD new source review.

This report presents a description of the proposed emission limit changes, and the rational and supporting information for such changes. A complete description of the requested changes, including air emission rates, is presented in Section 2.0. The air quality review requirements for the project and new source review applicability are discussed in Section 3.0. The control technology evaluation required by PSD rules is presented in Section 4.0. A discussion of air quality impacts is presented in Section 5.0. Supportive information is contained in the appendices.

2.0 PROJECT DESCRIPTION

2.1 GENERAL

OkPLP operates a 74.9 megawatt electric (MWe) cogeneration facility located adjacent to the Okeelanta Corporation sugar mill, approximately 6 miles south of South Bay in Palm Beach County, Florida. The facility is currently operating under state construction permit no. AC50-219413 and federal PSD permit (PSD-FL-196). The original permits were issued to OkPLP on September 27, 1993. The original permits have been modified several times. The latest amendment was permit no. 0990332-011-AC/PSD-FL-196K, issued October 31, 2000. This permit amended the provisions related to simultaneous operation of the OkPLP cogeneration boilers and the Okeelanta sugar mill boilers.

Construction was completed on the facility in 1995, and initial operations began in late 1995. However, the facility was operated at less than design capacity during 1996-1998. The facility operated normally during calendar year 1999. Calendar year 2000 operation has been somewhat abnormal in that the boilers have experienced downtime due to installation of mechanical dust collectors on each boiler.

The facility combusts biomass (bagasse and wood) and fuel oil in three steam boilers to generate steam and electricity. OKPLP recently requested approval to burn natural gas as a supplemental fuel, and the Department has given notice of its intent to approve this request (Draft Permit No. 0990332-013-AC; PSD-FL-196L). Current plans are to retrofit the boilers with natural gas burners in the summer of 2001.

Each boiler is capable of producing up to an average of 455,418 lbs/hr steam. The cogeneration facility also supplies the adjacent sugar mill with process steam during the sugar cane grinding season, approximately October through March, as well as the associated sugar refinery with process steam year around. The fuel burned in the facility boilers to date has been primarily bagasse and wood. Only a relatively small amount of No. 2 fuel oil has been combusted.

The construction permit limits the maximum heat input to each of the three boilers to 715 million British thermal units per hour (MMBtu/hr) when firing biomass, and 490 MMBtu/hr when firing fossil fuels (No. 2 fuel oil or low sulfur coal). Maximum annual heat input to the entire facility is limited to 11.5×10^{12} Btu/yr. Maximum annual coal burning for the entire facility is limited to 69,720 tons during any 12 month period.

Air pollution control equipment serving each boiler consists of mechanical dust collectors and an electrostatic precipitator (ESP) to control particulate matter (PM) and heavy metal emissions, a selective non-catalytic reduction (SNCR) system for the control of NO_x emissions, and a carbon injection system for mercury control.

A regional map showing the location of the site is presented in Attachment OC-FI-C1 of the application form. A plot plan of the OkPLP cogeneration facility is presented in Attachment OC-FI-C2 of the application form.

2.2 REVISIONS TO PERMITTED BOILER EMISSION LIMITS

The changes to the facility emission limits now being proposed by OkPLP consist of the following:

1. Revising the averaging time associated with the CO emission limit from a 30-day rolling average to a 12-month rolling average.
2. Revising the emission limits for SO_2 from biomass (bagasse and wood) to 0.20 lb/MMBtu, 24-hour average, and 0.10 lb/MMBtu, 30-day rolling average.
3. In order to retain the current annual ton per year emission limit for SO_2, the maximum permitted annual amount of coal burning will be reduced.
4. Revising the emission limits for SAM from biomass to 0.012 lb/MMBtu, due to the change in SO_2 emission limits.
5. Revising the annual lead emission limit upwards to account for changes in the percentages of wood burned.
6. Revising the fluoride emission limit downward to account for less coal burning.

A more complete description of these changes as well as the rationale for the changes is presented below.

2.2.1 CARBON MONOXIDE

The current limit for CO emissions from biomass burning is 0.35 lb/MMBtu based on a 30-day rolling average. The 30-day rolling average was established on June 22, 1999, based on the operational history of the boilers and the CEMs which showed variability in CO emissions due to the nature of the biomass fuels burned at the facility. OkPLP had requested an increase in the numerical emission limit to 0.50 lb/MMBtu, but the FDEP denied this request.

In late 1999, excursions of the 0.35 lb/MMBtu, 30-day rolling average limit, were experienced in Boilers A, B, and C. These excursions followed shortly after several very significant rainfall events at the facility. It is believed that the cause of these excursions was higher moisture content of the biomass fuel due to these rainfall events. All of the wood fuel, and a portion of the bagasse fuel burned at the facility is stored in outside storage piles. The remaining portion of the bagasse fuel is conveyed from the adjacent sugar mill directly to the boilers. At the time of the excursions, and prior to the excursions, primarily wood fuel was burned in the boilers.

To illustrate the potential affects of rainfall on CO emissions, plots of monthly rainfall amounts versus the monthly average CO emission rate (in lb/MMBtu) from April 1998 through October 2000 for Units A, B, and C are shown in Figures 2-1, 2-2 and 2-3, respectively. Monthly rainfall amounts were obtained from the Belle Glade Experimental Station. The CO emissions represent the monthly average CO emission rate over all operating hours for the month.

The plots show a frequent increase in CO emissions in the months with large rainfall amounts, and/or in the months immediately following. For example, for the time period of May 1999 through October 1999, average monthly rainfall was about 8 inches per month. Each unit shows an increase in CO emissions through this period and a peak in emissions in the months following the heavy rainfall months (due to the accumulation of moisture in the biomass fuel pile).

These plots also show that in months with lower rainfall, OkPLP is typically well within the 30-day rolling average CO limit of 0.35 lb/MMBtu. A 12-month rolling average emissions limit for CO is sought to allow for potentially higher emissions which may be experienced during and following months of heavy rainfall. It is requested, based on this information, that the current CO permit limit for the boilers be revised to be based on a 12-month rolling average, to replace the current limit based on a 30-day rolling average. No change is requested in the current annual emission limit for the OkPLP facility of 2,012.5 TPY for all three boilers combined. In order to be consistent, it is requested that the averaging time for the CO limits for biomass, No. 2 fuel oil, natural gas, and coal all be specified as a 12-month rolling average.

2.2.2 SULFUR DIOXIDE

The current permit limits for SO_2 emissions from wood fuel firing are 0.10 lb/MMBtu for a 24-hour average, and 0.05 lb/MMBtu as a 30-day rolling average. The current permit limits for SO_2 emissions from bagasse fuel firing are 0.10 lb/MMBtu for a 24-hour average, and 0.02 lb/MMBtu as a 30-day rolling average. The current annual ton per year emission limit for SO_2 is 1,154.3 tons per year (TPY).

It is noted that the state air construction permit and PSD permit issued to OkPLP allowed revision of the annual average SO_2 emission limits for wood and bagasse, following the first two years of semi-annual stack testing (refer to Specific Conditions No. 20 and 24).

In recent months, excursions of both the 24-hour average and the 30-day rolling average SO_2 limits have been experienced at the facility. Therefore, an investigation into the causes of the higher SO_2 emissions was undertaken. Two factors were believed to be responsible for this increase in SO_2 emissions:

- Changes to the boiler and or control system that might affect SO_2 emissions.
- Changes in the wood fuel quality.

These factors are discussed in more detail in remainder of this section.

The only changes to the boilers or air emission control system at the facilities this year were the installation of the mechanical dust collectors on each boiler. However, this change is believed to have affected SO_2 emissions due to the nature of SO_2 removal inherent in the system, as described below.

SO_2 removal in the OkPLP boiler/control device system occurs due to the alkaline nature of wood and bagasse ash. Such removal has been documented previously by OkPLP (refer to a 1997 application to revise OkPLP's emission limits), by other bagasse boilers, and by wood fired boilers in the pulp and paper industry. SO_2, generated in the boiler due to sulfur in the biomass fuels, is absorbed by the alkaline fly ash as it contacts the ash particles within and downstream of the boiler. The amount of SO_2 absorption is dependent on several factors, including ratio of SO_2 to ash, and the time the SO_2 and ash have to react. The lower the SO_2/ash ratio and the longer the reaction time, the greater the SO_2 absorption.

Prior to the installation of the mechanical dust collectors at OkPLP, the effective reaction time was longer since the flue gases traversed a longer length of ductwork prior to the ash being removed in the ESP. The new dust collectors were installed immediately following the boiler air preheater. Based on ash generation, the dust collectors are removing about 80 percent of the particulate matter in the flue gases. Therefore, the effective contact time between the ash and the flue gases has been decreased significantly, since a majority of the ash is now removed well prior to the ESP. This results in lower inherent SO_2 removal.

Biomass fuel characteristics could also affect SO_2 emissions. Therefore, historic fuel analysis data were analyzed. OkPLP performs biomass sampling and analysis in conjunction with its compliance testing. OkPLP also obtains fuel analysis data on the biomass fired in the boilers on a routine basis.

Historical daily SO_2 emissions (in lb/MMBtu from the CEMs) for Boilers A, B, and C are shown for the period June 1999 through October 2000 in Figures 2-4, 2-5, and 2-6, respectively. For all three boilers, the data show an upwards trend beginning in February 2000. This was due to a change in the ratio of bagasse and wood burned. Beginning in February 2000, based on historical operating experience, OkPLP began to burn a mix of wood/bagasse typically in about a 44/55 ratio. Prior to this time, OkPLP would burn about 80 percent bagasse/20 percent wood during the sugar cane processing season, and about 20 percent bagasse/80 percent wood during the off-season. During the present sugar cane crop, OkPLP is typically burning 30 percent wood/70 percent bagasse.

The installation dates for the mechanical dust collectors for each boiler are also shown in Figures 2-4 through 2-6. For Boiler B, not enough post-installation data are available to render any conclusions. For Boiler A, the SO_2 emissions due appear to be higher than during any previous period, although the emissions drop off to pre-installation levels during October 2000. Boiler C provides the greatest amount of post-installation data. During June and July 2000, just after dust collector installation, the SO_2 emissions were much higher than any previous period, while falling to closer to pre-installation levels during August and September 2000. These data indicate that the dust collectors potentially had an effect upon SO_2 absorption in the system, although the data are not conclusive.

Historical sulfur fuel analysis data from OkPLP is shown in Tables A and B in the appendix. These data are summarized in terms of potential SO_2 emissions (lb/MMBtu) in Figures 2-7 and 2-8 for bagasse fuel and wood fuel, respectively. The sulfur analysis for bagasse are limited to two time periods: late December 1999 through early February 2000; and December 1999. The data shown in Figure 2-7 indicate little variability in the potential SO_2 emissions due to bagasse fuel, as well as little difference for the two time periods.

The sulfur analysis for wood covers a broader time period: early January 2000 through early February 2000; late December 1999 through early January 2000; and periodic analysis from April 2000 through October 2000. The data shown in Figure 2-8 indicate greater variability in the potential SO_2 emissions due to wood fuel. The data also indicate that beginning in August 2000 relatively high sulfur contents were experienced much more frequently compared to previous data.

Another method to analyze potential dust collector influence is to calculate the theoretical SO_2 removal efficiency for periods when biomass fuel analysis data are available. Presented in Figures 2-9 through 2-11 is the theoretical SO_2 removal efficiencies for each boiler plotted versus time. The efficiencies were calculated based on the fuel analysis for a particular day (usually taken during stack tests) and the average daily SO_2 emission rate as recorded by the CEMs. The detailed data are presented in Table C in the appendix.

As shown in the figures, significant SO_2 removal occurs within the boiler and air pollution control system, typically between 90 and 99 percent. For Boilers A and B, not enough post-dust collector installation data is available to draw any conclusions. For Boiler C, the data do not indicate a difference between the pre- and post- dust collector installation SO_2 removal efficiency, although the lowest daily removal efficiencies were experienced after the dust collector installations (i.e., less than 90 percent removal).

In conclusion, it is not clear as to the specific causes of the higher SO_2 emissions being experienced recently at OkPLP. Higher fuel sulfur contents have been experienced more frequently in recent months, but more fuel analysis data is available compared to previous periods.

SO_2 emissions from OkPLP's CEMs, discussed previously, have ranged up to 0.12 lb/MMBtu, 24-hour daily average. The highest 30-day rolling average SO_2 emission rate experienced to date has been 0.6 lb/MMBtu. In order to provide an adequate margin of safety for future operation, considering potential variability in the sulfur content of the fuels and in the inherent SO_2 absorption, the following is proposed:

1. A maximum 24-hour daily average SO_2 limit of 0.20 lb/MMBtu for both bagasse and wood, and
2. A 30-day rolling average SO_2 emission limit of 0.10 lb/MMBtu for both bagasse and wood.

Identical limits for bagasse and wood is desirable from a tracking standpoint, since OkPLP's normal mode of operation will be to burn a combination of wood and bagasse throughout the year. This will make tracking and determining compliance with the limits much simpler.

A related change OkPLP is proposing is to change the estimated ratio of wood to bagasse fuel burned at the facility on an annual basis. Previous annual emission estimates have been based on the assumption of 60 percent bagasse/40 percent wood burned on an annual basis. Based on historical operation, and since wood firing produced higher emission for several pollutants, compared to bagasse firing, OkPLP is changing the basis of the annual emissions to a 50/50 mix of wood and bagasse. Revised annual fuel usage, heat input, and emissions are provided in Tables 2-2 through 2-5.

In order to retain the current annual SO_2 emission limit for the facility of 1,154.3 TPY, it is proposed to reduce the current permitted amount of coal that can be burned from 69,720 TPY to 44,920 TPY. This will affect annual emissions for several pollutants.

2.2.3 SULFURIC ACID MIST

Emissions of SAM result from SO_2 emissions. Therefore, it is appropriate to increase the permitted SAM emission limit commensurate with the increase in SO_2 emissions. Maximum potential SAM emissions are estimated on the basis of EPA Publication AP-42, which for fuel oil firing indicates that approximately 5 percent of SO_2 becomes SO_3 in the stack gas. The SO_3 is than converted to H_2SO_4 on the basis of molecular weights. The proposed SAM emission limit is therefore calculated as follows:

$$0.20 \text{ lb/MMBtu } SO_2 \times 0.05 \times 98/80 = 0.012 \text{ lb/MMBtu}$$

2.3 EMISSION RATES FOR REGULATED POLLUTANTS

Proposed maximum short-term emissions of CO, SO_2 and SAM for the OkPLP boilers are presented in Table 2-1. This table reflects the proposed SO_2, CO and SAM emission limits for biomass firing, as well as the current limits for No. 2 fuel oil and coal firing, which are not changing except for the averaging time associated with the CO emission limit.

The revised annual fuel usage and heat input rates, per boiler and for the combined operation of all three boilers, is shown in Tables 2-2 and 2-3, respectively. Note that the total annual fuel usage estimates, shown in Table 2-2, are based on 53.9 percent bagasse and 46.1 percent wood (instead of a 50/50 ratio) in order to estimate the maximum amount of total biomass which could be burned.

The maximum annual emissions per boiler for each fuel scenario, incorporating the revised emission limits, reduced coal firing and revised bagasse/wood ratio, are presented in Table 2-4. The combined maximum annual emissions for all three boilers are shown in Table 2-5. The maximum annual emissions for all of the criteria/designated pollutants are the same as currently permitted, except for the case of lead, fluorides and SAM. For Pb, annual emissions are slightly higher than currently permitted due to the assumption of greater amounts of wood versus bagasse being burned. Fluorides emissions are reduced due to the reduction in the amount of coal that can be burned. SAM emissions are increased due to the increase in SO_2 emissions from biomass.

2.4 ADDITIONAL REQUESTED CHANGES

The current construction permit for OkPLP requires that levels of chromium, copper and arsenic in the wood fuel not exceed specified levels (refer to Specific Condition 12 of the construction permit). In addition, Specific Condition 24 of the permit requires that semi-annual stack testing be performed for chromium, copper and arsenic. Annual stack testing is required thereafter, provided that the semi-annual testing demonstrates compliance with the facility emission limits. There are no emission limits for chromium, copper or arsenic.

The wood fuel concentration limits and stack testing were required due to Florida's Air Toxics Policy, which established Florida Air Reference Concentrations (FARCs). However, the FARCs are no longer in effect. It is therefore requested that the fuel concentration limits and the requirement to test stack emissions for chromium, copper and arsenic be deleted. OkPLP will continue to implement their fuel testing, management and inspection program in order to insure that undesirable materials are not burned in the boilers.

3.0 AIR QUALITY REVIEW REQUIREMENTS AND SOURCE APPLICABILITY

OkPLP is proposing changes to the emission limits for five pollutants and desires to amend the current PSD construction permit. The averaging time specified for the CO emissions limit for all fuels is also being revised. The requested emissions from the boilers are not greater than the currently permitted emissions, except in regards to annual emissions of lead and SAM.

A PSD source applicability analysis for OkPLP, incorporating these changes, is provided in Table 3-1. Current baseline emissions for CO and SO_2 were presented in OkPLP's application to burn natural gas (November 14, 2000, submittal letter by Golder Associates). An excerpt from this letter is provided in the appendix for ease of reference. Current baseline emissions for lead, beryllium and SAM are presented in the appendix.

As shown in Table 3-1, based on the permit limits and the current OkPLP annual emissions, PSD review is triggered for CO, SO_2, fluorides and SAM. The PSD review requirements are addressed in the following discussion.

OkPLP is not proposing to increase maximum permitted short-term or annual emissions of SO_2. OkPLP has previously performed air quality modeling analysis for SO_2 and CO emissions. The previous modeling demonstrated compliance with ambient standards and increments. These analyses would not change based on the proposed changes OkPLP is requesting.

OkPLP is currently employing best available control technology (BACT) to control pollutant emissions. SO_2 emissions from biomass or No. 2 fuel oil are very low, which renders any add-on control equipment, such as flue gas desulfurization, too costly. Potential coal burning at OkPLP, although not likely to occur, is now limited to less than 10 percent on an annual heat input basis. This low level of potential coal burning also does not warrant any add-on control equipment, particularly considering that low sulfur coal would be burned.

Emissions of SAM and fluorides are related to SO_2 emissions and the amount of coal burned. Therefore, BACT for SO_2 also represents BACT for these pollutants (i.e., no add-on control equipment and burning of limited amounts of low sulfur coal).

Table 2-1. Revised Maximum Short-Term Emissions for OkPLP Cogeneration Facility (per boiler)

Regulated Pollutant	Biomass			No. 2 Fuel Oil			Coal			Natural Gas			Maximum Emissions for any fuel (lb/hr)
	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Activity Factor (MMBtu/hr)	Maximum Emissions (lb/hr)	
Sulfur dioxide [a]	0.20	715	143.0	0.05	490	24.5	1.2	490	588.0	0.00058	605	0.4	588.0
Carbon monoxide [a]	1.0	715	715.0	1.0	490	490.0	1.0	490	490.0	0.08	605	48.4	715.0
Sulfuric acid mist	0.012	715	8.58	0.0015	490	0.74	0.036	490	17.64	3.55E-05	605	0.02	17.64

[a] 24-hour daily average.

Table 2-2. Maximum Fuel Usage and Heat Input Rates per Boiler, Okeelanta Power Limited Partnership

Fuel	Heat Input	Heat Transfer Efficiency (%)	Heat Output	Fuel Firing Rate	
	Maximum Short-Term (per boiler)				
	(MMBtu/hr)		(MMBtu/hr)		
Biomass - Bagasse	715	68	486	195,730	lb/hr [a]
- Wood	715	68	486	158,748	lb/hr [b]
No. 2 Fuel Oil	490	85	417	3,551	gal/hr
Natural Gas	605	85	514	605,000	scf/hr
Coal	490	85	417	40,833	lb/hr
	Annual Average (per boiler)				
	(Btu/yr)		(Btu/yr)		
NORMAL OPERATIONS (100% BIOMASS)					
Biomass	6.263E+12	68	4.259E+12	857,295	TPY [a]
No. 2 Fuel Oil	0	85	0	0	gal/yr
Natural Gas	0	85	0	0	MMscf/yr
Coal	0	85	0	0	TPY
TOTAL	6.263E+12		4.259E+12		
24.9% OIL FIRING					
Biomass	4.428E+12	68	3.011E+12	606,077	TPY [a]
No. 2 Fuel Oil	1.468E+12	85	1.248E+12	10,638,685	gal/yr
Natural Gas	0	85	0	0	MMscf/yr
Coal	0	85	0	0	TPY
TOTAL	5.896E+12		4.259E+12		
24.9% NATURAL GAS FIRING					
Biomass	4.428E+12	68	3.011E+12	606,077	TPY [a]
No. 2 Fuel Oil	0	85	0	0	gal/yr
Natural Gas	1.468E+12	85	1.248E+12	1,468	MMscf/yr
Coal	0	85	0	0	TPY
TOTAL	5.896E+12		4.259E+12		
18.0% COAL FIRING					
Biomass	4.915E+12	68	3.342E+12	672,735	TPY [a]
No. 2 Fuel Oil	0	85	0	0	gal/yr
Natural Gas	0	85	0	0	MMscf/yr
Coal	1.078E+12	85	9.164E+11	44,920	TPY
TOTAL	5.993E+12		4.259E+12		

[a] Based on bagasse firing.

[b] Based on wood firing.

Notes:

40 CFR 60, Subpart Da, limits fossil-fuel firing to less than 25% for each boiler (heat input basis).

Total heat output required = 4.259E+12 Btu/yr per boiler.

Fuels may be burned in combination, not to exceed total heat outputs.

Based on fuel heating values as follows:

- Bagasse - 3,653 Btu/lb
- Wood - 4,504 Btu/lb
- No. 2 Fuel Oil - 138,000 Btu/gal
- Coal - 12,000 Btu/lb
- Natural gas - 1,000 Btu/scf

Table 2-3. Maximum Fuel Usage and Heat Input Rates, Total All Three Boilers, OkPLP

Fuel	Heat Input		Heat Transfer Efficiency (%)	Heat Output		Fuel Firing Rate	
			Maximum Annual Average (total all three boilers)				
NORMAL OPERATIONS							
Biomass	1.150E+13	Btu/yr	68	7.820E+12	Btu/yr	1,436,945	TPY [a]
No. 2 Oil	0	Btu/yr	85	0	Btu/yr	0	gal/yr
Natural Gas	0	Btu/yr	85	0	Btu/yr	0	MMscf/yr
Coal	0	Btu/yr	85	0	Btu/yr	0	TPY
TOTAL	1.150E+13	Btu/yr		7.820E+12	Btu/yr		
24.9% OIL FIRING							
Biomass	8.130E+12	Btu/yr	68	5.528E+12	Btu/yr	1,015,857	TPY [a]
No. 2 Oil	2.696E+12	Btu/yr	85	2.291E+12	Btu/yr	19,533,086	gal/yr
Natural Gas	0	Btu/yr	85	0	Btu/yr	0	MMscf/yr
Coal	0	Btu/yr	85	0	Btu/yr	0	TPY
TOTAL	1.083E+13	Btu/yr		7.820E+12	Btu/yr		
24.9% NATURAL GAS FIRING							
Biomass	8.130E+12	Btu/yr	68	5.528E+12	Btu/yr	1,015,857	TPY [a]
No. 2 Oil	0	Btu/yr	85	0	Btu/yr	0	gal/yr
Natural Gas	2.696E+12	Btu/yr	85	2.291E+12	Btu/yr	2,696	MMscf/yr
Coal	0	Btu/yr	85	0	Btu/yr	0	TPY
TOTAL	1.083E+13	Btu/yr		7.820E+12	Btu/yr		
9.6% COAL FIRING							
Biomass	1.0152E+13	Btu/yr	68	6.903E+12	Btu/yr	1,268,510	TPY [a]
No. 2 Oil	0	Btu/yr	85	0	Btu/yr	0	gal/yr
Natural Gas	0	Btu/yr	85	0	Btu/yr	0	MMscf/yr
Coal	1.078E+12	Btu/yr	85	9.164E+11	Btu/yr	44,920	TPY
TOTAL	1.123E+13	Btu/yr		7.820E+12	Btu/yr		

[a] Assumes 53.9% of annual heat input from bagasse, and 46.1% from wood.

Note: Total heat output required = 486 MMBtu/hr each boiler, and
7.820E+12 Btu/yr total all boilers.
Fuels may be burned in combination, not to exceed indicated total heat outputs.

Table 2-4. Maximum Annual Emissions for Single Boiler at Okeelanta Power Cogeneration Facility

Regulated Pollutant	Biomass Emission Factor (lb/MMBtu)	Biomass Activity Factor (E12 Btu/yr)	Biomass Annual Emissions (TPY)	Alternate Fuel Emission Factor (lb/MMBtu)	Alternate Fuel Activity Factor (E12 Btu/yr)	Alternate Fuel Annual Emissions (TPY)	Total Annual Emissions (TPY)
			100% Biomass				
Particulate (TSP)	0.03	6.263	93.95	–	–	–	93.95 [a]
Particulate (PM_{10})	0.03	6.263	93.95	–	–	–	93.95 [a]
Sulfur dioxide	0.10	6.263	313.15	–	–	–	313.15
Nitrogen oxides	0.15	6.263	469.73	–	–	–	469.73 [a]
Carbon monoxide	0.35	6.263	1,096.03	–	–	–	1,096.03 [a]
VOC	0.06	6.263	187.89	–	–	–	187.89 [a]
Lead - Bagasse	2.5E-05	3.132 [b]	0.039	–	–	–	0.290 [a]
- Wood	1.6E-04	3.132 [c]	0.251				
Mercury - Bagasse	5.43E-06	3.132 [b]	0.0085	–	–	–	0.0148
- Wood	4.00E-06	3.132 [c]	0.00626				
Beryllium	–	–	–	–	–	–	–
Fluorides	–	–	–	–	–	–	–
Sulfuric acid mist	0.0061	6.263	19.10	–	–	–	19.10
			75.1% Biomass / 24.9% Fuel Oil				
Particulate (TSP)	0.03	4.428	66.42	0.03	1.468	22.02	88.44
Particulate (PM_{10})	0.03	4.428	66.42	0.03	1.468	22.02	88.44
Sulfur dioxide	0.02	4.428	44.28	0.05	1.468	36.70	80.98
Nitrogen oxides	0.15	4.428	332.10	0.15	1.468	110.10	442.20
Carbon monoxide	0.35	4.428	774.90	0.35	1.468	256.90	1,031.80
VOC	0.06	4.428	132.84	0.03	1.468	22.02	154.86
Lead - Bagasse	2.5E-05	2.214 [b]	0.028	8.9E-07	1.468	0.0007	0.205
- Wood	1.6E-04	2.214 [c]	0.177				
Mercury - Bagasse	5.43E-06	2.214 [b]	0.0060	2.4E-06	1.468	0.0018	0.0122
- Wood	4.00E-06	2.214 [c]	0.00443				
Beryllium	–	–	–	3.5E-07	1.468	0.00026	0.00026
Fluorides	–	–	–	6.27E-06	1.468	0.0046	0.0046
Sulfuric acid mist	0.0061	4.428	13.51	0.0015	1.468	1.10	14.61
			75.1% Biomass / 24.9% Natural Gas				
Particulate (TSP)	0.03	4.428	66.42	0.0073	1.468	5.36	71.78
Particulate (PM_{10})	0.03	4.428	66.42	0.0073	1.468	5.36	71.78
Sulfur dioxide	0.02	4.428	44.28	0.00058	1.468	0.43	44.71
Nitrogen oxides	0.15	4.428	332.10	0.15	1.468	110.10	442.20
Carbon monoxide	0.35	4.428	774.90	0.08	1.468	58.72	833.62
VOC	0.06	4.428	132.84	0.0053	1.468	3.89	136.73
Lead - Bagasse	2.5E-05	2.214 [b]	0.028	4.8E-07	1.468	0.0004	0.205
- Wood	1.6E-04	2.214 [c]	0.177				
Mercury - Bagasse	5.43E-06	2.214 [b]	0.0060	2.5E-07	1.468	0.0002	0.0106
- Wood	4.00E-06	2.214 [c]	0.00443				
Beryllium	–	–	–	1.2E-08	1.468	0.00001	0.00001
Fluorides	–	–	–	–	–	–	–
Sulfuric acid mist	0.0061	4.428	13.51	3.55E-05	1.468	0.03	13.53
			82.0% Biomass / 18.0% Coal				
Particulate (TSP)	0.03	4.915	73.73	0.03	1.078	16.17	89.90
Particulate (PM_{10})	0.03	4.915	73.73	0.03	1.078	16.17	89.90
Sulfur dioxide	0.02	4.915	49.15	1.2	1.078	646.80	695.95 [a]
Nitrogen oxides	0.15	4.915	368.63	0.17	1.078	91.63	460.26
Carbon monoxide	0.35	4.915	860.13	0.35	1.078	188.65	1,048.8
VOC	0.06	4.915	147.45	0.03	1.078	16.17	163.62
Lead - Bagasse	2.5E-05	2.458 [b]	0.031	6.4E-05	1.078	0.0345	0.2618
- Wood	1.6E-04	2.458 [c]	0.197				
Mercury - Bagasse	5.43E-06	2.458 [b]	0.0067	8.4E-06	1.078	0.0045	0.0161 [a]
- Wood	4.00E-06	2.458 [c]	0.00492				
Beryllium	–	–	–	5.9E-06	1.078	0.0032	0.0032 [a]
Fluorides	–	–	–	0.024	1.078	12.94	12.94 [a]
Sulfuric acid mist	0.0061	4.915	14.99	0.036	1.078	19.40	34.39 [a]

[a] Denotes maximum annual emissions for any fuel scenario.
[b] Represents 50% of total heat input due to bagasse.
[c] Represents 50% of total heat input due to wood.
Note: No emissions of total reduced sulfur, asbestos, or vinyl chloride are expected.
Fuel type percentages are based on heat input.

Table 2-5. Maximum Annual Emissions for Okeelanta Power Cogeneration Facility (total all boilers)

Regulated Pollutant	Biomass Emission Factor (lb/MMBtu)	Biomass Activity Factor (E12 Btu/yr)	Biomass Annual Emissions (TPY)	Alternate Fuel Emission Factor (lb/MMBtu)	Alternate Fuel Activity Factor (E12 Btu/yr)	Alternate Fuel Annual Emissions (TPY)	Total Annual Emissions (TPY)
			100% Biomass				
Particulate (TSP)	0.03	11.500	172.50	–	–	–	172.50 [a]
Particulate (PM_{10})	0.03	11.500	172.50	–	–	–	172.50 [a]
Sulfur dioxide	0.10	11.500	575.00	–	–	–	575.00
Nitrogen oxides	0.15	11.500	862.50	–	–	–	862.50 [a]
Carbon monoxide	0.35	11.500	2,012.50	–	–	–	2,012.50 [a]
VOC	0.06	11.500	345.00	–	–	–	345.00 [a]
Lead - Bagasse	2.5E-05	5.750 [b]	0.072	–	–	–	0.532 [a]
- Wood	1.6E-04	5.750 [c]	0.460				
Mercury - Bagasse	5.43E-06	5.750 [b]	0.0156	–	–	–	0.0271
- Wood	4.00E-06	5.750 [c]	0.01150				
Beryllium	–	–	–	–	–	–	–
Fluorides	–	–	–	–	–	–	–
Sulfuric acid mist	0.0061	11.500	35.08	–	–	–	35.08
			75.1% Biomass / 24.9% Fuel Oil				
Particulate (TSP)	0.03	8.130	121.95	0.03	2.696	40.44	162.39
Particulate (PM_{10})	0.03	8.130	121.95	0.03	2.696	40.44	162.39
Sulfur dioxide	0.10	8.130	406.50	0.05	2.696	67.40	473.90
Nitrogen oxides	0.15	8.130	609.75	0.15	2.696	202.20	811.95
Carbon monoxide	0.35	8.130	1,422.75	0.35	2.696	471.80	1,894.55
VOC	0.06	8.130	243.90	0.03	2.696	40.44	284.34
Lead - Bagasse	2.5E-05	4.065 [b]	0.051	8.9E-07	2.696	0.0012	0.377
- Wood	1.6E-04	4.065 [c]	0.325				
Mercury - Bagasse	5.43E-06	4.065 [b]	0.0110	2.4E-06	2.696	0.0032	0.0224
- Wood	4.00E-06	4.065 [c]	0.00813				
Beryllium	–	–	–	3.5E-07	2.696	0.00047	0.00047
Fluorides	–	–	–	6.27E-06	2.696	0.0085	0.0085
Sulfuric acid mist	0.0061	8.130	24.80	0.0015	2.696	2.02	26.82
			75.1% Biomass / 24.9% Natural Gas				
Particulate (TSP)	0.03	8.130	121.95	0.0073	2.696	9.84	131.79
Particulate (PM_{10})	0.03	8.130	121.95	0.0073	2.696	9.84	131.79
Sulfur dioxide	0.10	8.130	406.50	0.00058	2.696	0.78	407.28
Nitrogen oxides	0.15	8.130	609.75	0.15	2.696	202.20	811.95
Carbon monoxide	0.35	8.130	1,422.75	0.08	2.696	107.84	1,530.59
VOC	0.06	8.130	243.90	0.0053	2.696	7.14	251.04
Lead - Bagasse	2.5E-05	4.065 [b]	0.051	4.8E-07	2.696	0.0006	0.377
- Wood	1.6E-04	4.065 [c]	0.325				
Mercury - Bagasse	5.43E-06	4.065 [b]	0.0110	2.5E-07	2.696	0.0003	0.0195
- Wood	4.00E-06	4.065 [c]	0.00813				
Beryllium	–	–	–	1.2E-08	2.696	0.00002	0.00002
Fluorides	–	–	–	–	–	–	–
Sulfuric acid mist	0.0061	8.130	24.80	3.55E-05	2.696	0.05	24.84
			90.4% Biomass / 9.60% Coal				
Particulate (TSP)	0.03	10.152	152.28	0.03	1.078	16.17	168.45
Particulate (PM_{10})	0.03	10.152	152.28	0.03	1.078	16.17	168.45
Sulfur dioxide	0.10	10.152	507.60	1.2	1.078	646.80	1,154.40 [a]
Nitrogen oxides	0.15	10.152	761.40	0.17	1.078	91.63	853.03
Carbon monoxide	0.35	10.152	1,776.60	0.35	1.078	188.65	1,965.25
VOC	0.06	10.152	304.56	0.03	1.078	16.17	320.73
Lead - Bagasse	2.5E-05	5.076 [b]	0.063	6.4E-05	1.078	0.0345	0.504
- Wood	1.6E-04	5.076 [c]	0.406				
Mercury - Bagasse	5.43E-06	5.076 [b]	0.0138	8.4E-06	1.078	0.0045	0.0285 [a]
- Wood	4.00E-06	5.076 [c]	0.01015				
Beryllium	–	–	–	5.9E-06	1.078	0.0032	0.0032 [a]
Fluorides	–	–	–	0.024	1.078	12.94	12.94 [a]
Sulfuric acid mist	0.0061	10.152	30.96	0.036	1.078	19.40	50.37 [a]

[a] Denotes maximum annual emissions for any fuel scenario.

[b] Represents 50% of total heat input due to bagasse.

[c] Represents 50% of total heat input due to wood.

Note: No emissions of total reduced sulfur, asbestos, or vinyl chloride are expected.

Table 3-1. Current Actual and Future Potential Emissions, Okeelanta Power L.P.

Boiler	Operating Hours[a]	Heat Input[a] (MMBtu/yr)	Annual Emissions (TPY) CO	SO_2	Lead	Fl	SAM
Boiler A	7,265	3,824,398	478.34	47.11	0.047	0.154	5.7
Boiler B	5,927	3,206,304	485.29	38.32	0.076	0.073	4.8
Boiler C	6,978	3,694,714	562.44	47.80	0.334	0.124	5.5
Total	20,170	10,725,416	1,526.07	133.23	0.456	0.352	16.0
Requested Permit Limit		11,500,000	2,012.5	1,154.4	0.532	12.94	50.37
Net Increase			486.4	1,021.2	0.076	12.59	34.34
PSD Significant Emission Rate			100	40	0.6	3	7

[a] Based on the period April 1999 through March 2000.

Table 3-2. Current Actual PM, PM_{10}, and VOC Emissions for OkPLP Boilers

Parameter		Lead	Fluorides	Sulfuric Acid Mist		Lead	Fluorides	Sulfuric Acid Mist		Lead	Fluorides	Sulfuric Acid Mist
		Boiler A				Boiler B				Boiler C		
Emission Factor (lb/MMBtu)												
Wood waste [a]		2.96E-05	9.38E-05	0.003		8.39E-05	5.07E-05	0.003		3.97E-04	1.13E-04	0.003
Bagasse [a]		2.03E-05	7.06E-05	0.003		7.30E-06	4.07E-05	0.003		6.29E-06	3.04E-05	0.003
No. 2 Fuel [b]		8.90E-07	6.30E-06	0.0015		8.90E-07	6.30E-06	0.0015		8.90E-07	6.30E-06	0.0015
Heat Input (MMBtu/yr) [c]												
Wood	45.68%	1,746,985	1,746,985	1,746,985	52.05%	1,668,881	1,668,881	1,668,881	44.68%	1,650,798	1,650,798	1,650,798
Bagasse	53.69%	2,053,319	2,053,319	2,053,319	47.34%	1,517,864	1,517,864	1,517,864	54.48%	2,012,880	2,012,880	2,012,880
No. 2	0.63%	24,094	24,094	24,094	0.61%	19,558	19,558	19,558	0.84%	31,036	31,036	31,036
Total		3,824,398	3,824,398	3,824,398		3,206,304	3,206,304	3,206,304		3,694,714	3,694,714	3,694,714
Emissions (TPY)												
April 1999 - March 200(Emissions		0.047	0.154	5.7		0.076	0.073	4.8		0.33	0.124	5.5

[a] Based on actual stack test data for the fuel type.

[b] Based upon permit limit.

[c] Based upon actual boiler heat input for period April 1999 - March 2000.

Figure 2-1. OkPLP Boiler A
Rainfall vs. Carbon Monoxide (Monthly Average)

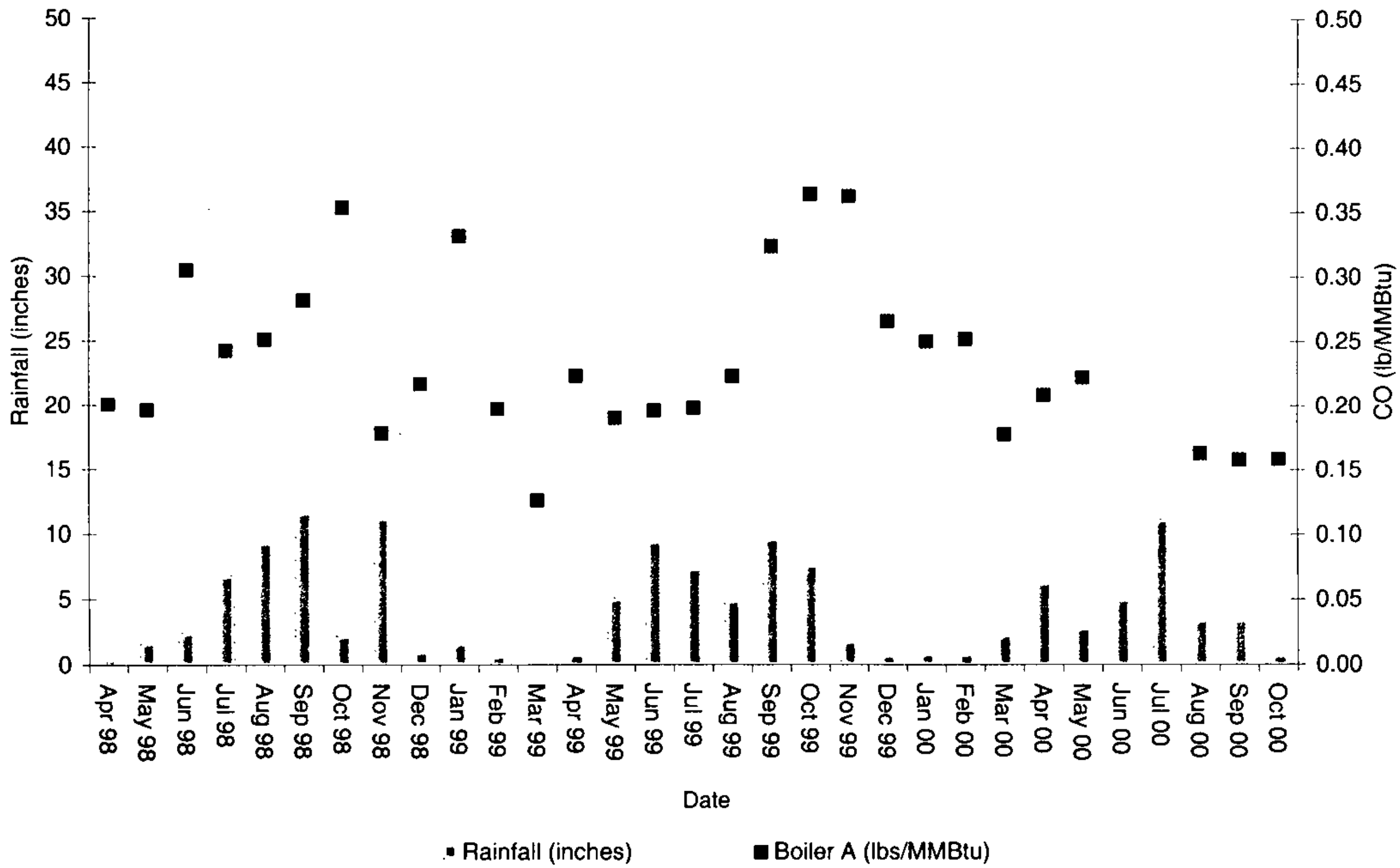


Figure 2-2. OkPLP Boiler B
Rainfall vs. Carbon Monoxide (Monthly Average)

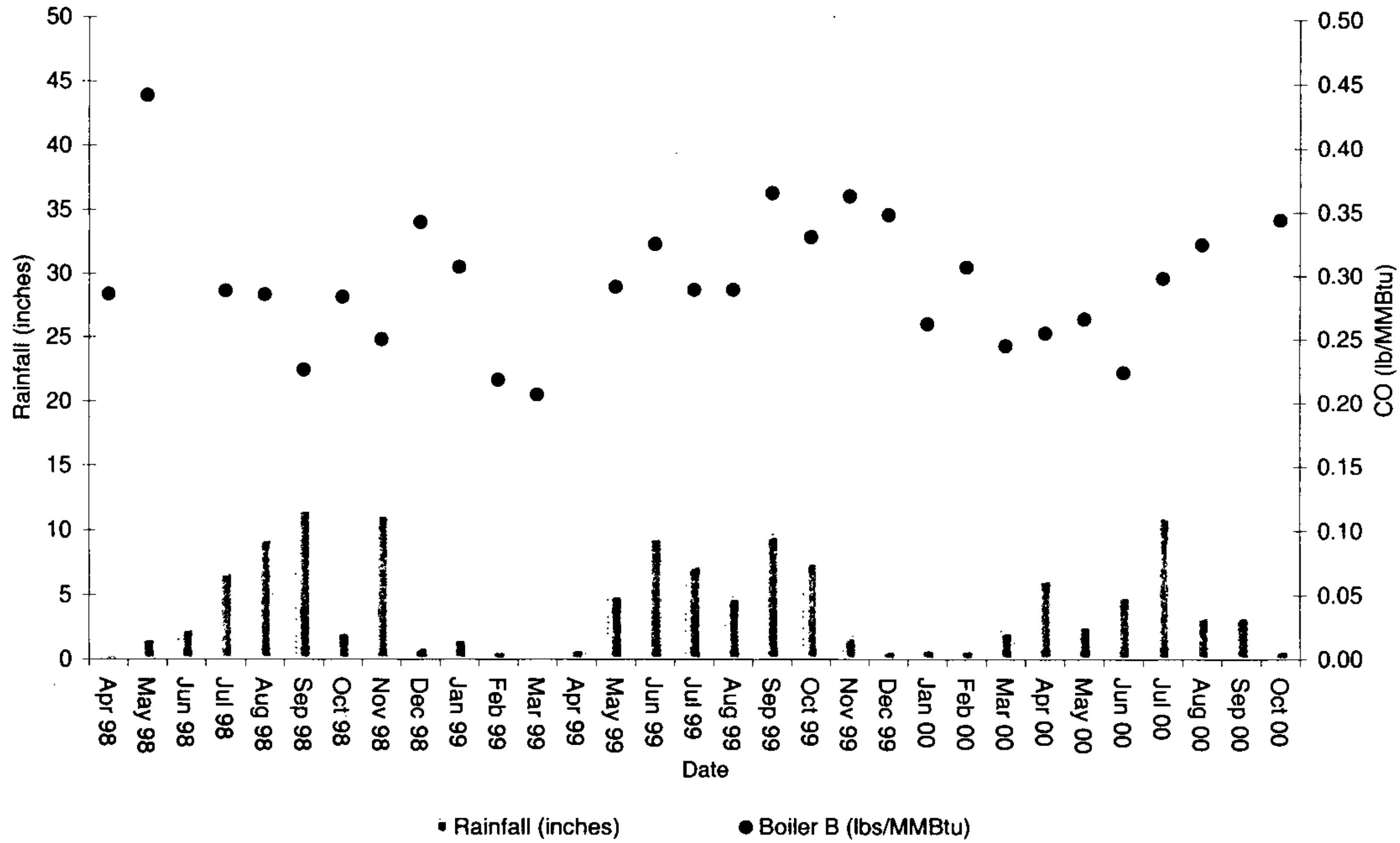


Figure 2-3. OkPLP Boiler C
Rainfall vs. Carbon Monoxide (Monthly Average)

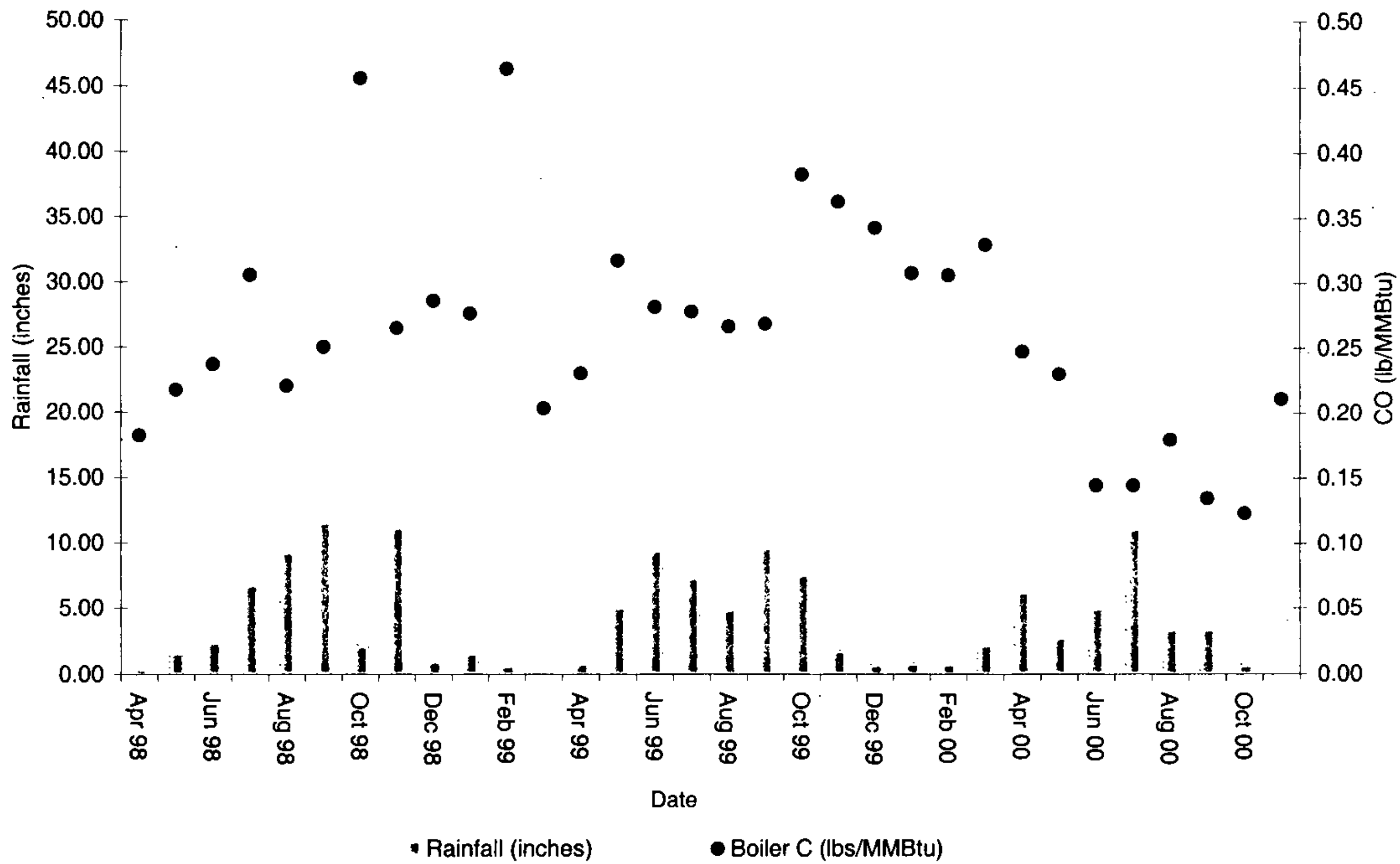


Figure 2-4. Unit A: Actual Daily SO_2 Emissions
June 1999 - October 2000

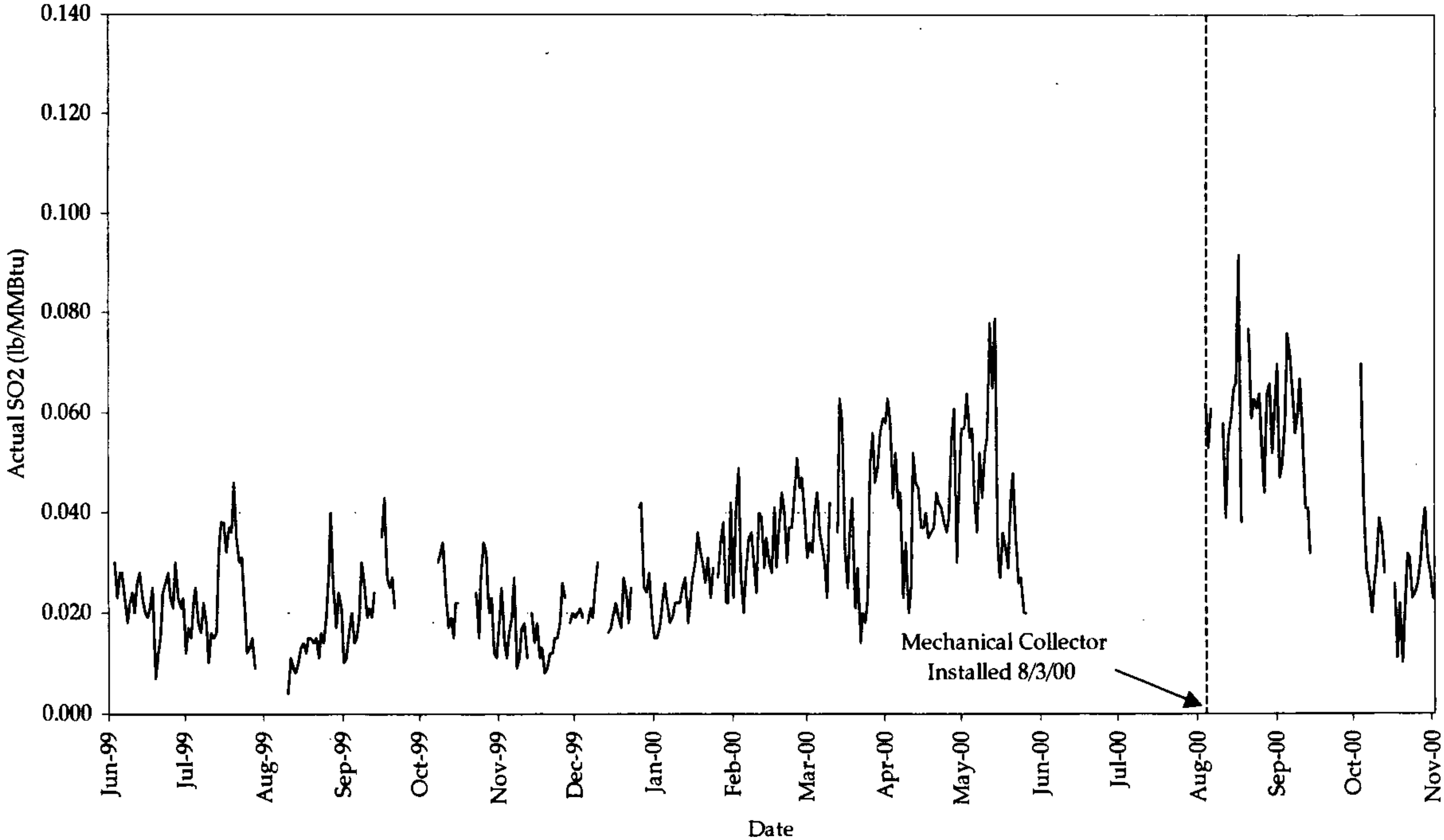


Figure 2-5. Unit B: Actual Daily SO_2 Emissions
June 1999 - October 2000

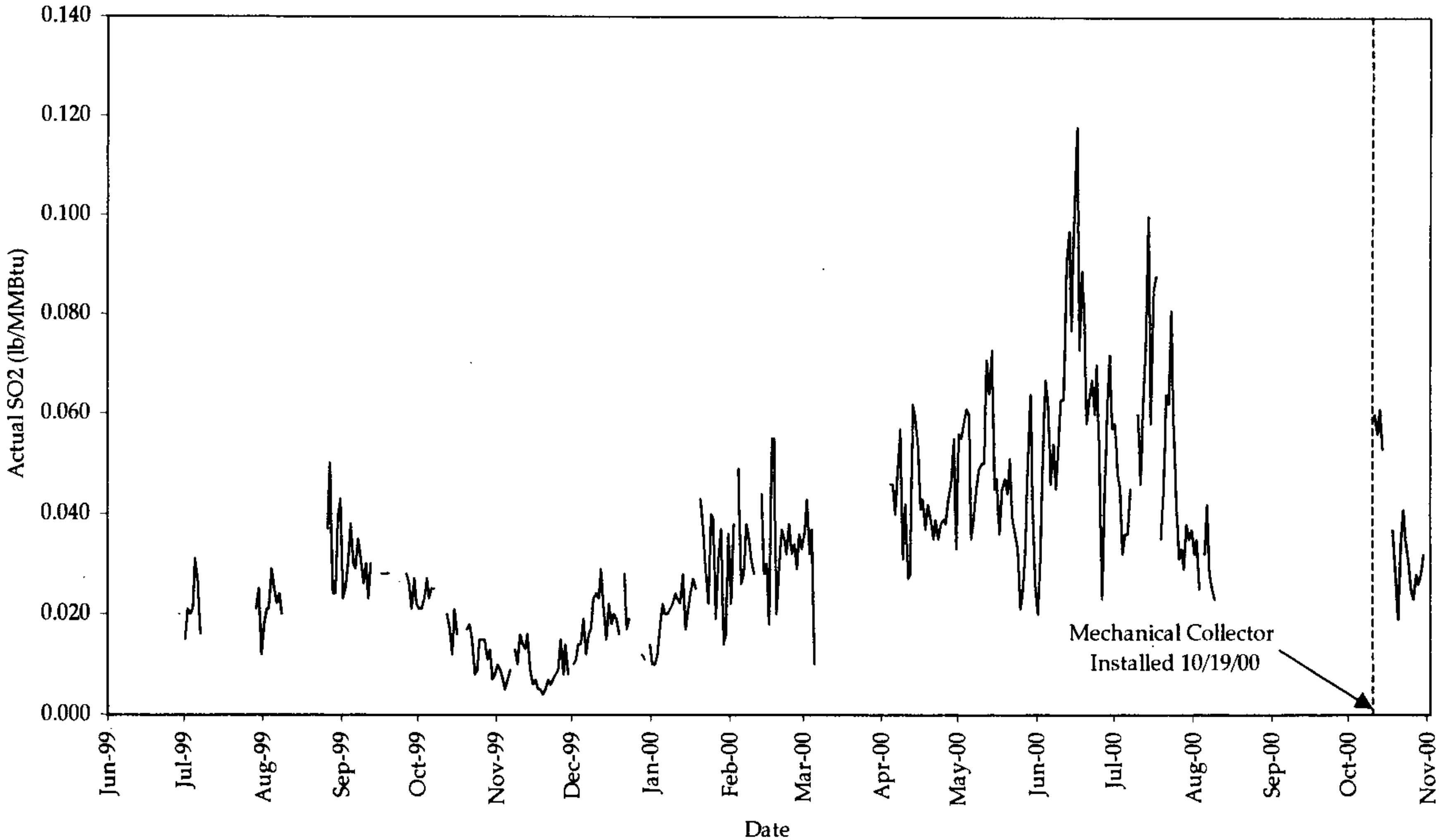
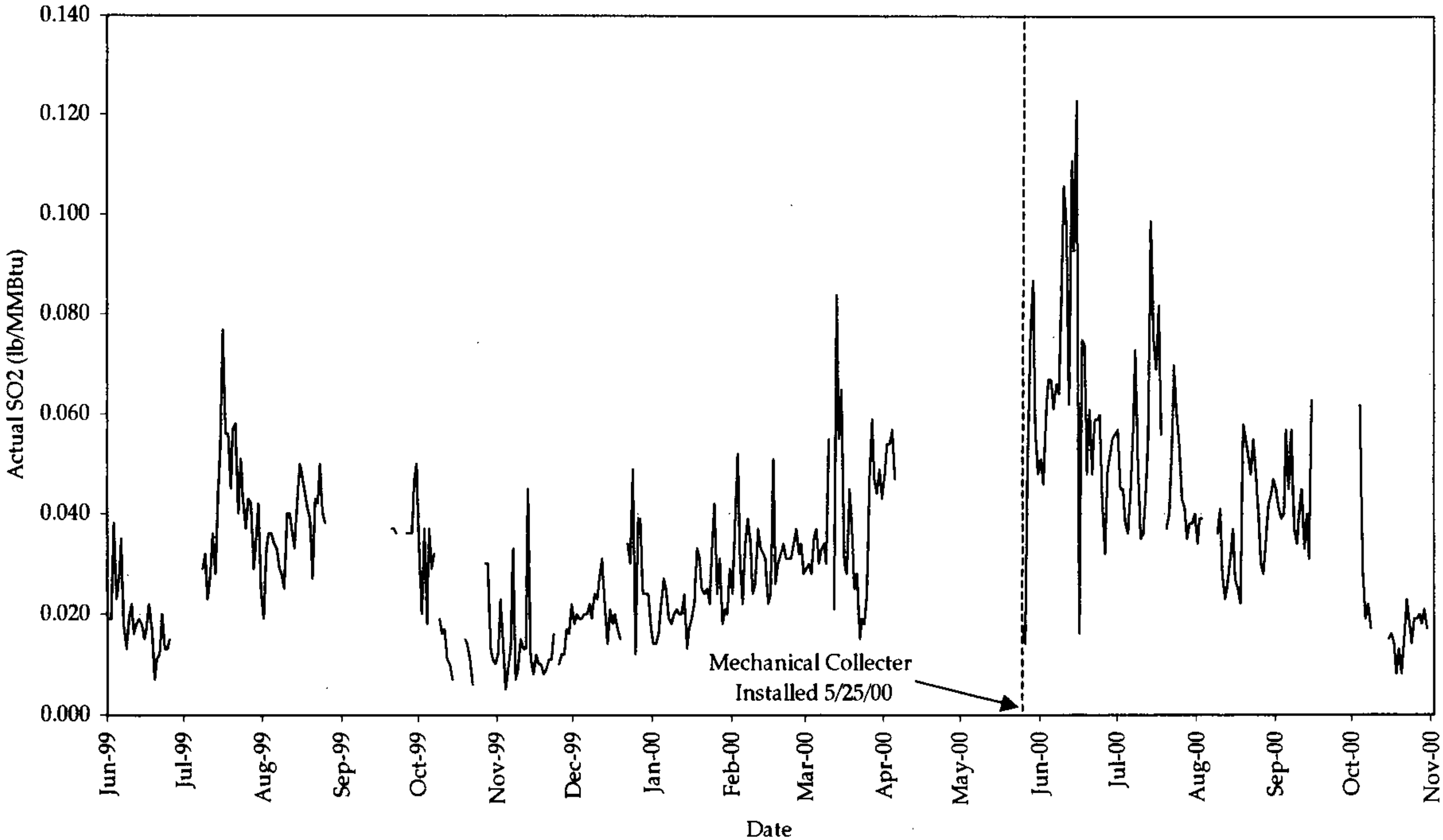


Figure 2-6. Unit C: Actual Daily SO_2 Emissions
June 1999 - October 2000



0037584Y/F1/WP/Fuel S.xls
Bag plot 12/11/00

Figure 2-7. Potential SO_2 Emissions from Bagasse Fuel
12/98 - 12/99

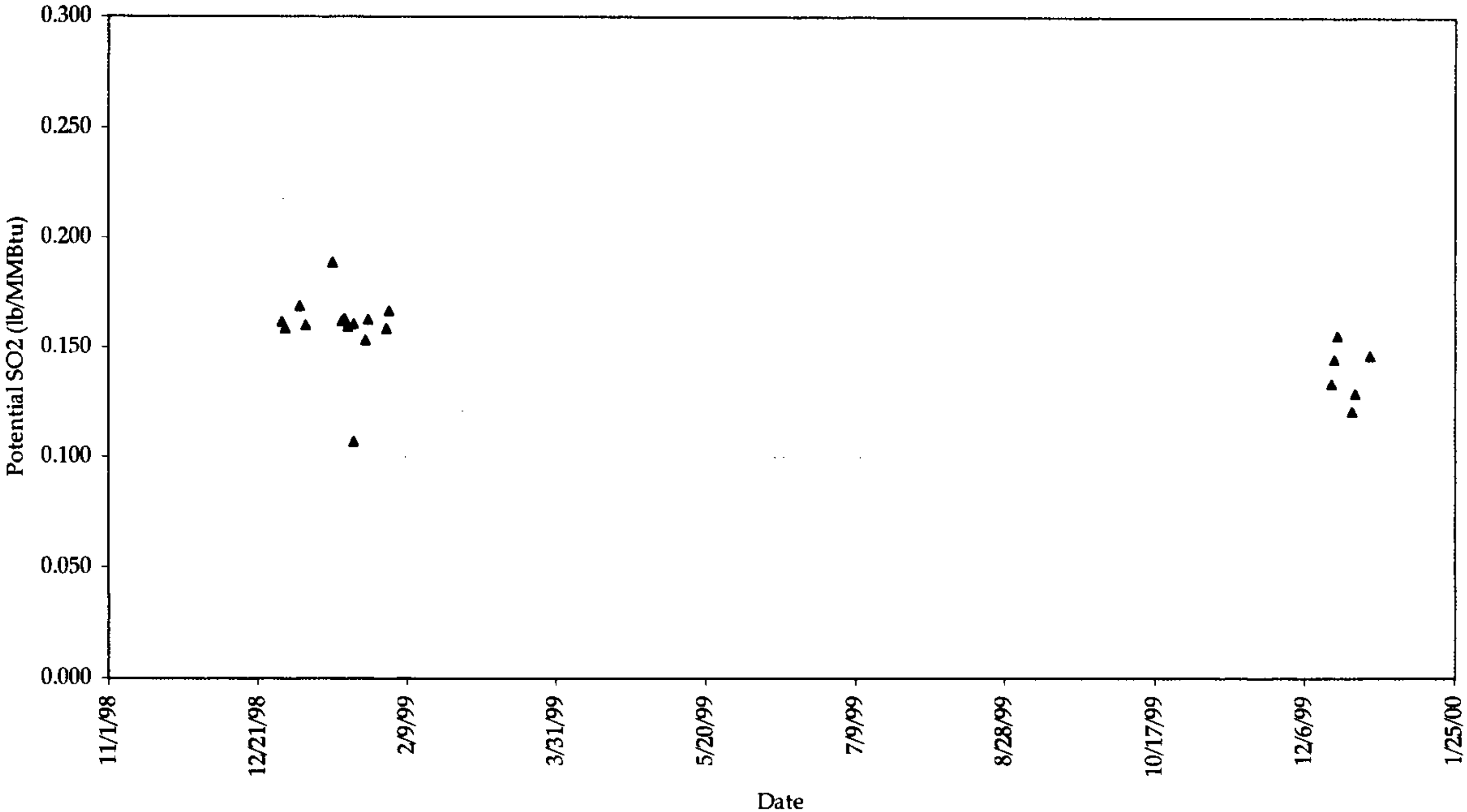


Figure 2-8. Potential SO_2 Emissions from Wood Fuel
1/99 - 10/00

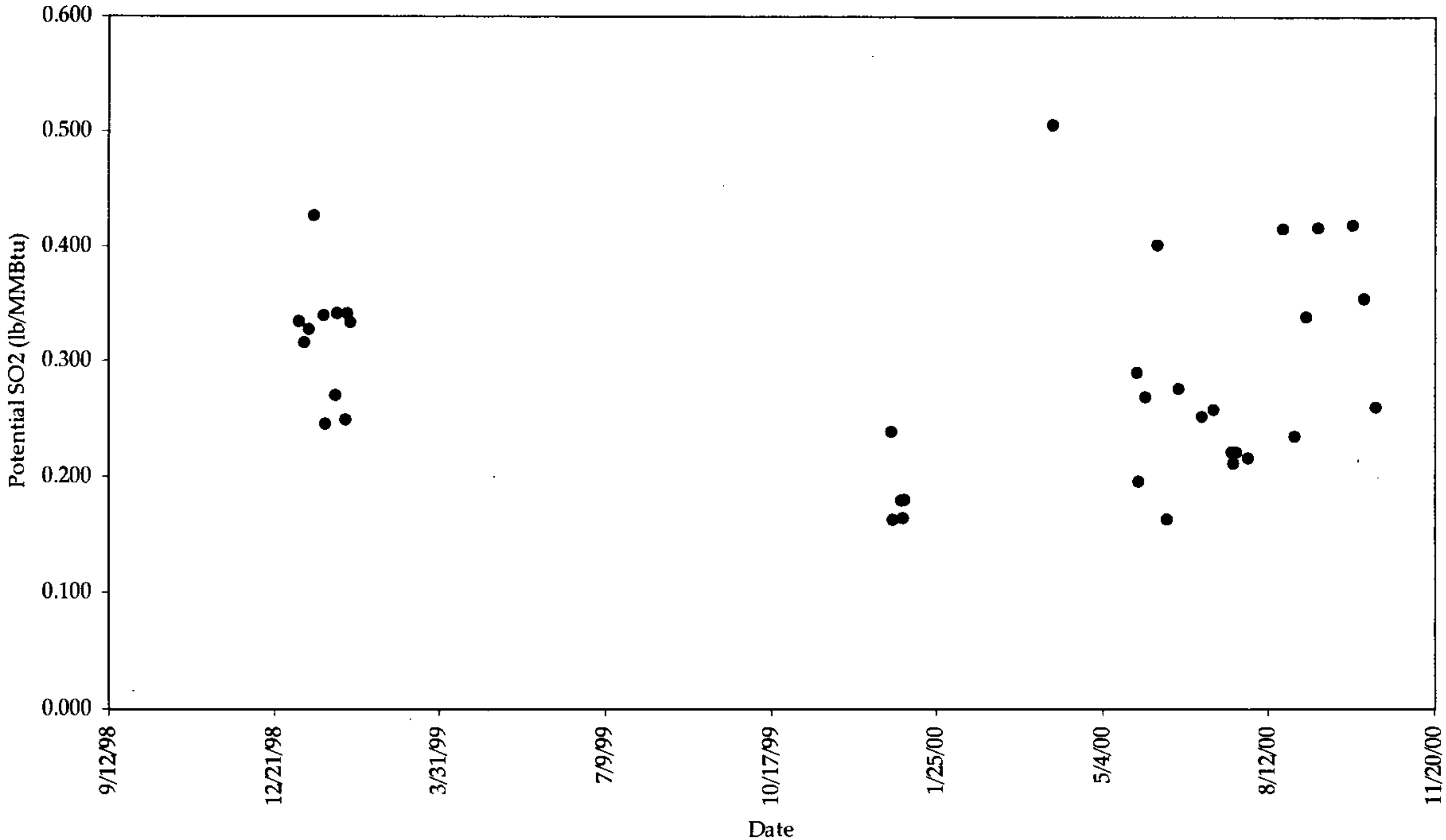


Figure 2-9. OkPLP Boiler A Inherent SO_2 Removal Efficiency

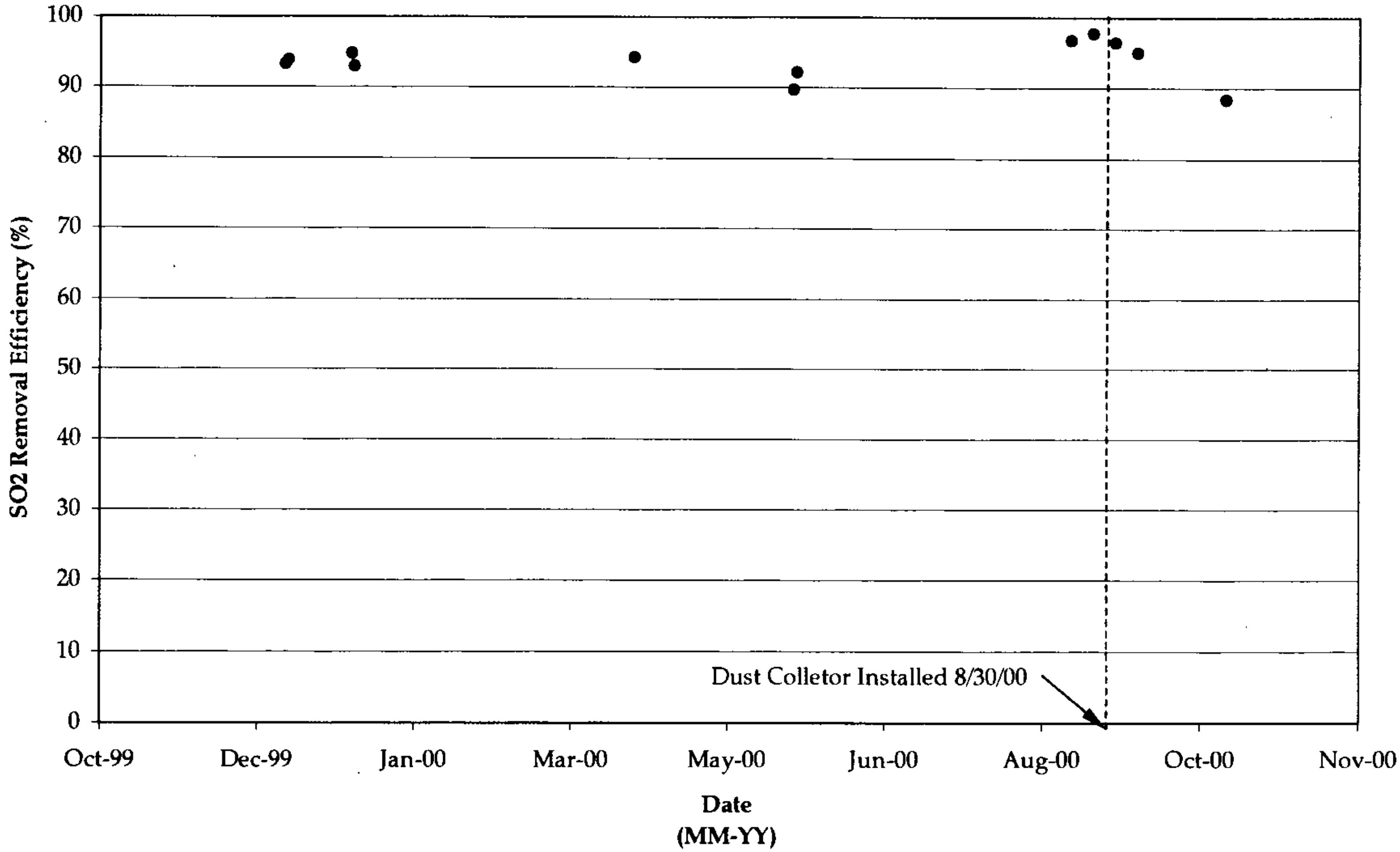


Figure 2-10. OkPLP Boiler B Inherent SO_2 Removal Efficiency

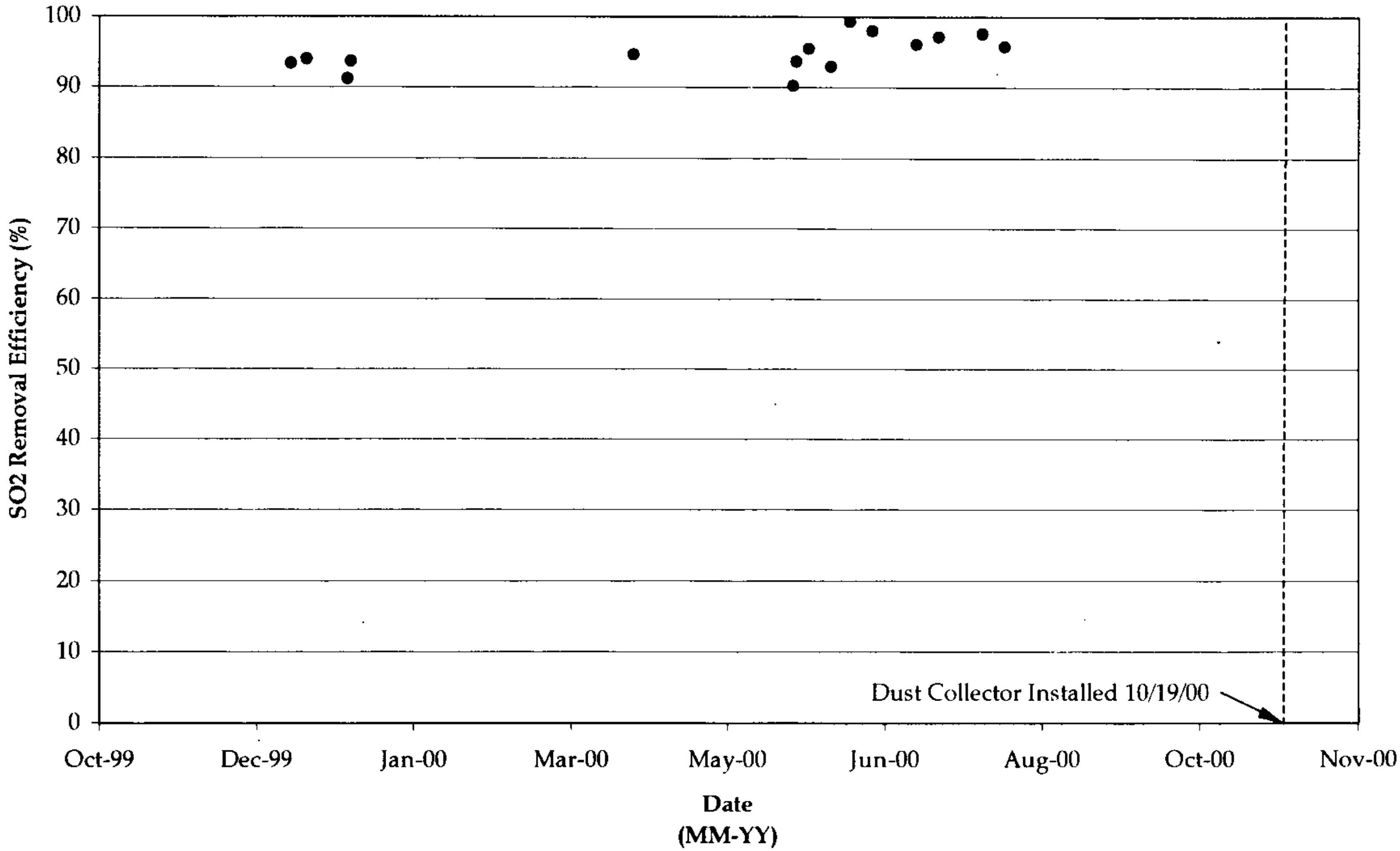
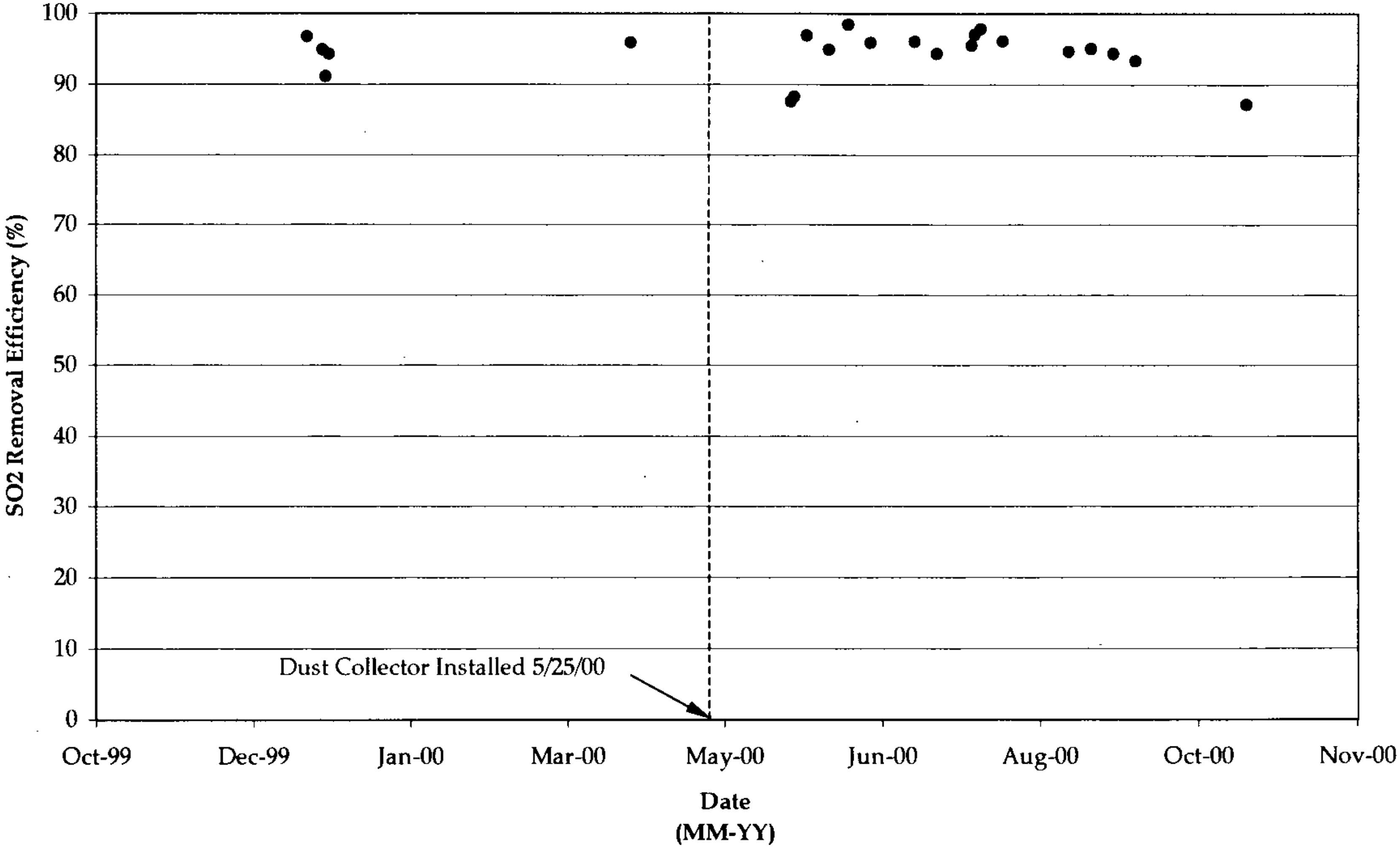


Figure 2-11. OkPLP Boiler C Inherent SO_2 Removal Efficiency



APPENDIX

Table A. Summary of Wood Fuel Analyses, Okeelanta Power L.P.

Sample ID	Test Date (MM/DD/YY)	As Received Analysis			Potential SO_2 Emission Rate (lb/MMBtu)	Daily Average SO_2 (lb/MMBtu)
		Moisture (%)	Sulfur (%)	Heating Value (Btu/lb)		
B-1030	1/5/99	37.11	0.09	4,972	0.36	
B-1220	1/5/99	39.99	0.08	4,769	0.34	
B-1510	1/5/99	38.86	0.07	4,583	0.31	0.334
C-0915	1/8/99	33.40	0.07	5,359	0.26	
C-1405	1/8/99	35.74	0.10	4,804	0.42	
C-1545	1/8/99	33.80	0.07	5,172	0.27	0.316
C-1115	1/11/99	30.44	0.05	5,429	0.18	
C-1400	1/11/99	41.71	0.09	4,019	0.45	
C-1615	1/11/99	34.33	0.07	3,997	0.35	0.327
C-1305	1/14/99	35.95	0.10	5,172	0.39	
C-1530	1/14/99	33.57	0.11	5,255	0.42	
C-1650	1/14/99	34.39	0.11	4,634	0.47	0.427
B-1125	1/20/99	36.60	0.10	4,907	0.41	
B-1400A	1/20/99	31.89	0.08	5,260	0.30	
B-1455	1/20/99	34.03	0.08	5,220	0.31	0.339
B-0950	1/21/99	35.68	0.07	5,229	0.27	
B-1400B	1/21/99	33.90	0.07	5,298	0.26	
B-1530	1/21/99	35.32	0.05	4,894	0.20	0.245
A-1300	1/27/99	27.77	0.08	5,920	0.27	0.270
A-1125	1/28/99	38.85	0.06	3,516	0.34	0.341
A-0950	2/2/99	38.52	0.06	4,394	0.27	
A-1115	2/2/99	34.04	0.06	5,197	0.23	
A-1315	2/2/99	35.45	0.06	4,927	0.24	0.249
A-1705	2/3/99	34.26	0.08	4,686	0.34	0.341
A-1030	2/5/99	33.76	0.07	4,509	0.31	
A-1325	2/5/99	33.94	0.08	4,582	0.35	0.334
B-C20	12/29/99	41.35	0.05	4,850	0.21	
B-C21	12/29/99	40.01	0.04	4,949	0.16	0.239
B-C22	12/30/99	41.10	0.04	5,073	0.16	
B-C23	12/30/99	43.08	0.04	4,759	0.17	0.162
B-B24	1/4/00	42.53	0.04	4,845	0.17	
B-B25	1/4/00	42.65	0.05	4,835	0.21	
B-B26	1/4/00	40.91	0.04	4,833	0.17	0.179
B-A28	1/5/00	40.40	0.04	5,030	0.16	
B-B27	1/5/00	41.20	0.04	4,739	0.17	0.164
B-A29	1/6/00	40.86	0.05	5,031	0.20	
B-A30	1/6/00	39.74	0.04	4,919	0.16	
B-A31	1/6/00	39.54	0.04	5,029	0.16	
B-A32	1/6/00	39.67	0.05	5,029	0.20	0.180
169	4/4/00	23.82	0.03	4,417	0.14	
268	4/4/00	35.51	0.16	5,298	0.60	
1200	4/4/00	31.21	0.04	4,235	0.19	

Table A. Summary of Wood Fuel Analyses, Okeelanta Power L.P.

Sample ID	Test Date (MM/DD/YY)	As Received Analysis Moisture (%)	Sulfur (%)	Heating Value (Btu/lb)	Potential SO_2 Emission Rate (lb/MMBtu)	Daily Average SO_2 (lb/MMBtu)
1202	4/4/00	30.38	0.14	5,866	0.48	
1204	4/4/00	30.29	0.04	4,606	0.17	
1612	4/4/00	26.04	0.22	5,216	0.84	
7063	4/4/00	23.94	0.07	4,190	0.33	
7159	4/4/00	31.36	0.15	5,744	0.52	
1611A	4/4/00	33.25	0.27	4,571	1.18	
1611B	4/4/00	30.83	0.23	4,835	0.95	
734A	4/4/00	34.84	0.15	5,182	0.58	
734B	4/4/00	31.75	0.02	4,929	0.08	0.506
BF-170	5/25/00	31.52	0.08	5,508	0.29	0.290
BF2-171	5/26/00	49.95	0.04	4,089	0.20	0.196
BF-172A	5/30/00	40.65	0.08	4,346	0.37	
BF2-173	5/30/00	41.72	0.04	4,707	0.17	0.269
#1 Reclaim	6/6/00	32.72	0.05	4,831	0.21	
#2 Reclaim	6/6/00	30.08	0.15	5,024	0.60	0.402
BF-172B	6/12/00	36.85	0.04	4,882	0.16	
BF2-173A	6/12/00	51.74	0.03	3,869	0.16	
BF2-173B	6/12/00	41.72	0.04	4,707	0.17	0.163
BF-174	6/19/00	33.98	0.09	5,091	0.35	
BF2-175	6/19/00	50.40	0.04	4,000	0.20	0.277
BF-178	7/3/00	36.97	0.08	4,638	0.34	
BF2-179	7/3/00	52.74	0.03	3,755	0.16	0.252
BA-7/10	7/10/00	50.75	0.05	4,060	0.25	
BF-180	7/10/00	39.62	0.07	4,900	0.29	
BF2-181	7/10/00	55.75	0.04	3,592	0.22	
HOX-1 7/11	7/10/00	29.65	0.09	5,511	0.33	
HOX-2 7/11	7/10/00	31.07	0.06	5,720	0.21	0.258
BF-184	7/21/00	34.42	0.05	4,899	0.20	
BF2-185	7/21/00	51.92	0.03	4,024	0.15	
C-Boiler	7/21/00	34.91	0.05	4,810	0.21	
C-Test-1	7/21/00	35.52	0.08	4,911	0.33	
C-Test-2	7/21/00	34.02	0.06	5,447	0.22	0.221
C-BLR 0900	7/22/00	35.80	0.05	4,497	0.22	
C-BLR 1100	7/22/00	37.90	0.04	5,008	0.16	
C-Test-3	7/22/00	39.46	0.06	5,002	0.24	
C-Test-4	7/22/00	36.54	0.06	5,364	0.22	0.211
BF-NS	7/24/00	39.46	0.04	4,585	0.17	
BF-182A	7/24/00	42.88	0.04	4,426	0.18	
BF2-183A	7/24/00	58.72	0.03	3,366	0.18	
BF-182B	7/24/00	38.69	0.09	4,320	0.42	
BF-186	7/24/00	36.32	0.07	4,841	0.29	
BF2-183B	7/24/00	56.33	0.03	3,455	0.17	

Table A. Summary of Wood Fuel Analyses, Okeelanta Power L.P.

Sample ID	Test Date (MM/DD/YY)	As Received Analysis Moisture (%)	Sulfur (%)	Heating Value (Btu/lb)	Potential SO_2 Emission Rate (lb/MMBtu)	Daily Average SO_2 (lb/MMBtu)
BF2-187	7/24/00	63.70	0.02	2,917	0.14	0.221
BF-188	7/31/00	36.66	0.07	4,717	0.30	
BF2-189	7/31/00	63.35	0.02	2,957	0.14	0.216
BF-194	8/21/00	32.67	0.14	5,135	0.55	
BF2-195	8/21/00	49.11	0.06	4,177	0.29	0.416
BF-196	8/28/00	40.10	0.07	4,796	0.29	
BF2-197	8/28/00	58.58	0.03	3,370	0.18	0.235
BF-198	9/4/00	39.44	0.12	4,371	0.55	
BF2-199	9/4/00	61.84	0.02	3,094	0.13	0.339
BF-200	9/11/00	43.35	0.13	4,027	0.65	
BF2-201	9/11/00	60.88	0.03	3,183	0.19	0.417
BF-202	10/2/00	34.71	0.07	5,583	0.25	
BF2-203	10/2/00	49.72	0.12	4,081	0.59	0.419
BF-204	10/9/00	39.78	0.08	4,657	0.34	
BF2-205	10/9/00	59.94	0.06	3,279	0.37	0.355
BF-206	10/16/00	38.15	0.09	4,854	0.37	
BF2-207	10/16/00	50.16	0.03	3,991	0.15	0.261
Average		39.43	0.07	4,664		

Table B. Summary of Bagasse Fuel Analyses, Okeelanta Power L.P.

Sample ID	Test Date (MM/DD/YY)	As Received Analysis Moisture (%)	Sulfur (%)	Heating Value (Btu/lb)	Potential SO_2 Emission Rate (lb/MMBtu)	Daily Average SO_2 (lb/MMBtu)
C-1130	12/29/98	55.08	0.03	3,714	0.16	
C-1630	12/29/98	54.88	0.03	3,715	0.16	0.162
C-0837	12/30/98	54.26	0.03	3,780	0.16	0.159
B-1240	1/4/99	56.30	0.03	3,607	0.17	
B-1515	1/4/99	55.20	0.03	3,619	0.17	
B-1700	1/4/99	57.57	0.03	3,441	0.17	0.169
C-1250	1/6/99	54.71	0.03	3,741	0.16	
C-1402	1/6/99	54.95	0.03	3,716	0.16	
C-1714	1/6/99	54.21	0.03	3,790	0.16	0.160
C-0950	1/15/99	54.53	0.04	3,737	0.21	0.189
C-1425	1/15/99	54.98	0.03	3,680	0.16	
B-1630	1/18/99	54.17	0.03	3,779	0.16	
B-1400	1/18/99	55.88	0.03	3,621	0.17	
B-1630	1/18/99	54.96	0.03	3,725	0.16	0.162
B-1200	1/19/99	55.40	0.03	3,682	0.16	
B-1400	1/19/99	55.31	0.03	3,677	0.16	0.163
B-0900	1/20/99	54.57	0.03	3,762	0.16	0.159
C-1140	1/22/99	54.67	0.03	3,734	0.16	0.161
A-0904	1/22/99	54.15	0.02	3,712	0.11	
A-1154	1/22/99	54.16	0.02	3,769	0.11	0.107
A-1120	1/26/99	63.47	0.02	2,953	0.14	
A-1330	1/26/99	53.69	0.03	3,740	0.16	
A-1555	1/26/99	55.13	0.03	3,656	0.16	0.153
A-0930	1/27/99	54.43	0.03	3,689	0.16	0.163
A-1455	2/2/99	53.39	0.03	3,790	0.16	0.158
A-0930	2/3/99	55.96	0.03	3,605	0.17	0.166
B-A1	12/15/99	57.03	0.03	3,542	0.17	
B-A2	12/15/99	60.41	0.02	3,234	0.12	
B-A3	12/15/99	54.82	0.02	3,704	0.11	0.134
B-A4	12/16/99	58.01	0.03	3,451	0.17	
B-A5	12/16/99	57.57	0.03	3,490	0.17	
B-A6	12/16/99	56.01	0.02	3,634	0.11	
B-A7	12/16/99	60.56	0.02	3,254	0.12	0.145
B-B8	12/17/99	59.58	0.03	3,298	0.18	
B-B9	12/17/99	56.54	0.03	3,579	0.17	
B-B10	12/17/99	58.46	0.02	3,401	0.12	0.156
B-B11	12/22/99	57.03	0.02	3,495	0.11	
B-B12	12/22/99	54.93	0.03	3,889	0.15	
B-B13	12/22/99	47.23	0.02	4,229	0.09	0.121
B-C14	12/23/99	53.92	0.02	3,772	0.11	
B-C15	12/23/99	52.42	0.02	3,892	0.10	
B-C16	12/23/99	58.76	0.03	3,359	0.18	0.129
B-C17	12/28/99	55.71	0.03	3,626	0.17	
B-C18	12/28/99	55.28	0.03	3,594	0.17	
B-C19	12/28/99	53.79	0.02	3,731	0.11	0.147
Average		55.65	0.03	3,636	0.15	0.153

Table C. Estimated Inherent SO_2 Removal Efficiency for Boilers A, B and C

Date (MM/DD/YY)	Boiler	Fuel	Fuel Analysis Potential SO_2 Emissions (lb/MMBtu)	CEM Data Actual 24-Hour Average SO_2 (lb/MMBtu)	Removal Efficiency (%)	
12/15/99	A	Bagasse	0.134	0.017	93.1	
12/16/99	A	Bagasse	0.145	0.020	93.8	
01/05/00	A	Wood	0.164	0.026	94.7	
01/06/00	A	Wood	0.180	0.022	92.8	
04/04/00	A	Bagasse/Wood	0.296	0.043	94.1	
05/25/00	A	Bagasse/Wood	0.228	0.020	89.6	
05/26/00	A	Bagasse/Wood	0.179	0.020	92.1	
08/21/00	A	Bagasse/Wood	0.334	0.077	96.7	Unit A dust collector- 8/30/00
08/28/00	A	Bagasse/Wood	0.210	0.064	97.7	
09/04/00	A	Bagasse/Wood	0.267	0.058	96.4	
09/11/00	A	Bagasse/Wood	0.345	0.057	94.9	
10/09/00	A	Bagasse/Wood	0.318	0.025	88.3	
12/17/99	B	Bagasse	0.156	0.020	93.2	
12/22/99	B	Bagasse	0.121	0.017	93.9	
01/04/00	B	Wood	0.179	0.018	91.1	
01/05/00	B	Wood	0.164	0.022	93.5	
04/04/00	B	Bagasse/Wood	0.296	0.046	94.6	
05/25/00	B	Bagasse/Wood	0.228	0.021	90.1	
05/26/00	B	Bagasse/Wood	0.179	0.024	93.6	
05/30/00	B	Bagasse/Wood	0.237	0.042	95.4	
06/06/00	B	Bagasse/Wood	0.374	0.046	92.9	
06/12/00	B	Wood	0.163	0.091	99.2	
06/19/00	B	Bagasse/Wood	0.248	0.080	97.9	
07/03/00	B	Bagasse/Wood	0.224	0.045	96.0	
07/10/00	B	Bagasse/Wood	0.235	0.060	97.1	
07/24/00	B	Bagasse/Wood	0.195	0.057	97.6	
07/31/00	B	Bagasse/Wood	0.197	0.037	95.7	Unit B dust collector- 10/19/00
12/23/99	C	Bagasse	0.129	0.030	96.7	
12/28/99	C	Bagasse	0.147	0.024	94.9	
12/29/99	C	Wood	0.239	0.024	91.0	
12/30/99	C	Wood	0.162	0.024	94.3	
04/04/00	C	Bagasse/Wood	0.296	0.057	95.8	
05/25/00	C	Bagasse/Wood	0.228	0.017	87.6	Unit C dust collector- 5/25/00
05/26/00	C	Bagasse/Wood	0.179	0.014	88.2	
05/30/00	C	Bagasse/Wood	0.237	0.057	96.8	
06/06/00	C	Bagasse/Wood	0.374	0.061	94.9	
06/12/00	C	Wood	0.163	0.062	98.4	
06/19/00	C	Bagasse/Wood	0.248	0.048	95.8	
07/03/00	C	Bagasse/Wood	0.224	0.045	96.0	
07/10/00	C	Bagasse/Wood	0.235	0.035	94.3	
07/21/00	C	Wood	0.221	0.040	95.5	
07/22/00	C	Wood	0.211	0.053	97.0	
07/24/00	C	Bagasse/Wood	0.195	0.060	97.7	
07/31/00	C	Bagasse/Wood	0.197	0.040	96.1	
08/21/00	C	Bagasse/Wood	0.334	0.052	94.6	
08/28/00	C	Bagasse/Wood	0.210	0.035	95.0	
09/04/00	C	Bagasse/Wood	0.267	0.040	94.3	
09/11/00	C	Bagasse/Wood	0.345	0.045	93.3	
10/16/00	C	Bagasse/Wood	0.222	0.016	87.1	

FLORIDA CRYSTALS

OKEELANTA CO-GENERATION FACILITY

RECEIVED

JAN 02 2001

BUREAU OF AIR REGULATION

December 27, 2000

Florida Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Attn: C.H. Fancy, P.E., Chief
Bureau of Air Regulation

Re: Okeelanta Power L.P.
DEP File No. 0990332-013-AC; PSD-FL-196L
Application to Modify CO/SO2 Emission Limits

Dear Mr. Fancy:

Please find enclosed six (6) copies of the Application to Modify CO/SO2 Emission Limits for the Okeelanta Power L.P. Also attached is check # 28929 in the amount of $7,500 to pay the application processing fee. If you have any questions please contact me at (561) 993-1003 or David Buff at (352) 336-5600.

Sincerely,

J. M. Meriwether

James M. Meriwether
Environmental and Safety Manager

cc: (w attachment)
Sherrill Culliver – FDEP/Ft. Myers
Ajaya K. Satyal – PBCHD
(w/o attachment)
Rodney Williams
David Buff
David Dee

Florida Crystals Corporation
P.O. Box 9 • South Bay, Florida 33493 • Phone (561) 993-1010 • Fax (561) 992-7744